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REGION I

Report Nos. 50-334/91-80
50-412/91-80

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50-412

License Nos. DPR-66
NPF-73

Licensee: Duquesne Light Company
Post Office Box 4
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Facility Name: Beaver Valley Power Station, Units 1 & 2

Inspection Conducted: November 6 through December 6, 1991

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Inspection Summary

Areas Inspected: Announced team inspection by regional and contract personnel to review the functionality of the electrical distribution system.

Results: Refer to the Executive Summary.

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EXECUTIVE SUMMARY

During the period between November 6 and December 6, 1991, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at the Beaver Valley Power Station, Units 1 and 2 (BV1 and BV2) to determine if the electrical distribution system (EDS) was capable of performing its intended safety functions, as designed, installed and configured. A second objective of the inspection was the assessment of the licensee's engineering and technical support for EDS activities.

To address the first objective, the team performed plant walkdowns and technical reviews of studies, calculations, and design drawings pertaining to the EDS of both units, paying particular attention, to Unit 1, the older of the two plants. To address the second objective, the inspectors evaluated the technical adequacy of: calculations and studies; plant modifications; and corrective actions for previously identified deficiencies. In addition, they conducted interviews of management, engineering, and plant personnel.

Based upon the sample of design drawings, studies and calculations reviewed and equipment inspected, the team's conclusions were that the electrical distribution systems at BV1 and BV2 are capable of performing their intended functions. In addition, the team concluded that the engineering and technical support staff is adequate to support operation of the plant. The inspection also identified a number of strengths and weaknesses as discussed in the paragraphs below.

The most notable strength identified by the inspectors was the quality of the technical staff provided for the support of the operation organizations. Engineering personnel were found to be generally knowledgeable in their areas of expertise, particularly the Materials Section. Also, the drafting organization and the computerized performance evaluations were good. The modification process was found to be effective, as were the various licensee initiatives. Two areas of concern were the small amount of supervisors allowed for the large I&C and electrical staff, and the limited system knowledge displayed by the engineering personnel. The licensee is addressing these issues. Plant and equipment conditions were found to be generally good with major components clearly labeled.

Although the team did not identify any operability issues, they did observe weaknesses affecting both units. Two of these, pertaining to the resolution of identified deficiencies, resulted in violations. One other issue, related to the operation of the river water valves in a potentially flooded area, was considered to be a deviation from the FSAR commitment.

Other areas of concern were: (1) the capability of the BV1 auxiliary feed pumps to operate at runout conditions; (2) the dynamic loading of the BV1 and BV2 emergency diesel generators; (3) sizing of the Unit 2 cables in 4 kV applications; and (4) the availability of design documents for the Unit 1 plant. Areas of concern affecting both plants include: (1) setting of degraded grid relays; (2) seismic qualification of 480 V switchgear and breakers; and (3) short circuit calculations for the 125 Vdc buses. The lack of Unit 1 documentation resulted in various unresolved items which need further attention. Some of these include: interrupting rating of the 4 kV breakers, penetration heat loads; and short circuit calculations.

A summary of the team's findings is contained in the attached table. The table also identifies the applicability of the issue to each unit and the sections of the report which discuss the specific issues.

SUMMARY OF INSPECTION FINDINGS

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1.0 INTRODUCTION

During recent inspections, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants, the functionality of safety related systems had been compromised by design modifications affecting the electrical distribution system (EDS). The observed design deficiencies were attributed, in part, to improper engineering and technical support. Examples of these deficiencies included: unmonitored and uncontrolled load growth on safety related buses; inadequate review of design modifications; inadequate design calculations; improper testing of electrical equipment; and use of unqualified commercial grade equipment in safety related applications.

In view of the above, the NRC initiated electrical distribution system functional inspections (EDSFI). The objectives of these inspections were to assess: (1) the capability of the electrical distribution system's power sources and equipment to adequately support the operation of safety related components and (2) the adequacy of the engineering and technical support in this area.

To achieve the first objective, the team reviewed calculations, design documents and test data, paying particular attention to those attributes which ensure that quality power is delivered to those systems and components that are relied upon during and following a design basis event. The revi. v covered portions of onsite and offsite power sources and included the 345 kV and 138 kV offsite power grids, main transformers, unit station and system station service transformers, 4.16 kV normal and emergency buses, emergency diesel generators, 480 V safety related unit substations and motor control centers, station batteries, battery chargers, inverters, 125 Vdc safety related buses, and the 120 Vac vital distribution system.

The team verified the adequacy of the emergency onsite and offsite power sources for the EDS equipment by reviewing regulation of power to essential loads, protection for calculated fault currents, circuit independence, and coordination of protective devices. The team also assessed the adequacy of those mechanical systems which interface with and support the EDS. These included the air start, lube oil, and the cooling and heating systems for the emergency diesel generators and for the electrical distribution equipment.

A physical examination of selected EDS equipment verified the equipment configuration and rating. In addition, the team reviewed maintenance, calibration and surveillance activities for selected EDS components.

The capabilities and performance of the engineering and technical support organizations for the electrical distribution system area were also evaluated. Particular attention was given to their resolution of identified non-conformances and their involvement in the design and operations issues.

The inspection considered conformance to General Design Criteria and other regulatory requirements as well as the licensee's commitments contained in applicable portions of the plant's Technical Specifications, the Final Safety Analysis Report and appropriate safety evaluation reports.

Section 2 of this report provides a general description of the BV1 and BV2's electrical systems. The details of the specific areas reviewed, the team's findings and the applicable conclusions are described in Sections 3 through 6.

2.0 ELECTRICAL SYSTEMS

Beaver Valley Power Station, Units 1 (BV1) and 2 (BV2), generate 1,026 MVA of power each at 22 kV. This power is transmitted from the generator to the main transformer and two unit station service transformers through isolated-phase bus duct. The main transformer steps up the voltage from 22 kV to 345 kV and transmits it to two separate 345 kV switchyard buses. The 345 kV buses are connected through autotransformers to associated 138 kV buses in the switchyard. The 138 kV and 345 kV switchyards, combined, constitute the Beaver Valley transmission and switching system. This includes six transmission lines connected to the 345 kV buses and seven lines connected to the 138 kV buses. A simplified single line diagram of the BV1 and BV2 electrical systems is provided as Attachment 2.

The unit station service transformers step the voltage down from 22 kV and feed four 4160 V buses A, B, C, and D. An alternate source of station service power is provided by the system station service transformers. These transformers receive their power from two separate 138 kV buses, in the switchyard, and feed the same buses after stepping the voltage down to 4160 V. During normal plant operations, the station service power can be derived either from the two unit station service transformers or from the two system station service transformers. In addition, power can be supplied from a combination of a unit and a system station service transformers. In the event of a loss of the selected power source, an automatic fast bus transfer to the remaining source occurs. During plant start-up, hot standby, and shutdown, the 4160 V buses receive power from the two system station transformers.

Medium voltage distribution at the plant is accomplished at 4160 V using the four normal buses, A, B, C, and D. These four buses provide power to all station auxiliary loads. Two of the normal buses, A and D, supply preferred power to the 4160 V emergency buses AE and DF, respectively. In the event that normal power is lost, power to buses AE and DF is supplied from the emergency diesel generators (EDG) which are automatically initiated and loaded. Buses AE and DF provide power to all safety related 4160 V and 480 V loads.

The 480 V normal distribution system includes eight buses arranged into four double ended unit substations, each substation being supplied by one of the four 4160 V normal buses. The emergency 480 V unit substation buses N and P are supplied by buses AE and DF, respectively. In turn, they supply all the 480 V safety related loads and motor control centers.

The station's safety related dc system consists of four separate 125 Vdc batteries, each with an associated battery charger. The four buses provide dc power for circuit breaker and motor control, instrumentation, emergency lighting, and for the vital 120 Vac inverters. The four safety related batteries, without associated chargers, are capable of supplying the power requirements for two hours to their respective emergency loads. In addition to the safety related dc buses, Unit 1 has one and Unit 2 has two non-safety related 125 Vdc batteries and associated battery chargers which provide power to the main turbine generator auxiliaries, emergency lighting, and other miscellaneous non-safety related loads.

The station's vital 120 Vac system consists of four buses, each including an inverter and a static transfer switch. This system provides vital 120 Vac power to all safety related instrumentation and safety related loads. The buses normally derive their power from the associated inverters. However, in the event of an inverter failure, the static transfer switch automatically transfers the affected bus to an associated alternate source. These alternate sources of 120 Vac power are supplied from the 480 V emergency buses through voltage regulators.

3.0 ELECTRICAL DESIGN

To assess the adequacy of BV1 and BV2's electrical design, the team reviewed the features and components of the electrical distribution system (EDS) included within the scope of the inspection. The design was evaluated for compliance with specifications, industry standards, and regulatory requirements and commitments. The documents were reviewed for accuracy and conformance with accepted engineering practices.

The scope of the review included drawings, design calculations, and studies associated with:

1. The ac and dc systems loading, including steady-state and transient load profiles of diesel generators and batteries, under normal and abnormal operating conditions;

2. Voltage regulation during normal and degraded grid conditions;

3. Voltage regulation during sequencing of engineered safeguards equipment onto the preferred power supply and onto the emergency diesel generators;

4. Short circuit and ground fault detection and protection, including selection and coordination of overload protective devices for ac and dc electrical equipment;

5. Ratings of EDS equipment, such as switchgear and transformers, batteries and battery chargers, and emergency diesel generators;

6. Sizing of cables for fault withstand capability, and voltage drop during steady-state and transient conditions;

7. Protection of electrical containment penetrations,

The team also reviewed procedures and guidelines governing the EDS design calculations, design control, and plant modifications.

The team's findings are described in the paragraphs below.

3.1 Load Flow, Voltage Regulation, and System Capacity

To ensure that quality power is available to the load when the system is fed from the preferred sources, the team reviewed two calculations titled "Station Service Voltage and Load Analysis." For Unit 1, the applicable calculation is 8700-E-68, Revision 1, dated February 15, 1991. For Unit 2 the applicable calculation is E-68, Revision 2, dated December 12, 1986, supplemented by calculation E-141, Revision 1, dated April 1, 1987, "Adjustment of Calculation E-68." The analyses provide an evaluation of the voltage profile from the 138 kV and 345 kV switchyard transformers down to the Unit's 480 V motor control center level.

For each analysis, the team reviewed steady state maximum allowable and minimum required bus voltages; maximum and minimum voltages and maximum connected loads for all load flow scenarios; and margin for voltages and loads when compared to allowable voltages and transformers capacities. The team observed worst case scenarios for both units. The acceptance criteria for the minimum allowed motor voltage, under running, transient, and starting conditions, were 90%, 75%, and 80% of motor nameplate, respectively.

While reviewing the Unit 1 calculation, the team observed that, in one case when the switchyard voltage was at the minimum level of 135.7 kV, during the starting of pumps RS-P1A and RS-P1B, the terminal voltage fell to 74%. The team was concerned that the lower starting voltage would cause the current and starting time to sufficiently increase to cause a tripping of the supply breaker. The licensee was able to show that acceleration of the motor plus load inertia resulted in starting currents below the tripping curve of the associated circuit breaker by a satisfactory margin. Additionally, the motor voltage at the running condition was found to be above the 90% required. The team concluded that the ac system could supply satisfactory voltages for all loads analyzed.

The team made a summary review of Unit 2 Calculation E-140, Revision 1, dated April 4, 1987, "Verification Test of NUREG-0800, Branch Technical Position PSB-1." The purpose of this calculation was to verify the accuracy of the analytical techniques and assumptions used to determine maximum and minimum voltage levels in Auxiliary Station Electrical systems, as shown in Unit 2 Calculation E-68. Verification was done per NUREG-800, Appendix B, PSB-1, position 4, by demonstrating that the measured voltage levels were not more than 3% lower than the calculated ones, and that their difference, when subtracted from the calculated voltage, was not less than the equipment's rated voltage. The team also reviewed an architect engineer letter, dated February 17, 1987 which summarized the analysis and concluded that the measurements taken correlated with the calculation model. No analysis had been performed for Unit 1.

Based upon the review performed, the team concluded that the distribution equipment was adequately sized to carry the required loads when the system is fed from the preferred sources. The team further concluded that, under normal grid conditions, the voltage levels at the evaluated buses were adequate to provide quality power to the respective loads.

3.2 Load Growth Monitoring

The team reviewed BV1 and BV2 Section Instruction No. NED-SI-E003, "Management of ac and dc Loads and Calculations", Revision 1, dated May 31, 1990. This document establishes the guidelines and procedures to be followed for selecting ac and dc power sources and for the maintenance of electrical calculations associated with load additions, changes, and deletions.

The team found the administrative controls in this area to be adequate.

3.3 Transmission Grid

3.3.1 Stability

The team reviewed the grid transient stability study performed by the licensee to support the BV1 and BV2 FSAR statements in this area. The stability studies of 1988 Summer Conditions, performed to demonstrate BV2's compliance with General Design Criterion (GDC) 17, considered lines on a common tower as one line, thus evaluating double circuit faults. This study concluded that a full load trip of both units, or a tripping of one unit with the other unit either online or offline, or the tripping of a transmission line, or three-phase faults on the 345 kV and 138 kV systems, would not impair the Unit 1 and 2 preferred power sources.

The team found the study's methodology and results acceptable.

Discussions with the licensee's System Planning Group indicated that new stability studies are undertaken whenever modifications to the transmission and distribution systems are performed. Presently they are commencing a new study to analyze some changes.

3.3.2 Frequency Regulation

The team reviewed the controls that are in place to ensure adequate frequency regulation of the transmission grid.

The BV electrical transmission system operates in parallel with other North American Electrical Utilities, in accordance with the North American Reliability Council Operating Guides 1A and 1C. The grid system's frequency is scheduled to be 60 Hz ± .02 Hz. To bring the frequency to the required schedule, the Beaver Valley Station uses the Automatic Generation Control (EMPLOYS) system after the speed of the turbine generators has been stabilized by the speed governors.

3.3.3 Capacity and Reliability

The team reviewed the historical voltage level of the 138 kV system. For 1990 (no data were compiled for 1989 and 1991), the minimum voltage registered was 139.08 kV (Spring and Summer) and the maximum voltage was 144.00 kV (Winter), representing a + 0.7% to a + 4.0% variance from the nominal voltage. In an agreement with the Transmission and Distribution Systems Operation Group, the transmission bus voltages are required to be maintained at ± 5% nominal, but the actual voltage tolerance is much better. The good regulation and voltage level registered are attributed to the large number of generating stations in the proximity to the Beaver Valley plants. In addition, the station service transformers are equipped with automatic load tap changers which have the capacity to move 16 steps in each direction and compensate for voltage changes within ± 10%.

The team also reviewed a Summary of Forced Outage Rates and Interruption Data for an operating life of over seven years and determined the lines to be very reliable. The licensee indicated that, for abnormal or emergency conditions, the plant operator can send a standby alarm to the system operator, communicate with him over a dedicated telephone, and request available resources to improve grid voltage.

On the basis of the documents reviewed, the team concluded that the capacity and reliability of the grid system were good.

3.4 Voltage for Motor Control Center (MCC) Loads and Circuits

A review was performed of BV2's Calculation 10080-E-82, Revision 3, dated March 6, 1987, "600 V Cable Sizing for Loads from 480 V Motor Control Centers", and Addendum A1, dated October 16, 1990. The purpose of this calculation and its addendum was to verify the adequacy of the cables used with MCC load, by considering allowable voltage drop, cable ampacity, and short circuit capacity. The team also reviewed BV2's Calculation 10080-E-113-0, Revision 0, dated March 25, 1980, "Maximum Control Circuit Lead Lengths for Class 1E Motor Control Centers", and Addendum A1, dated October 30, 1990. The purpose of this calculation was to ensure that, when the MCC's bus voltage was at its minimum design level, adequate voltage was available at the contactors for their pick up and starting the motors. An evaluation of the results of the above calculations concluded that the calculated voltage levels were adequate for their intended application.

Discussions with the licensee indicated that equivalent calculations applicable to BV1, Nos. E-82 and E-113, had been prepared, but were not available for review. The reason provided was that the calculations had not been approved because the assumptions were too conservative. Therefore, adequacy of the voltage at the BV1 MCC loads and control devices could not be fully evaluated.

3.5 Setting of Degraded Grid Relays

A review was performed of degraded grid relay settings and reset capability, coordination with the EDG start and fast bus transfer schemes, and applicable schematics. This review determined that the degraded grid relays on the 4160 V and 480 V safety related buses were set at 90% $\pm$ 1.6% of their respective nominal bus voltage. Therefore, the minimum theoretical voltages allowed on the switchgear and on the load center buses, before the appropriate automatic action takes place, are 3677 V and 424 V, respectively.

To ensure that the specified settings adequately protect the safety related motors from undervoltage conditions, the continuous ratings of the motors were also surveyed. A sampling of several 4160 V and 480 V motors revealed a continuous rating of 90% of the nominal (nameplate) voltage, i.e., 3744 V and 414 V (460 V x 0.9), respectively. A comparison of the above values shows that, under degraded voltage conditions, the 4160 V motor would be operating at a voltage below their minimum continuous rating and that a 10 V margin exists for the 480 V motors. In addition, when the cable voltage drop from the bus to the motors is taken into consideration, the voltage at the motors' terminals could be considerably less than the motors' continuous rating.

The 90% relay setting was verified through a review of several Relay Setting Sheets and is in accordance with the guidelines contained in BV1 and BV2's "Protective Relaying Philosophy and Practices for 4160 V and 480 V Systems", Engineering Standards No. ES-E-004, Rev. 0, dated September 11, 1989, and No. ES-E-003, Rev. 0, dated February 14, 1989, respectively. The $\pm$ 1.6% tolerance was calculated in a Westinghouse analysis of the relay loop.

The team discussed the concern with the licensee who pointed out that the settings were in agreement with item 6 of Table 3.3-4 of BV1 and BV2's Technical Specification. The licensee also indicated that the transformer tap settings kept the bus voltage near the nominal values. However, they were unable to provide an analysis to show that the motors could be operated below their continuous rating should a degraded voltage condition exist.

The setting of the degraded grid relays and/or the capability of the safety related motors to operate below their continuous setting is unresolved pending appropriate analysis or justification by the licensee (50-334/91-80-04, 50-412/91-80-04).

3.6 Fast Bus Transfer

The Beaver Valley electrical distribution system utilizes a fast bus transfer scheme between the station and offsite sources of power. This transfer is automatically initiated upon loss of bus voltage from the preferred source, provided that the bus is not faulted. Either source may be selected as the preferred source. The scheme uses an early "b" contact from the tripping breaker to initiate closure of the alternate source breaker. It is designed to complete the bus transfer before the residual bus voltage and the alternate source voltage are able to develop substantial out-of-phase conditions.

To ensure that the electrical equipment was adequately protected during the fast bus transfers, the team reviewed applicable calculations and analysis, logic and elementary diagrams, and coordination with degraded grid protection. The purpose of BV2's Dynamic Motor Study, Work Package 166, dated March 25, 1987, and Supplements 1 and 2 was to: 1) determine the maximum bus voltage drops and transformer current increases during the starting of large motors; 2) verify motor stability during automatic and manual bus transfers between the 22 kV and 138 kV sources; 3) determine motor and bus voltage decay and decay times during de-energization; and 4) verify motor starting, starting times and motor recovery after bus transfers. The review determined that the study case modeling the transfer from the 22 kV source to the 138 KV source yielded the greater phase angle difference. However, this phase angle difference was still enveloped by 1.33 Volts/Hertz recommended by ANSI C50.41. Additional cases simulated a transfer of a 6 cycle dead bus with no protective device operating. Actual transfer operation has been accomplished in 4 cycles.

Within the scope of review of the documents the team concluded that the fast transfer scheme used by BV2 was adequate. The licensee is currently evaluating Information Notice 91-57 for impact on existing design philosophies.

The summary of results for the Unit 1 Fast Bus Transfer study were lost and only a printout of the analysis data was retrievable. The licensee was unable to draw conclusions or develop a new summary from this data during the inspection period.

3.7 Battery and Battery Charger Capacities

To confirm that the safety related batteries are capable of providing adequate voltage to the respective loads for the design period, the team reviewed Unit 2 calculation No. 10080-E-202, Revision 0. The calculation was found to follow the procedure outlined in IEEE 485-1983 and to appropriately account for the bus loads. On the basis of their observation, the team concluded that the sizes of the Unit 2 batteries, as installed, were satisfactory. To address the Unit 1 battery sizes, the team reviewed calculation 8700-E-202, Revision 0, and concluded, as for Unit 2, that the batteries had been adequately sized.

To determine the adequacy of the Unit 2 battery chargers to recharge a depleted battery and at the same time, supply the applied essential loads, the team examined calculation 10080-E-38, Revision 6. The calculation covered all of the battery chargers for Unit 2. The calculation was found to conform to the recommendations of IEEE 946-1985 and the team confirmed that no derating of the chargers was required to address high ambient temperature. However, the team noted that the loads had not been adjusted to take into account the higher charging voltage. This fact had no effect on the final choice of battery charger size, because of the margins applied.

3.8 Dc Voltage Drop Calculations

Voltage drop calculations for the dc system are needed to determine the voltage drop for the most limiting components, and to set the battery discharge limits to ensure that adequate voltage levels exist at the end devices. The voltage at the Unit 2 dc loads was addressed in calculation 10080-E-202, Revision 0. The team reviewed in detail the equations for determining the voltage of battery system 2-2, including the critical voltage at the terminals of inverter UPS*VITBS2-2.

The team found the method of calculation and the voltage levels at specific loads acceptable. The licensee was also requested to repeat the calculation with a battery voltage of 1.84 volts/cell, to correspond with the minimum voltage specified by the FSAR. Even with this conservatism, it was confirmed that the minimum voltage at the battery terminals was two volts higher than the minimum specified voltage of 105 Vdc.

Based upon the above, the team concluded that the voltage profile of the battery 2-2 system was acceptable. Upon reviewing Unit 1 calculation No. 8700-E-202, Revision 0, the team similarly concluded that the voltage profiles for Unit 1 battery systems were equally adequate.

3.9 Short Circuit Analysis

3.9.1 Ac System

The magnitude of fault currents in the ac system and the adequacy of the momentary and interrupting fault current rating of the electrical distribution system equipment were examined. For this purpose, calculation No. 10080-E-074, Revision 2, which calculated the three phase bolted fault on the 138 kV system station service transformers' on the main generator 22 kV bus; on 4160 V buses; and on 480 V buses was reviewed. The calculation considered separately the short circuit current levels when the station load was supplied from the unit station service transformers and from the reserve supply (138 kV sub-systems), and included contributions from the 4160 volt emergency diesel generators operating in parallel with the offsite power sources. The calculation used a computer program based on the techniques of ANSI/IEEE C37.010-1979 and ANSI/IEEE C37.13-1981.

The team reviewed the assumptions used in the generation of short circuit values, and found them to be generally conservative. However, it was noted that for all voltages but one, values of 1.0 per unit had been used. For the 4160 V buses a value of 1.05 per unit had been assumed. When asked about the maximum voltages available on the systems, the licensee advised that they were 1.018, 1.06, 1.07 and 1.04 per unit for the 138 kV, 22 kV, 4160 V, and the 480 V systems, respectively .

The team's review of the calculation results determined that the maximum fault currents available at the various buses were:

a. 42,500 A symmetrical on non-safety bus 2A and 41,900 A symmetrical on safety bus 2AE, at 4370 volts. In comparison, the interrupting capacity of the Gould/Brown-Boveri circuit breakers was 46,200 A symmetrical at the same voltage.

b. 28,800 A symmetrical at 480 V on safety bus 2N. In comparison, the interrupting capacity of the smallest circuit breaker was 30,000 A symmetrical.

c. 21,800 A symmetrical at 480 V on emergency motor control center bus MCC2-E8. In comparison, the interrupting capacity of the smallest circuit breaker was found to be 22,000 A symmetrical, at 480 volts.

On the basis of the above observations, the team concluded that the Unit 2 circuit breakers had been adequately sized. The team noted that higher per unit values of voltages would affect the calculated short circuit currents. However, it concluded that the higher voltage would only slightly reduce the margin of safety.

For Unit 1, an equivalent calculation was not available for review. Therefore, the team was unable to make an assessment of the adequacy of the breakers to interrupt the system fault currents. However, the team determined that the 4 kV breakers had an interrupting capacity of only 30,000 A. When this is compared to the 46,200 A interrupting rating of the Unit 2 circuit breakers and when the small margin of the Unit 2 circuit breakers is considered the adequacy of the Unit 1 circuit breaker is of concern. Therefore, this issue is unresolved pending appropriate calculations by the licensee. (50-344/91-80-05)

The team also examined the magnitude of fault current available at the 120 Vac system. For this purpose, the team reviewed calculation No. 10080-E-120, Revision 2, which evaluated fault currents in the three phase essential bus system, in the single phase vital bus system , and in the single phase emergency panel system.

The assumptions of the calculation were found to be conservative and the methodology appropriate. An evaluation of the fault levels indicated that they were below the rating of the protective devices. Based on the above, the team concluded that the equipment was appropriately protected. A similar Unit 1 calculation was requested, but the licensee advised that it was not available.

3.9.2 125 Vdc System

The team examined BV2 calculation No. 10080-E-62, Revision 4, which analyzed the short circuit currents available in battery systems 2-1 to 2-6. The results of this calculation were then used to assess the interrupting capability of the circuit breakers and the ability of the cables to withstand the maximum, predicted short circuit currents. The team focused on the Class 1E battery system 2-2, but all Class 1E and non Class 1E systems were considered.

Pertaining to the calculation, the team noted that it had not included the contribution from battery chargers and the dc motors. The team considered the 125A contribution from the battery chargers, by itself, to be of minor significance to the results. However, the combined effect of this and the energy feedback from the applied motors, e.g., a 60 hp motor on battery system 2-5, could have a significant impact on the calculation results and should have been considered.

No short circuit calculations were available for the Unit 1 battery systems. Therefore, no conclusions could be reached. For these calculations the licensee indicated that they would be prepared as part of the design basis reconstitution program which is in progress.

Based upon the above, the analysis for available short circuit current in the battery system is unresolved pending the licensee's revision of the Unit 2 calculations and preparation of the Unit 1 calculations (50-334/91-80-06) (50-412/91-80-06).

The team assessed the short circuit ratings of selected cables when carrying fault currents and concluded that the temperature rise would not exceed the 250°C allowed by IPCEA Standards. However, the team expressed concern regarding the handling of parallel cables of disparate lengths in the same circuit. The total circuit resistance for the two parallel cables was found to be correct, but the calculation made no allowance for uneven sharing of the current between the cables.

The team's evaluation of this issue concluded that the current as-built conditions were not a problem, but the calculation should be revised to ensure no unforeseen effects when future loads are added.

A review of the calculation E-62 conclusions determined, and the team concurred, that several safety related circuit breakers, Heinemann Type CD and Airpax Type 209, had a short circuit interrupting capability of only 5000 A whereas the required interrupting capability was 8000 A. Therefore, these breakers were not adequate to interrupt the fault currents calculated at their installed locations. The above breakers were found in all Class 1E and non-Class 1E battery systems.

Discussions with the licensee indicated that the calculation E-62 would be revised to eliminate conservatism. However, there was no indication of the extent to which the revision would affect the results. Also, the team found no evidence that the licensee had taken any corrective actions to address the deficiency identified by their calculation. This represents a violation of 10CFR 50, Appendix B, Criterion XVI, which requires, in part that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformances are promptly identified and corrected." (50-412/91-80-02)

3.10 Dc System Ground Detection

The team reviewed the method used by BV1 and BV2 for detecting grounds on the ungrounded 125 Vdc systems and for signaling such occurrences. The scope of this review covered the five Unit 1 and the six Unit 2 battery systems, both Class 1E and non Class 1E.

In all cases, the ground detection system utilized a voltmeter with center zero scale connected, in a voltage divider arrangement, between the center of two resistors and ground. In this arrangement, a ground on either battery system pole would cause the voltmeter's needle to swing to a position on either side of the center zero. The magnitude of the perturbation would depend on the magnitude of the resistance of the pole to ground. Redundant voltmeters were used, one in the switchgear room and one in the control room.

Because this type of system is essentially inactive (needle at the zero point) until a ground develops, the team requested details on the testing of the units, but determined that apparently the test consisted only of a periodic visual inspection of the voltmeter pointer.

Although the ground detection scheme used by the licensee was considered generally adequate to identify dc system grounds, the lack of or inappropriate surveillance performed on the scheme rendered it ineffective and misleading. The reason for this is that a loose connection anywhere in the detection scheme or the failure of the voltmeter itself would cause the voltmeter to read zero, in the same manner as an ungrounded system.

The team considered the lack of testing of the dc system ground detectors a weakness in the licensee's testing program.

3.11 Electrical Coordination of Protective Devices

The basic function of protective devices such as fuses and breakers is to guard equipment against overload conditions and to isolate faulted circuits without affecting other parts of the power systems. The coordination of protective devices and the protection of Class 1E equipment and systems is essential to shutdown, containment isolation, core cooling, and containment and reactor heat removal. Coordination is particularly important when non-safety related loads are powered by safety related buses.

The team reviewed the coordination of the ac circuit breaker tripping devices, concentrating primarily on the emergency buses for Unit 2. Coordination of Unit 3 emergency buses and breakers was also sampled. In all cases examined, the team concluded that the relay and circuit breaker settings were satisfactory and that coordination of protective devices had been adequately achieved.

The coordination of circuit breakers associated with the Unit 2 dc system were also examined to ensure that proper selectivity existed in clearing system faults. For this purpose, the team reviewed calculation 10080-E-062, Revision 4, and coordination curves 12241-ESK-130 A, B, E and F.

The calculation, in its conclusions, stated that, for the values of fault current available at particular panels, the coordination between several Heinemann CD Type circuit breakers and the upstream ITE K600 type bus supply breakers could not be achieved. The team reviewed the coordination curves and concurred with the licensee's conclusion. For attainable fault currents on the downstream side of the small Heinemann breakers, the ratio of tripping time was approximately 2:1 in favor of the ITE breaker.

This is another example where a finding by the licensee was not dispositioned in timely manner. The licensee's failure to address the calculation finding constitutes a violation of 10CFR 50, Appendix B, Criterion XVI. (50-412/91-80-03)

An equivalent calculation for Unit #1 was not available for review.

3.12 Emergency Diesel Generator

3.12.1 Design Bases

In order to evaluate the emergency diesel generators' design bases, the team requested the documentation relating to the electrical characteristics of the BV1 units, but was informed that the information was not available. This was the case for the generator, the voltage regulator, and other electrical design features, such as the machine's fundamental impedance, provided by the original vendor. The licensee explained tha' were doing design reconstitution and would ask the vendor for that information.

The licensee did provide some documents that were obtained through the architect-engineer, but the information appeared to be generic when compared to actual values pertaining to the BV1 machines. In addition, a review of this documentation indicated that the voltage regulator had a current limiting feature that causes the generator's voltage to be reduced when the current limit point is reached. This feature could render the generator ineffective in supplying the starting current of the emergency loads, if this were to exceed the setpoint of the current limit.

The team also received the vendor's Maintenance Instructions, M.I. 4523. A review of these indicated that the current level should be calculated and set on the bases of the specific unit, but no tolerances or environmental criteria were given for setpoint adjustment. This lack of information made the verification of the maximum current during motor starting conditions and, thus, the validation of a current limit setpoint difficult. This issue is also addressed under Section 3.12.3, below.

3.12.2 Steady State Loading Analysis

Calculation 8700-DEC-E-048, Rev. 0, dated January 13, 1989, using the spread sheet method, evaluated the steady state loads for the BV1 emergency diesel generator (EDG) No. 1. The study identified the loads imposed on the EDG at each step of the automatic sequence and for the period after the automatic loading under three scenarios: Design Basis Accident, Loss of Normal Power, and Safety Injection.

The team's review of this calculation revealed that the acceptance criteria specified that the maximum coincident (short time) load should not exceed 90% (2745 kW) of the 30 minute diesel generator's rating (3,050 kW). Based upon the load summary tables, the maximum coincident load for the worst case scenario (Safety Injection) was 2741.3 kW or slightly below the value stated in the acceptance criteria. In addition, the team determined that the maximum calculated continuous load was 2579.3 kW, also slightly below the continuous rating (2,600 kW) of the EDG.

Although both values were well within the 2000 hour rating of the machine, 2850 kW, the team noted that minimal margin existed between the calculated loads and the imposed limits. However, the licensee responded that, since the maximum coincident and continuous loading occurred after the automatic sequencing, potential overloads could be handled administratively. The licensee also indicated that the calculation was undergoing revisions. In support of this, they provided an internal memorandum, dated February 25, 1991, which identified incorrect entries found during a review of mechanical inputs in EDG Load Study Calculation E-48. The summary sheets of this memorandum were an updated version of Attachment F to Calculation E-048.

The team's review of the revised loads list identified several areas of concern:

1. The worst case loading occurs under the Loss of Normal Power scenario and, for this case, the maximum steady state load is 2754 kW, which slightly exceeds the acceptance criteria of 2745 KW of Calculation E-048. The licensee reiterated that the loads are limited by administrative controls and provided operating procedures to show how certain loads are cycled. However, this was not clear from the body of the calculation.

2. For the motor loads on Pages 2A. 3A, and 4A, the memorandum identifies the nominal horsepower, "HP"; the flow curve break horsepower, "Curve BHP"; and a calculated break horsepower, "Calc BHP". Since, in some cases, the EDG loading uses the "Calc BHP" which is less conservative than the "Curve BHP", the team asked the licensee to provide an analysis or calculation identifying the bases for the calculated break horsepower and the criteria for selecting these values instead of the ones derived from the flow curves. The team was unable to determine the availability of such data

3. The motors for Auxiliary Feed Water Pumps FW-P-3A and -3B appear to be underrated for the intended functions. This issue is discussed in details under Section 4.1 of this report.

4. Several discrepancies exist between the loads as identified in the FSAR and in the memorandum. The FSAR did not appear to reflect the changes identified in Attachment F of the calculation, dated January 1989.

In order to verify that the 2745 kW load at the running power factor would be carried by the EDG, the team compared it to the Reactive Capability Curve included in the EDG Data, 8700-1.30-32, Page 15, but determined that this curve was generic. The licensee was not able to supply the documented basis and applicability of this curve for Unit 1 EDGs during the inspection period.

The team observed that calculation E-048 only addressed EDG No. 1. The reason for this was that EDG No. 1 was more heavily loaded. In view of the February 25, 1991 memorandum, the team calculated the EDG No. 2 loads and found them to be less than those on No. 1. The team also observed that swing pump load had not been considered to be carried either by EDG No. 1 or by EDG No. 2.

The above issues were identified and discussed with the licensee who agreed that the revised calculation would include necessary clarifications. In view of the above, the steady state loading of the diesel generator is unresolved pending revision of the calculation by the licensee and review of the results by the NRC. (50-334/91-83-07)

The team also performed a summary review of Unit 2 Calculation E-48, Revision 9, dated November 17, 1987. As for Unit 1, the objective of the calculation was to determine the maximum coincident load for three scenarios, Loss of Normal Power, Safety Injection, and Design Basis Accident. This calculation was performed using a hand calculated tabulation method.

The team determined the worst case condition to be the Design Basis Accident. For this case, the maximum coincident load was 3705 kW. In comparison, the maximum continuous rating of the EDGs was 4238 kW and the 2000-Hour rating was 4535 kW. On the basis of the design margin available, the team concluded that the Unit 2 diesel generators were adequately sized to handle the anticipated steady state loads.

3.12.3 Transient Loading Analysis

An analysis to demonstrate the transient loading capability of the BV1 emergency diesel generators was included in calculation E-48, as discussed in Section 3.12.2, above. The team's review of the applicable portions of this calculation revealed that the analysis was based upon a generic Dead Load Pick up Capability Curve and upon a manufacturer's letter, dated December 4, 1972 to Stone and Webster Engineering Corporation. The Dead Load Curve was used to analyze Step 1 of the EDG's automatic loading, whereas the manufacturer's letter was used to analyze the other steps. This letter included a summary of sample EDG loading cases to which the licensee was to compare the postulated accident loading steps. As long as these were enveloped by a sample loading case, it was concluded that the voltage drop and its recovery time to 90% were acceptable.

The team's evaluation of the analysis indicated that there was no assurance that the curve was applicable to the Unit 1 EDG's and no back up calculations to support the design basis of the sample cases. In addition, no diesel generator test as described in Sections 8.6.2 and 8.6.3 of the FSAR was available for review at the time of the inspection. Unit 2 Calculation E-48, similarly, did not include a transient analysis. Based on the above, the team concluded the transient loading capability of the Unit 1 and Unit 2 emergency diesel generators is unresolved pending the licensee's retrieval of applicable tests or their preparation of an appropriate analysis. This issue is further addressed under Section 5.2 (50-334/91-80-08) (50-412/91-80-08).

The licensee stated that they had recognized the weakness of the transient analysis and that they had initiated a review of the "A-Fault" Computer Software Program with the intent of performing a new Computer Simulated Transient Analysis.

3.12.4 Load Sequencing

To address the sequencing of safety related loads on the emergency diesel generators following a loss of offsite power, the team reviewed Drawing 8700-RE-21 CE-4, Revision 4, dated March 21, 1989, for Unit 1, and Drawing 12241-E-12A, Sheet 1, Revision 12, dated June 9, 1987, for Unit 2. The review included the control schemes for stripping the 4160 V bus and sequencing the safety related loads on the bus, the type and setting of the sequence timers, and the setpoint drift.

For Unit 1, sequencing was accomplished using an electro-mechanical timer with a cam actuated contact. With this type of timer, the cams are assembled on the same shaft and are rotated by the same motor. Therefore, the time between load addition remains essentially constant and the possibility of two motors being started at the same time because of drift is non existent. For Unit 2, the automatic sequence was accomplished using individual solid state timing relays with negligible drift.

The review of the Beavery Valley 1 electrical schematic revealed that, when the EDG is in parallel with the offsite transmission system, a degraded grid condition or a loss of offsite power would cause the tripping of the normal breaker and the immediate addition of emergency bus loads, before the governor could change from the droop to the isochronous operation, and the voltage regulator could change from the parallel to the isolated mode. This is caused by the fact that a set of contacts associated with the tripped breaker, along with the already closed EDG breaker, signal the load sequencer to load the emergency bus. The estimated time for this occurrence could be 0.5 seconds or less. This condition exists every time the EDGs are tested, including those times when they are tested to support Limiting Conditions for Operation.

The licensee was unable to provide an analysis for this event by the end of the inspection. The licensee indicated that they would review their design bases documents to see if the issue had been addressed. This item is unresolved pending appropriate review and evaluation by the licensee (50-334/91-80-09) (50-412/91-80-09).

3.12.5 Protective Relays

Primary protection against internal faults for the BV1 and BV2 emergency generators is provided by static differential relays. Additionally, the generators are equipped with loss of field and anti-motoring protection. Back up phase fault protection is provided by overcurrent relays which are torque controlled externally by a reactance relay.

The team's review of the Unit 1 setpoint calculations for the Reverse Power and Loss of Field Relays determined that they had been performed at the time of the plant construction. However, these calculations were not retained as part of the plant's records, therefore, the calculated bases for the settings could not be verified. These relays only protect the EDG when it is operated in the exercise mode. However, the concern was that an improper setting of these relays could allow the generator to be damaged during the parallel operation and, hence, result in the inability of the EDG to respond to an accident. The team discussed the observation with the licensee and concluded that, despite the fact that the back up calculations had not been retained, there was no reason to believe that the settings were incorrect.

The team had no further questions on the subject, but reviewed the Unit 2 diesel generator relay protection and found it to be adequate.

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3.13 Penetration Heat load Calculation

3.13.1 Continuous Loads

The suitability of the Unit 2 electrical containment penetrations to carry continuous load currents without exceeding the allowable temperature rating is addressed by calculation No. 10080-E-84, Revision 3.

A review of this calculation revealed that, although the FSAR referenced IEEE 317-1976, this standard was not directly identified in the calculation. Because of the importance of this equipment in ensuring containment integrity, the team compared the requirements of 10080-E-84 against the design limits of IEEE 317. The team, thus, determined that the calculation had used an important, conservative assumption that the maximum continuous currents were equal to the overload settings of the protective devices rather than the loads demand. In addition, the calculation assumed a 100 % load factor and an ambient temperature of 40 °C for each penetration. The requirements of IEEE 317, particularly the maximum heat loading of 30 watts per foot length, were appropriately reflected in the calculation.

In view of the above, the team concluded that the design of the electrical penetrations for Unit 2, from a continuous rating viewpoint, was acceptable.

For Unit 1, no calculation was available for review and, although the licensee furnished specification No. BVS-384, Revision 3, which referenced the IEEE 317 Standard, in the absence of a relevant calculation, the team had no basis for concluding that the Unit 1 penetrations were adequately sized and protected for the continuous loads. See also Sections 3.13.2 and 3.13.3, below. Therefore, the capability of the Unit 1 penetrations is unresolved pending appropriate calculations by the licensee. (50-334/91-80-10)

3.13.2 Short Circuit Loading

The capability of the Unit 2 electrical penetrations to carry overcurrents without exceeding the limits on temperature and mechanical loading were addressed by calculation No. 10080-E-143, Revision 0.

Because the above calculation did not specifically reference IEEE Standard 317-1976, the team compared the calculation requirements with those of the standard. Using the values from Tables A3 and A4 of IEEE 317 as a guide, the team determined that, from electromagnetic forces standpoint, the calculated short circuit currents were less than or equal to the tables values, except for 1000 MCM conductors passing through a type X penetration. For this case, the value in the calculation was greater than the one in the table, but the team considered it acceptable since the penetration design, with adequate bracing, can withstand a greater short circuit current.

For the heating effect of short circuit currents, the team noted that all the I^2t values used in the calculation were less than the recommended values given in Table A5 of IEEE 317 for 90°C insulation and that the assumptions were conservative.

For Unit 1, specification BVS-384 specified 30,000 A and 60,000 A asymmetrical, respectively, for the 480 volt and 4160 volt circuits. In addition, for I^2t, a value of 4.8E8 was specified at both voltages. These numbers are similar to those observed for the Unit 2 penetration assemblies.

Based upon the above, the team concluded that the design of the electrical penetration assemblies for Unit 2, from an overcurrent standpoint, was satisfactory. For Unit 1, however, the team concluded that, although the design appeared to be satisfactory, they had no basis for making an appropriate determination (See also Section 3.13.1 and 3.13.3).

3.13.3 Protective Devices Coordination

The team examined the effectiveness of the protective devices in guarding the conductors of the Unit 2 containment electrical penetrations against prolonged overcurrents. An evaluation of calculation E-143 concluded that the circuit breakers tripping mechanisms had been correctly chosen and that, for the 480 V circuits, two breakers in series had been supplied. For the 4160 V circuits, each penetration assembly was protected by a circuit breaker which was in turn backed by the associated bus supply breaker. In all cases, the circuit breaker was set to trip before the thermal limit curve of the penetration assembly was exceeded.

The team concluded that protection of the conductors in the Unit 2 containment electrical penetrations was satisfactory. For Unit 1, as above, the team was unable to conclusively determine whether an appropriate protection had been provided. However, a check of the curves for the 300 hp Residual Heat Removal Pump motor, RH-P-1B, indicated satisfactory protection (See also Sections 3.13.1 and 3.13.2 above).

3.14 Cable Sizing

To address the sizing of feeder cables used with both safety and non safety related loads of Unit 2 the team reviewed calculation No. 10080-E-072, Revision 2. This review revealed that the calculation allowed the use of a 550°C upper limit for insulation temperature, instead of the usual 250°C required by the IPCEA Standards, when the cable is subjected to short circuit currents. The team expressed concern regarding the finding since the allowed temperature was close to the 577°C auto-ignition temperature of the cable jacket material supplied by the Kerite Company. The team also found that an associated calculation, No. 10080-E-020, Revision 3, produced even higher temperatures than the allowed limit. However, in this case, the use of larger sizes cables, effectively reduced the maximum predicted temperature to below the imposed limit.

The team was particularly concerned for the absence of a station procedure to inspect cables after a short circuit, a practice specified as important by the architect-engineer in 1985. Additionally, there was no information available regarding melting and flow of the insulation and cascading effects on adjacent equipment.

In consideration of the observations pertaining to the short circuit current available and of the fact that no procedure existed requiring a full inspection of the cable after an overload trip of the feeder breaker, the completeness of the calculation for the BV2 4.16 kV cables is unresolved pending appropriate analysis and corrective action by the licensee (50-412/91-80-11).

3.15 Cable Separation

(Closed) Violation 50-334/89-12-01 - pertaining to safety related cables separation.

Previous inspections, reports Nos. 50-334/88-11 and 50-334/88-17, identified the existence of cable separation deficiencies at the Unit 1 plant. A further review of the issues concluded a programmatic weakness existed at both plants and a Notice of Violation, 50-334/88-22-03 and 50-412/88-15-02, indicated that adequate separation between safety related cables could not be assured. The finding resulted in the licensee's re-evaluation of the separation program and the initiation of corrective actions which included plant walkdowns.

The progress of the licensee's corrective actions was reviewed by the NRC in July 89. This inspection concluded that the licensee had expended and committed a substantial amount of resources for the resolution of the deficiency. The corrective actions for Unit 2 were found to be adequate. However, during a walkdown of the Unit 1 areas for which corrective actions had been completed, the NRC identified several other deficiencies. As a result of the new findings, the NRC issued a Notice of Violation, 50-334-89-12-01, indicating ineffective corrective actions by the licensee.

The progress of the licensee's corrective actions pertaining to Unit 1 were last reviewed by the NRC in July 1991. At that time extensive progress was noted, but the NRC requested that the licensee discuss the status of their separation program with the regional NRC management. A presentation was prepared and made by the licensee on November 12, 1991. At that time, the licensee indicated that only 16 more cables needed resolution and that rerouting would be accomplished during the ninth refueling outage.

During the current inspection, the team reviewed the remaining issues for safety impact and determined that most issues involved non safety related cables routing deficiencies and that, in all cases, low energy cables were involved. In addition, all deficiencies were properly documented and scheduled for future corrective measure. For one purple (division II) cable improperly routed through an orange (Division I) tray, the team asked whether an analysis had been done to ensure that a redundant circuit was not run into the same tray. Apparently, no analysis had been performed. However, the licensee immediately issued a justification for continued operation. A review [illegible] n conjunction with further discussions with the licensee concluded that the issue was not a safety concern. No deficiencies were identified during the conduct of the EDSFI walkdowns performed by the team. Based on the above, the Unit 1 separation issue is closed.

3.16 Conclusions

Based upon the inspection sample of the BV1 and BV2 electrical systems, the team concluded that no operability concerns existed, that most of the original design requirements were still met and that the design of the EDS, as modified during the life of the station, was generally acceptable. However, the team did note several design weakness and areas of concern. The most significant of these was a lack of timely corrective action when areas of potential concern are identified. Two specific examples were identified. Other areas of concern are: adequacy of Unit 2 cables sized for 550°C; the interrupting rating of the Unit 1 medium voltage circuit breakers; the capability of the diesel generators of both units to accept accident loads under worst case design conditions and the setting of the degraded grid relays of both units.

The team noted that much of the design documentation for Unit 1 was not readily available for review during the inspection. The licensee indicated that the documentation is retained in deep storage and would require additional time for retrieval. Some specific unresolved issues, e.g., short circuit available at the 125 Vdc bus and electrical penetration heat loads, were identified in the section above. However, the team also identified other areas where an adequate evaluation of the Unit 1 electrical system could not be fully evaluated because of the lack of documents. These areas include: (1) sizing of MCC cables for power and control circuits (Section 3.4); (2) acceptability of the fast bus transfer scheme (Section 3.7); (3) short circuit current available at the 120 Vac buses (Section 3.9.1); and (4) coordination of dc protective devices (Section 3.11). These issues are unresolved and will be reviewed when appropriate documentation can be made available by the licensee (50-334/91-80-12).

4.0 MECHANICAL SYSTEMS

In order to verify the loading on the emergency diesel generators, the team reviewed the power demands of major loads (selected pumps) and the translation of mechanical into electrical loads used as input into the design basis calculations. To determine the ability of the mechanical systems to support the operation of the EDGs during postulated design basis accidents, the team reviewed sample documentation and conducted walkdowns of the fuel storage and transfer system, starting air system, lube oil and jacket water systems, and service water system. The team also reviewed the heating, ventilation and air conditioning (HVAC) systems that ensure adequate operating environment for the safety related equipment in the diesel generator building, the switchgear room, the cable spreading room, and the battery rooms.

4.1 Power Demand for Major Loads

A review was performed of the manufacturers' pump and fan characteristic curves to determine the power demand on the emergency diesel generators for the three accident scenarios listed in the FSAR: (1) Design basis accident (DBA); (2) Loss of normal power with unit trip; and (3) Safety injection signal with coincident loss of power and unit trip.

Major pump loads on the 4160 V emergency system, according to table 8.5-1 of the FSAR, included: the charging high head safety injection pumps (CH) with a nameplate rating of 600 HP; the 250 HP low head safety injection pumps (SI), the 300 HP outside recirculation spray pumps (RS), the 500 HP river water pumps (RW), the steam generator auxiliary feed pump (FW) with a 400 HP rating, the 300 HP residual heat removal pumps (RH), and the primary plant component cooling water pumps (CC) rated at 400 HP. On the 480 V system, the team identified the major pumps to be the quench pumps, the inside recirculation spray pumps, the containment air circulation fans, and the leak collection exhaust fans, each pump rated at between 150 and 300 HP.

In conjunction with the pumps head/flow curves, the team reviewed a recent reassessment of the Unit 1 diesel generator electrical loads (study 08700-DEC-E-048) and the Mechanical Engineering review of the same, documented in an internal memorandum, dated February 25, 1991. The team noted that the steam generator auxiliary feed pump load had been changed to 495 BHP, a 23.7% increase above the motor nameplate, 400 HP with 15% service factor, and a 28.9% increase over the 384 BHP specified in the FSAR. The pump motor appeared to be operating above its continuous rating, even when the service factor was considered. Significantly, in Unit 2, flow restricting devices had been installed in the feedwater lines to protect the auxiliary feed pumps from run out conditions.

Pertaining to the FSAR, the licensee stated that it was outdated and that it did not reflect run out conditions and maximum power demand for a postulated pipe break in the pump discharge line.

The auxiliary feedwater system comprises two motor operated pumps, each powered by a redundant emergency bus, and one turbine driven pump. The turbine driven pump is not considered available in an accident involving steam generation or supporting systems. Following a feedwater pipe break coincident with a loss of normal power, if one diesel failed to start, the remaining redundant motor driven pump would automatically start and operate at run out conditions. In the initial phase of the accident, the pump is not essential, therefore, this pump could be shut off without consequences. However, later, when the heat sink capacity of the affected steam generator begins to deplete, the pump is needed to maintain a minimum flow through the steam generators and must be available after the break is isolated.

During the estimated 10 minutes, minimum, required by the operator to diagnose the accident and temporarily stop the pump, the pump would be subjected to runout conditions with consequent cavitation and potentially serious damage. Similarly, the motor could suffer damage because of its operating beyond its rating.

Discussions with the licensee pertaining to the pumps' operation in the above mode indicated that a series of high capacity tests simulating the runout conditions had been conducted to evaluate the pumps behavior. The licensee stated that no visual or audible abnormalities were observed at the time except for a noise reduction when the pump reached its runout condition. Flows, pressures and motor amperes had also been measured.

The team evaluated the net positive suction head available at the tested runout flow and found it to be below the required value indicating that during the runout tests, the pump had operated in cavitation. However, there was no evidence that the pump had been subjected to a comprehensive damage assessment program and, therefore, no positive indication of the present conditions of the pumps. The team also noted that the licensee had failed to check the motor efficiency against the given curves. On the other hand, the team verified that the hydraulic to shaft horsepower ratios for both motor driven pumps matched the curve efficiency value for the tested flow.

The licensee recognized the possibility of having run the pump in cavitation for the duration of the tests and that they could not prove absence of damage to either the pump or the motor. However, they indicated that recent monthly performance tests, conducted at the pumps' rated flow (350 GPM), showed no performance degradation.

Following the inspection, the licensee further evaluated the conditions of the pumps and concluded that apparently no damage had occurred during the run out tests that had been previously conducted. However, the capability of the pump to operate at run out conditions, in the event of a feedwater line break, is unresolved pending appropriate analysis and corrective actions by the licensee. This analysis should consider the effects on the motors' operability and environmental qualification if the motors are operated above their nameplate rating under worst environmental and voltage conditions. In addition, the analysis should address the setting of the breakers' protective devices to ensure that the breakers do not trip on overload (50-334/91-80-13).

Other than the considerable AFW pump load increase on the diesel generator, the load study, No. 8700-DEC-048, identified other minor load increases over the FSAR values for an estimated total of 296 HP. The effects of these added loads on the operability of the diesel generators are discussed elsewhere in the report.

4.2 Diesel Generator and Auxiliary Systems

4.2.1 Fuel Oil Storage And Transfer System

BV1 and BV2 are equipped with two emergency diesel generators per unit. The two diesel generators have their own fuel oil day tanks plus two underground storage tanks to support a seven day continuous operation. During engine operation, the day tanks are filled from the storage tanks on an automatic low level signal. The two units have different layouts. In Unit 2, the storage tanks are located below the diesel generator rooms. They are interconnected and the transfer pumps are mounted on the tanks. In Unit 1, the storage tanks are in an underground missile protected location, adjacent to but outside the confines of the diesel building. The transfer pumps, on the other hand, are inside the buildings, approximately 150 feet away from the storage tanks.

<u>Transfer Pump Suction Head</u>

While reviewing the BV1 diesel fuel transfer pump specification, the required NPSH of 15 feet appeared not to be met by the present configuration. The licensee performed a calculation showing that the total suction head from the tank low level was 15.98 feet. However, the calculation did not take into account acceleration and exit losses.

Further discussions with the licensee indicated that the 15 feet NPSH required by the original specification sheet, did not reflect the capabilities of the actual pump. The licensee provided vendor data showing that the pump could actually lift up to 21 feet of suction, amply bounding the 15.98 feet available. The licensee committed to revise the pump data sheet.

The team had no further concerns on this subject.

4.2.2 EDG Jacket and Lube Oil Cooling System

The Unit 1 jacket water cooling system consists of two centrifugal pumps powered by the governor drive gear; an inlet water manifold with individual feeders to each liner and cylinder head; an outlet manifold; a three way temperature regulating valve capable of bypassing the heat exchanger; and an external tube and shell type heat exchanger using river water (RW) for cooling medium. In addition, it includes an expansion tank and an immersion heater to maintain the required lube oil and coolant temperatures when the diesel is not operating.

The lube oil system consists of four separate sub-systems: the main lubricating, the piston cooling, the scavenging oil, and the auxiliary oil system. Each sub-system had its own pump, of which three were shaft driven and the fourth was motor driven.

To evaluate the capability of the systems, the team requested flow diagrams and design descriptions of both the jacket water and the lube oil systems. However, neither was available. The licensee did provide valve operating diagrams, but they were considered inadequate in that they lacked important information such as line sizes, proper flow distribution, function description and design conditions. During a walkdown, the team noted that operating diagrams did not reflect the actual layouts in the area of the skid-mounted equipment.

The licensee was unable to clarify functional and design features of these systems, but forwarded the team questions to the vendor. No response was received prior to the end of the inspection. Although the team identified no areas of concern regarding these systems, they were not able to draw appropriate conclusions.

4.2.3 River Water System

The River Water (RW) System supplies water to the jacket water (JW) of the two redundant emergency diesel generators via two redundant river water headers ("A" and "B"). Each EDG can be supplied with cooling water from either header via motor operated valves (MOV). When the diesels are not operating, the MOVs are closed. In Unit 1, all of the MOVs are located in a pump room, below grade, adjacent to the EDG room.

Originally, the jacket cooling heat exchanger was fed by either valve RW 13C connected to header "B" or by RW 13D connected to header "A". As a result of an appendix "R" scenario postulating a common failure of all four valves due to a fire in the pump room, valve RW 13D was locked open and "retired in place" and a new valve, RW 13D-1, was installed downstream of the locked open valve. The new valve was located in the EDG room.

The team reviewed the design and observed that the three river water MOVs remaining in the pump room were located at an elevation (approx. 727') which was below the station design flood limit (730'). Yet the MOVs were not qualified for flooding and the room itself was not water tight. For instance, the access steps were outdoors with a small curb to prevent normal ground water from flowing down the steps and a drain was located right outside the pump room access door.

The team was concerned that no analysis existed showing that the valves were capable of operating and meeting their design requirements in a flooded environment, that no evaluation had been prepared showing that the area would not be flooded, and that, with three disabled MOVs, the station would not be able to meet the single failure design criterion.

The licensee stated that 730' flood level was the probable maximum flood (PMF) which could be termed as a geological event. This is an extremely rare event. They also observed that the PMF would occur progressively and not without warning. The estimated time for the river to rise from the mean sea level (695') to the PMF was 23 hours, according to the FSAR (pages 2.3-41 and 2.3-43). Therefore, enough time existed for initiating appropriate corrective actions.

The licensee recognized the design deficiency and suggested that an action statement could be added to their abnormal operating procedure 1/2.53V.4A, "Acts of Nature - Flood", to require these valves to be verified open and the power to be removed from them.

While the above actions may be appropriate for the MOVs, the team expressed concern that other essential components in the pump room or other areas of the station (Units 1 and 2) similarly might not be qualified to the PMF.

The MOVs issue is considered to be a deviation from the commitments of the FSAR, Section 2.3.3, which states in part that "all safety related equipment and connecting piping and wiring is either located above elevation 730.0 ft or adequately protected so that its function is unaffected by a flood to elevation 730.0 ft." (50-344/91-80-03).

Because a second valve had been added to one of the lines, the team inquired whether a hydraulic check had been performed to ensure that the pressure drop was compatible with the system operating requirements. The licensee referred to calculation No. 11700-N-134 which verified that the new valve provided adequate flow to the cooler within 26 seconds of receiving an open signal. In addition, they indicated that, at every refuelling outage, the system was tested to DBA flow requirements. Flows and pressures were recorded at the heat exchangers inlets and outlets and engineering routinely reviewed the test results.

A review of the jacket cooling heat exchanger calculations noted that the diesel cooling water heat exchanger was originally designed to 400 GPM and 86°F, according to the FSAR and to the component specification sheet, but that the licensee had used 260 GPM and 90°F in calculation 8700-DMC-2469.

The licensee stated that a safety system functional evaluation (SSFE), in 1989, had identified that the failure of one river water pump would leave the other one having to supply cooling to both diesels and to the other loads in the system. In response to this finding, they did an evaluation of the heat exchanger performance and found that the reduced river water flow at the maximum allowable river water temperature was adequate for maintaining the diesel cooling within the operating limits recommended by the manufacturer. However, the heat exchanger fouling factors had to be maintained within the limits defined in calculation 8700-DMC-2469. A performance test program had been established to measure the fouling level on a quarterly basis. The FSAR has not yet been updated to reflect this analysis.

In calculation 8700-DMC-2469, the team further noticed a discrepancy between the pressure reading taken during the 5/26/91 test on diesel EE-E-1B (24 psig) and the pressure input to the heat exchanger used to calculate heat transfer coefficients (35 psig). The licensee stated that pressure input to the program of 35 psig (50 psia) was intended to represent a nominal value for the system. The program used this pressure only as a check for saturation conditions and the value itself had no effect on the results.

The team had no further concerns in this area.

4.3 CLASS 1E HVAC

In Unit 1, ventilation in each EDG building is provided by one 28,000 CFM ceiling mounted propeller exhaust fan to remove excess equipment heat through motor operated discharge dampers. Air enters the room through intakes with motor operated, thermostatically controlled dampers. Power for all fans and dampers is provided, under accident conditions, by their respective emergency generator buses.

Since there is no separate turbocharger air intake, the diesel draws its own combustion air (10,550 CFM) from the room and the outdoors through the intake damper. To guarantee combustion air, starting of either diesel will cause its respective air intake damper to open regardless of exhaust fan operation.

The team reviewed the HVAC calculation for the Unit 1 EDG buildings, No. 13387.18, and noted that heat input from the electrical panels and ground resistor, although small, had not been taken into account. Based upon this calculation, the maximum temperature in the diesel building was determined to be 123°F. The team also determined that the mechanical and electrical components in the Unit 1 EDG buildings were not specifically qualified to meet that temperature. In Unit 2, on the other hand, the calculated temperature (calculation No. 12241-B-181) was used to qualify the equipment to IEEE 323 standards. Since the equipment is located in a mild environment and, therefore, not included in the environmental qualification list, the question regarding differences was never addressed. An assessment of the equipment in the Unit 1 diesel building concluded that the ambient temperature should have minimal impact on the equipment.

The team had no further concerns on this subject.

No areas of concern were identified during the team's review of the switchgear and battery rooms and of the safeguards building.

4.4 Seismic Qualification

During a walkdown, the team noticed an unusual amount of 480 V breakers in the racked out position and expressed concern regarding the impact of such configurations on the seismic qualification of the switchgear. The licensee stated that the "racked out" configuration had been evaluated by way of "in-situ" testing of safety related MCCs and that this had showed virtually no change in vibratory response, despite the numerous racked out pans. Therefore, they believed that the 480 V switchgear would respond in a similar manner. The licensee also indicated that the issue was under review and it would be resolved by analysis or test or a combination of both.

This item is unresolved pending completion of the licensee's evaluation. (50-334/91-80-14) (50-412/91-80-14)

To assess the capability of the EDG and support systems to perform their safety function during and following a design basis earthquake, the team reviewed selected Unit 1 systems and components. On the basis of the documents reviewed, the team concluded that the equipment adequately met seismic qualification. The piping systems were designed to meet the 1971 edition of the ANSI B.31.1 Code stress requirements and seismically qualified portions were designed to both the operating basis earthquake and the design basis earthquake, as described in the FSAR, Appendix B - Seismic Design. The team verified that the program used to conduct the piping stress analysis was applied conservatively.

Dynamic transients (water hammer) were not analyzed in Unit 1. Vacuum breakers had been installed in those areas potentially more affected by dynamic transients. In addition, historically no significant water hammer problems had been reported in the plant. In Unit 2, water hammer had been analyzed for those systems identified in document EMTP 9.12-0 as being at risk.

The team verified that those piping portions at the transitions between an underground section and a concrete foundation or an above ground structure were adequately de-coupled. The team found that the transitions consisted of a combination of flexible joints and sleeves cast into the concrete. The sleeves were of a greater diameter and large enough to absorb the maximum relative seismic and thermal movements of the pipe with ample margin. The flexible joints consisted of in-line expansion joints. The whole sleeve assembly was sealed with a flexible weatherproof membrane. A review of a sample piping stress analysis in the river water system containing a sleeve application and of two support calculations showed them to be correct.

4.5 Conclusions

The team concluded that the technical staff was knowledgeable of the mechanical systems, including those affecting the EDGs.

The major areas of concern identified by the team were the unanalyzed condition involving the AFW pumps and motors, in the event of a pipe break and their operation at run out conditions, and the lack of protection against the probable maximum flood level for the river water motor operated valves which control the cooling flow to the diesel generator.

Another area of concern was the inadequate information available for vendor supplied systems associated with the diesel generator, such as the lube oil system and portion of the jacket cooling system.

The seismic qualification of the switchgear with a random number of breakers in a racked out position needs to be addressed to ensure operability of the switchgear following a seismic event.

5.0 EDS EQUIPMENT

The scope of this inspection element was to assess the effectiveness of the controls established by the licensee to ensure that the design bases for the electrical distribution system are maintained. This effort was accomplished through a physical inspection of the electrical equipment which verified that the as-built configuration corresponded to that specified in single-line diagrams and modification packages. In addition, the maintenance and test programs developed for electrical components as well as the controls established for plant modifications were reviewed to determine their technical adequacy. Inspection attributes for plant modifications included the design review process and the resulting safety evaluations to meet the requirements of 10 CFR 50.59.

5.1 Equipment Walkdowns

The team inspected various areas of both BV1 and BV2 to verify the as-built configuration of the installed equipment. Equipment inspected included emergency diesel generators, 4.16 kV and 480 V switchgear, motor control centers, 125 Vdc batteries and battery boards, and control room panels. To verify the accuracy of the EDS calculations and of applicable design drawings the team compared the design data to the nameplate data for transformers, battery chargers, inverters, uninterruptible power supply (UPS), circuit breakers, pump motors, and motor operated valves (MOV). A sample of protective relay settings was also recorded and compared with the current calibrations data.

The inspected equipment generally was found to be installed in accordance with the design documents, except as follows.

(1) The nameplates for the four 4160-480 V Unit 1 substation transformers (1-8N, 1-8N1, 1-9P and 1-9P1) were not available. The nameplate data is necessary for important design documents such as short circuit and load studies. Discussions with the licensee indicated that the nameplates were located inside the transformers cabinet when modification DCP 263 was performed. Maintenance work requests (MWR) 2960 and 2962 were initiated on September 14, 1991 to verify the transformer ratings.

(2) The nameplate's kVA and kW ratings for the Unit 2 emergency diesel generators (EDGs) did not match those indicated on single line diagrams 10080-RE-1C and 10080-RE-1F and in the FSAR. However, the nameplate data was used for the Unit 2 short circuit calculation 10080-E-074, Revision 2. To ensure that the one line diagrams and the FSAR were updated to reflect the correct ratings, the licensee initiated a technical evaluation report (TER), No. 6451.

(3) The horsepower (HP) rating for the Unit 1, dual speed, containment air recirculation fan shown on drawing No. 8700-RE-1K (300/150 HP) did not agree with the rating indicated on the Figure 8.1-1 (sheet 1 of 3), "Electrical One Line Diagram, Beaver Valley Power Station Unit No. 1" (375/175 HP), and Table 8.5-1 (page 3 of 6), "Emergency Diesel Generator Loading Maximum Loading of Diesel Generator No. 1" (500 HP) of the FSAR. When informed, the licensee took immediate actions to confirm the correct horsepower rating and to revise the FSAR.

The plants were found to be clean and organized. The batteries had adequate level of electrolyte and that the battery terminals were clean and corrosion free. During the plant inspection, the team noticed an unusually high amount of 480 V circuit breakers in the drawn out position. The concern regarding the impact of this configuration on the seismic qualifications of the switchgear is covered in Section 4.5 of this report.

Based upon the above observations the team concluded that adequate measures were in place to control the systems configuration. With the exception of the above mentioned discrepancies, the inspected equipment was found to be well kept and installed in accordance with the design drawings. Plant areas were found to be clear of safety hazards.

5.2 Equipment Maintenance and Testing

5.2.1 Batteries and Battery Chargers

A review was performed of the BV1 and BV2 maintenance and surveillance testing procedures for the Class 1E batteries and battery chargers to ensure that procedures were appropriate. These procedures included:

- Operations Surveillance Test (OST) 1/2.39, "Weekly Station Battery Check", performed to check the level and specific gravity of the electrolyte and the voltage of the pilot cell.

- Maintenance Surveillance Procedure (MSP) 1/2.39, "Battery Test and Inspection", used to quarterly test the electrolyte's level and specific gravity and the cells voltages.

- Beaver Valley Test (BVT) 1/2.39, "Battery Service Test", performed every 18 months to verify that the batteries can maintain for two hours the battery terminal voltage above the Technical Specification acceptable values.

- BVT 1/2.39, "Battery Charger Load Test", conducted every 18 months to verify that the battery chargers can supply 100 amps at 140 Vdc for four hours.

- MSP 1/2.39, "Inspection and Interconnection Resistance Check", performed every 18 months to verify that the batteries' interconnection resistance is less than the Technical Specification acceptable values.

- BVT 1/2.39, "Station Battery Capacity Test", performed every 60 months to verify that the capacity of batteries is greater than 80% of its rated capacity.

The review addressed acceptance criteria and conformance with the requirements of the station's Technical Specifications and the guidelines of IEEE Standard 450. The team also reviewed the maintenance performed on the Unit 1 battery chargers and compared it to the activities recommended in the vendor's manual.

Based upon the above review and a sampling of the test results, the team concluded that the tests adequately verified the design function and the capacity of the Class 1E battery system.

5.2.2 Uninterruptible Power Supply (UPS)

The BV1 UPS design consists of four (4) Class 1E inverters and associated static switches. Each UPS is connected to one of the four station batteries, such that a loss of any one source only affects one 120 Vac vital bus. The inverter's output is automatically regulated at 120 $\pm$ 2.4 V and 60 $\pm$ 0.3 Hertz.

The testing and maintenance of the UPSs are described in preventive maintenance procedures 1PMP-38VB-UPS-1-2-3I, Revision 0, and 1PMP-38VB-UPS-3-4-3I, Revision 1. These procedures were reviewed for technical adequacy and compared with the vendor's operating and instruction manuals. In addition, a sample of completed tests was also reviewed. The procedures and the completed tests were found to adequately support operability of the UPS equipment. However, procedure 1PMP-38VB-UPS-3-4-3I, reflecting the vendor's recommendations, required a periodic replacement of various components like capacitors and fuses. Nevertheless, the licensee had no controls in place to ensure timely replacement of these components. The licensee concurred that there was a need for a tracking mechanism and indicated that they would evaluate this issue further. There were no indications that the components had not been replaced as scheduled.

During a walkdown of the Unit 1 and Unit 2 uninterruptible power supplies, the team noted that a work request, #09130, indicated that the cooling fan of the Unit 1 dc inverter No. 1. was not operating. In addition, the Unit 2 inverter 2-4 was found with a cooling fan out of service. Both fans had been out of service since June 1991. Discussion with the licensee indicated the loss of one cooling fan did not affect the operation of the inverters because each inverter had at least three other operating cooling fans and the ambient temperature was maintained within the manufacturers' recommended range. The licensee had no plans to repair the cooling fan of the Unit 1 inverter due to difficulties in obtaining replacement parts. Both Unit 1 inverters are scheduled to be replaced during the next refueling outage (9R); inverter 2-4 is scheduled to be repaired during the next Unit 2 refueling outage (3R). Maintenance work requests had already been issued. The team had no further concerns in this area.

5.2.3 Relay Testing

The calibration was witnessed of a Class 1E undervoltage relay used to start the Unit 1 diesel generator A. During this test, the Asea Brown Boveri relay exhibited a setpoint drift which appeared to be temperature related since the test cart was located in an area where a cold draft was blowing on the cart and on the relay.

The testing personnel stated that a letter would be sent to Nuclear Plant Engineering requesting an evaluation and a determination of the impact of this condition on plant operation. By the end of the inspection, the licensee had not completed its evaluation.

The team also reviewed letter RBRB142, dated September 6, 1991, which discussed a setpoint problem with relays 27-VB100 and 27-VC100. These relays are used to detect undervoltage on the supply to the reactor coolant pumps. The writer of the letter had suggested that, the day before their testing, the relays should be set outside their Technical Specification limits so that, by the time they were tested, they would have drifted into the correct band.

The team requested a copy of Engineering Memorandum No. EM 101626 which responded to the letter, but the licensee was not able to retrieve the response by the end of the inspection. Therefore, the response of the under voltage relays to temperature changes is unresolved pending appropriate evaluation by the licensee and review by the NRC. (50-334/91-80-17)

5.2.4 EDG Surveillance Testing

A review was conducted of the documentation demonstrating that the BV1 EDGs could supply the required real and reactive power during the automating sequencing of the Design Basis Event (DBE) loads. For this purpose, the licensee provided the results of the EDG tests that were conducted during refueling shutdowns. This data indicated that the EDGs underwent two tests: one test during which load was slowly added up to between 2750 and 2850 kW, at a power factor of between 0.8 and 1.0; the other which simulated a LOCA with a loss of offsite power. In this second test, the total load was approximately 1725 kW. The team expressed concern that neither test adequately demonstrated the capability of the EDGs to accommodate the DBE loads. The reason for this was that, while the first test enveloped the maximum anticipated DBE loads, it did not test the response of the machine to large reactive loads added in a short period of time. The second test appropriately verified the response of the machine, but the loads added did not envelop the DBE loads. Regarding these tests the team also observed that they did not adequately record critical performance parameters, such as voltage, frequency, and rack position.

Further discussions with the licensee indicated that they had a Reactive Power Loading Curve in one of their documents. However, this curve appeared to be only for steady state loading with a reactive power limit of approximately 3450 kVAR. In comparison, the BV1 EDG specification required 12,400 kVA to start 2,200 horsepower of motor load. At a 0.80 power factor, a rating of 9,920 kVAR would be required. No other documentation showing the instantaneous and short term ratings of the generator, static exciter and voltage regulator was available.

The licensee provided a letter from General Motors which gave several motor starting scenarios and predicted voltage drops. This data was used by the Architect Engineer to establish the plant motor starting requirements. The letter did not specifically state that the data pertained to the BV1 installation and did not contain actual calculations. It only contained a summary of "predictions". However, the FSAR, Section 8.6, states that prior to shipment, the EDGs were tested with accident loads.

In view of the above, the lack of documentation demonstraing the capability of the EDGs to provide starting power to design basis accident loads, under worst case conditions, is unresolved (See also Section 3.12.3).

5.3 EDG Potential Transformers

A review of BV1 drawings 8700-RE-21BT revealed that the potential transformers (PT) for the voltage regulator and the static exciter were rated at 2,400/120 V and 2,400/240 V, respectively. These rating are adequate when the EDG is operated in the test mode with its "Y" point grounded. However, when the EDG is operated with the "Y" point ungrounded, as in the Design Basis Accident mode, a ground on one phase would drive the other two phases to 4,160 V with respect to ground.

The concern was that ground detection relays, in this application, are normally set at approximately 21 A to eliminate nuisance trips. Therefore, a small ground on any phase would go undetected. This ground, however, would be adequate to elevate the potential of the ungrounded phases to 4,160 V above ground. The potential transformers associated with these phases would then be exposed to a potential of 4,160 V between live parts and the core steel and case bushings, with potential damage to the PTs. Damage to the PTs' insulation would ultimately adversely impact the operation of the voltage regulator and the static exciter.

By the end of the inspection, the licensee was not able to provide design bases documents to show that the insulation rating of these PTs was adequate for operation with a postulated grounded phase. This issue is unresolved pending appropriate review and analysis by the licensee (50-334/91-80-15).

5.4 Plastic Pipe in EDG Installation

During an inspection of the BV2 EDGs, plastic pipe was used for the cooling water supply to the rear bearing of the EDGs. This pipe appeared to have been replaced and, in one case, the use of a toothed tool was evident. The team was concerned that a failure of these lines could ultimately render the EDGs inoperable as a result of a rear bearing failure, loss of jacket cooling water, or shorting of the generator from the broken pipe water spray.

The licensee had no analysis clearly demonstrating the capabilities of the pipe. However, they indicated that, to their knowledge, the units had been supplied with the plastic pipe. Apparently, the reason for the pipe was that an electrical insulating material was required to totally isolate the rear bearing from the rest of the EDG.

Regarding the observation that the pipe appeared to have been replaced with one of a different color, the licensee noted that they had replaced six of the eight installed pieces of pipe over a period of several years, including some that had been damaged and replaced during start-up. The last replacement occurred in October 1990. According to Maintenance Work Request No. 909461 the pipe had been broken in such a manner as to allow the jacket cooling water to go into the bearing oil. During this replacement, the Maintenance Department requested Engineering to review and approve the use of a material with physical characteristics different from the originally specified ones. The new material was approved. However, the team found no evidence that an evaluation had been done of the new material's performance in the environment of the EDG room and compared to the original material's specification requirements.

In view of the above, the acceptability of the new plastic pipe is unresolved pending appropriate analysis by the licensee (50-412/91-80-16).

5.5 Fuse Control

Fuse characteristics differ among manufacturers and classes. Therefore, proper evaluation, installation, and replacements are necessary to ensure appropriate circuit protection and coordination. A review was conducted of the licensee's fuse control program and a plant walkdown was performed to verify that the installed fuses were in conformance with as-built drawings.

Currently, guidance for the replacement of fuses is provided by Section 4.5 of the Maintenance Manual, "Daily Maintenance Job Planning and Scheduling", Revision 1. This Manual, to ensure circuit protection coordination is maintained, requires that fuses and circuit breakers be replaced with devices of identical type and ampacity. Discussions with the licensee's maintenance staff indicated a strong cognizance of this requirement. If the correct replacement fuse is not available, an engineering evaluation is initiated to identify valid alternate parts.

To address potential inadequacies of existing fuses, the licensee was developing a formal fuse control program that included verification of design, walkdowns, creation of a database, and revision of applicable administrative procedures. The development of a database for the Unit 1 fuses was already in progress; the one for Unit 2 was to follow.

The team found the licensee's program for the control of fuses to be good, and had no further concerns in this area.

5.6 Switchyard Relay House Fire Protection/Detection

A walkdown was conducted of the Beaver Valley Units 1 and 2 switchyard relay house. It was observed that it contained three CO_2 extinguishers located by two interior doors. The facility has a high temperature alarm; but it was Class 2 and it sounded at the Raccoon service area, located about ten miles from the plant.

The licensee stated that they had planned to install, within the next several years, a fire detection system at the relay house. The modification was the result of concerns expressed by the insuring company pertaining to the loss of the facility.

5.7 Conclusions

Based upon the sample of equipment and documents reviewed, the team concluded that, except as indicated below, the licensee had established acceptable configuration controls. Acceptance criteria for surveillance and testing for most electrical equipment were appropriate. Maintenance and test procedures were found to be technically adequate. Similarly, the test and calibration records reviewed showed that the devices were operating within the applicable acceptance ranges.

The team found areas of concerns, nonetheless, particularly in the performance testing of the emergency diesel generators' accident loading documentation, and insulation rating of the EDG potential transformers.

6.0 ENGINEERING AND TECHNICAL SUPPORT

The team performed an assessment of the capability and performance of the licensee's organization to provide adequate engineering and technical support to the plant organizations. The scope of the inspection included the engineering organization, engineering performance, the modification process, and engineering initiatives.

6.1 Engineering Organization

A review of engineering organization charts indicated a clear division of organizational responsibility. Quality and safety functions were separated from engineering, providing for an independent oversight of quality control and safety issues. The Nuclear Engineering Department was organized into four functional sections: materials, general, electrical, and mechanical engineering. The staffing of each section appeared to be appropriate. However, the team observed that the Electrical and Control Engineering Divisions which comprised 22 and 16 engineers, respectively, had only one supervisor for each section. Approximately 50% of the engineer were "contract" or "consulting" personnel. The number of engineers reporting to one supervisor was discussed with the licensee. The licensee indicated that the two sections would be broken down into four sections, thereby alleviating the supervisory burden.

The Nuclear Group's goals were reflected in the Engineering Department's goals which, in turn, formed the basis for individual managers' goals. The nuclear group goals were presented in the detailed action program objectives and strategies issued through the Office of the Group's Vice President. Included in the objectives were high levels of operating performance and safety as measured by oversight agencies such as NRC and INPO.

The plant modification projects were generally led by engineers within the Engineering Department who were selected on the basis of their particular functional specialty experiences. Modifications were reviewed by a Change Review Committee which provided for an assessment of resources to be applied to a particular project. Utilization of project program engineers to lead such projects was minimal. Evaluations in accordance with 10CFR 50.59 were performed within the Engineering Department.

6.2 Engineering Performance

The performance of the Engineering Department was assessed by reviewing the "Monthly Performance Report" and "the Corrective Action Backlog Report Monthly Performance Indicators." These monthly performance review documents were considered to be an effective management tool since they stated and defined goals, analyzed performance results, and provided a graphic portrayal of the results considering the goals.

The performance trends of backlogs noted in the "Corrective Action Backlog Report" were considered to be especially useful to indicate areas where appropriate action might be taken to alleviate an undesirable trend in backlog accumulation. Generally, the trending analysis showed mixed results with some issues needing improved performance and others exhibiting performance beyond expectation. In either case, the report was such that management personnel could identify trouble areas and initiate appropriate corrective action, if necessary.

6.3 Equipment Modifications

The team reviewed the licensee's program for plant modifications and design changes to ascertain that they were processed and implemented in conforma :ce with established procedures and regulatory requirements.

Modifications and design changes are controlled by Procedure NGAP 7.2, Revision 1, "Design Change Control" and are classified as either design changes or minor design changes. Changes that do not require revision of the Technical Specifications, can be installed without major coordination or planning, and require minor engineering involvement. These changes are processed as minor design changes.

The team reviewed a sample of design change packages (DCP), including minor DCPs. The review included safety evaluations under 10 CFR 50.59 and compliance with Procedure NEAP 8.18, Revision 0, "10 CFR 50.59 Evaluations". The review found the packages generally to be well organized, thorough, and documented in accordance with the applicable procedures. The team also reviewed two modifications selected by the licensee as indicative of their performance. In each case, the lead engineer responsible for carrying out the modification program was selected by the engineering manager. In these examples, the management of the modification by the lead engineer was highly successful.

<u>Service Water System Modification</u>

This modification was performed to resolve a problem of chronic clogging of the small bore piping in the service water system caused by the accumulation of silt. After four incidents of high temperature alarm activation, an engineering modification request was issued by Operations. The resolution of the clogging issue, proposed by a contractor, was reviewed for design adequacy, for safety impact and for consistency with NRC regulations, and licensee procedures. The lead engineering displayed competence and ownership of this modification as evidenced by the effective approach to implementation of the modification package. The modification was not as yet complete.

<u>Moisture Separator Design Modification</u>

This modification was initiated to resolve a problem with heat exchangers which had been plagued by heavy tube plugging maintenance, performance deficiency, and internal structural failures. To meet the design basis performance standards, an improved design which involved replacement of the moisture separators was obtained from a contracted vendor.

The lead engineer effectively directed the implementation of the moisture separator reheater replacement, following established plant design review and test procedures. The program included pre-operational testing which confirmed the improvements in heat transfer performance and cycle heat rate.

6.4 Temporary Modifications

Temporary modifications, for both units 1 and 2, are administrated and controlled by Nuclear Group Administrative Procedure (NGAP) 7.4, Revision 1, "Temporary Modifications". This procedure requires that modifications be upgraded to permanent status within six months, or by the next refueling outage, if an outage is required to install the modification. It also provides guidelines and control methods to maintain the temporary status for longer periods of time. Installed temporary modifications are reviewed quarterly in accordance with Operating Surveillance Test (OST) 48.8, Revision 6, "Temporary Modification Quarterly Review".

An evaluation of selected Unit 1 and Unit 2 temporary modifications revealed that they contained proper technical and operational reviews, approvals and appropriate safety evaluations and reviews. A log of the open temporary modifications, for each unit, was kept in the control room. These logs were reviewed and the number of open temporary modifications was found to be low. The licensee's goal for the total number of open temporary modifications was less than 50 for both units. This number was tracked through the "Corrective Action Backlog Report Monthly Performance Indicators". In order to achieve this goal, the licensee revised the temporary modification program to require a thorough technical evaluation of all temporary installations and developed a minor design change package (DCP) for minor permanent modifications. In addition, they performed an audit of the temporary modification program. The licensee has committed to incorporate the minor improvements identified during the next revisions of NGAP 7.4 and OST 48.8 in January, 1992.

Based upon the above review, the team concluded that the licensee had a good program for the controlling temporary modifications.

6.5 Other Engineering Considerations

Discussion with the Nuclear Engineering Department Manager indicated that he recognized the need for systems engineering knowledge by his engineers and stated that a training program for this was in process.

The Materials Engineering Section had completed projects related to steam generators and corrosion/erosion of piping, published papers on the subject, and participated in external engineering research efforts relating to utility materials issues.

Several licensee initiatives that were identified are indicative of the Beaver Valley efforts to provide for an effective engineering organization. These included: (1) Establishment of a digitized drawing system; (2) Development of a configuration control computer process; (3) Institution of a computerized performance indication process; (4) Implementation of a system to streamline small design changes; (5) Development of a Project Management Manual for Engineers, including training; (6) Establishment of a "Constructability Review" and (7) Conduct of an in-house EDSFI to ensure adequacy of the electrical system.

6.6 Conclusions

The engineering organization was found to be staffed with generally competent personnel. One area which needs further attention by the licensee is the system engineering approach to plant performance and review. The lack of system knowledge was evident in various interviews performed by the team.

Good engineering performance was evident in the permanent and temporary modification packages reviewed. In each case, the packages were well organized and proper safety evaluations had been prepared.

Several licensee initiatives were viewed by the team as indicative of the ongoing effort to improve plant operability and effectiveness of the engineering organization.

7.0 UNRESOLVED ITEMS AND WEAKNESSES

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items or violations. Unresolved item(s) identified during this inspection are discussed in Details, Sections 3.5, 3.9.1, 3.9.2, 3.11, 3.12.2, 3.12.3, 3.12.4, 3.13.1, 3.14, 3.16, 4.1, 4.2.3, 4.4, 5.2.3, 5.2.4, 5.3, and 5.4.

Weaknesses are conditions that do not constitute regulatory requirements and are presented to the licensee for their consideration.

8.0 EXIT MEETING

The inspectors met with licensee corporate personnel and licensee representatives (denoted in Attachment 1) at the conclusion of the inspection on December 6, 1991. The inspectors summarized the scope of the inspection and the inspection findings.

ATTACHMENT 1

PERSONS CONTACTED

Duquesne Light Company

* J. F. Ankney	Senior Engineer - Electrical
R. F. Balcerck	Manager Many Services
C. Bussick	Maintenance Technical Support Director
* E. Chatfield	Nuclear Training Manager
* R. Dambaugh	Senior Engineer - Electrical
* P. W. Dearborn	Supervising Engineer - NED Electrical
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A. J. Fenwick	Director Nuclear Records
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* T. A. Mayers	Acting Manager C.E. Department
* D. G. McLain	Manager Technical Services
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* F. A. Obertliner	Supervising Engineer - Environmental Qualification
* T. M. Patel	Senior Engineer
* R. G. Patel	Senior Engineer - Electrical
* M. Paulick	Director Quality Services
* F. E. Rehrig	Operations Assessment Manager
* D. Schmidt	Director ECE
* J. D. Sieber	Vice President Nuclear Group
* T. A. Slavic	Supervising Engineer - I&C
J. Smarsh	Supervisor Micrographics/Reproduction
D. E. Spoerry	General Manager Nuclear Operations Services
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* S. Szucz	Senior Engineer
* G. S. Thomas	General Manager CNSD
* N. Tonet	Manager NSD
* G. T. Westbrook	Senior Engineer - NED
* K. E. Woesser	SSFE Project Manager

Consultants/Contractors

*	J. T. Jenson	Consultant - Devonrue

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U.S. Nuclear Regulatory Commission

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*	C. J. Anderson	Section Chief, DRS/EB/ES - RI
*	J. E. Beall	Senior Resident Inspector
*	W. Lanning	Deputy Director, Division Reactor Safety - RI
	P. Wilson	Resident Inspector

* Indicates personnel present at exit meeting on December 6, 1991.

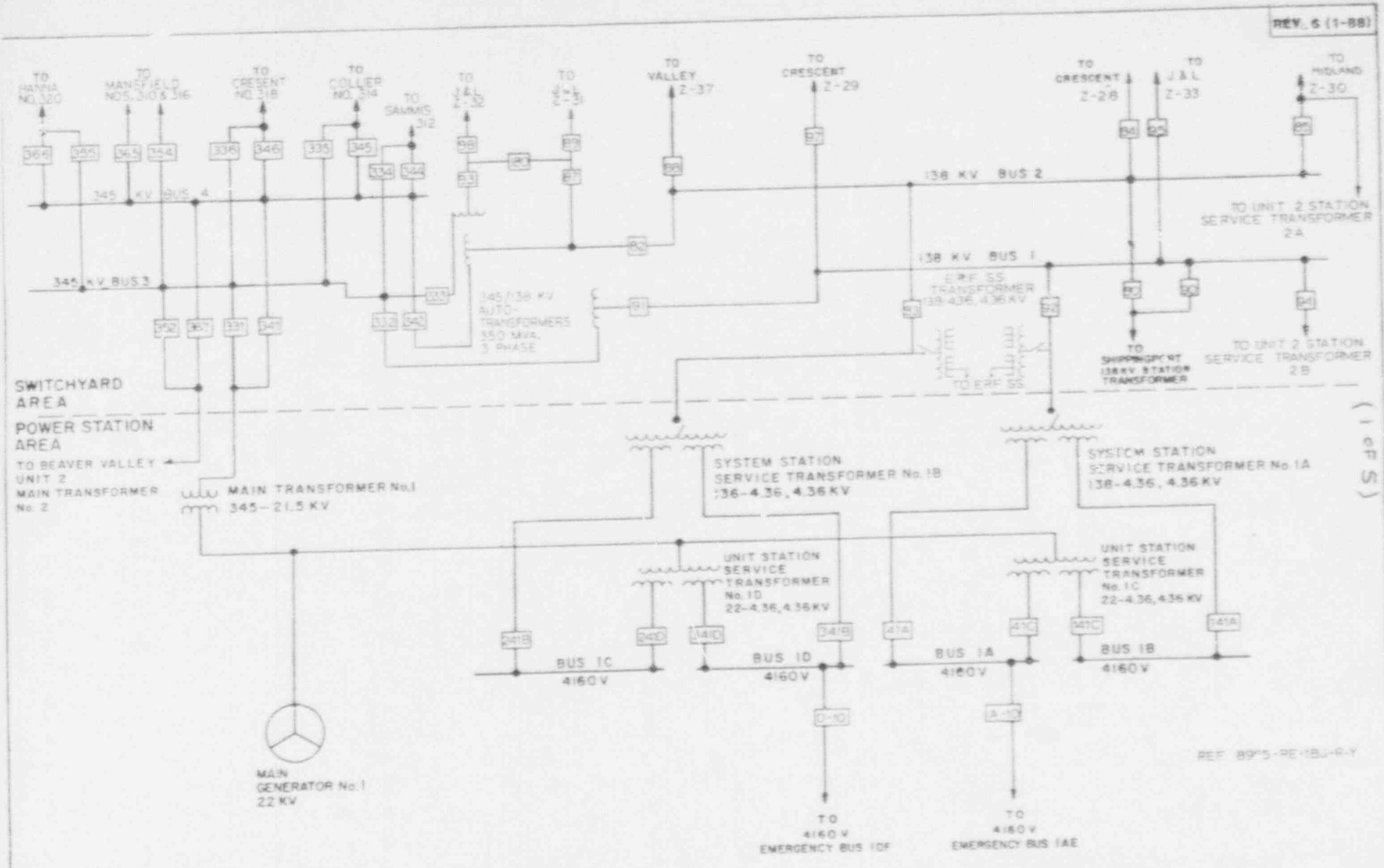

FIG. 8.3-1
ELECTRICAL INTERCONNECTIONS
SWITCHYARD - POWER STATION
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

ATTACHMENT 2 (1 of 5)

REV. 3 (1-85)

ATTACHMENT 2

(2 OF 5)

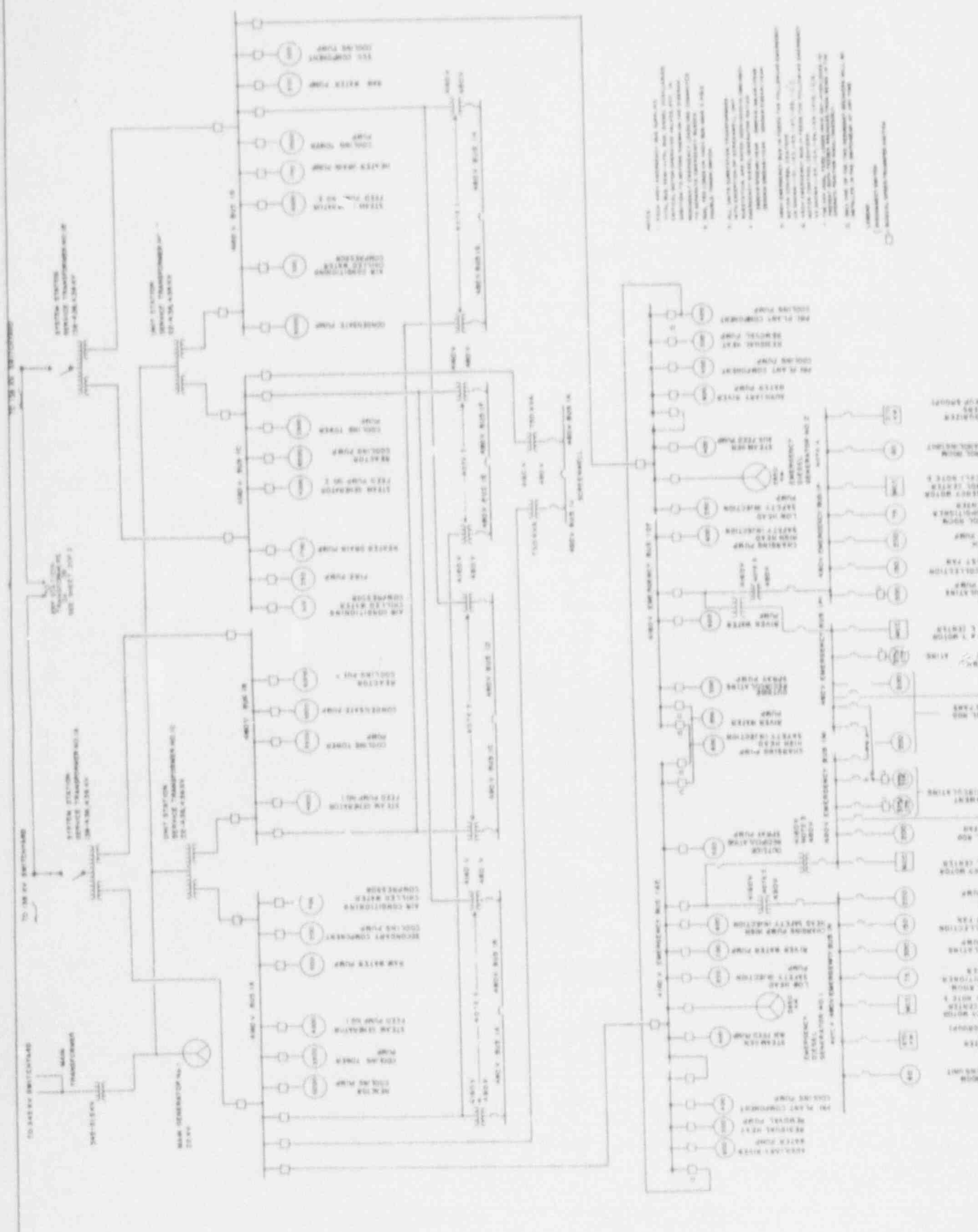

FIGURE 8.1-1 (SHEET 1 OF 1)
ELECTRICAL ONE LINE DIAGRAM
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REV. 7 (1-E

ATTACHMENT 2

(3 OF 5)

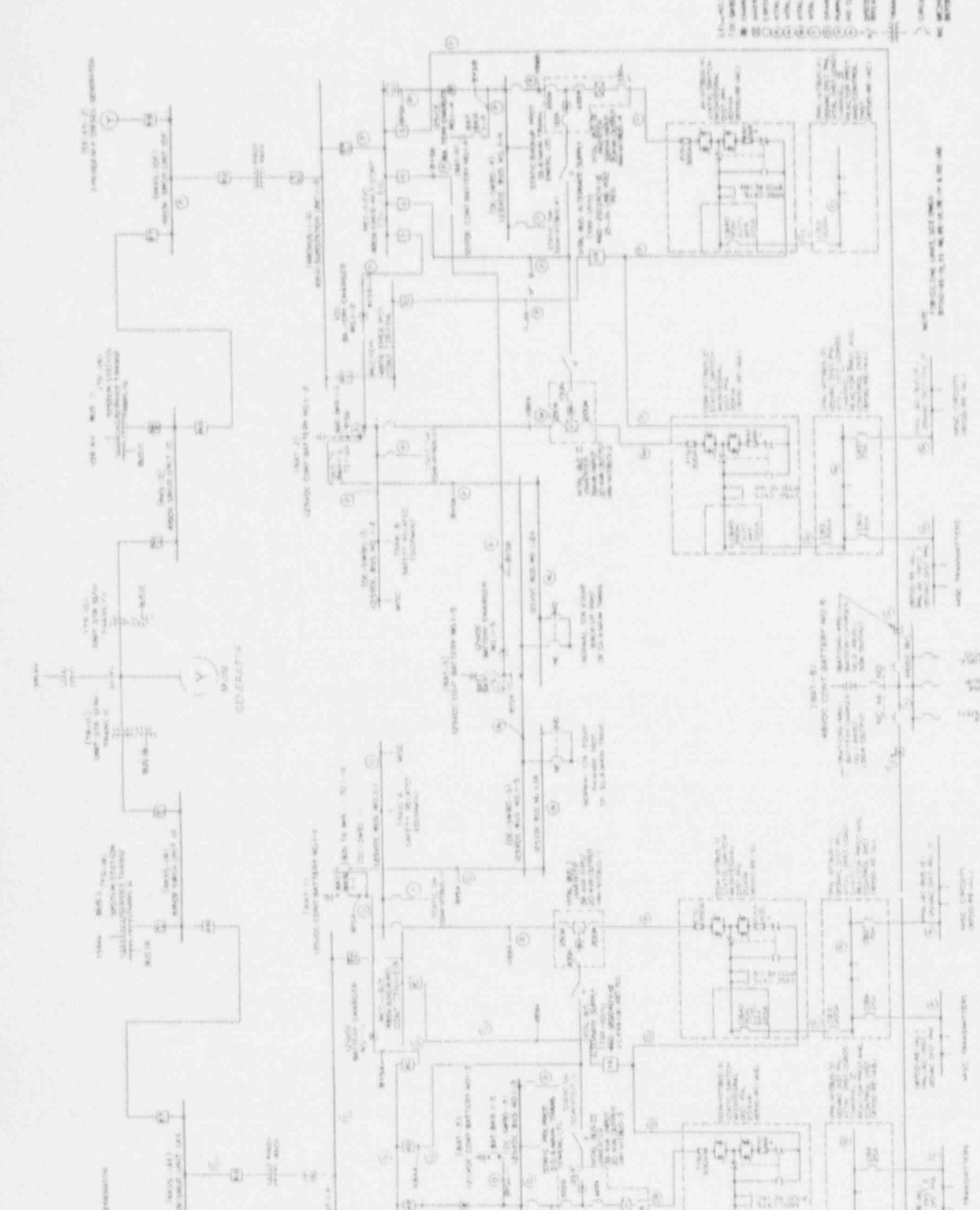

FIGURE 8.4-1
(RE-1Z, REV.11)
EMERGENCY BUSES AND VITAL BUS
AND 125 V DC ONE LINE
BEAVER VALLEY POWER STATION UNIT NO. 1
UPDATED FINAL SAFETY ANALYSIS REPORT

ATTACHMENT 2

(4 of 5)

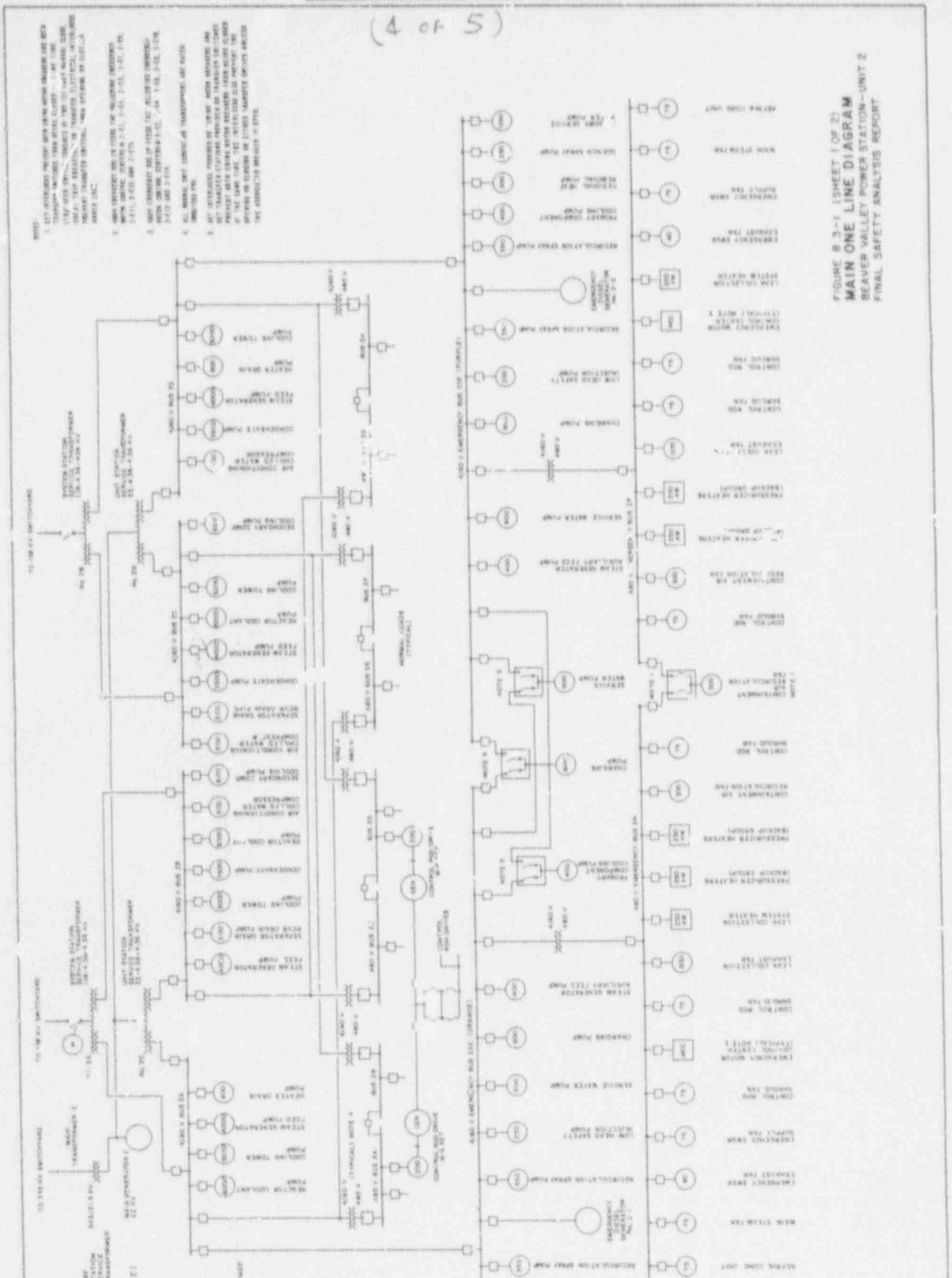

FIGURE 8.3-1 (SHEET 1 OF 2)
MAIN ONE LINE DIAGRAM
BEAVER VALLEY POWER STATION—UNIT 2
FINAL SAFETY ANALYSIS REPORT

ATTACHMENT 2

(5 of 5)

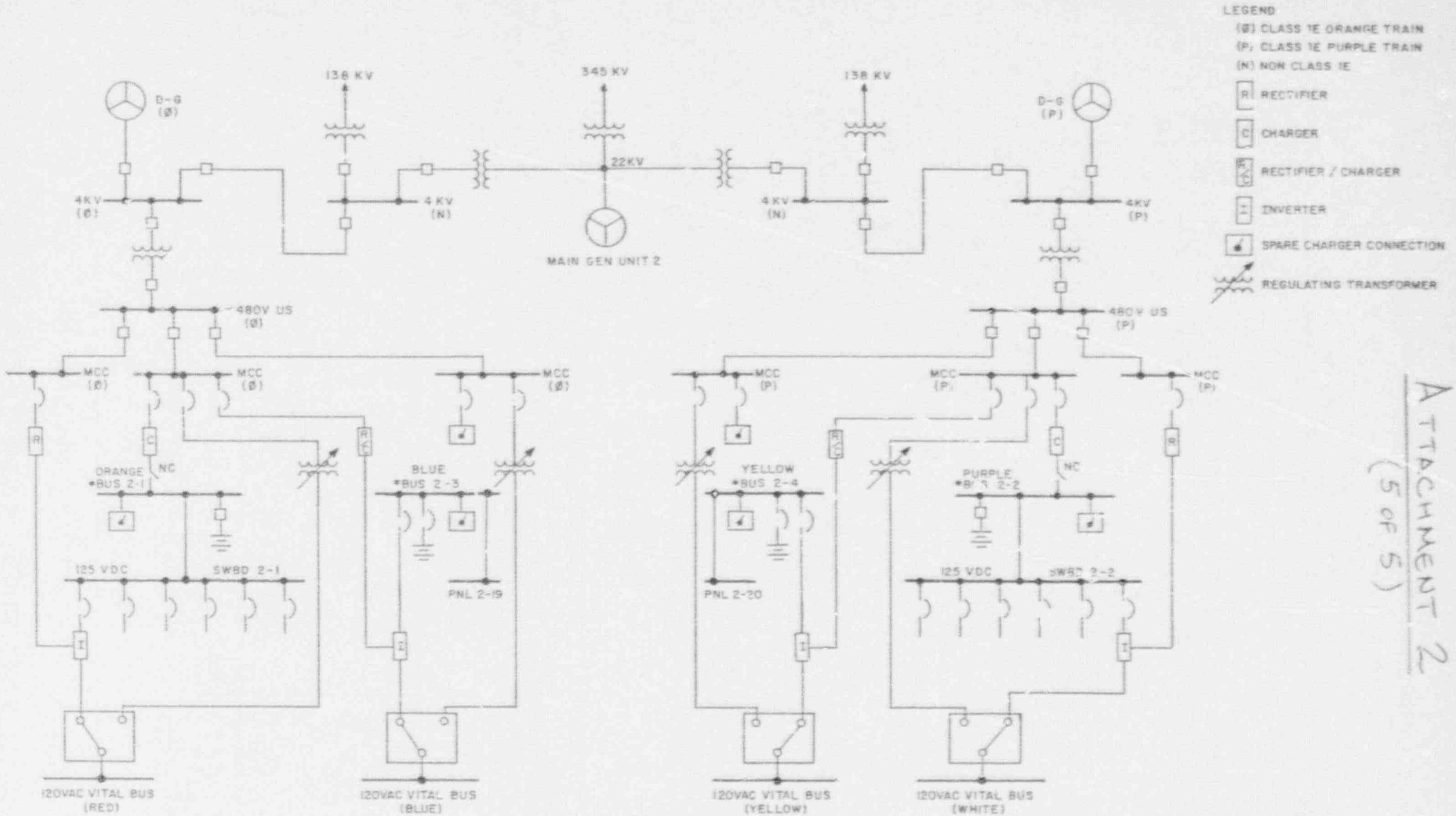

FIGURE 8.3-14
CLASS 1E 125 VDC
DISTRIBUTION SYSTEM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

ATTACHMENT 3

ABBREVIATIONS

A or Amp	Amperes.
AC or ac	Alternating Current.
ANSI	American National Standards Institute.
ASME	American Society of Mechanical Engineers.
BHP or Bhp	Brake Horsepower.
BIL	Basic Insulation Level.
CRF	Containment Recirculation Fan.
CB	Circuit Breaker.
CFR	Code of Federal Regulations.
CONED	Consolidated Edison
CCR	Central Control Room.
CVT	Constant Voltage Transformer.
DBA	Design Basis Accident.
DC	Direct Current.
DEMA	Diesel Engine Manufacturers Association.
ECCS	Emergency Core Cooling System.
EDG	Emergency Diesel Generator.
EDS	Electrical Distribution System.
FLA	Full Load Amps.
FSAR	Final Safety Analysis Report.
FTOL	Full Term Operating License.
GDC	General Design Criteria.
GE	General Electric.
GM	General Motors.
GPM or gpm	Gallons per Minute.
HV	High Voltage.
HVAC	Heating Ventilation and Air Conditioning.
IEEE	Institute of Electrical and Electronics Engineers.
kV	kilovolts.
kVA	kilovolt-amperes.
kW	kilowatts.
LC	Load Center.
LOCA	Loss of Coolant Accident.
LOOP	Loss of Offsite Power.
LV	Low Voltage.
MCC	Motor Control Center.
MOV	Motor Operated Valve.
MS or ms	Milliseconds.
MVA	Mega Volt-Amperes.
NEC	National Electrical Code.
NEMA	National Electrical Manufacturers Association.

PR	Protective Relay(s).
PSI or psi	Pounds per Square Inch.
RCP	Reactor Coolant Pump.
RG	USNRC Regulatory Guide.
SCR	Silicone Controlled Rectifier.
SEP	Self Evaluation Program.
SF	Service Factor.
SI	Safety Injection.
STD or Std	Standard.
TS	Technical Specification.
UL	Underwriters Laboratories.
UPS	Uninterruptible Power Supply.
USNRC	United States Nuclear Regulatory Commission.
UST	Unit Service Transformer(s).
UV	Undervoltage.
V	volt(s).
Vac	volts alternating current.
Vdc	volts direct current.
W	Westinghouse.