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REGION I

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LICENSEE: Philadelphia Electric Company
Post Office Box 195
Wayne, Pennsylvania 19087-0195

FACILITY NAME: Limerick Generating Station, Units 1 and 2

INSPECTION DATES: August 31 - October 9, 1992

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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.

TABLE OF CONTENTS

Table of Contents

EXECUTIVE SUMMARY

During the period between August 31 and October 9, 1992, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at the Limerick Generating Station (LGS) and at the Philadelphia Electric Corporate Offices 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 of the 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. To address the second objectives, 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 documents reviewed and equipment inspected, and taking into consideration the compensatory actions regarding the electrical bus transfers, the team concluded that the electrical distribution systems at Limerick are capable of performing their intended functions. In addition, the team concluded that the engineering and technical support staff is adequate for the safe operation of the plant. The inspection also identified a number of design and operational weaknesses which require added management attention. Three of these findings resulted in violations of the NRC requirements. In addition, six issues are unresolved and several other findings were reported as observations.

One area of concern was the design of the automatic electrical bus transfer schemes, particularly the one pertaining to the emergency bus. The review of this area indicated that, in the event of a LOCA with a loss of one offsite source, the emergency loads could result in the degradation of the alternate source and initiate a periodic opening and closing of the supply circuit breaker until stopped by manual action from the operator. Degradation of the alternate source was also identified by the licensee during an Independent Design and Construction Assessment, in 1989, but the initiating event was considered to be outside the design bases and the consequences were not fully developed. This apparent violation is being considered for escalated enforcement action, in accordance with the Enforcement Policy.

In the dc power area, the team noted that the licensee's loading calculations did not reflect the actual battery loadings and they were less conservative. As a result, the Technical Specification (TS) surveillance tests and TS values for dc loading were equally non-conservative. In addition, the voltage requirements for dc components identified by the design calculation were not properly reflected in the battery's surveillance test requirements. These findings, as well as the electrical bus transfer issue indicated that the thoroughness of their technical reviews could be improved. This is needed to assure that applicable regulatory requirements are met and design basis information is documented properly.

Another area considered by the team as requiring added management attention was the testing of safety-related equipment. In this area, a protective relay test witnessed by the inspectors resulted in violations of the Appendix B requirements. In addition, the result of a protective relay test were considered to be less than adequate and the issue is unresolved pending further investigation by the licensee. A licensee evaluation is also required for five additional design issues.

During and after the inspection, the licensee took appropriate actions to address the team's questions and concerns and took adequate interim compensatory measures to address the bus transfer issue. The licensee maintained their focus on safety.

Based on interviews conducted and documents reviewed, the engineering organization was found to be staffed with competent personnel. Good engineering performance was evident in the root cause evaluations and in the modification packages reviewed. Root cause evaluations were well done and identified appropriate corrective actions; modification packages were well organized with safety evaluations properly prepared. The self-assessment program and several licensee initiatives were viewed by the team as indicative of the ongoing effort to improve plant operability and effectiveness of the engineering organization.

A summary of the team's findings is contained in the attached table. The table also identifies the sections of the report which address the specific issues.

SUMMARY OF INSPECTION FINDINGS

		Section	50-352 & 50-353
A.	Apparent Violations		
	1. Inadequate Design Evaluation	3.3	92-81-01
B.	Violations		
	1. Inadequate Control of 125 Vdc Loading	3.14.1	92-81-02
	2. Inadequate Battery Testing	3.14.2	92-81-03
	3. Inadequate Test Control	5.2.3	92-81-04
B.	Unresolved Items		
	1. Transformer Sizing	3.5	92-81-05
	2. 120 Vac Components Voltage	3.7	92-81-06
	3. Control Circuit Fuse Size	3.9	92-81-07
	4. Emergency Bus Loading	3.12.1	92-81-08
	5. RHR & CS Pump Back Pressure	4.1.3	92-81-09
	6. Relay Testing	5.2.3	92-81-10

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 to remain functional during and following a design basis event. The review covered portions of onsite and offsite power sources and included offsite power grids, transformers, normal and emergency buses, emergency diesel generators, 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, fuel and lube oil systems for the emergency diesel generators, and the cooling and heating for the EDS equipment areas.

A physical examination of selected EDS equipment verified their configuration and ratings. In addition, the team reviewed maintenance, calibration and surveillance activities for selected EDS components, and the capabilities and performance of the engineering and technical support organizations in the EDS area. Particular attention was given to the resolution of identified nonconformances and engineering's involvement in the operations issues.

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

Section 2 of this report provides a general description of the Limerick 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

Limerick Generating Station (LGS) Units 1 and 2 generate power at 22 kV and transmit it to their respective switchyard. Two main transformer banks, composed of three single phase transformers each, are used to step up the voltage from 22 kV to 220 kV, for Unit 1, and 500 kV, for Unit 2. An autotransformer and transmission line interconnect the 500 kV and 220 kV switchyard. A simplified single line diagram of the LGS electrical system is provided as Attachment 2.

During unit operation, the required power for the station auxiliary loads is supplied by two 47 MVA unit auxiliary transformers, one per unit, which step the voltage down from 22 kV and feed their respective 13.8 kV buses. In the event of a loss of a unit auxiliary transformer, its auxiliary buses are shifted to two station auxiliary transformers by an automatic fast transfer. These transformers are powered by the 220 kV and 500 kV offsite grids, respectively, and have, each, adequate capacity to supply the 13.8 kV auxiliary buses as well as the emergency buses during startup, shutdown and normal full load operation.

Each unit includes four Class 1E emergency 4.16 kV buses normally aligned, two each, to the two offsite sources. In the event that one of the offsite sources is lost, the associated buses are shifted to the other offsite source by an automatic fast transfer. If all normal power is lost, the four buses are supplied by four 2850 kW diesel generators which are automatically initiated and loaded. An additional emergency backup power source is provided by a 66 kV substation capable of providing power to all connected loads, when a loss of coolant accident (LOCA) in one unit coincides with a safe shutdown in the other unit. Availability of this offsite source is through a delayed manual action. The 480 Vac emergency power is supplied by four load centers (LC) and associated motor control centers (MCC). Power for vital instruments is provided by four 120 Vac buses supplied by dc/ac inverters backed by a 120 Vac emergency source.

The station safety-related dc power consists of four independent battery systems for each unit: two 125/250 Vdc three-wire systems and two 125 Vdc two-wire systems. Each battery is equipped with its own battery charger and distribution equipment. The dc distribution buses provide power to the diesel generators, to the circuit breaker controls, to the 120 Vac vital instrument bus inverters, and to the various safety-related process control components.

3.0 ELECTRICAL DESIGN

To assess the adequacy of Limerick's electrical design, the team reviewed the features and components of the electrical distribution system (EDS). 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 the EDS equipment. In addition, procedures and guidelines governing the design and design change process were also reviewed.

3.1 Offsite Power and Grid Stability

Units 1 and 2, at the Limerick Generating Station, supply two separate switchyards, 220 kV and 500 kV, inter-connected by two 515-230 kV auto-transformers in the 500 kV switchyard. To verify that the offsite power source was in compliance with 10 CFR 50, Appendix A, General Design Criterion (GDC) 17, the team reviewed the results of several analyses addressing the 500 kV and 220 kV systems response under various operating and faulted conditions, e.g., sudden loss of generation, sudden loss of transmission lines or transformers, and major system disturbances (faults). Besides the dynamic analyses, the team also reviewed the normal maximum and minimum power flows surrounding the Limerick Generating Station, the installed capacity and the spinning reserve power of the Philadelphia Electric Company (PECo) system.

The team's review of the Mid-Atlantic Area Coordination (MAAC) Filing report, dated 1982, showed that the analyses had evaluated the post-transient load flow resulting from a simultaneous loss of both LGS generators, but not the systems' transient stability. Therefore, the impact of the loss of the two Limerick 1200 MWe units on the Pennsylvania-New Jersey-Maryland system grid was not known. However, the results of the report indicated that, in the event of a loss of the largest generating unit (1300 MW at Salem) or of the 220 kV and 500 kV transmission facilities, the PJM system would remain stable, its availability would not be adversely affected and the voltage and frequency would recover to their normal range seconds after the clearance of the disturbance. Based on these analyses, the offsite power supply to Limerick generating station was considered to adequately meet the source stability requirements of the GDC 17.

3.2 Bus Alignments

Under normal operating conditions, the non-Class 1E ac station auxiliary loads of Units 1 and 2 are supplied by their respective main generators through the unit auxiliary transformers. The non-Class 1E auxiliary system distributes power to two symmetrical bus systems at 13.8kV, 2.4 kV, 480 V, and 208/120 V levels. Each Unit also is equipped with four 4.16 kV Class 1E buses, arranged in four Divisions, that provide power to all the Class 1E 4.16 kV, 480 V, 120 Vac loads. Each bus is normally powered by either of two offsite power supplies, with the other power supply serving as an alternate power source. On loss of both offsite supplies, the Class 1E buses are powered by four emergency diesel generators (EDGs). Three of the four divisions are required to mitigate the consequences of an accident. The electrical distribution system for Units 1 and 2 are essentially identical except for some common loads associated with the Standby Gas Treatment System (SGTS), and the control room and control structure ventilation systems which are fed from the Unit 1 Class 1E buses.

The team noted that the voltage of the same motor control center or load center was referred to as 440 V, 460 V, or 480 V in the same document or in different documents. Further evaluation concluded that 480 V represented the bus nominal voltage and that 460 V was the motor rated voltage. The 440 V designation had no apparent basis. Although no problems were identified with the voltage designations, the team expressed a concern that the indiscriminate use might lead to confusion and human errors. A similar problem also was noted with the terms "division" and "channel" which appeared to be used interchangeably.

3.3 **Bus Transfers**

Limerick uses two types of bus transfer schemes: for the non-Class 1E 13.8 kV buses, the transfer consists of a simultaneous opening and closing of the normal and alternate supply breakers; for the Class 1E 4160 V buses, a residual voltage (40%) transfer scheme is used.

<u>13.2 kV Bus Transfer Scheme</u>

On loss of the normal power supply from the unit auxiliary transformer, the generator "86 relay lockout signal" initiates two simultaneous signals, one to open the normal supply breaker and the other to close the alternate power supply breaker to the bus. The team noted that the closing circuit of the alternate power source breaker did not include a permissive signal from the opening breaker or from a synchronizing check relay. Discussions with the licensee determined that no transient analysis had been performed to evaluate voltages during the bus transfer nor the effects of an accidental paralleling of the two sources. A study had compared the Limerick transfer scheme to the Susquehanna fast transfer scheme, but the study did not address the phase angle between the sources, the inertia and electrical characteristics of the loads, or the response time of the relays and other components.

The transfer scheme for the 13.8 kV buses includes selector switches to align each bus to one of the two offsite sources. The review of the applicable control circuitry revealed that the switches were not mechanically or electrically interlocked to ensure that both buses were not aligned to the same offsite source and that no alarm had been provided to alert the operator of an inadvertent alignment to the same source. The team expressed a concern that the transfer of both 13.8 kV buses to the same source in conjunction with the energizing of the LOCA loads from the same source might overload the particular station auxiliary transformer and cause a degraded voltage condition on that source. The result would be the initiation of an automatic transfer of the 4.16 kV emergency buses to one of the other sources.

The transients resulting from a potential paralleling of the sources or from a potential transformer overloading were considered to be particularly significant in view of the deficiencies identified in the emergency buses transfer scheme described below.

Emerge. :y Bus Transfer Scheme

The loss . degradation of the normal offsite source voltage below the relay setpoint initiates a transfer of the 4.16 kV emergency buses from the normal to the alternate (preferred) offsite source or to the emergency diesel generator supplied source. Selection between these sources is done automatically by two timers, set at 250 and 500 milliseconds, respectively. Timing of both timers starts when the residual bus voltage has dropped below 40% of the nominal voltage and the associated source is available; timing of the 500 msec timer is interrupted and reset when the preferred alternate source breaker closes. In the event of a LOCA affecting one of the LGS units, all the breakers on the 4.16 kV emergency buses of the affected unit, except those supplying the Residual Heat Removal (RHR) pumps, are tripped. In all cases, the required emergency equipment is automatically loaded on the buses in accordance with a preset time sequence. The LOCA signal causes all emergency diesel generators (EDGs) to start, but loading of the EDGs is not initiated unless the alternate offsite source also is not available.

The team's review of the transfer scheme determined that a LOCA in one unit in conjunction with the loss of one offsite source would cause the remaining safeguard transformer to supply all eight 4.16 kV buses. Considering the size of the emergency loads, the team expressed a concern that the combination of all steady state and transient loads could degrade the second (alternate) offsite power source. Initial discussions with the licensee indicated that, under the postulated scenario, the potential existed for the voltage from the second offsite source to drop below the setting (94.5%) of the degraded grid voltage relays and that tripping of the second source would occur approximately 20 seconds after the loading of the bus had initiated. It was thought the loss of the second offsite source then would have caused the automatic loading of the emergency diesel generators according to the preset sequence.

Apparently this concern was initially raised by the licensee or his consultant, in 1989, during an Independent Design and Construction Assessment (IDCA) of the voltage regulation study. Evaluation of this issue concluded that, to ensure that the loss of the second source would not occur, it would be necessary to lower the setting of a timer that delays the response of the transformer automatic load tap changer from 30 to 10 seconds. The resetting of the timer would have permitted the automatic tap changer to start increasing the transformer secondary voltage before it degraded below the actuation settings of the relays. The licensee planned to reset the timer after the voltage had stabilized (within approximately two hours). They also reviewed the regulations and requirements in this area, but concluded that a LOCA concurrent with the loss of one offsite source was not a design basis event and it was not credible.

In response to the team's concern regarding the impact of the potential delay in accident mitigation, resulting from powering the emergency load initially from the alternate offsite source and later from the EDGs, the licensee performed a preliminary analysis which concluded that, under the postulated scenario, the injection time of the core spray and RHR pumps could be delayed by five seconds and four seconds, respectively. The analysis also concluded that the original accident analysis provided sufficient margin to bound the new scenario.

Regarding the loss of one offsite source, the licensee provided their interpretation of the GDC 17 requirements and indicated that the second offsite source could be a delayed one. This interpretation was their basis for setting at two hours the time for lowering the response time of the transformer load tap changer. In support of their position, the licensee cited statements from GDC 17 and various other references addressing offsite sources availability requirements. These included IEEE Standard 308-1974 (Section 5.2.3(4); Regulatory Guide (RG) 1.32, Revision 2; RG 1.93, dated 1974; and a NRC safety evaluation, dated October 16, 1991, for the Brunswick Steam Electric Plant.

A subsequent detailed review of the control wiring diagrams and further discussions with the licensee identified two additional concerns regarding the emergency buses transfer scheme. First, timer inaccuracies together with breaker contact opening times might cause the two timers to actuate at the same time and result in an unsupervised paralleling of the diesel generator and the alternate offsite source. Second, the team determined that, if the 250 msec and 500 msec timers operated accurately, the emergency loads would be cycled on and off the alternate source at approximately 20 seconds intervals. The cycling would result from the postulated degradation of the alternate source, the subsequent tripping of the supply breaker, and the consequent recovery of the alternate source voltage.

Regarding the potential unsupervised paralleling of the sources, following the inspection, on October 8, 1992, the licensee provided an analysis showing that a minimum of 60 milliseconds existed between the two timers actuation times; therefore paralleling was not possible without a failure of the components involved. To address the cycling of the alternate offsite source, as well as the concerns raised regarding the 13.8 kV bus transfer scheme, the licensee, after an appropriate evaluation, took temporary compensatory measures that included various procedure enhancements and, on October 5, 1992, a reduction of the automatic load tap changer timer from 30 to 10 seconds. However, they still considered the loss of one offsite source concurrent with a LOCA to be outside the design basis.

The licensee's interpretation of the GDC 17 requirements regarding power source availability was considered to be narrow and not to meet the intent of the requirements. In discussing the safety function of the onsite and offsite sources, GDC 17 states that, "...for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that...the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents." Recognizing the importance of the ac sources in the accident mitigation effort, GDC 17 requires that the onsite sources "shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure." For the offsite ac power, GDC 17 requires two physically independent circuits and that "one of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that the core cooling, containment integrity and other vital safety functions are maintained". In addition, it requires that "Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies." The design of the LGS emergency buses transfer scheme and the setting of the degraded grid voltage relays did not ensure that the accident mitigation capability by the onsite and offsite systems were retained following the loss of one offsite source. In addition, the independence of the onsite sources from the offsite sources was not ensured.

In view of the above observations, the team concluded that the electrical distribution system, prior to lowering the actuation time of the automatic load tap changer times on October 5, 1992, did not comply with the requirements of GDC 17. The above requirements could have not been met since, in the event of a LOCA with a loss of one offsite source: (1) the alternate offsite source was not fully capable of accepting the LOCA loads; and (2) the onsite emergency diesel generators were not available to mitigate the consequences of the LOCA until manual action by the operator.

The unavailability of the emergency buses under the postulated condition is considered to be an apparent violation of the GDC 17 requirements and possibly GDC 35 requirements (50-352/92-81-01 and 50-353/92-81-01).

3.4 Load Growth Control

The team reviewed Limerick's Nuclear Engineering Division Procedure NEDP 3.17, which establishes the guidelines and procedures for controlling load changes in the electrical distribution system. The administrative controls provided to address load changes resulting from plant modifications and non-conformance reports were considered adequate. However, the procedure did not address the process to be used for the resolution of load discrepancies identified through the calculations. The load discrepancies identified in the dc system are discussed in Section 3.14.1.

3.5 Equipment Sizing

The team reviewed the station auxiliary loading demands, during various reactor operating and accident conditions, and compared them with the transformer, motor, and switchgear ratings. The ratings of selected sample equipment were found to be generally compatible with their designed duties. However, the team noted that, under worst-case loading conditions, the safeguard transformers were overloaded by about 1 MVA over their maximum rating of 14 MVA and that the transformers associated with load centers 10B201 and 10B202, rated at 1000 kVA, could be overloaded up to 1034 and 1079 kVA, respectively. In response to the team's concerns regarding the capability of these transformers to carry the calculated accident loads, the licensee stated that the transformers could be overloaded for short periods. For instance, ANSI standard C57.96 shows that the 1000 KVA transformers could carry loads 1113 KVA for approximately four hours daily followed by 900 KVA for the remainder of the day without sacrificing their normal life expectancy. Although the calculated overloads were small, it was not clear how long they would persist. In addition, the licensee had not established operating instructions to ensure that the load carrying capability of the transformers defined in the ANSI standards was not exceeded.

This item is unresolved pending the licensee's establishing appropriate load controls to prevent degradation of the transformers (50-352/92-81-05 and 50-353/92-81-05).

The team also reviewed the sizing of the neutral grounding resistors for the EDGs and station service and safeguard transformers and the sizing of the 4.16 kV Class 1E motors for the core spray, service water, residual heat removal, and safety auxiliary cooling system pumps. The team identified no concerns.

3.6 Voltage Regulation

A review of the ac system voltage was performed to ascertain that quality power was provided to the safety-related components. The review determined that both the station auxiliary transformers (SAT) and the safeguards transformers (ST) were equipped with on-load tap changers (LTC). To avoid undesirable momentary tap changes due to starting large motors, the LTC initiating signals of the SATs were delayed by 20 seconds and those of the STs were delayed by 30 seconds. The LTCs of safeguard transformers were set to maintain a voltage of 1.05 per unit (pu) (4364.5 V) of the nominal 4160 V at the transformer output and about 1.03 pu (4285 V) at the 4.16 kV buses.

With the LTCs operating to maintain the selected voltage, the 4 kV and 480 V motors had adequate voltage for both running and starting conditions. The team also reviewed the time coordination of the various LTCs and the starting times of large motors and identified no deficiencies.

The review of the cable sizing calculation for the 120 Vac power circuits (6470E.24) and the voltage regulation study (6300E.20) determined that the cables were sized for 118 V minimum voltage at the 120 V panel. Under heavily loaded conditions, the voltage at the 120 V panel was estimated to be about 111 V. The team expressed a concern that some circuits might not have adequate voltage to perform their design function. Discussions with the licensee indicated that, as part of their self-assessment program, a study was in progress to verify the adequacy of the 120 V circuits. At the team's request, the licensee calculated the minimum voltage for a selected circuit and found it to be acceptable.

3.7 Degraded Voltage Relays

In accordance with Branch Technical Position PSB-1, the isolation of the offsite and Class 1E onsite power systems is accomplished by tripping the offsite source breakers to the 4.16 kV Class 1E buses through three levels of degraded voltage (27) relays. The first level undervoltage relay is set at 0.7 pu of 4160 V and has a pick up time delay of 0.9 second; the second level undervoltage relay is set at 0.875 pu and picks up a 15 second time delay relay; the third level undervoltage relay is set at 0.945 pu and picks up a 60 second time delay relay. In the event of a LOCA, the tripping time of the supply breaker is dropped from 60 to 10 seconds.

The review of the degraded voltage relay setpoints determined that, when the 4160 V Class 1E bus voltage is just above the setting of the third level undervoltage relay, i.e. 3932 V, the corresponding voltage at the 120 V Class 1E panel would be about 106 V, which is 12 V lower than the 118 V basis used for cable sizing. Based on a preliminary analysis performed during the inspection period, under degraded voltage conditions the voltage available at some of the sampled circuits appeared marginal. As indicated above, a study is underway. The acceptability of the voltage at the safety-related 120 Vac components is unresolved pending completion of the licensee's study (50-352/92-81-06 and 50-353/92-81-06).

A review of the second level degraded voltage relay (127Y) determined that, to achieve a drop out time of 22 seconds at 95 V, the voltage relay was operated outside the curve published by the manufacturer. A review of recent calibration identified no concerns with the particular set of relays. However, their accuracy and repeatability cannot be guaranteed when operated outside the manufacturer's specified range. The team considered this a weakness of the degraded voltage tripping design.

3.8 Ac Short Circuit Study

LGS uses 750 MVA circuit breakers with a 60 kA momentary rating on the 13.8 kV bus, and 350 MVA circuit breaker with a 80 kA momentary rating on the Class 1E 4.16 kV bus. The team reviewed short circuit calculation 6300E.19 and found that all the cases studied were based on 1.01 p.u. pre-fault voltage at the 4.16 kV bus, and on 14.3 kV at the 13.8 kV bus. A review of the computer result indicated that the system fault current would fall within the interrupting and momentary ratings of the 4.16 kV breakers. However, the three phase short circuit fault current exceeded the 13.8 kV breaker momentary and interrupting ratings by as much as 34%. The team also observed that the calculation: (1) had not considered the LTC positions of the station auxiliary and safeguard transformers; (2) used a short circuit value for the 500 kV system that was about 10% lower than the more recently calculated value; and (3) did not take credit for the current limiting reactors added at the low voltage side of the station auxiliary transformers.

To address the team's concerns in this area, before the conclusion of the inspection, the licensee revised the system short circuit calculation. The revised results showed that the short circuit fault level fell within the 13.8 breaker ratings. The subsequent short circuit fault current level at 4160 V and 480 V systems also fell within the ratings of the 4160 V and 480 V breakers.

3.9 Equipment Protection and Coordination

The team reviewed the ac system protection and coordination to ensure that safety-related equipment was adequately protected and that, under short circuit or overload occurrences, only a minimum section of the distribution system would be isolated.

A review of coordination study No. 6900E-11 for the 480 volt Class IE system indicated that the protective device settings and coordination were adequate. In addition, a review of several protective relay settings associated with 4.16 kV motor feeders, load center transformer feeder, emergency diesel generator, and offsite power supply breakers identified no protection or coordination concerns. No safety concerns were also identified in the ground fault detection and protection of several 4.16 kV loads that were reviewed on a sampling basis. However, while reviewing the controls circuits of 4.16 kV breakers, the team observed that the closing, tripping, and control circuits were protected by a single 35 A fuse.

The use of 35 A fuses is appropriate in trip circuits, because of the high current drawn by the trip coil, but seldom necessary in control circuits. A fault at the end of a cable might not generate a fault current high enough to be cleared by the fuse. In this case, an undetected fault could cause damage to surrounding cables and prevent other equipment from performing their function.

A worst-case preliminary evaluation by the licensee confirmed the possibility of the occurrence. Therefore, the acceptability of 35 A fuses in control circuits is unresolved pending a detailed evaluation by the licensee (50-352/92-81-07 and 50-353/92-81-07).

3.10 Electrical Penetration Protection and Sizing

The team reviewed Calculation 6900 E.14, Revision 8, and equipment Specification E-40 to evaluate the adequacy of the electrical containment penetrations design. This review determined that the penetrations, supplied by Conax Corporation, had been designed to withstand the temperature rise and mechanical forces developed by the anticipated continuous and short circuit currents and that qualification testing had been performed by the manufacturer to demonstrate their capabilities. In addition, the penetrations circuit conductors were found to be oversized relative to the field cables to accommodate thermal derating.

A sample review of the protection coordination used for the 4160, 480 and 120 Volt electrical penetration circuits indicated that the primary and backup protective devices had been selected and set correctly. Based upon the above review, the team concluded that the electrical penetrations had been properly sized and protected.

3.11 Cable Sizing

LGS uses cable with 90°C rated insulation, shielded, and grounded at both ends, for the 15 kV and the 4 kV Class 1E systems. The cable used in the 480 V Class 1E system uses 90°C insulation and is not shielded. The team reviewed the cable selection calculation for the 4160 V and 480 V Class 1E systems loads and determined that it addressed long term and short term ampacity, short circuit capability, and cable voltage drop during normal running and motor starting conditions. A sample verification of motor cable sizes was also performed. The methodology was considered to be acceptable and the cables appropriately sized.

3.12 Emergency Diesel Generators

The team reviewed the licensee's on-site emergency power supplies. They include four emergency diesel generators (EDG) per plant, each EDG consisting of a Fairbanks-Morse 38 TD 8-1/8 engine coupled to a Beloit 3562 KVA, 900 RPM, 4160 Vac, Model VI-30 FR synchronous generator. A review was also performed of the steady state and transient loading calculations for each EDG. The calculations determined worst-case loading conditions for a particular EDG and calculated the expected loading. The analyses acceptance criteria were that the short time ratings would not be exceeded and that the minimum voltage and frequency recovery requirements of Regulatory Guide 1.9 would be met. Calculation assumptions, analytical procedures, and results with respect to these criteria were also reviewed.

3.12.1 Steady State Loading Analysis

To address the steady state loading of the EDGs, the team reviewed the power demands for the emergency and non-emergency loads on the emergency buses and calculation 6880 E.07, "Diesel Generator Loading (Steady State)," Revision 3, dated July 28, 1992. The data presented were adequate to support the licensee's conclusion that the EDGs and buses are adequate to supply the design basis loads.

A review was also conducted of the electrical one line diagrams for the four emergency buses at each unit and it was determined that there are several large, nonsafety-related loads on each bus. These loads include the Drywell Chillers, on buses C and D, and the Control Rod Drive (CRD) pumps, on buses A and B. The team identified two concerns. The first involved the potential addition of nonsafety-related loads to the four safety-related buses.

The second involved the lack of calculations supporting the assumption regarding the Emergency Service Water (ESW) Pump motor brake horsepower. Because of this lack of data, the team could not verify that the 460 brake horsepower used for the ESW pump was a conservative assumption.

Two nonsafety-related Drywell Chillers, 1303 kW each, and two nonsafety-related control rod drive (CRD) pumps, 250 Hp each, are connected to safety-related buses. These units are shed from their respective buses, during a loss of coolant accident (LOCA) event, by a momentary contact in the breakers trip circuits. However, the breakers close control circuits use signals from nonsafety-related relays. Power to the control circuits comes, in part, from nonsafety-related MCCs that are re-energized a few minutes into the event via operator action. The team was concerned that, if the contacts of the nonsafety relays failed close, the Drywell Chillers and the CRD pump motors might attempt to start. The calculation did not account for either the 1303 kW Drywell Chiller loads or the 250 hp CRD pump loads.

In response to this concern, the licensee explained that the Chillers and the CRD pumps, as well as their control power sources, were tripped by the LOCA signal and that the pumps were not automatically reloaded on the bus. Also, the operating procedures prohibited the addition of these loads to the buses if the loads exceeded the rating of the EDG. Therefore, the calculation need not include those loads. The team noted that the control circuits would be "armed" and, therefore, a failure of the nonsafety-related components could cause the loads to be applied to the bus in an uncontrolled manner. Such occurrence could result in the overloading of the affected buses.

This issue is unresolved pending the licensee's detailed evaluation of the circuits and administrative controls involved to ensure that the emergency buses are not inadvertently overloaded (50-352/92-81-08 and 50-353/92-81-08).

Based on the manufacturer's curve, the ESW pump draws a maximum of 460 brake horsepower. However, a computer model of the system in an off-normal but allowed alignment showed that 589 horsepower was needed to provide the required flow and head. The licensee stated that the model contained errors and could not be used to determine with certainty the maximum horsepower requirements in the described flow alignment. The licensee agreed that the proposed ESW alignment might not be acceptable and could make the associated ESW loop inoperable. Therefore, a procedure change would be necessary to prevent the operator from performing the improper line up. The ESW lineup is further discussed under Section 4.1.2.

Regarding the assurance that the ESW horsepower requirements used by the calculation bounded the actual anticipated requirements, the team requested that calculations or test results be provided. Also, the team requested calculations to show that adequate flow was available to all the EDGs during a combined loss of offsite power (LOOP)/LOCA event in one unit, and a LOOP event in the other unit.

Following the inspection, on October 8, 1992, the licensee supplied the team with the Emergency Service Water test data taken during the pre-operational phase of the Unit 2 start up. The licensee stated that this data represented one running ESW pump, to emulate a single failure, aligned to supply all the coolers and ESW loads expected during a LOOP/LOCA event. This data shows that there is adequate flow to the coolers for heat removal, and that the pump horsepower was below the 460 hp value used in the loading calculation.

The team observed that the demand on the most heavily loaded EDG was about 2772 kW, or about 2.5% less than the continuous rating of the machines (2850 kW). With a margin on the least loaded machine of only about six percent, accurate and conservative mechanical loading calculations were considered necessary to ensure that potential un-analyzed conditions, such as the ESW lineup, would not increase the demand beyond the rating of the machine.

3.12.2 Dynamic Loading Analysis

The team reviewed Design Analysis 6380 E08, "Perform a Diesel Generator Voltage Regulation Study," Revision 3, dated October 24, 1991, to ensure that the EDGs can handle the transient loading placed upon them by the load sequencing circuitry during a LOOP/LOCA design basis event. The computer analysis identified the various loads, sequence times, and cable reactance, as well as methods for integrating the data into a final answer.

The team reviewed the transient and subtransient reactance of the EDG and confirmed that they were the correct values and that these were used in the calculation. The team also reviewed the "one-line" model of the 4160 Vac bus and loads contained in the package and confirmed that the values for loads, bus, generator, and cable reflected the loading as stated in other design documents. No verification of the computer program was made. Based on this evaluation, the team concluded that the results of the computer calculation were reasonable. Also, the licensee's conclusion was reasonable that the EDGs can successfully load and power the required LOOP/LOCA loads.

The team noted that the calculation did not include the effect of stopping and later restarting a load, or the effects of starting a large nonsafety-related load such as the Drywell Chillers. The licensee suggested that, although they had the flexibility to do certain evolutions, they had no requirement for doing them and they would not do them unless a calculation had been prepared to support their acceptability. The team had no further concerns in this area.

3.13 120 Vac Class 1E System

LGS uses four 120 Vac Class 1E panels to supply power to various safety-related loads. These panels are fed from four independent, electrically and physically isolated, Class 1E 480/120 Vac diesel backed MCCs. There are no uninterruptible power sources connected to these panels. However, the reactor protection system is designed with redundant static class 1E battery backed inverters.

Since the Class 1E 120 Vac system was not uninterruptible, the team questioned the adequacy of the power supply for the safety-related instruments and protective systems until the power was restored by the diesel generator during a LOOP event. The licensee stated that vital loads were also powered from "Topaz" inverters which were backed-up by class 1E dc batteries. The team reviewed sample design drawings and determined that essential loads for Emergency Core Cooling System (ECCS), Engineered Safety Features (ESF), and post-accident monitoring systems were provided with these inverters at the control cabinets. A review of the High Pressure Coolant Injection (HPCI) inverter showed that the loading, setpoint and voltage regulation were adequate to meet the design basis requirement. The team also reviewed transformer sizing, loading and protective coordination for class 1E vital panel 10Y101. No unacceptable conditions were noted during this review.

The team noted that the licensee did not have a formal calculation addressing voltage available at the component level. However, discussions with the licensee indicated that they were in the process of performing a voltage study. Refer to Section 3.7 for further discussion regarding the adequacy of the voltage at the 120 Vac component level.

3.14 125/250 Vdc Class 1E System

The Class 1E dc system consists of two redundant (Division I and II) 125/250 V battery systems and two redundant(Division III and IV) 125 V battery systems. The 125 and 125/250 volt batteries consist of 60 lead-calcium cells and are each equipped with its own charger, fuse box, MCC and distribution panels. The capacity of Division I and II batteries are 1500 ampere-hour, whereas the capacity of Division III and IV batteries are 250 ampere-hour. The battery chargers for Division I and II are rated 300 amperes, whereas the capacity of the Division III and IV chargers is 75 amperes.

3.14.1 Battery and Battery Charger Capacity

The team reviewed battery sizing calculation 6600.E.03, Revision 7, to determine the adequacy of the battery capacity. A review of the sizing calculation for the Division I and II batteries determined that, for the worst-case condition, the batteries had adequate design margin. The batteries were designed for a four hour duty cycle. The licensee had considered appropriate aging and temperature correction factors in accordance with IEEE Standard 485-1978.

The battery loading calculation, 6600.E.09, Revision 4A, dated December 1991, was also reviewed to determine the accuracy of the load study. The team's review identified several discrepancies which are discussed below.

Spring Charging Motor

The licensee's review of calculation 6600.E.09, documented in Appendix IX of the calculation, determined that 80 amperes, the maximum inrush current from the spring charging motor, were not reflected in the original loading calculation prepared in 1983 and were not reflected in Tables 8.3-18 through 8.3.26 of the USAR and in Section 3/4.8.2 of the Unit 1 and 2 Technical Specifications (TS). The licensee had verified the impact of this additional load on the sizing of the batteries and determined that the battery had adequate margin. The licensee also had made the determination that, as long as the batteries had adequate margin, the licensing documents, such as FSAR and TS, were not required to be updated. However, the team pointed out that because the affected documents were never updated to reflect the actual loading values, the existing TS surveillance tests were performed based on the original 1983 calculated values and, therefore, were less conservative.

This issue was further discussed with the licensee after the inspection, on October 6, 1992. The discussions confirmed that the update of the design and licensing documents was delayed solely on an engineering judgement that the battery was adequately sized to handle the added load.

High Impedance Fault

An additional 28 amperes resulting from a postulated undetected high impedance fault at the nonsafety-related inverters (identified in calculation 6600 E22, Revision 1) were also not accounted for in the battery loading calculation and in FSAR and Technical Specifications loading tables. The team noted that, as in the above case, the licensee performed a similar battery sizing verification, confirmed that the battery had adequate margin, but did not include this additional loading in the TS surveillance tests.

HPCI Valve

During the review of the licensee's HPCI audit, dated January 1992, the licensee's audit team questioned the loading of HPCI pump discharge valve HV 55-1F105 operation during a design basis accident. The loading calculation and TS values had assumed no amperes from this load. The licensee's review and resolution of this issue indicated that, for the worst-case loading, this valve was not required to operate. Therefore, they concluded that no action was required. During this inspection, the NRC team discussed the load with the licensee and determined that the valve would operate, thus adding 137 amperes to the battery load.

In addition to the above discrepancies, the team noted that the licensee's calculation had not considered the increase in current for constant KVA loads. The licensee stated that they were not committed to IEEE standard 946-1986 which addressed these loads. A subsequent licensee's review of the impact of the additional loads on the battery concluded that the battery was adequately sized. No other discrepancies were identified during this review.

Considering the above discrepancies, the team determined that Division II battery 1B1D101 had the highest load. The team's estimated loads for this battery were 1026.1, 186.1, and 349.1 amperes for the first, second, and third discharge periods, respectively. The corresponding Technical Specifications loading values were 889, 158 and 321 amperes. The team also estimated that, based on the above loading, the battery design margin was approximately 0.8%, assuming a 1.75 volt/cell design.

The existing 60 month performance discharge test acceptance criteria were found to be based on a minimum battery capacity of 80% of the manufacturer's rating, signifying that the battery should be replaced before it reaches 80% capacity. The team determined that the present condition was not an immediate concern since the present capacity was found to be above 100%; the existing surveillance procedures required the licensee to evaluate the battery conditions if the capacity was less than 90% ; and the negative capacity margin was only 2.5%. However, failure to incorporate all the loads from the batteries loading calculations, in the TS surveillance procedures, constitutes a violation of 10 CFR 50, Appendix B, Criterion XI (50-352/92-81-02 and 50-353/92-81-02).

The battery charger sizing calculation 6600.E04, Revision 1, was reviewed to determine the capacity of the charger to support the battery charging loads and to carry the continuous load of the system. The ratings were verified and found to be adequate to meet the loading requirements.

3.14.2 Voltage Regulation

The team noted that the licensee did not have any voltage drop calculation for the 125 Vdc system. The team requested the licensee to evaluate voltages available at certain safety-related components such as the 4160 volt breaker control circuits including closing and tripping coils. Based upon the results of this sample calculation, the components were considered to have adequate operating voltage. The licensee stated that they are in the process of performing a voltage study for the 125 Vdc system and it is expected to be completed by late 1993.

The team also reviewed calculation 6470 E.26, Revision 3, to determine the control circuit wire length design. The review indicated that the licensee designed the maximum allowable control circuit length for the dc system assuming that the battery terminal voltage would not drop below 108 Vdc for the 125 volt battery. However, this design requirement was not reflected in the Technical Specifications surveillance test procedures. The acceptance criteria for the surveillance tests stated the minimum battery terminal voltage to be 105 volts. Failure to take adequate measures to incorporate the design requirements into the surveillance test procedures is a violation of 10 CFR 50 Appendix B, Criterion XI (50-352/92-81-03 and 50-353/92-81-03).

In response to the team's concern regarding the effects of the overvoltage on the dc components during equalizing periods, the licensee stated that this issue had been evaluated during their own independent assessment. The 125 Vdc batteries were equalized at 140 Vdc. A review of the licensee's evaluation determined that they had concluded that the components would perform satisfactorily at the equalizing voltage levels and that the impact on component qualified life would be insignificant. The licensee also stated that they trended component failures to detect age-related problems resulting from overvoltage conditions. No problems were identified in this area.

3.14.3 **Short Circuit Analysis**

The team reviewed the licensee's short circuit calculation No. 6600 E.10, Revision 3, to ensure that 125 Vdc safety-related equipment was adequately protected against short circuit fault currents. The review concluded that the available short circuit current was well within the interrupting rating of the breakers and therefore the protection was considered to be acceptable.

3.14.4 **System Protection and Coordination**

Protective coordination calculation 6900.E15, Revision 5, was reviewed to ensure that faulted or overloaded electrical components were isolated with minimal system supply interruptions. The team noted that there were no nonsafety-related loads fed from the 125 Vdc Class IE buses. The review of the calculation indicated that the 150 ampere fuse in panel 1AD105/1BD105 and the 70 ampere fuse in panel 1AD102/1BD102 were not coordinated properly. A fault downstream of the 70 ampere load could blow both fuses and cause a power outage for the rest of the circuits fed from this panel. Since the lack of coordination resulting from a fault would not impact the redundant 125 Vdc system, the team concluded that this condition did not represent a safety concern. However, the lack of coordination between the fuses was considered to be a weakness of the above panels protection.

The team also reviewed the licensee's ground protection system. A review of the licensee's ground detector circuit calculation No. 6600 E.08 determined that the ground relay pick up setpoints were adequate; that grounds in the dc system were alarmed in the control room; and that a procedure, No. RT-1-095-900-0, Revision 0, had been prepared to locate grounds in the dc distribution system. No unacceptable conditions were identified during this review.

The team also reviewed modifications 6108-1, 6108-2 and 6109-1 that replaced under-sized fuses in 125/250 Vdc applications. The review indicated that 10 CFR 50.59 evaluations, design input and design review were thorough. No unacceptable conditions were noted during this evaluation.

3.15 Conclusions

Based on the sample review of Limerick's EDS design attributes and taking into consideration the compensatory actions regarding the emergency bus transfers, the team concluded that no operability or safety concerns existed and that the design, as modified during the life of the station, was generally acceptable. However, the team identified several areas of concern in the design of both the ac and dc systems. One such area was the design of the automatic bus transfer schemes, particularly the one pertaining to the emergency buses. The team also noted that the licensee's dc loading calculations did not reflect the actual loadings and were less conservative. Furthermore, the TS surveillance tests and TS values for dc loading and voltage requirements were less conservative than the design requirements. These findings indicated that, despite the technical capabilities of the engineering staff which were considered good, the thoroughness of their technical reviews could be improved. This is needed to assure that applicable regulatory requirements are met and design bases information is documented properly.

In addition to the above, several areas require further evaluation by the licensee. These include: (1) potential inadvertent overloading of emergency buses as a result of non-Class 1E components failures; (2) several transformers appeared to be overloaded and no operating procedures existed to prevent degradation; (3) the 120 Vac voltage drop calculations need to be completed to ensure adequacy of voltage at the safety-related components; and (4) certain control fuses appeared to be oversized.

4.0 MECHANICAL SYSTEMS

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 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.

4.1 Power Demands for Emergency Loads

4.1.1 Process Power Demands

The team reviewed various large safety-related loads to determine the hydraulic horsepower demands placed on the EDGs during a LOCA. They chose the Emergency Service Water (ESW), Residual Heat Removal (RHR), and Core Spray (CS) systems. In addition, they reviewed the Instrument Air system, powered by the emergency bus but tripped on a LOCA signal. Like other nonsafety-related loads powered by the emergency bus, the operator has the freedom of loading the Instrument Air compressors on the EDGs after the initial ten minutes following a LOOP/LOCA event. However, the Instrument Air compressors require cooling water from the ESW system. The licensee learned that a realignment of the ESW system to supply cooling to the Instrument Air compressors could make the ESW system inoperable. Therefore, they concluded that the Instrument Air compressors would not be an EDG load during a LOOP/LOCA event. The team noted that the licensee used certified pump curves for ESW, RHR, and CS to determine the pumps maximum required brake horsepower. These values were then used to calculate the maximum electrical horsepower for the steady state EDG loading.

4.1.2 ESW System

The team requested the licensee's calculations for the ESW system hydraulic performance, but determined that a current calculation was not available. Instead, the licensee used a computer model to determine ESW performance and acceptability of modifications. They also used this model as a check to determine the various cooler flows and the total system head and flow.

The team reviewed the computer-generated listing of ESW loads and required flow and head from the ESW pumps for the worst-case flow condition. The review determined that, for the specified conditions, 589 brake or pump horsepower (about 600 electrical horsepower) was required to meet the flow demand. The EDG loading calculation used 460 electrical horsepower. The licensee's review of the calculation found that the program had an error in the modeling of the pump curve. The model was corrected. The licensee also determined that the worst-case lineup included the Reactor Enclosure Cooling Water (RECW) and Turbine Enclosure Cooling Water (TECW) Loops. Therefore, they took procedural steps to assure that the operator knew that placing the TECW or RECW loops in service would render the affected ESW loop inoperable. Regarding worst-case brake horsepower, the licensee noted that they did not have design basis information, but they did have their pre-operational test data to show the adequacy of the system. The test data presented did support the operability of the system and acceptability of the maximum horsepower value used.

4.1.3 RHR and CS Systems

The team reviewed the RHR and CS pump curves to determine horsepower requirements. The review revealed some unusual pump characteristics since the horsepower required at the lowest head and highest flow points on the curve was lower than the mid range required horsepower. The literature provided by the licensee described these pumps as centrifugal pumps. Therefore, horsepower should continue to rise as a centrifugal pump approaches run-out.

To address the apparent discrepancy, the pump vendor, Ingersoll-Rand, was contacted. They reported that the pumps were not centrifugal, but rather mixed-flow pumps. This type of pump provides an axial, or propeller component as well as the radial or centrifugal component, creating a different pump curve from that of a centrifugal pump. The vendor also noted that while the horsepower required did not increase with an increase in net positive suction head (NPSH), the pump horsepower was sensitive to the back pressure at the outlet of the pump.

Since the certified pump curves end at a head and flow above the run-out condition, it is not clear whether the pumps could chug or become unstable if the system conditions allowed the flow and head to fall outside the certified curve conditions. The licensee noted that they were not aware of the need to maintain some minimum back pressure on the pumps, but would explore this requirement.

Based on the vendor's explanation of the pump curve, the team concluded that the horsepower value used for the electrical calculation was conservative. However, the need for and acceptability of a minimum back pressure is unresolved pending the licensee's evaluation (50-352/92-81-09 and 50-353/92-81-09)

4.2 EDG Combustion Air

The licensee's design bases for the EDG combustion air intake system includes a March 4, 1975, letter from the EDG manufacturer which quantifies the combustion air requirements for rated load output. The intake structure piping size and air filter design must provide the required quantity of air to the engine at approximately atmospheric pressure to ensure that the pressure does not degrade the EDG performance.

The inspectors reviewed the licensee's intake air system design, performed independent calculations, reviewed confirmatory test data, and conducted walkdown inspections of the system. The reviews found that the system was capable of providing the quality and quantity of air required under all loading conditions provided that the intake air filter pressure drop is not allowed to exceed the maximum acceptable value. The inspectors found that the licensee's periodic monthly and outage surveillance tests of the EDG include recording the air intake system pressure drop from a local EDG room manometer. Typical readings ranged from 6 to 7.5 inches of water which were considered acceptable. However, the expected reading provided in these surveillance test procedures was "0.3 min" inches of water. This value appeared to be erroneous. It appears that it should be "maximum" and should be expressed in psi since the published pressure drop of the new air filter is 2 inches of water. The licensee acknowledged that the test data sheet "expected value" was in error and indicated that they would conduct an overall evaluation of both the inlet air and exhaust system restriction values.

4.3 EDG Exhaust System

The EDG exhaust system consists of all of the piping, flanges, elbows, mufflers, and screens that are connected to the EDG exhaust headers downstream of the turbocharger, and serve to direct the combustion gases to the outside atmosphere. The inspectors confirmed that the exhaust back pressure did not exceed the maximum allowable of 12" H_2O, for rated EDG output, as indicated in the EDG manufacturer letter of March 4, 1976, to the licensee.

The inspectors also reviewed the licensee's January 17, 1991, EDG exhaust system calculation which included a proposed design modification to extend the exhaust stack an additional 38 feet beyond the present top of building termination. Based upon this review and independent calculations, the team concluded that the exhaust system design, including the proposed modification, is within the manufacturer's acceptable back pressure criteria.

During the review and physical walkdown of the system, the team noted that the roof top exhaust outlet was prone to the collection of water in the EDG exhaust silencer located below in the EDG room. The design included provisions to drain this water through a normally open one-inch drain line at the bottom of the silencer into a locally mounted drain tank. The inspectors found that the water level in this drain tank was routinely verified during operator rounds to ensure that it was maintained above 24 inches to prevent exhaust gases from venting in the EDG room.

The inspectors concluded that the EDG exhaust system satisfied the EDG manufacturer's maximum exhaust back pressure criteria. Furthermore, the licensee's design and procedures provided assurance that the exhaust gases would not vent into the EDG rooms.

4.4 EDG Fuel Oil Storage

The team reviewed the fuel oil storage tanks to ascertain whether sufficient fuel was available for emergency diesel generator operation. The Technical Specifications requires that each storage tank contain a minimum of 33,500 gallons of fuel, equivalent to a 7-day supply for EDG operation at full load, and that each day tank contain a minimum of 200 gallons of fuel.

The team reviewed calculation No. LM 007, dated December 27, 1989, and verified the TS capacity of a fuel oil storage tank. This calculation was based on a horizontal tank 12 feet in diameter and 49 feet long. Review of this calculation indicated that the tank contained sufficient fuel for diesel generation operations. Review of the diesel day tank calculation indicated that the day tank was conservatively sized for the diesel generator operation. The EDG fuel oil quantity is also addressed in Section 5.2.1 above.

4.5 EDG Fuel Oil Quality

The EDG manufacturer specified that the licensee use a commercial grade No. 2 diesel fuel which conforms to specification ASTM D975. The licensee's Technical Specification requirements of Section 4.8.1.1.2 specify that new fuel oil receipts be analyzed to confirm its conformance to the ASTM requirements. However, only partial analysis is required prior to offloading the new fuel into the storage tanks. Complete analyses are not required until 31 days later.

The team questioned whether these requirements could lead to the introduction of improper material into multiple EDG tanks and, hence, to a common mode failure. It was found that procedures S92.3.N and S92.3.0 specifically prohibit offloading unanalyzed fuel into but one tank and transferring unanalyzed fuel oil from one fuel system to another. The periodic analysis of stored fuel oil consists of monthly verification and removal of water and once-per-outage verification and removal of excessive particulate. This sampling and analysis program is sufficient to meet the Technical Specification requirements. However, it does not address long term dilution, breakdown, and contamination of the fuel oil in the tanks, such that it no longer meets the EDG manufacturer's requirements. The inspectors found that the rate of fuel consumption for operational and maintenance testing provides a complete turnover approximately every two to three years. Furthermore, a Technical Specification requirement provides for pumping out and cleaning the tanks every ten years.

The inspectors concluded that the licensee's procedures meet the Technical Specification requirements for the fuel oil quality. The licensee plans an overall evaluation of the fuel oil program to determine if changes are warranted.

4.6 Seismic Qualification

The inspectors reviewed the seismic qualification of selected portions of the EDG system. The licensee has committed to the seismic requirements of GDC 2 and to the guidance of R.G. 1.29, as documented in the FSAR. The review included the qualification analysis documentation for the EDG skid-mounted turbocharger, scavenging air blower and governor and for the off-skid static exciter and voltage regulator panels. The seismic analysis for the above equipment had been performed by the EDG manufacturer. During walkdown inspections, the inspectors noted seismic anchoring and bracing of equipment.

Based upon these reviews, the inspectors found the seismic qualification of the EDG and its auxiliary equipment acceptable.

4.7 EDG Room Heating and Cooling (HVAC)

The licensee's HVAC design is to maintain the EDG rooms normally between 65 to 115°F when the outside air temperature ranges from 0 to 95°F. According to the FSAR, outside ambient temperatures beyond this range are expected, approximately 1% of the time. The consequences are also addressed; e.g., higher room temperatures could slightly increase the thermal aging of some equipment, but would not cause a prompt failure of any safety-related equipment.

Cooling is provided to each EDG room by means of two independent Class 1E duct fan systems which interchange outside air for inside air. Cooling is thermostatically controlled and the fans are sized such that one fan is sufficient to provide the maximum cooling capability for a fully loaded EDG with an outside air temperatures of up to 75°F. The other fan increases this capability up to the design bases of 95°F outside ambient temperature. A high temperature alarm to alert the operators is provided when the room temperature reaches 110°F. Heating is provided to the EDG rooms using auxiliary boiler steam and two nonsafety-related room heaters. A low temperature alarm is also provided when room temperature drops to 55°F.

The inspectors reviewed the licensee's design calculation M-81-14, Revision 3, dated November 18, 1991, which included the EDG manufacturer's letter, dated July 27, 1973, providing the heat balance details required to substantiate the calculations. A review was also performed of the licensee's pre-operational confirmatory tests and evaluations of the adequacy of the Units 1 and 2 HVAC performance (1P-28-1 and 2P-28-1); current EDG operational test data; and independent calculations of HVAC adequacy. Based upon these evaluations, the inspectors concluded that the HVAC is capable of providing proper heating and cooling for sustained EDG operation at rated load. However, they observed that although continued operation of the EDGs with room temperatures either above 115°F or below 65°F was anticipated, the licensee did not appear to have any procedures in place to provide guidance to the operators for such operation.

4.8 Emergency Service Water

The Emergency Service Water (ESW) provides cooling to the EDG jacket water, lube oil and combustion by means of shell and tube heat exchangers mounted on the EDG skid. The BTU heat removal requirements for these heat exchangers at the maximum 3500 kW short-term rating of the EDG are confirmed by the manufacturer to the licensee by a letter, dated July 27, 1973.

To assure the adequacy of ESW cooling to the EDGs, the inspectors reviewed the ESW system design and confirmatory EDG and ESW operational test data, walked down the system, confirmed heat exchanger maintenance cleaning, and performed independent calculations and evaluations of the ESW and EDG systems.

Based upon the above review, the inspectors concluded that the EDG can be properly cooled by the ESW system when provided with not less than the design flow rates and inlet temperature from the ESW system. The capability of the ESW system is also discussed under Section 3.12.1, above.

4.9 Conclusions

Based upon the above reviews, the team concluded that the design of the mechanical systems supporting the EDS was adequate and the that mechanical engineering staff was technically competent and generally knowledgeable of their area of responsibility. The capability of the RHR and CS pump to provide adequate cooling under minimum back pressure conditions requires further licensee review.

5.0 EDS EQUIPMENT

The scope of this inspection element was to assess the effectiveness of the controls that were in place to ensure that the design bases for the electrical system were properly tested and maintained. This effort was accomplished through field walkdown and verification of the as-built configuration of electrical equipment as specified in the electrical single-line diagrams, modification packages, and site procedures. In addition, the maintenance and test programs developed for electrical system components were also reviewed to determine their technical adequacy.

5.1 Equipment Walkdowns

The team inspected various areas of the plant to verify the "as-built" configuration of the installed equipment. Areas inspected included the emergency diesel generators (EDG), 500 kV and 220 kV switchyard, 4 kV switchgears, batteries, inverters, and 480 V load centers.

The walkdown indicated that adequate measures were in place to control system configuration. Electrical equipment inspected was found to be generally well maintained with surrounding areas clear of safety hazards.

5.2 Electrical Equipment Maintenance and Testing

The team reviewed various maintenance and testing procedures for such equipment as the diesel generator, switchgear, circuit breakers, batteries and battery chargers, and protective relays. Licensee personnel were interviewed to assess their understanding of the testing and maintenance programs. The team observations are described below.

5.2.1 Emergency Diesel Generator

Periodic surveillance testing of the emergency diesel generators (EDG) is conducted to assure their operational availability and capacity to perform their emergency shutdown functions. The Technical Specifications require the EDGs to be tested monthly to demonstrate operational readiness and once every refueling outage to demonstrate their capability to start each emergency load within the specified time. In addition, the Technical Specification requires that once every four years, during a refueling outage, all four diesel generators be started simultaneously to verify that they accelerate to at least 882 rpm in less than 10 seconds.

Limerick does not use an integral load sequencer. Instead, time-delay relays are used to stagger the starting of the ECCS pumps at predetermined intervals. The team verified that the starting circuits and the time-delay relays were tested each outage. The team also reviewed the test records to ensure that the sequence intervals were adequate to prevent simultaneous motor starts. Except as described under Section 3.3, no safety concerns were identified in this area.

While watching the monthly surveillance test of EDG 13, the team made the following observations:

Fuel Oil Storage Tank Level Measurements

To check the level of the outside underground fuel oil storage tank, the operator used a weighted steel measuring tape. The method was considered cumbersome, but use of the tape was necessary because of the physical location of the access port. As a result, the operator had trouble getting consistent readings and had to check or sound the tank five times and use a cloth to find the oil level line before he was satisfied with the reading. The team's concern with this observation was that, since the difference between the minimum acceptable level specified by the surveillance procedure and the Technical Specification limit was only four inches in a 12 foot diameter tank, oil deposited on the edge of the access port from repeated checks could cause the Technical Specification limit to be inadvertently exceeded.

Prelube Pump Operation

The diesel generator slow start operability test procedure, ST-6-092-313-1, Revision 5, requires that the operator verify the operation of the prelube pump before continuation of the test. According to the procedure, verification can be done by observing pressure on gage PIGA-102C on the local engine gage panel. The procedure also states that the diesel generator start should not be permitted on a failure of the prelube pump to prevent excessive engine wear.

During the particular test observed, the team noted that the operator did not use the gage to verify prelube oil pressure. Instead, the operator listened for the prelube pump motor running. However, because of the loud sound of the ESW flow, the operator was not able to confirm the starting of the pump motor, nor was he able to locate of the pump to verify operation. As a result, according to the procedure, he notified the Control Room operator to abort the test. The justification provided later for not using the gage was that the slight needle deflection caused by the prelube pump start was too difficult to read. The gage has a full scale range of about 100 psig, whereas the prelube oil pressure is about 2 psig.

A floor shift supervisor dispatched to the EDG room located the pump and the test was continued. To limit the noise in the room, the branch of the ESW system was isolated. When the Control Room operator attempted the second start of the prelube pump by placing the switch to the start position, the pump failed to start. Once again the test was aborted. The operator and floor shift supervisor concluded that the logic controlling the prelube pump had not properly reset before the second attempt. Therefore, the EDG start circuitry was reset to the pre-test condition, and the test restarted for the third time. This effort was successful.

Recognizing that prelube pump operation is necessary to ensure that the EDG is not damaged during periodic testing, the team observed that: (1) the operator should have known the location of the pump; (2) listening for a motor starting in a noisy environment may not confirm operation; (3) the scale of the gage, which provides positive indication of the proper operation of the pump, is too large for proper verification; and (4) the test was restarted two times without trouble shooting the subsystem to properly verify pump operation. These observations were considered to be weaknesses of the prelube system design and of the EDG test procedure implementation.

5.2.2 Station Batteries

The team reviewed the maintenance and testing program of the station batteries to assure that adequate dc power was available to operate the dc equipment. There are four sets of safety-related batteries identified in the Technical Specifications (TS) as requiring surveillance testing. Each battery requires a weekly and a quarterly test of electrolyte and cell voltages, an 18-month service test in accordance with the battery load profile, and a 60-month performance test for battery capacity.

The team reviewed the test procedures of each type of test and found adequate acceptance criteria consistent with the TS requirements with one exception as discussed below. The service test load profile and the performance test final voltage also agreed with the TS.

The TS indicated that each of the 125/2. J V safety-related batteries was rated at 1500 ampere-hours (AH) at an 8-hour discharge rate. However, the battery was tested on a 4-hour basis at a discharge current of 327.5 amperes, which translated to 1310 AH. In response, the licensee obtained a chart from the battery manufacturer. The chart indicated that when an 8-hour based, 1500 AH battery was discharged at a 4-hour rate, after accounting for correction factors, the resulting capacity would be 1310 AH. The team verified that the battery model numbers matched those on the chart and considered this explanation acceptable.

Review of test records of various battery tests indicated that the tests were conducted in accordance with the procedures, and that the final voltages of the performance tests, after 4 hours, were above 108 Volts, although 105 Volts was specified in the TS

The team concluded that the station batteries at Limerick were properly maintained and tested to provide adequate dc power as specified in the TS. However, a dc load calculation (cal #6600E.09), dated December 19, 1991, indicated that the battery load profiles were higher than those specified in the TS and that the final voltage acceptance criterion after a 4-hour discharge test should be 108 V instead of 105 V. These issued are discussed in Sections 3.14.1 and 3.14.2 of this report.

5.2.3 **Protective Relays**

The team observed the surveillance test of degraded voltage relays of emergency bus 201-D14 to ascertain whether the test was conducted in accordance with procedure ST-2-092-324-1. There are three levels of degraded voltage (93%, 87% and 70%) to initiate a bus transfer to the alternate power source. Each level consists of an undervoltage relay and one or more time-delay relays. At 93% degraded voltage, the total time delay is 61 seconds without a LOCA signal, and 10 seconds when LOCA signal is present. The TS allows a maximum of 64 seconds and 11 seconds, respectively. If the total time delay exceeds the TS value, the test procedure requires the technician to notify the shift supervisor immediately, and the TS requires the licensee to declare the degraded voltage logic circuitry inoperable within one hour.

While measuring the time delay value with a simulated LOCA signal present, the test technician measured a time delay of 12 seconds when the test instrument failed. The technician subsequently terminated the test and stated that the test could not be resumed until another test instrument, which was also broken and waiting to be repaired, was ready for use. He also indicated that the shift supervisor had been informed of this condition.

Subsequent discussions with the shift supervisor revealed that no actions had been taken to address operability of the circuit because the shift supervisor only had been informed of the test instrument failure, not the reading of 12 seconds before the test instrument failed. The shift supervisor verified the 12 second reading with the System Manager who witnessed the test and, subsequently, declared the degraded voltage logic circuitry inoperable by racking out the affected breaker. Total elapsed time was about 20 minutes from test termination to declaring the circuitry inoperable.

The team determined that failure to notify the shift supervisor immediately of the 12 second reading, as required by step 6.7.20.1 of the test procedure, constituted a violation of 10 CFR 50, Appendix B, Criterion XI, which states in part that, "A test program shall be established to assure that all testing required to demonstrate that structures, system and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits... Test results shall be documented and evaluated to assure that test requirements have been satisfied" (50-352/92-81-04 and 50-353/92-81-04).

The test was resumed after a new test instrument was obtained from the Philadelphia Electric Valley Forge Test Laboratory. The time delay measured with the new instrument was 10.00 seconds. The degraded voltage logic circuitry was returned to operable status. The failed test instrument was sent to their Valley Forge Test Laboratory for evaluation and repaired in accordance with their M&TE (material and test equipment) procedure.

Following the conclusion of the inspection, on October 8, 1992, the licensee provided further clarifications regarding this issue. The licensee's submittal and subsequent discussions provided no new information. Therefore, the violation stands as stated.

The team reviewed the results of a surveillance test (ST-2-092-324-1, test #3) of relays 127-11702 and 102-11802, associated with emergency bus 201-D14. At 70% degraded voltage level, the actuation time delay of the combined relays should be about 1.00 second. The acceptance criteria for the undervoltage relay setting is 80 to 86 volt; the acceptance criteria for the two relays' combined time delay is 0.9 to 1.00 second. The corresponding TS limits are 79.0 to 87.0 volts and 1.50 seconds. The test result indicated that the as-found undervoltage setting was 85.3 volts and the total time delay was 1.28 seconds. Since the total time delay exceeded the acceptable limit, the technician adjusted the timing to within 0.9 and 1.00 second. However, instead of adjusting the setting of the time delay relay, which was more difficult to adjust according to the technician, the setting of the undervoltage relay was lowered to 83.5 volts. The resulting combined time delay was 0.97 second.

According to the information supplied by the licensee, the undervoltage relay is a fast response General Electric NGV relay. A typical response time for this relay, at 80% dropout voltage (equivalent to 90 volts), is 43 milliseconds (ms) and, at 60% dropout voltage (equivalent to 72 volts), is 34 ms; a reduction of 9 ms for a change of 24 volts. However, the test record indicated that for a change of 1.8 volts, the response time was reduced by

310 ms. The licensee was unable to provide an explanation during the inspection. However, at the exit meeting, the licensee indicated that the 310 ms difference was probably due to drift of the Agastat time delay relay and "cold" and "warmed-up" operating conditions. Since the response raised more questions regarding the validity of the test, the licensee agreed to investigate the matter further.

Currently, the monthly test procedure does not have provisions to measure the individual response times of the undervoltage relay and the Agastat time-delay relay. This item is unresolved pending the NRC's review of licensee's evaluation to determine: 1) the cause of the deficiency, and 2) whether the procedure should be revised to avoid similar problems in the future (50-352/92-81-10 and 50-353/92-81-10).

5.2.4 Circuit Breakers

The licensee has established a maintenance and testing program for their safety-related 4 KV breakers. Accordingly, each breaker receives an overhaul every 5 years using procedure PMQ-092-003, entitled preventive maintenance procedure for Q-listed 4 KV air circuit breaker. Important breakers, such as the 24 breakers feeding power to the 8 safeguard buses from the preferred, alternate, and EDG power sources, are tested monthly in conjunction with the EDG monthly test. Review of maintenance and test records indicated that safety-related 4 KV breakers were adequately maintained and tested.

The licensee also had established a test program for safety-related 480 Vac molded case circuit breakers (MCCB). Each MCCB was tested at 5 years intervals, using procedure PMQ-093-004. Review of test records indicated that these breakers were adequately tested. The MCCB test program did not include 120 Vac and 125 Vdc breakers. Limerick did not use low voltage MCCBs to isolate nonsafety-related loads from safety-related buses.

5.2.5 Switchyard Equipment

Some switchyard equipment plays an important role in the operation of the electrical distribution system. This equipment includes the switchyard transformers; the 500 kV, 220 kV and 13.8 kV circuit breakers; and the switchyard batteries, which provide control power to operate these high voltage breakers. The electrical equipment in both the 500 kV switchyard and the 220 kV switchyard were maintained and tested by the Philadelphia Electric's Transmission and Distribution Division using procedures issued by the Limerick Station. The transformer maintenance consists of Doble tests, oil analyses, and transformer cooling equipment routine maintenance. The load tap changer also received routine maintenance such as contact cleaning and oil level check. The maintenance of the switchyard transformers and the high voltage breakers were performed every second outage. The switchyard batteries were maintained with procedures similar to those for the station batteries. Review of maintenance records indicated that the switchyard transformers, the high voltage breakers, and the switchyard batteries were properly maintained.

5.3 Protective Relay Setpoint Change Control

The program for controlling protective relay setpoint changes at Limerick was prescribed in Procedure A-32, Revision 6, dated January 6, 1992. This procedure also applied to control of instrument setpoint changes, such as transmitter trip unit setpoint changes. It included the initiation, preparation of setpoint change package, safety review, and the PORC (Plant Operation Review Committee) approval of setpoint changes. The final approved setpoint changes are then incorporated into the calibration and test procedures for implementation, and into the protective relay list (Bechtel Drawing E-99).

The team reviewed setpoint change packages for a time-delay relay, for a differential relay, and for a loss-of-field relay. A fourth package reviewed was a Nonconformance Report (NCR) because drawings were not consistent with the Technical Specifications. These packages indicated that the protective relay setpoint changes were being controlled adequately.

5.4 Conclusions

Based upon the above observations, the team concluded that the licensee has an acceptable maintenance and testing program for the Limerick electrical distribution system equipment and a satisfactory program for controlling protective relay setpoint changes. However, two deficiencies were identified in the surveillance testing of an emergency diesel generator and in the functional testing of protective relays. In the first deficiency, the licensee failed to ascertain the proper operation of the prelube oil pump prior to continuing the test; in the second, the technician performing the test failed to notify the shift supervisor that a time delay relay had exceeded the Technical Specifications limit before the test instrument failed. In addition, one item is unresolved and needs further evaluation by the licensee to ensure that it does not impact relay testing in general. The issue pertains to the response time of a General Electric NGV undervoltage relay which deviated substantially from the published characteristics when the setpoint was adjusted.

6.0 ENGINEERING AND TECHNICAL SUPPORT

An evaluation was performed of the licensee's capabilities to provide acceptable engineering and technical support to the plant organization. For this purpose the team reviewed organization and staffing, interfaces between the engineering organizations and the technical support groups responsible for the plant operations, and self-assessment programs. To address the licensee's performance in the electrical engineering and technical support area, the review evaluated the implementation of programs and procedures and examined a sampling of Licensee Event Reports (LER's), Self-assessment Reports, Quality Assurance Audits, Root Cause Analysis and Corrective Action Programs, and Major, Minor, and Temporary Modification Programs.

6.1 Organization and Key Staff

The Nuclear Engineering Division (NED) located at Chesterbrook, Pennsylvania is organized into sections by disciplines. Each section manager reports to the NED Manager, who in turn, reports to the Vice-President, Nuclear Engineering and Services Department (NESD). There is a site branch of NED at the Limerick facility whose head reports to the Manager, Site Engineering section at Chesterbrook. The site NED branch consists of two groups, the Mechanical/Civil and Electrical/I&C, each with its own branch head. At the time of this inspection, and based on the support provided during this inspection, staffing for the electrical engineering discipline was considered sufficient for the technical support of plant operations. Experience and knowledge of licensee staff personnel was varied, both in duration (up to 30 years) and educational backgrounds (advanced degrees in various disciplines).

The location of the site branch of NED is intended to enhance the support provided by NED to the site. The site branch staff provides direct contact with site personnel, expediting communication and resolution of engineering problems with limited need for contacting NED at Chesterbrook. Activities in which NED is involved include modification planning, the performance of internal safety systems functional inspections, and detailed walkdowns in conjunction with site personnel which are performed before, during, and after plant modifications. The major NED effort is expended on preparation of design basis document packages, response to engineering work requests, and resolution of non-conformance reports from the site. Other visible indications of NED support are the development of common procedures for the nuclear facilities. The establishment of design review boards as a self-assessment tool to perform in depth reviews of selected modifications has been effective in centering management attention on the modification process and the resolution to associated problems. The NED self-assessment program has evolved into a program that involves all personnel and management.

To improve communication between NED and the site, the licensee has implemented a program that includes staff rotation, monthly site interface meetings during which ongoing activities are discussed, frequent telephone conversations with site management, and mutual participation on modification teams. In addition, training bulletins are issued to the site in which specific items are discussed. These bulletins are issued on an as needed basis.

Based on the above, the team concluded that the reorganization of the NED site branch was a positive step in improving the departments ability to provide engineering support on a daily basis. The licensee's personnel rotational program provides an excellent opportunity for cross training and has the added feature of improving cooperation and communication between site personnel and corporate engineering at Chesterbrook. The electrical engineering department is involved in a variety of activities and is capable of providing good support to the site for these activities.

6.2 Root Cause Analysis and Corrective Action Program

The team assessed the license's program for root cause analysis and the corrective action process. The program is described in the licensee's document " Root Cause Analysis Guidelines ", Revision 1, used as part of the Nuclear Group Root Cause Analysis Program and In-House Event Investigation Program. The manual provides the necessary information and analytical tools needed to properly conduct an event investigation and determine root causes. It presents five root cause analysis techniques, which, when taken together, represent the Root Cause Analysis Program. These five techniques include: Events and Casual Factors Charting, Root Cause Tree, Barrier Analysis, Change Analysis, and Task Analysis. Training required to implement Root Cause Analysis Technique is provided by the licensee's training department personnel for three days.

Root cause analysis techniques were used to evaluate Licensee Event Report (LER) No. 01-90-013, Revision 1, dated November 1, 1990. The LER pertained to the licensee's failure to meet Limerick Generating Station, Units 1 & 2, license condition 2.C(3), Fire Protection, due to under-rated buses in the Division 1 and Division 2 dc electrical distribution system. A detailed analysis, performed using the Root Cause Analysis Guidelines, Revision 1, determined that the lack of isolation between Class 1E and non-Class 1E components resulted from the use of an inadequate fuse application guide which resulted in under-rated fuses, including the installation of 150 Vdc fuses in the 250 Vdc circuit. Corrective action was immediately initiated with the release of modification packages No. 6108-1, 6108-2 and 6109-1. The corrective action included the replacement of the under-rated fuses with fuses that were properly rated and capable of meeting the design requirement for voltage and interrupting capacity. In addition, the dc panel specification guide was revised to include voltage and time constant criteria and a fuse application guide for the application of fuses in dc circuits.

The team concluded that the licensee's root cause analysis program, as outlined in " Root Cause Analysis Guidelines ", Revision 1, and demonstrated in LER 01-90-013, was comprehensive and an effective tool in determining root causes for complicated issues.

6.3 Self-Assessment Program

Self-Assessment is defined in the licensee's procedure No. AG-82, Revision 0, as a process where an individual or an organization self-identifies and self-corrects their own performance and behavior that does not meet expectation. This is accomplished using the Self- Checking and Evaluation Checklist NED-UG-4-I. Supervisors self-assess their performance in the task of supervisor. Expectations reflect performance standards and behavior expected by customers, higher organizational levels within the licensee organization, and industry. Validation of assessments is accomplished through the comparison of outside inputs such as audits, surveillance, quality control reports, NRC reports, events and outside assessments.

The team reviewed the Technical Section and Electrical Systems Branch self-assessment program to determine the extent of the issues being identified and whether the issues were resolved in a timely manner. This review found that the program encompasses various engineering activities including Safety Systems Functional Inspections (SSFI), QA Audits and Surveillance in various performance levels.

The first licensee's self-assessment meeting was held in August, 1991. Topics discussed include: Strength/Good Work Practices and Concerns/Watch Areas. Opportunities for enhancement of the self-assessment process were identified and are being pursued. Teamwork within the Technical Section was identified as a strength. Procedural compliance was assessed by each branch, concluding that hand held procedures are followed exceptionally well. However, it was noted that there have been occasions where memory was relied upon or individuals were not aware of an existing procedure. Other areas of concern that were discussed and noted in the "Watch Area" include: overdue Procedure Problem Identification System (PPIS) items, technical staff experience levels, systems engineers versus maintenance expectations, and cumbersome procedures for various processes. Task Groups were developed to address these areas of concern.

The Technical Section Electrical Branch performed its second Self-Assessment of 1992 in July. Improvements were noted in systems engineer communication with the staff, increased participation in outage planning, coordination with operations during bus outages, and good support with other branches within the technical group.

The team's review of subsequent meetings indicated a trend toward a more rigorous self-evaluation and effort to resolve issues. Self assessments appeared to be used by LGS as a valuable tool in determining root causes of identified issues and to improve staff performance.

6.4 Technical Staff Training

The Technical Staff Training Program consists of five courses targeted for permanent LGS engineers and technical assistants. The 4 week Boiling Water Reactor Fundamentals course is designed to familiarize the trainee with the basic theory and fundamentals associated with the operations of LGS units 1 & 2. The 6 weeks Technical Curriculum provides basic training in the engineering skills peculiar to nuclear power plants, in general, and to LGS, specifically. The program also includes 4 weeks of job specific training to personnel assigned systems engineering responsibilities; 13 weeks of advanced classroom and simulator instructions to develop the technical knowledge and skills normally required of control room operation; and 16 hours of training to ensure staff is cognizant of the modification process, procedure revisions, changes to regulatory requirements, and operating experience. Specific criteria has been established for remedial training, re-examination, and passing grade requirements.

The team's review of the above program concluded that it contains the necessary elements for a successful training of the technical staff.

The team also reviewed the licensee's Crafts/Technicians training offered at the Barbados Training Center and found that the classroom training along with the hands-on experience to be comprehensive and beneficial in understanding each process.

6.5 Plant Modifications

The team reviewed the area of plant electrical design changes and modifications to ensure that changes to the plant were controlled and performed in accordance with approved licensee procedures and in conformance with regulatory requirements. The team noted that design changes and plant modifications were categorized into major and minor, depending upon cost and engineering impact. Several recent major and minor modification packages affecting the electrical distribution system were reviewed for compliance with licensee and regulatory requirements. Measures to control the identification, coordination, implementation, and documentation of modification packages is specified in licensee procedure No. A-014, Revision 12, dated November 27, 1991. This procedure applies to modifications for both safety-related and nonsafety-related components and systems. The packages reviewed were found to be well organized, thorough, and documented in accordance with established applicable procedures. In all cases, the design had been evaluated for safety impact under 10 CFR 50.59. Applicable drawings were also reviewed to verify current status of the documentation and incorporation of applicable design changes. The team concluded that modifications were procedurally controlled, well planned with implementation and documentation in accordance with established controls.

In addition, the team reviewed modification related nonconformances (NCRs) to determine whether they were processed properly and whether the disposition was adequately justified. The NCRs selected for review included: NCR Nos. L-91304, L-92018, L-91165, L-91064, L-91156 and L-91028. The review found the packages complete, the problem clearly identified, the dispositions properly documented, and the technical justifications adequate to support the disposition.

6.6 Conclusions

To the extent of the interviews conducted and documents reviewed, the engineering organization was found to be staffed with generally competent personnel. Good engineering performance was evident in the root cause evaluations and in the modification packages reviewed. Root cause evaluations were well done and identified appropriate corrective actions; modification packages were well organized with safety evaluations properly prepared. The self assessment program and 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 Sections 3.5, 3.7, 3.9, 3.12.1, 4.1.3, and 5.2.3.

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 personnel, denoted in Attachment 1, at the conclusion of the inspection on October 2, 1992 and summarized the scope of the inspection and the inspection findings.

ATTACHMENT 1

PERSONS CONTACTED

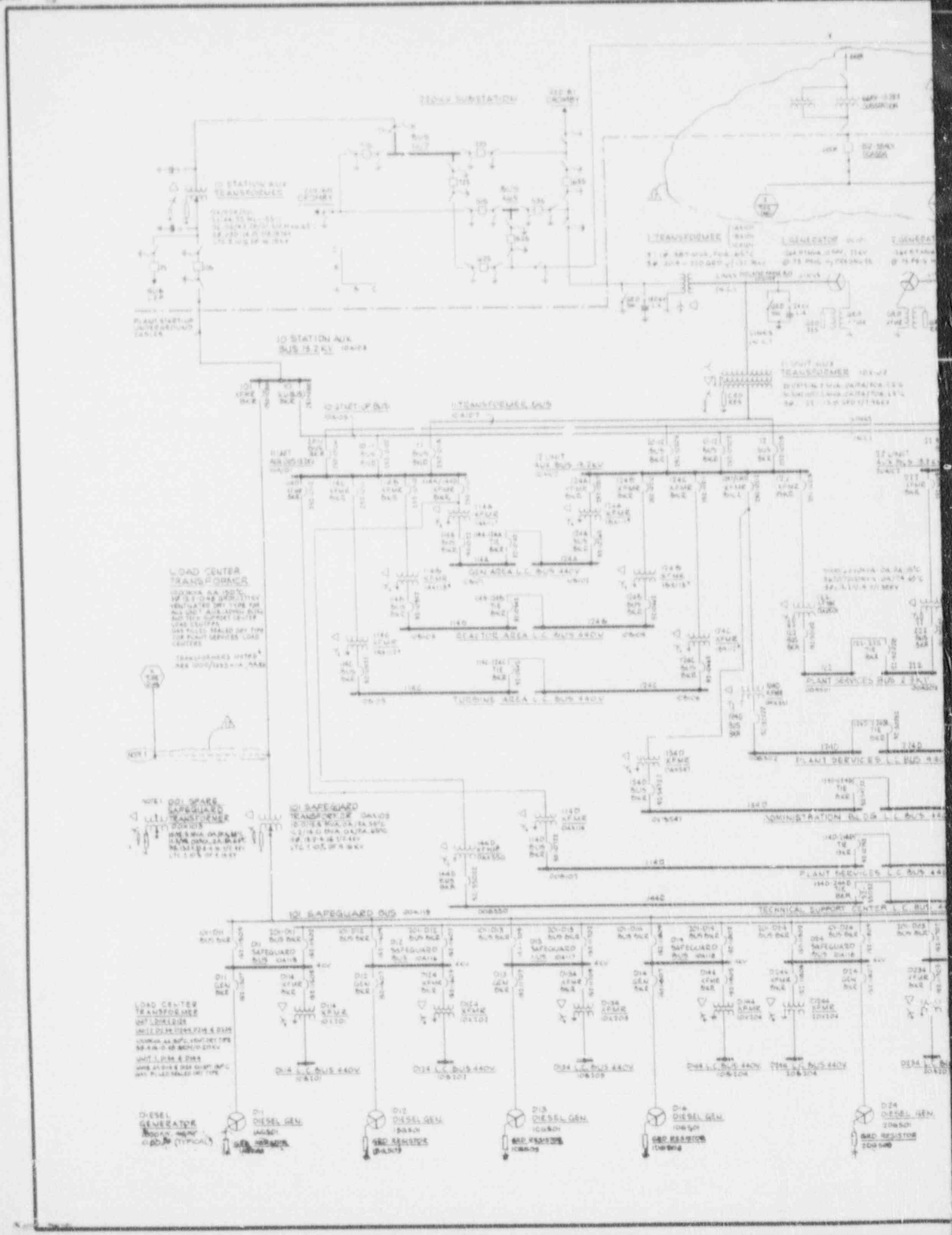
Philadelphia Electric Company

*	W. J. Boyer	Manager Electrical Plant Section
	K. Brennan	Electrical Systems Engineer
	M. Cory	Shift Supervisor
*	J. Coyle	Branch Head - PBAPS Tech.
*	G. V. Cranston	General Manager Nuclear Engineering
*	N. Davey	Maintenance
*	J. Doering, Jr.	Limerick Plant Manager
	J. Evans	Maintenance/I&C Technician
	T. S. Faust	Engineering Instructor
*	M. P. Gallagher	Operations Support Supervisor
*	J. J. Gyrath	Branch Head, Engineering Assurance
*	C. B. Harmon	Engineer, NQA
*	A. Hartman	EDSFI - NED Coordinator
*	R. R. Hess	Manager Mechanical Systems Section
	L. Hopkins	Operations Superintendent
*	J. Hurfnagel	Branch Head, BOP Systems
*	S. Hutchins	EDSFI Preparation Manager
*	A. K. Kar	Consultant
	K. Kemper	Maintenance Planning & Scheduling
*	J. Krais	Branch Head Electrical Systems
*	R. Krich	Branch Head, Licensing
*	G. J. Madsen	Regulatory Supervisor
*	W. McFarland	Engineer, NED
	F. Michaels	Site Engineer
*	W. J. Mindick	Branch Head Power Engineering
*	J. Muntz	Technical Superintendent
*	D. B. Neff	Licensing Engineer
*	J. F. O'Rouke	Manager Projects Division
	J. Phillabaum	Engineer
*	R. B. Rock	Senior Engineer, T&D
	M. Schwicker	Surveillance Test Coordinator
	F. R. Scott III	Senior Engineer
*	T. Shannon	Electrical Systems Engineer
	A. Spector	Senior Engineer
*	G. H. Stewart	Licensing Engineer
	R. Stipcevich	Branch Head, NED
*	T. Strawley	System Manager
*	C. M. Vose	Chief Clerk
	R. Walker	Engineer
	E. Weber	Designer

U.S. Nuclear Regulatory Commission

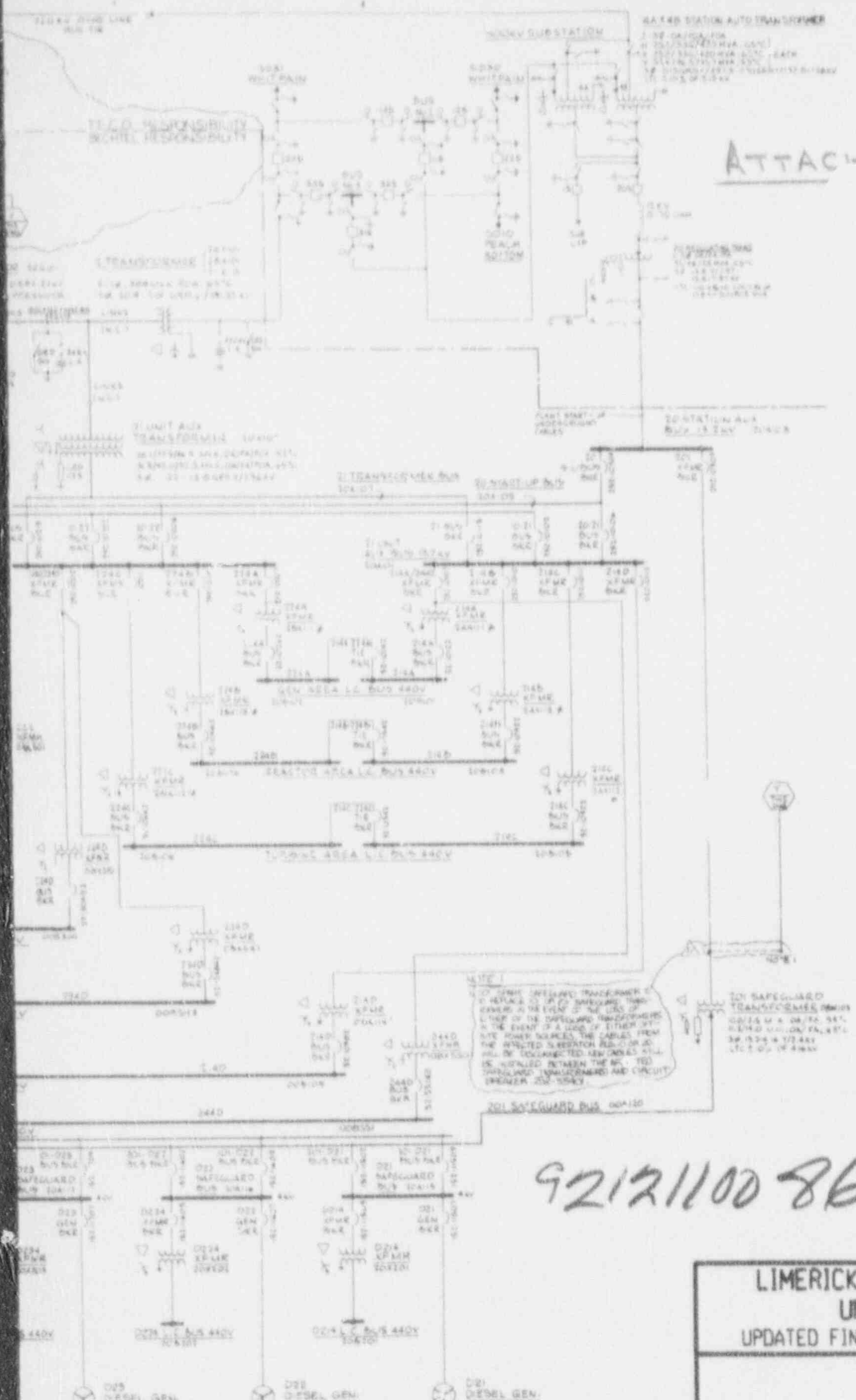
* C. J. Anderson	Chief, Reactor Projects Section 2B
* J. P. Durr	Chief, Engineering Branch,
* M. W. Hodges	Director, Division Reactor Safety
* T. J. Kenny	Senior Reactor Inspector
* W. H. Ruland	Chief, Electrical Section
* L. L. Scholl	Resident Inspector
* D. Spaulding	Reactor Engineer - Intern
* J. Shannon	Electrical Engineer
* E. C. Wenzinger	Chief, Projecus Branch
* J. I. Zimmerman	Electrical Engineer, NRR

* Indicates Present at the Exit Meeting



230KV SUBSTATION
10 STATION AUX TRANSFORMER
10 STATION AUX BUS 13.2 KV
10 START-UP BUS
11 TRANSFORMER BUS
11 UNIT AUX BUS 13.2KV
12 UNIT AUX BUS 13.2KV
1 TRANSFORMER
1 GENERATOR
11 UNIT AUX TRANSFORMER
LOAD CENTER TRANSFORMER
GEN AREA L.C. BUS 440V
REACTOR AREA L.C. BUS 440V
TURBINE AREA L.C. BUS 440V
PLANT SERVICES L.C. BUS 440V
ADMINISTRATION BLDG L.C. BUS 440V
TECHNICAL SUPPORT CENTER L.C. BUS
001 SPARE SAFEGUARD TRANSFORMER
101 SAFEGUARD TRANSFORMER
101 SAFEGUARD BUS
D14 L.C. BUS 440V
D24 L.C. BUS 440V
D34 L.C. BUS 440V
DIESEL GENERATOR
D11 DIESEL GEN.
D12 DIESEL GEN.
D13 DIESEL GEN.
D14 DIESEL GEN.
D24 DIESEL GEN.
GRD RESISTOR

ATTACHMENT 2



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E-1, REV. 17

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STATION SINGLE-LINE DIAGRAM

FIGURE 8.1-1 Rev. 1 July/91

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 or 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.