U.S. NUCLEAR REGULATORY COMMISSION
Region I

Report No. 50-388/84-34

Docket No. 50-388

License No. NPF-22 Priority -- Category C

Licensee: Pennsylvania Power and Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station, Unit 2

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: July 26-31, 1984

Inspectors:

Inspectors:	L. E. Briggs (signed L E Briggs), Lead Reactor Engineer	9/17/84 date
	J. Chung (signed Jin W. Chung), Lead Reactor Engineer	9/17/84 date
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	D. Florek, Reactor Engineer (signed D. Florek)	9/17/84 date

Approved By: T. T. Martin, Director, Division of Engineering and Technical Programs (signed T T Martin) 9/17/84 date

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Inspection Summary: Inspection on July 26-31, 1984 (Report No. 50-388/84-34)
Areas Inspected: Special, announced inspection by 3 region based inspectors (146 hours), 3 resident inspectors (174 hours) and a senior NRC:RI management representative, of the loss of all AC power event of July 26, 1984 at the Susquehanna Unit 2 facility. The inspection consisted of a review and evaluation of: startup test ST-31.1, electrical lineup, sequence of events, plant and equipment response, operator response, administrative controls and corrective actions.

Conclusion: Licensee corrective actions were acceptable. Permission to restart was granted on July 31, 1984.

Results: Four violations were identified: inadequate corrective action for previously experienced problems with plant operator manipulation of DC auxiliary relay and bus control knife switches in 4.16KV ESS breaker cubicles (See Section 3.3), inadequate independent verification of adequacy of rack out activities associated with the 4.16KV ESS bus feeder breakers (See Section 3.4), inadequate procedures for establishing initial test conditions (See Section 3.4) and inadequate training of plant operators in the rack out of 4.16KV ESS breakers, reset of emergency diesel generator alarms and trips, meaning of breaker indicating lights and the restoration of suppression pool temperature monitoring equipment (See Section 3.6).

One deviation from licensee commitment to Regulatory Guide 1.47 was identified for failure to annunciate in the control room safety circuits that are rendered inoperable by tests more frequently than once per year (See Section 3.5).

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LOSS OF ALL AC POWER AT SUSQUEHANNA UNIT 2
INSPECTION REPORT 84-34 - July 26, 1984

1. Introduction

1.1 Purpose

This report documents the results of an NRC review of the circumstances surrounding the July 26, 1984, loss of all Alternating Current (AC) power event at the Susquehanna Steam Electric Station (SSES), Unit 2. It focuses on a description of the event and provides a mechanistic explanation of the event sequence. Additional information is recounted as necessary to place the event in perspective. The report is intended to describe factual information and significant findings associated with the event; and thereby, provide the required data base for appropriate detailed analysis and action by various NRC offices. This latter effort and the resulting dissemination of information will ensure that NRC and the nuclear industry continue to profit from experience.

1.2 Executive Summary

SSES, Unit 2, is a 3293 megawatt thermal, boiling water reactor, Class 4 unit, with a Mark II containment and an advanced control room, the latter in common with Unit 1. The licensee, Pennsylvania Power and Light Company, received a full power license for Unit 2 on June 27, 1984.

On July 26, 1984, the licensee was making final preparations for the conduct of Startup Test ST 31.1, Loss of Turbine Generator and Offsite Power. The test was to be conducted in accordance with the Unit 2 Startup Test Program and was a test recommended by Regulatory Guide 1.68. A successful test would "...Demonstrate that the dynamic response of the plant is in accordance with design for a condition of loss of turbine-generator coincident with loss of all sources of offsite power (i.e., station blackout)..."; and that without manual assistance, the diesel generators would start and power the engineered safeguards system (ESS) busses, and the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) systems would operate to maintain reactor vessel water level above the initiation level of the low pressure ESS equipment.

As part of the preparations for ST 31.1, an experienced nuclear plant operator and test engineer were directed to disconnect (rack out) the Unit 1 to Unit 2 feeder breakers, thereby disabling the Unit 1 capability to assume Unit 2 ESS loads. Normal practice in racking out a breaker includes opening the knife switch which provides direct current (DC) control power to the breaker. Upon opening the first of four Unit 2 ESS bus breaker cubicles containing Unit 1 feeder breakers, the operator and engineer found two knife switches (most breaker cubicles contain only one knife switch). The operator incorrectly opened the knife switch labelled "DC CONTROL" (the title with the greatest similarity to the functional description of the circuit he was attempting to deenergize) instead of the correct switch labelled "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES." The test engineer who was assigned to independently verify the performance of this activity did not detect the error. The operator and engineer repeated the incorrect procedure on all four Unit 2 ESS busses. The result of these errors was:

- complete loss of local, remote and automatic start capabilities for all Unit 2 low pressure emergency core cooling systems

- complete loss of each emergency diesel generator auto start function for loss of power to its associated Unit 2 ESS bus

- complete loss of each Unit 2 ESS bus auto load shedding and power transfer functions

- complete loss of each Unit 2 ESS bus degraded grid voltage protection features

- complete loss of each Unit 2 ESS bus feeder breaker's overcurrent and differential current protection features

No annunciation in the control room was provided for this condition and the only indication of the error, other than the incorrectly positioned knife switches, was two extinguished (normally energized) amber lights on the front of each Unit 1 to Unit 2 feeder breaker cubicle. The condition remained unnoticed for approximately 32 minutes until after the test sequence was initiated.

ST 31.1 was initiated from about 30% power by simultaneously opening the Unit 2 turbine generator output breakers and the offsite feeder breaker to the Unit 2 Startup Bus. The turbine tripped, the turbine bypass valves opened, the reactor scrammed, the recirculation pumps tripped and the primary and secondary containment isolated as expected.

The first anomalies noted by control room operators were the failure of the emergency diesel generators to start and the failure of the Unit 2 feeder breakers to the Unit 2 ESS busses to open. The operator at the diesel panel in the control room opened the Unit 2 feeder breakers, but the diesels still failed to start. The diesels were then remote manually started; but two of the four tripped on overvoltage (signals that would be bypassed during an emergency start), one was tripped by the operator due to large frequency oscillations, and one idled but could not be connected to its' associated Unit 2 ESS bus (probable operator error). Attempts to energize the Unit 2 ESS busses from the Unit 2 Startup Bus similarly failed. Eleven minutes into the event, plant operators, at the direction of the Unit Supervisor, racked in the first of four Unit 1 to Unit 2 feeder breakers. When the associated open knife switch in the feeder breaker cubicle was closed, the associated diesel generator started and the preferred power source energized that ESS bus. Within the next seven minutes, the remaining three open "DC CONTROL" knife switches were closed, restoring the lost functions and equipment capabilities to the associated ESS busses.

Computer driven displays were of little use during the total loss of AC power, even though powered by uninterruptable power supplies (UPS), since most of the sensors upon which they rely are AC powered. The plant instrument AC busses are powered from the ESS busses and are not supported by UPS equipment.

During the period of loss of all AC power to Unit 2, the control room operators monitored reactor power using the uninserted DC powered source range monitors, reactor pressure using HPCI and RCIC steam line pressures, reactor vessel level down to zero inches using installed control room DC powered instrumentation, reactor vessel level below zero inches using local readings telephonically communicated back to the control room, safety relief valve operations from pressure transients and DC powered control room indicator lights, and HPCI and RCIC systems status by DC powered control room instrumentation.

SSES, Unit 1 remained at power throughout the event. Unit 2 electrical and mechanical systems were restored to normal alignment for a hot shutdown condition during the six hour period following the start of the event.

The licensee conducted an extensive multi-department investigation of the event and developed a four tier system of corrective actions for identified problems and concerns. The NRC negotiated a confirmatory action letter on July 26, 1984, and the next day confirmed in an order the licensee's plans to keep SSES, Unit 2 shutdown, until completion of the licensee's investigation and NRC permission to restart. The NRC initiated on July 26, 1984, an independent review of the circumstances surrounding the event, an evaluation of the results of the licensee's investigation and plans for corrective actions, and participation in a meeting with the licensee to compare results of the independent efforts and to assure the adequacy of completed short-term corrective actions. As a result of further review and observation of licensee corrective actions, the NRC granted the licensee permission to restart SSES, Unit 2 on July 31, 1984.

1.3 Significant Findings

1. The event probably could have been prevented had the licensee:

   - ensured that all operators had been trained in the lessons learned from the two previous instances of incorrect operator manipulation of the knife switches providing DC power to the 4.16KV ESS bus auxiliary relay and bus control circuitry (Violation - Corrective Action);

   - provided annunciation in the control room for the loss of power to the 4.16KV ESS bus auxiliary relay and bus control circuitry, as should have been provided in meeting the licensee's commitment to Regulatory Guide 1.47 (Deviation);

   - changed the labelling of the 4.16KV ESS bus cubicle knife switches to clearly reflect their function, and the descriptive names utilized in training and day-to-day operator communications;

   - ensured the person providing independent verification of the correctness of the rack out activity was adequately trained and capable of detecting the operator error (Violation - Inspection);

   - expanded the test procedure description of the expected breaker rack out activity to account for the level of training of the operator and the unusual equipment configuration (two versus one knife switch) to be found is the target breaker cubicles (Violation - Procedures);

   - divided the assignment of 4.16KV ESS bus feeder breaker rack out activities among two or more operators to minimize potential for common mode failures (operator induced) of redundant safety related equipment;

   - trained operators in the meaning and use of 4.16KV ESS bus feeder breaker cubicle panel indicating lights; and/or,

   - required control room and nuclear plant operators to rack out 4.16KV ESS breakers in a step by step process, where each operator would compare available indicators with expected indications.

2. Instrument AC power is derived from the 4.16KV ESS busses and is not supported by UPS equipment. The Safety Parameter Display System, Performance Monitoring System and Display Control System are powered by UPS equipment, but the majority of the sensors which feed these systems are powered by instrument AC, and the outputs of these systems are of little use during a blackout. Regulatory Guide 1.97 instrumentation is also powered by instrument AC and therefore unavailable during blackouts.

With the exceptions of reactor water level (below a vessel level corresponding to zero inches on the narrow range level instruments), rod position and suppression pool temperature instrumentation, available direct reading control room instrumentation was adequate to implement the licensee's station blackout procedures to control the plant and safely place it in a normal hot shutdown condition.

3. The licensee's operator training program was inadequate; in that:

   - Nuclear Plant Operators (NPOs) did not know how to reset sealed-in trips of the Emergency Diesel Generators (EDG's);

   - NPOs were unaware of the meaning of some local indications on switchgear cubicles that would indicate abnormal breaker or control power lineups; further, proper methods for racking out breakers had never been formally taught;

   - Control Room Operators (CROs) did not know how to determine control rod position after the blackout using the OD-7 program and the Performance Monitoring System (this technique is only available on Unit 2);

   - CROs had not been formally trained in the techniques to be utilized in achieving a remote manual emergency start of the EDGs (no dedicated pushbutton for this function is provided at SSES) or in remote manually energizing a dead 4.16KV ESS bus with the EDGs;

   - CROs did not know how to reset the suppression pool temperature monitor instrumentation following the restoration of plant AC power; and

   - SSES did not have a training program tracking system to ensure all operators had received required non-routine operator training prior to assuming shift duties (Violation - Training).

4. SSES, Units 1 and 2, have four shared EDGs, each with two redundant control/starting circuits. The redundant circuits provide assurance that failure of one circuit would not prevent the respective EDG from starting or from continuous operation, when required. Required Surveillance Testing demonstrates that the associated EDG starts and runs without ascertaining that both redundant start circuits are operational. No specific requirement is stipulated in the Technical Specifications or FSAR to do otherwise.

5. In general, the performance of SSES supervisors and operators during the event reflected a good knowledge of plant equipment and of station procedures, and a capability to coordinate human and hardware resources to safely cope with the plant outside the design envelope.

1.4 List of Abbreviations

AC	Alternating Current
ADS	Automatic Depressurization System
ATWS	Anticipated Transient Without Scram
CRO	Control Room Operator
CS	Core Spray
DC	Direct Current
ECCS	Emergency Core Cooling Systems
EDG	Emergency Diesel Generator
ESS	Engineered Safeguards System
IRM	Intermediate Range Monitor
LCO	Limiting Condition for Operation
LPCI	Low Pressure Coolant Injection
MSIV	Main Steam Isolation Valve
NPO	Nuclear Plant Operator
NSSS	Nuclear Steam Supply System
PCO	Plant Control Operator
PMS	Performance Monitoring System
RCIC	Reactor Core Isolation Cooling
RSCS	Rod Sequence Control System
RHR	Residual Heat Removal
RPIS	Rod Position Indication System

SDV	Scram Discharge Volume
SIP	Standby Information Panel
SPDS	Safety Parameter Display System
SRM	Source Range Monitor
SRV	Safety Relief Valve
STA	Shift Technical Advisor
TS	Technical Specifications
UPS	Uninterruptable Power Supply

2. Startup Test ST-31.1 - Loss of Turbine Generator and Offsite Power

2.1 Purpose and Acceptance Criteria

In accordance with Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants", the purpose of the test was to demonstrate that the plant responded in accordance with design for a condition of loss of turbine-generator coincident with loss of all sources of offsite power. The test meets acceptance criteria when the required safety systems initiate and function properly without manual assistance.

2.2 Planned Conduct of Startup Test

2.2.1 Description of Test Method

With the Unit 2 loads isolated from Unit 1 sources and the reactor at approximately 30% power, the main turbine-generator and the unit's offsite power source breakers were tripped from the control room. The initial power level was established greater than turbine bypass capability to permit verification of recirculation pump trip logic actuation.

The loss of offsite power condition was to be maintained for at least 30 minutes to demonstrate that necessary equipment, controls, and indication were available to remove decay heat from the core using only emergency power supplies.

2.2.2 Licensee Pretest Predictions

The licensee completed a pretest prediction of the loss of turbine-generator and offsite power startup test using the RETRAN-02 computer code to simulate the reactor response.

Assumptions

The simulation was performed with the following initial conditions:

Reactor power = 30% of rated power
Feedwater flow = 3.6 Mlb/hr (26.5% of rated flow)
Core flow = 39 Mlb/hr
Recirculation flow = 12 Mlb/hr
Water level = 35 inches

A coast down time of 5 seconds was used for the feedwater pumps. The time delays between the initiation of the main turbine trip and reactor scram, bypass and MSIV valve movement, and recirculation pump trips were taken from Unit 1 data. The nominal setpoint used for SRV actuation was 1076 psig. HPCI and RCIC initiation setpoints were taken as -38 and -31 inches respectively, and the injection water temperature for both systems was assumed to be 77°F. The initial suppression pool temperature was assumed to be 70°F. The RETRAN calculation was based on the assumption that no operator action takes place for the first 30 minutes of the test.

Predicted Results

The turbine and feedwater pumps trip at time = 0.0. A trip of the feedwater pumps is assumed to occur due to low suction pressure caused by the loss of the electrically driven condensate pumps. The reactor scrams at 0.17 seconds followed by a trip of the recirculation pumps at 0.29 seconds.

Following the closure of the main steam isolation valves (MSIV's) at 10 seconds, the reactor pressure gradually increases due to the generation of decay heat within the isolated vessel. At 578 seconds, the Group-1 SRV's (2 valves) actuate at a set point of 1076 psig. The valves discharge steam to the suppression pool for a period of about 5 seconds about every 100 seconds until the initiation of RCIC injection to the vessel. The reactor water level reaches the set point for RCIC initiation (-31 inches) at 1343 seconds into the transient. The RETRAN model used a constant RCIC injection flow of 616 gpm which caused a water level increase of about 1.6 inches/minute. After RCIC initiation, the reactor pressure increases for about 250 seconds to within a few psi of the Group 1 SRV initiation set point before starting to decrease.

The steam discharged to the suppression pool through the SRV's and from the RCIC turbine exhaust causing an increase in pool temperature of about 4°F.

2.3 Preparation for Testing

2.3.1 Test Procedure Review, Approval and Briefings

The licensee was found to have conducted 20 separate reviews, briefings and analyses prior to the conduct of ST-31.1, "Loss of Turbine-Generator and Loss of Offsite Power".

2.3.2 Test Personnel/Staffing

The licensee predesignated a startup test director and an operations coordinator, the latter to work with the startup test personnel in procedure review and development. A specific date and time for conduct of the test was established to minimize interferences of and with other work activities. The licensee assigned a shift supervisor and unit supervisor for conduct of the test and planned specific activities to be performed to recover from the test. Additional shift operations crew and startup test engineers were held over from the previous shift to assist the shift responsible for performing the test. The Operations Supervisor and Plant Superintendent were in the control room during the conduct of the test. Technical staff personnel were also monitoring plant/system/component performance.

2.3.3 Initial Plant Conditions and Deviations from Normal Electrical Distribution

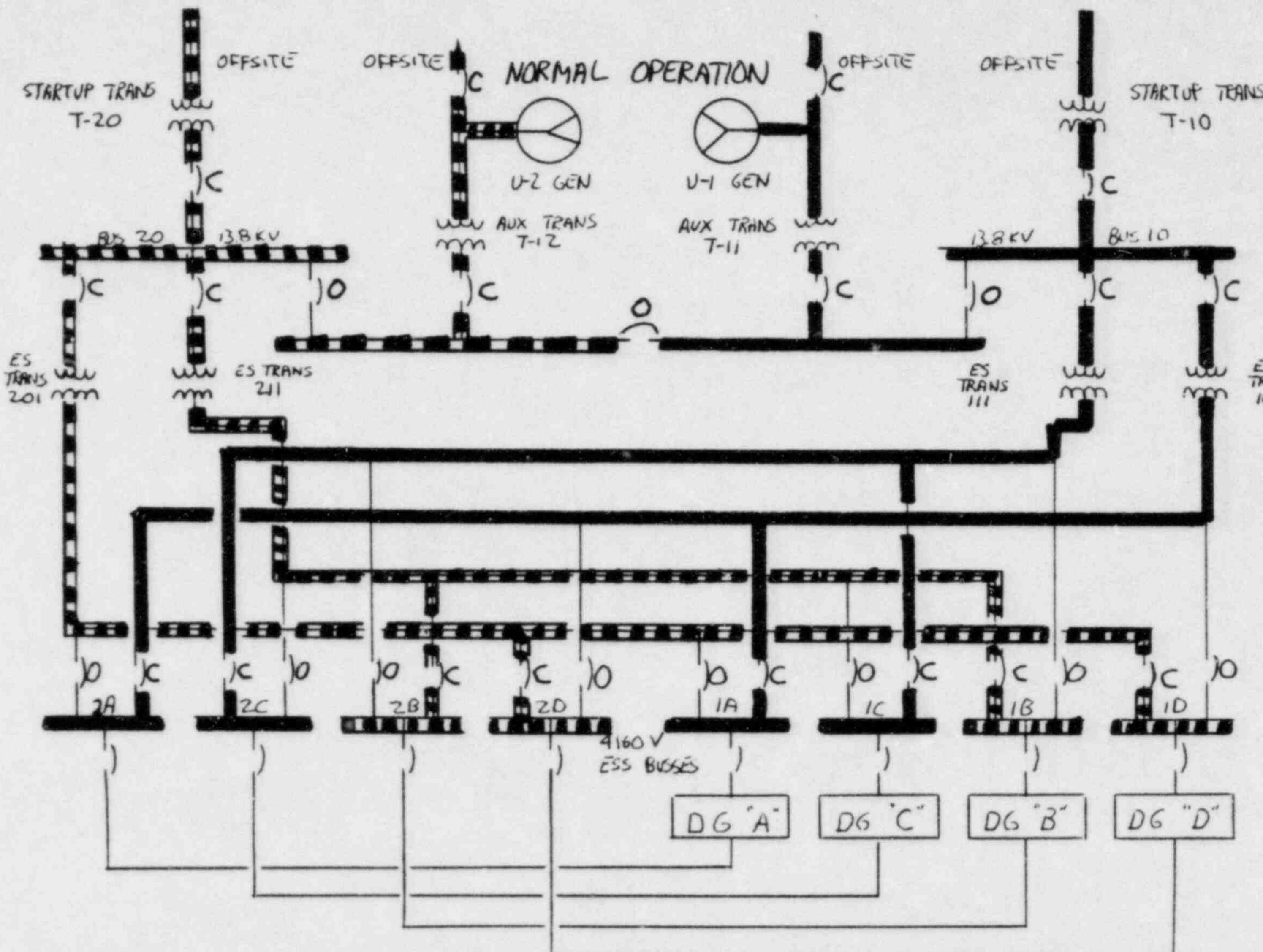
The startup test required electrically isolating Unit 2 from Unit 1. All Unit 2 loads were fed from the Unit 2 busses, all Unit 1 and common loads were fed from the Unit 1 busses and the appropriate breakers were racked out to prevent automatic transfer of Unit 2 loads to Unit 1 sources.

The normal station electrical line up for both units synchronized to the grid is shown on Figure 2-1. Normally Unit 1 Auxiliary Transformer (T-11) supplies the Unit 1 auxiliary bus and the Startup Transformer T-10 supplies the Unit 1 startup bus and ES transformers T-111 and T-101. ES Transformer T-111 feeds Unit 1 ESS bus 1C and Unit 2 ESS bus 2C. ES Transformer T-101 feeds Unit 1 ESS bus 1A and

Unit 2 ESS bus 2A. Unit 1 ESS bus 1B and Unit 2 ESS bus 2B are fed from ES transformer T-211 which in turn is fed from Startup Transformer T-20. T-20 also feeds ES transformer T-201 which supplies Unit 1 ESS bus 1D and Unit 2 ESS bus 2D. The Unit 2 Auxiliary transformer (T-12) feeds the Unit 2 auxiliary busses. Should the preferred supply to one of the ESS busses be lost, the supply from the alternate source would automatically be connected. Capability also exists to feed the auxiliary busses from either unit.

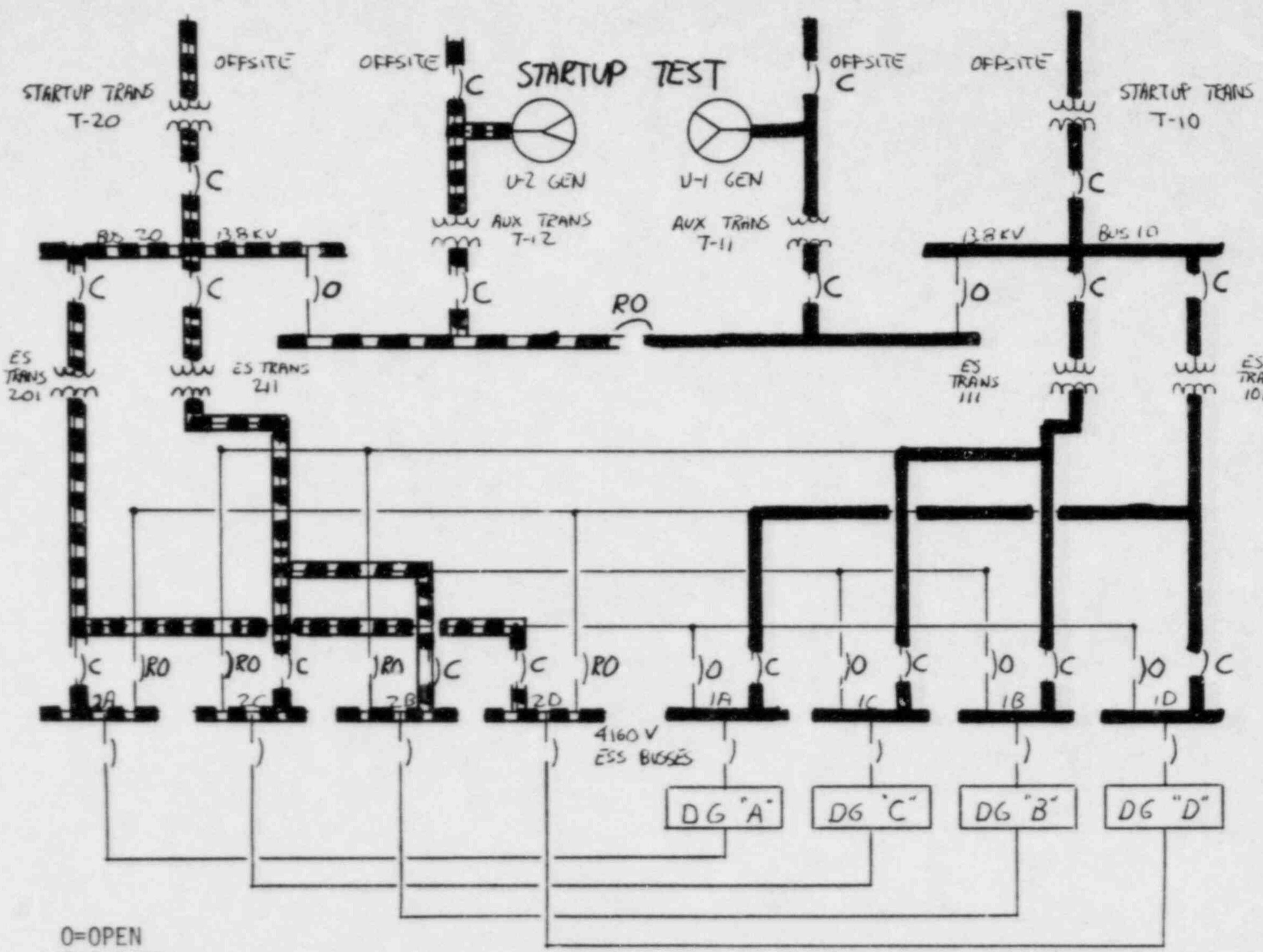
The electrical lineup for this startup test is shown in Figure 2-2. The Unit 1 was lined up so that the Unit 1 ESS busses 1A, 1B, 1C and 1D are fed from startup transformer T-10. The Unit 1 Auxiliary Transformer was feeding the Unit 1 Auxiliary bus. Unit 2 was lined up so that ESS busses 2A, 2B, 2C and 2D were fed from startup transformer T-20 and the feeder breakers to Unit 2 busses 2A, 2B, 2C and 2D from startup transformer T-10 were racked out. Unit 2 auxiliary bus was fed through auxiliary transformer T-12 and the tie breaker between the Unit 1 and Unit 2 auxiliary busses was racked out.

The electrical breaker configuration placed Unit 2 in a Limiting Condition for Operation (LCO) under Technical Specification 3.8.1.1. The actual performance of the test, when the output breaker from Startup Transformer T-20 was opened, placed Unit 1 in a LCO under Technical Specification 3.8.1.1 and 3.8.3.1 and Unit 2 in LCO 3.8.3.1. These technical specifications basically require redundant offsite supplies to the ESS busses.



O=OPEN
C=CLOSED

FIGURE 2-1 NORMAL OPERATION



O=OPEN
C=CLOSED
RO=RACKED OUT

FIGURE 2-2 STARTUP TEST

3. Personnel Error - Electrical Lineup

3.1 Operator Actions

As noted earlier, the electrical lineup for the test involved among other actions, isolating the Startup Transformer T-10 supply to the four Unit 2 4.16KV ESS busses by racking out the Unit 1 feeder breakers at the Unit 2 ESS busses. To accomplish this, a Reactor Building Nuclear Plant Operator (NPO) was told by the control room to meet the Startup Test Engineer (STE) at the ESS busses. The STE had a copy of the startup test procedure which indicated that the above breakers should be racked out. The procedure did not specify the process to be followed in racking out the breakers. It was standard practice at Susquehanna to rack out a breaker by (1) ensuring that a breaker was open, (2) de-energizing the breaker DC control power, and (3) disconnecting the breaker.

Prior to racking out the breakers, the NPO called the control room and indicated that he was going to rack out the four required breakers. He also asked if the control room wanted DC control power removed and he received an affirmative response. The NPO then opened the first breaker cubicle and verified the breaker was open. He found that the cubicle contained two knife switches, a 15 amp knife switch labeled "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES" and a 30 amp knife switch labeled "DC CONTROL". A diagram of bus 2A breaker compartments is found in Figure 3-1. The NPO incorrectly opened the 30 amp knife switch and disconnected the breaker. The STE looked into the cabinet and verified that the operator opened the knife switch labeled "DC CONTROL". Neither the NPO nor the STE looked at the front of the cubicle to see which, if any, indicating lights were extinguished. They then proceeded to the other three ESS busses and repeated the incorrect process. After completing the above breaker lineup, at approximately 1:05 a.m., the NPO informed the control room that the breakers were racked out and DC control power was removed. The Plant Control Operator then verified that the indicating lights for the Startup Transformer T-10 supply breakers to the four Unit 2 ESS busses were extinguished as he expected.

When the NPO incorrectly opened the 30 amp knife switches, he de-energized DC auxiliary relay and bus control power for each of the 4.16KV ESS busses. The control room had no annunciation or specific indication of loss of DC auxiliary relay and bus control power. Had the control room operator been watching his indication of breaker position and known when the knife switch was opened, he might have noted the breaker position indication remained lit and determined that breaker control power had not been removed. This anomalous indication was subsequently lost when the indicator deenergized on disconnecting the breaker. Indirect indication of loss of this DC power was available locally on the front of the breaker cubicles, but neither the NPO nor the STE checked the front of the cubicle. One of the functions interrupted by opening the knife switches was bus lockout protection. On the front of the cubicle, there are three (or two depending upon the bus) lockout relay amber indicating lights which extinguish upon loss of DC auxiliary relay and bus control power. If the correct knife switch had been opened, these lights (which are labeled "86A", "86A1", and "86A2") should not have extinguished. Even if they had checked it, it is unlikely that they would have realized that the wrong knife switch had been opened, since neither had been trained in the meaning of the indicating lights.

3.2 Consequences of Loss of DC Auxiliary Relay and Bus Control Power

3.2.1 Circuit Description

The auxiliary relay and bus control circuit for each of the 4.16KV ESS busses is identical in function. A simplified schematic diagram is shown in Figure 3-2, and was derived from licensee drawing No. E-103 Sheet 14, Revision 12.

The six (6) major control functions are:

(1) Bus Electrical Protection.

(2) Degraded Grid Voltage Protection.

(3) Undervoltage Detection.

(4) Dead Bus Manual/Auto Closure Permissive.

(5) Emergency Diesel Generator Auto Start.

(6) ECCS Sequence Start Permissive.

3.2.2 Loss of Functions

Loss of DC auxiliary relay and bus control power results in the following consequences for the involved 4.16KV ESS bus (busses):

- Loss of bus, feeder and EDG electrical protection (lockout relays 86A, 86A1 and 86A2).

- Loss of ability to manually re-energize a 4.16KV ESS bus from either the preferred or alternate offsite power sources during dead bus conditions.

SIMPLIFIED BUS 2A BREAKER CUBICLE

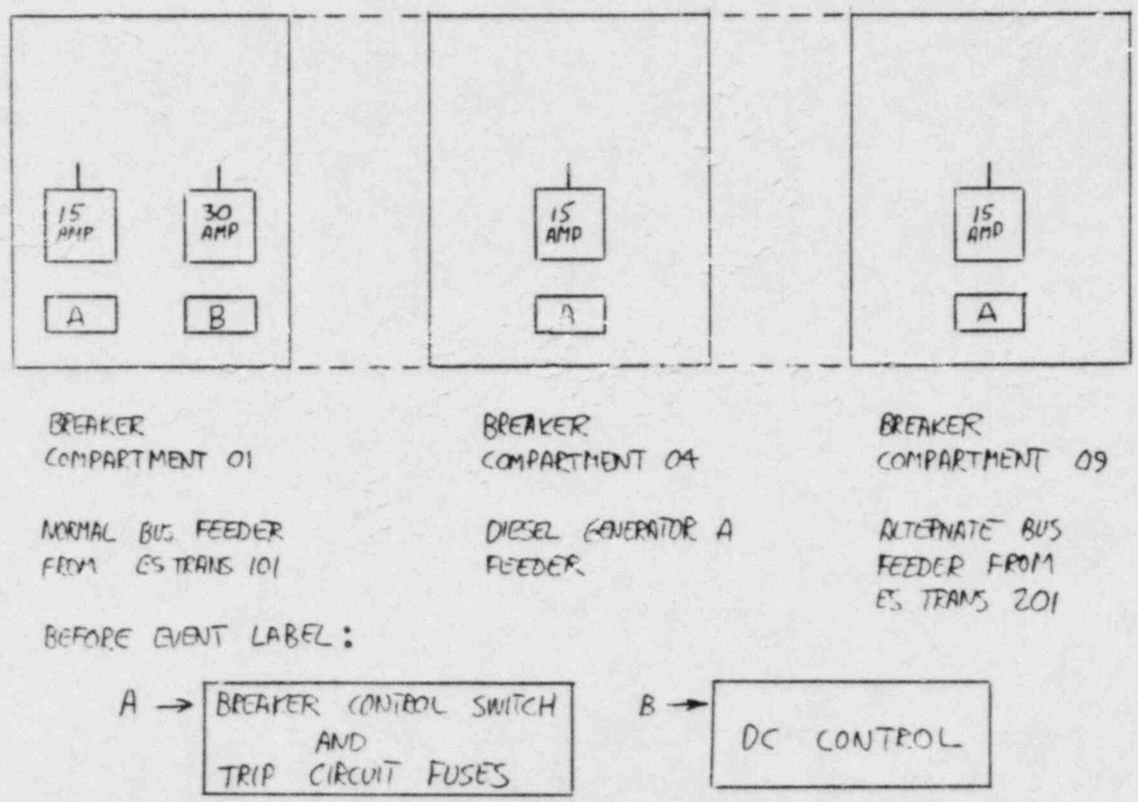


FIGURE 3-1

SIMPLIFIED ESS 4160V BUS AUX RELAY CONTROL
(TYPICAL 1 OF 4)

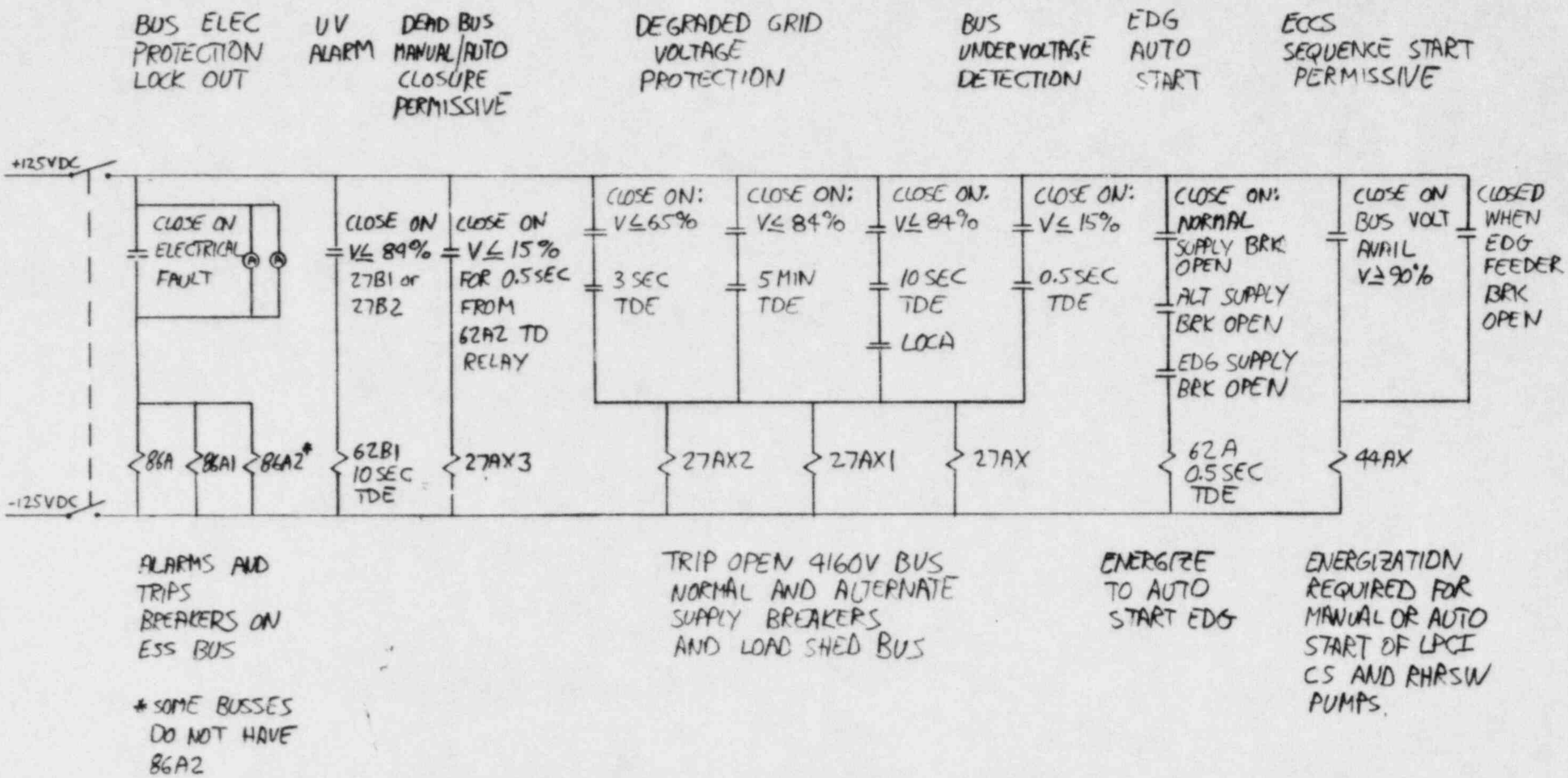


FIGURE 3-2

- Loss of 4.16KV ESS bus 3-way automatic transfer capability between the preferred, alternate or EDG sources.

- Loss of degraded grid voltage and undervoltage protection on the ESS 4.16KV bus.

- Loss of the 4.16KV ESS bus load shedding feature.

- Loss of automatic start of the EDG on opening of all 4.16KV ESS bus feeder breakers.

- Loss of ability to manually (locally or remotely) or automatically start the RHR, Core Spray or RHR Service Water Pumps.

The consequences associated with the loss of this circuit could, if applied to more than one of the 4.16KV ESS busses, result in operation of the plant outside the design basis envelope. The specific plant operations involved with the Unit 2 event on July 26, 1984 resulted in a loss of all enumerated functions described above on all four 4.16KV ESS busses. The moment the operator opened the knife switch labelled "DC CONTROL", the ECCS functions of the associated 4.16KV ESS bus were disabled.

3.2.3 4.16KV Feeder Circuit Breaker Operation

Each Class 1E 4.16KV ESS bus (A-D) is provided with a preferred and an alternate offsite power feeder and one EDG feeder. In the event of loss of preferred power to an ESS bus, bus undervoltage relays, which are set at less than 15 percent rated voltage on the 4.16KV switchgear, will initiate an automatic transfer to the alternate power source. If both offsite supplies are lost, the EDG will start automatically and the EDG output breaker will automatically close after the EDG reaches nominal voltage and speed. The transfer mechanism allows only one source breaker to be closed at any one time and to ensure this, breaker auxiliary switch contacts are used for interlocking. See Figure 3-3.

The EDG output breaker can be closed manually if the following permissives are met:

-- breaker control switch in closed position

-- keylocked synchronizing switch "ON"

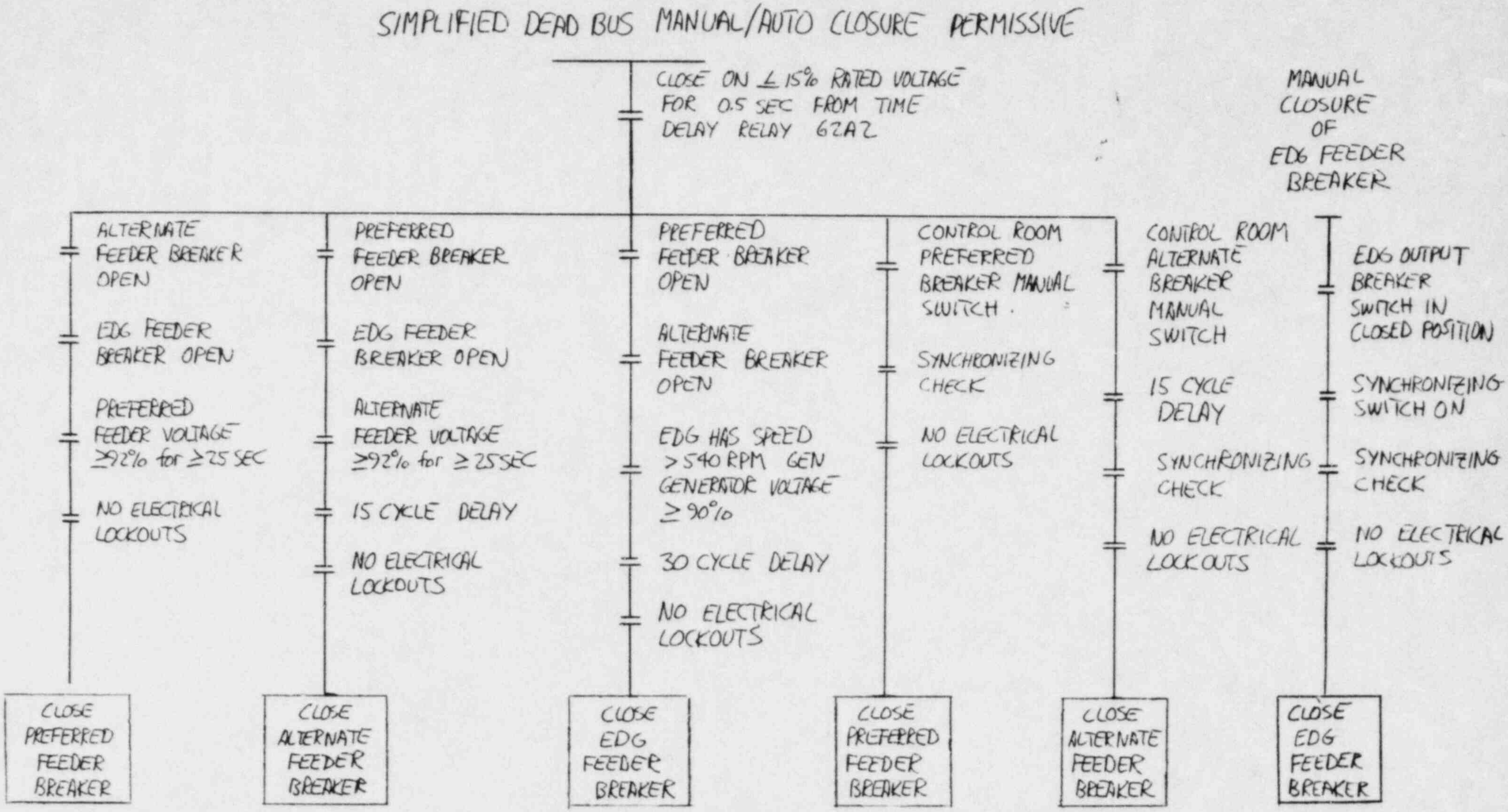

SIMPLIFIED DEAD BUS MANUAL/AUTO CLOSURE PERMISSIVE
CLOSE ON ≤ 15% RATED VOLTAGE FOR 0.5 SEC FROM TIME DELAY RELAY 62A2
MANUAL CLOSURE OF EDG FEEDER BREAKER
ALTERNATE FEEDER BREAKER OPEN
EDG FEEDER BREAKER OPEN
PREFERRED FEEDER VOLTAGE ≥92% for ≥25 SEC
NO ELECTRICAL LOCKOUTS
CLOSE PREFERRED FEEDER BREAKER
PREFERRED FEEDER BREAKER OPEN
EDG FEEDER BREAKER OPEN
ALTERNATE FEEDER VOLTAGE ≥92% for ≥25SEC
15 CYCLE DELAY
NO ELECTRICAL LOCKOUTS
CLOSE ALTERNATE FEEDER BREAKER
PREFERRED FEEDER BREAKER OPEN
ALTERNATE FEEDER BREAKER OPEN
EDG HAS SPEED >540 RPM GEN GENERATOR VOLTAGE ≥90%
30 CYCLE DELAY
NO ELECTRICAL LOCKOUTS
CLOSE EDG FEEDER BREAKER
CONTROL ROOM PREFERRED BREAKER MANUAL SWITCH
SYNCHRONIZING CHECK
NO ELECTRICAL LOCKOUTS
CLOSE PREFERRED FEEDER BREAKER
CONTROL ROOM ALTERNATE BREAKER MANUAL SWITCH
15 CYCLE DELAY
SYNCHRONIZING CHECK
NO ELECTRICAL LOCKOUTS
CLOSE ALTERNATE FEEDER BREAKER
EDG OUTPUT BREAKER SWITCH IN CLOSED POSITION
SYNCHRONIZING SWITCH ON
SYNCHRONIZING CHECK
NO ELECTRICAL LOCKOUTS
CLOSE EDG FEEDER BREAKER

FIGURE 3-3

-- synchronizing check permissive (sources synchronized or ESS bus deenergized and EDG voltage present)

-- no bus lockout present

3.2.4 4.16KV Load Circuit Breaker Operations

The Class 1E system is divided into four load groups per unit. All Class 1E AC loads are divided among the four load groups so that any combination of three out of four load groups has the capability of supplying the minimum required safety loads. The distribution system of each load group normally consists of one 4.16KV ESS bus, one 480V load center, four or five motor control centers, and several low voltage distribution panels. The following are typical loads supplied by the 4.16KV ESS buses:

-- RHR pumps

-- Core Spray pumps

-- Emergency Service Water pumps

-- RHR Service Water pumps

-- Control Rod Drive pumps

-- Reactor Building Chillers

-- Turbine Building Chillers

-- Engineered Safeguard Load Centers (480 VAC)

In the event of loss of preferred and alternate offsite power supplies, the Class 1E 4.16KV ESS buses will shed all loads except the 480V load centers. Under accident conditions, the 4.16KV ESS loads are sequenced onto the bus by individual timing devices. The actual timing sequence is dependent upon whether offsite power is available, or the EDG is providing power. For example, the Core Spray pump breaker receives an auto-close signal 15 seconds after a LOCA initiation signal if offsite power is available, or 10.5 seconds after the diesel generator is providing power. The Core Spray pump breaker will then automatically close if the following permissives are satisfied:

-- control switch in normal position

-- Unit 1/Unit 2 pump interlock (Unit 1 and Unit 2 pumps cannot operate at the same time)

-- no bus lockouts present (86A relay)

-- bus voltage permissive (44AX relay)

-- pump breaker open

-- no breaker overcurrent condition (seal-in)

The offsite power available signal in the pump initiation signal is provided by the bus undervoltage auxiliary relays (27AX) from the bus auxiliary relay control circuit. The diesel generator power availability signal is provided by the diesel generator output breaker auxiliary contacts. The bus voltage permissive (44AX relay) for the breaker auto-close scheme is provided by an energize to operate relay which is set at 90% voltage. This permissive is bypassed when the diesel generator breaker is open.

The 4.16KV load breakers receive automatic trip signals from the bus undervoltage relay (27AX) for load shedding purposes, and bus lockout relays (86A) for equipment protection.

The breakers can be manually closed on the bus if the bus lockout, bus voltage and breaker overcurrent permissives are satisfied.

3.2.5 Emergency Diesel Generator (EDG) Control Circuitry

There are two redundant EDG control/starting circuits for each diesel for added reliability. Each circuit is supplied from the same 125V DC battery system from each unit, but through separate circuit breakers. Only one circuit is required for starting and keeping the EDG in a running mode. The system is designed so that any single component failure cannot prevent the EDG from starting.

The emergency start circuit contains three normally closed contacts in series with the LOCA condition repeater relay. When the repeater relay deenergizes, a EDG start is initiated. Two of the contacts open on a total loss of offsite power to the associated 4.16KV ESS bus (1 contact for each unit).

The loss of power signal is received from the DC auxiliary relay and bus control circuit (see Figure 3-2) when the 62A relay energizes. The third contact opens on a safety injection initiation signal (low reactor vessel level, high drywell pressure, or manual actuation). After auto-starting, the EDG are designed to be ready to accept loads within 10 seconds after the initiation of the start circuit.

Control power for each EDG is provided by one of two corresponding 125V DC systems, from Unit 1 and Unit 2, respectively. Each pair of DC systems have been provided for ease of maintenance, since automatic power seeking source switching is not provided. Indication of which unit is supplying the DC control power is not provided in the control room or locally. Manual switches installed at the local EDG panel allow selection of the power source. Since each EDG is shared by both units, either source of DC control power is considered adequate. Loss of DC control power to the diesel generator start circuit is indicated in the control room and on the local control panel.

3.3 Precursor Events

3.3.1 Nature of Events

The licensee had two previous occurrences of operators incorrectly opening a DC auxiliary relay and bus control knife switch in an ESS bus breaker cubicle, when trying to open the knife switch associated with breaker control power.

Most ESS bus breaker cubicles had only one knife switch, labelled "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES", which distributed DC power to the associated breaker control circuitry. One ESS bus breaker cubicle in each ESS bus load center contained two knife switches, one labelled and distributing DC power as described above and one labelled "DC CONTROL", the latter distributed power to the ESS bus DC auxiliary relay and bus control circuitry (bus logic circuitry). Regardless of the label of the knife switch distributing DC power to the breaker control circuit, the switch was loosely referred to by supervisors, engineers and operators as the breaker "DC Control Power Switch".

On June 4, 1983, while performing preoperational bypass indication testing (A263.1B), the operator opened the incorrect knife switch causing a loss of power to the ESS bus 2C. The operator had opened the knife switch that distributes power to the DC auxiliary relay and bus control circuitry rather than DC to the breaker control circuitry.

On October 6, 1983, during a tagging evolution, an operator mistook a DC knife switch that distributes power to the DC auxiliary relay and bus control circuitry as the switch that provided breaker control power. A complete loss of the ESS bus 2A resulted when the incorrect DC knife switch was opened.

3.3.2 Licensee Corrective Action to Preclude Reccurrence of Earlier Events

In the first event, the licensee concluded that the procedure specified the correct knife switch. The licensee indicated that if operations personnel were in doubt as to how to properly operate the equipment, then the system startup engineer should be contacted.

In the second event, the involved operator was counseled on the need to positively identify the component/device to be tagged. Although the operations department was directed to review the need for changing the switch labelling, the department concluded that switch labelling was adequate. This event was included on the Supervisor of Operations Weekly Meeting agenda. All shifts received training in the period January 6 - January 27, 1984. Approximately 100 individuals received training in the event. The operator who performed the breaker rackouts on July 26, 1984 to setup for the test did not receive the training.

The activities of the licensee in providing training to plant personnel to preclude reccurrence of improper operation of the 4.16KV DC auxiliary relay and bus control knife switch was not effectively implemented such that significant conditions adverse to quality of previous occurrences were not corrected. This is contrary to 10 CFR Part 50, Appendix B, Criterion XVI and as such constitutes a violation (388/84-34-01).

As described in Appendix A, to preclude reccurrence, the licensee has: taken action to assure that individuals have received all the training necessary prior to assuming duty (Item No. 2-84-04-22); revised the labelling on the knife switches (Item No. 2-84-04-01); conducted lessons learned training from this event (Item No. 2-84-04-17); and reviewed operations, maintenance and startup procedures (Item 2-84-04-35).

3.4 Human Factors

3.4.1 Procedures

ST-31.1, Loss of Turbine-Generator and Offsite Power, Revision 3, dated July 24, 1984, steps 97, 98, 99 and 100 require the bus 10 supply breakers to ESS busses 2A, 2B, 2C and 2D be RACKED OUT with a footnote that disabling these breakers results in entering an LCO on Unit 2 per technical specification. The lack of specific steps in the procedure for the proper selection of one of the two knife switches in these breaker cubicles was a contributing factor to the personnel error. Reliance was placed on the operators training and qualification for performing routine tasks, such as racking out breakers in the development of the procedure, without compensation for the unusual situation to be encountered by the operator, namely, finding two knife switches versus the normal one knife switch found in most breaker cubicles.

The rackout operation of the 4.16KV feeder breakers is not a frequent operation. On the job training was utilized to train operators.

The operator asked the control room if they wanted "DC control power" removed when the breaker was racked out. When the control room responded affirmative, the operator opened the knife switch labeled "DC CONTROL".

The operators utilized the function description name of "DC CONTROL POWER" for the knife switch that was actually labeled "BREAKER CONTROL SWITCH AND TRIP CIRCUIT FUSES". If the proper label had been addressed in the startup procedure, or the label changed to reflect popular usage, or additional training been provided to the operator, or proper terminology been utilized by the two operators in communication, the proper test setup might have been obtained.

The licensee activities affecting quality did not include documented instructions appropriate to the circumstances. This is contrary to 10 CFR Part 50, Appendix B, Criterion V and as such, constitutes a violation (388/84-34-29).

3.4.2 Independent Verification

An experienced startup engineer accompanied the operators to verify proper breaker lineup. There were 101 steps in the electrical lineup and all but the rackout of the Bus 10 supply breakers to the Unit 2 ESS busses and the Unit 1 and Unit 2 tie breaker were completed by the afternoon shift. The night shift completed the last five breaker rackouts at 1:05 am on July 26, 1984.

Interviews were conducted with the operator and startup engineer that performed the rackout of the ESS breakers. Both acknowledged that the actions were completed without hesitation and with the thought they accomplished what was required in the procedure. The startup engineer was an experienced individual who had been through the preoperational program and had seen breakers racked out before. He had accompanied the operator on all four ESS breaker rackouts.

The independent verification was not effective. The independent verification did not observe the indications available on the local panels when the knife switch was opened, only after the breaker was racked out. The status lights in the other breaker cubicles were also not observed. Had breaker status indication been observed during the steps of breaker rackout, the error in the operators actions might have been detected.

The licensee program for independent verification of activities affecting quality was not effectively executed. This is contrary to 10 CFR Part 50, Appendix B, Criterion X and as such, constitutes a violation (388/84-34-30).

The startup engineer had not been trained to the same extent as the operator performing the breaker operations, and even if he had received the same training, it is doubtful that he would have detected the error. The licensee is reviewing their independent verification program as described in Appendix A, Item No. 2-84-04-31.

3.4.3 Engineering/Design Adequacy

The engineering/design adequacy factors contributing to the personnel error involved in racking out the Unit 2 ESS 4.16KV bus feeder breakers from the ESS transformers 101 and 111 were reviewed. Engineering design was inadequate and misleading in designating the labelling for the DC auxiliary relay and bus control power as "DC CONTROL".

The engineering drawing developed for the 4.16KV ESS bus auxiliary relay control, E-103 Sheet 14, specifies the multiplicity of functions provided. A designation of the label for the knife switch disconnect as "DC CONTROL" is, from a human factors viewpoint, a design inadequacy. Common power industry practice for the racking out of air circuit breakers call for opening the DC control power for the breaker once the breaker is verified to be open. The similarity of labelling for the knife switch in question established conditions that contributed to the actions which resulted in the multiple improper racking out of the 4.16KV ESS bus compartment 1 feeder breakers. Following the precursor events, (see paragraph 3.3), the adequacy of the labeling was considered by the Operations Department, but an engineering review of the human factors involvement in those occurrences was not adequate. As a result, appropriate labelling changes were not made. Although training operators in the correct operation of racking out these specific breakers is important in preventing errors, as long as the obtuse and misleading labelling existed, operations personnel could conceivably follow common nomenclature and inadvertently utilize the wrong switch as part of the breaker rackout process.

A second design inadequacy involves the ability to purposely remove or have an inadvertent loss of power from this very important DC auxiliary relay and bus control circuit without a clear annunciation of this condition to alert operations personnel. There appears to be inconsistencies between this circuit and other important circuits when it comes to annunciation of DC control power loss. This is exemplified by the fact, that, loss of the emergency diesel generator (EDG) feeder breaker closing circuit DC control power is annunciated by both the Bypass Indication System (BIS) and Computer System. The only knowledge that an operator would have relative to loss of functions from the removal of DC power to the auxiliary relay and bus control circuit would be from either of the following:

-- control room observations that remote indications of breaker position did not extinguish at the exact time that the incorrect knife switch was opened, or

-- observation by the operator racking out the breaker in compartment 1 that the amber indicating lights for the two or three lockout relays were extinguished on that compartment's door.

Even with the use of the lockout relay amber lights as indication of DC power availability, loss of various control functions due to removal or failure of various circuit fuses, would not be indicated. Although the circuit power is fed by the same knife switch, not all functions are monitored by the amber lights. The licensee assessed the indications available to detect a loss of DC power in various breaker controls in resolution of Appendix A action item 2-84-04-10.

3.5 FSAR Commitments

FSAR Sections 8.1 and 8.3, sections referenced therein and Questions/ Response Section 040 were reviewed to identify any commitments in the FSAR that were not satisfied by the conditions found on July 26, 1984.

This review determined that the commitments in FSAR Section 3.13.3 regarding Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems" were not satisfied. That Regulatory Guide requires automatic indication in the control room for each deliberately induced inoperable status that renders safety systems or their auxiliaries unable to perform their safety function if this occurs more frequently than once per year. The licensee performs a monthly surveillance SM-204-009, "Monthly 4KV Degraded Voltage Channel Functional Check" on all Unit 2 ESS busses. This surveillance opens links T11-3 and T11-4 in the DC auxiliary relay and bus control circuitry. The consequences of this action is to disable emergency diesel generator (EDG) loss of power auto starts. No annunication of this condition is provided in the control room. This is a deviation from an FSAR commitment (388/84-34-03).

The licensee completed the equivalent monthly surveillance SM-104-009 on the Unit 1 ESS busses on July 30, 1984. At the request of NRC, the licensee verified restoration of links T11-3 and T11-4 connections subsequent to performance of the surveillance. The continuity checks were witnessed by the NRC inspector with no problems identified.

The licensee has instituted actions to review the Regulatory Guide 1.47 compliance based on the actions on July 26, 1984. These actions are discussed in Appendix A, Item No. 2-84-04-26.

3.6 Training

As described in other sections of this report, several instances of inadequate training were identified:

- inadequate training in 4.16KV breaker rack out (Sections 3.4.1 and 3.4.2)
- inadequate training in emergency diesel generator alarm reset (Section 5.14)
- inadequate training in breaker indicating light recognition (Section 3.1)

- inadequate training in restoration of suppression pool temperature monitoring (Section 5.11)

Inadequate training was a contributing factor to the event of July 26, 1984. The training provided to the operators did not provide assurance that suitable proficiency is achieved and maintained. This is contrary to 10 CFR Part 50, Appendix B, Criterion II and is considered a violation (388/84-34-02).

4. SEQUENCE OF EVENTS

SUSQUEHANNA UNIT 2 EVENT CHRONOLOGY

Time and Event	Section Reference	Contributing Cause and Comment
July 25, 1984		
10:30 p.m.		
Preparation for Startup Test: ST31.1, Loss of Turbine-Generator and Off-Site Power	2.2 and 2.3	Incoming 3rd shift personnel were briefed on test scope, pre-test conditions and anticipated sequence of events.
Reactor lineup completed for test;		
Breakers aligned for test, except 4.16 KV ESS bus feeder breakers from unit 1 T10, and unit 1 to 2 tie breaker.	3.4.2	
11:00 p.m.		
Third shift personnel assumed the watch in preparation for the startup test.		
July 26, 1984		
01:05 a.m.		
Final Preparation for Startup Test:		
Unit 1 to unit 2 tie breaker racked out;		

Time and Event	Section Reference	Contributing Cause and Comment
4.16 KV ESS Bus feeder breakers feeding power from Unit 1 Startup Bus 10 racked out. (Note: "DC CONTROL" knife switch was opened (the wrong knife switch) was opened and the associated 01 breaker was disconnected.)	3.1, 3.2.2, 3.2.3, 3.3.1, and 3.4	Instead of opening the breaker control power knife switches, four switches supplying DC power to the associated bus logic circuitry, located in the same cubicle with the associated 01 feeder breaker were opened.
	3.1	Reactor building operator and startup test engineer were not aware they had opened wrong knife switch.
01:37 a.m.		
Initial Startup Test Conditions: Plant power, 30.2% (995.13 MW_t; 273.7 MW_e); Reactor pressure, 925 psig; Core flow, 45.0% Recirculation pump speeds, 33% for A and 31% for B; Reactor water narrow range indication, +35"; Feedwater level control, 3 elements (auto); Control rod sequence, A-sequence.		Two NRC resident and one region-based inspectors were in the control room to witness the startup testing.
01:37:33 a.m.		
ST 31.1, Loss of Turbine-Generator and Off-Site Power transient was initiated by opening; Unit 2 main generator transformer 500 KV output breakers 2T and 4T; and,		GETARS traces indicated that the reactor dome pressure was 950 psig.

Time and Event	Section Reference	Contributing Cause and Comment
Startup transformer T20 to 13.8 KV Bus 20 breaker		
Turbine control valve fast closure and load reject; Turbine Master trip:		Design base fail-safe on loss of power.
Reactor scram;		Reactor scram on main turbine control valve fast closure.
Main turbine stop valve closed;		Fail-safe.
Main turbine trip;		Turbine overspeed.
Recirculation pumps tripped;		RPT on turbine control valve fast closure at >24% power.
Control room operator observed that control rod scram indications on full core display board did not show all rods were inserted.	5.3 and 6.2	Although full core display was powered from uninteruptable power source, status information to the display system was fed through A.C. powered Rod Sequence Control System (RSCS). GETARS indicated that all turbine control valves closed within 100 milliseconds.
RPS M/G set coasting down on loss of power.		

Time and Event	Section Reference	Contributing Cause and Comment
01:37:34 a.m.		
Turbine bypass valves opened and closed;		Bypass valves opened to limit the reactor pressure transient; According to plant operators, the reactor pressure did not decrease below 900 psig.
Analog signals to GETARS lost, except digital position indications;	5.9, 5.10 and 6.2	Safety Relief Valve (SRV) group indications were available.
Instruments powered by 125 V DC available;	5.10	
01:37:35 a.m.		
Feedwater pumps "A" and "B" tripped; "C" was not running;		Pump trip on low suction pressure due to loss of AC powered condensate pumps.
01:37:38 a.m.		
Primary containment isolation (PCI) actuation;		PCI actuation on loss of RPS MG set power.
MSIV isolation initiation;		(see table below)

Valve #	MSIV Closure Time, Second Inboard	Outboard
A	4.3	3.8
B	4.3	4.1
C	4.2	4.5
D	4.0	4.1

TS requirements for MSIV closure time were 3-to-5 seconds.

Time and Event	Section Reference	Contributing Cause and Comment
Secondary containment isolation actuation;		Due to loss of RPS MG set power.
Standby gas treatment system (SGTS) initiated;	5.12	Due to loss of RPS MG set power.
Standby gas treatment system later tripped;	5.12	Due to loss of AC power, SGTS dampers failed to open, resulting in SGTS fan trip.
01:37:40 a.m.		
Unit 2 13.8KV startup Bus 20 to ESS transformers 201 and 211 breakers opened;		Breakers opened due to loss of power to the Bus 20 without an alternate source of power.
Reactor trip signal "A" actuated.		The trip signal actuated on low reactor water level. Low level reactor trip setpoint was +13". NOTE: Actual scram had occurred earlier due to turbine control valve fast closure.
01:37:43 a.m.		
Plant control operator noted that four EDGs did not start and the four 4.16KV ESS feeder breakers from Unit 2 ESS transformers 201 and 211 remained closed;	3.2.1, 3.2.2, 3.2.3, 3.2.5 and 5.1, 5.2	EDGs were expected to start in 10 seconds when the ESS Busses were de-energized upon loss of AC power.
Load shedding did not take place; EDGs did not start.	3.2.1, 3.2.2, and 3.2.4	

Time and Event	Section Reference	Contributing Cause and Comment
01:37:53 a.m.		
Reactor wate~ level narrow range indicator pegged low;	5.10	The narrow range indicator had a range of 0" to 60"; upset range (0" to 180") indicated +5".
Reactor water level was monitored from local instruments.	6.2	Reactor water level indicators below 0" are only available at local instrument racks, since D.C. powered instruments peg low at this point.
01:38 a.m.		
Operator opened manually the unit 2 feeder breakers from ESS transformers 201 and 211 to the 4.16KV ESS Busses, but the EDGs still did not start.	3.2.2, 3.2.5 and 5.2	This was intended to isolate the 4.16KV ESS Busses so as to start the EDGs. However, due to the loss of power ("DC CONTROL" switches) to the bus logic circuitry, diesel generators failed to start.
01:39 a.m.		
Operator manually started all four EDGs	6.1	
"A" EDG started, but demonstrated large frequency oscillation;	5.5	
"B" EDG started but tripped on overvoltage and underfrequency;	5.4	
"C" EDG started and idled properly but failed to energize the dead 4.16KV ESS bus 2C;	5.6	

Time and Event	Section Reference	Contributing Cause and Comment
"D" EDG started but tripped on overvoltage.	5.4	
Operator manually tripped "A" EDG.	5.5	Operator action was justified; "A" was demonstrating large frequency oscillation.
Operator attempted to energize dead 4.16KV ESS bus 2C by remote manually closing 'C' EDG breaker, but failed to energize the dead bus.	5.6 and 6.1	Attempt should have been successful, it is assumed he did not operate the correct switches.
Operator then attempted to re-energize ESS transformer 211 from the 13.8KV Unit 2 startup bus 20 by closing the connecting breaker; the breaker failed to close.	5.7 and 6.1	The breaker failed to close because the startup bus 20 was not energized.
01:41 a.m.		
Operator recognized that 13.8KV bus 20 was not energized, and closed a breaker to re-energize bus 20 from the T20 transformer; then,	6.1 and 5.7	
Operator closed the two 13.8KV bus 20 breakers to the ESS transformers in order to re-energize ESS transformers 201 and 211;	6.1	
Operator then attempted to close the feeder breakers from ESS transformers 201 and 211 to the 4.16KV ESS busses; but breakers would not close.	6.1 and 5.8	No DC control power to bus undervoltage relay scheme
01:43 a.m.		
"J" Safety Relief Valve (SRV) opened to relieve the reactor pressure.	5.9	"J" SRV, is a group 4 SRV (others are "G", "K" and "L") with a normal opening setpoint of 1106 psig. "B" and "E" were expected to open first, at 1076 psig to "J" SRV.

Time anu Event	Section Reference	Contributing Cause and Comment
01:46 a.m.		
"J" SRV opened again.	5.9	
The reactor water level was -3".		The water level was extrapolated to -3" from GETARS traces of upset range indication.
01:48 a.m.	6.1	Plant operation could not resolve the problems, and decided to energize the dead buses from unit 1 T10 startup transformers.
Under the direction of the Unit 1 operations supervisc., a reactor building operator re-connected the 2B 4.16KV ESS bus feeder breaker from the Unit 1 ESS transformer 111.	6.1	At this point, unit supervisor and operators still did not know that the 'wrong' DC control knife switch was opened, interrupting the DC power supply to the bus logic circuitory.
Once the Unit 1 feeder breaker to the 4.16KV bus 2B was connected, the, operator then closed the "DC CONTROL" knife switch in the same cubicle;	5.13 and 6.1	
4.16 KV ESS Bus 2B was energized from T20; "B" EDG started automatically.	5.13 and 6.1	When the "DC Control" switch was closed, the associated 2B bus logic circuitry recovered its DC control power, and consequently the preferred source feeder breaker to the 4.16 KV ESS Bus closed, re-energizing the 2B Bus from T20 and re-starting automatically the tripped "B" EDG.

NOTE: Power to ESS Bus 2B restored in 10 minutes and 15 seconds.

Time and Event	Section Reference	Contributing Cause and Comment
01:50 a.m.		
An "UNUSUAL EVENT" under the Emergency Plan was declared.	6.2 and 7.6	When the EDGs failed to start and initial attempts to re-energize the 4.16KV Busses failed Technical Support Center (TSC) was activated; at 01:38 a.m., the shift supervisor decided to enter the Emergency Plan. Actual declaration was delayed.
NRC was notified.		
Racked in feeder breaker to 4.16KV ESS bus 2D from the unit 1 ESS transformer 101; closed associated "DC CONTROL" knife switch in the cubicle.	5.13 and 6.1	
The preferred feeder breaker closed to energize the dead 4.16 KV ESS bus 2D from T20;		When the "DC CONTROL" switch was closed, the associated 2D bus logic circuitry recovered its DC control power, and closed preferred source feeder breaker.
"D" EDG started automatically.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	GETARS traces indicated that the reactor dome pressure peaked at 1055 psig when the "J" SRV was lifting and that the pressure decayed to 970 psig when the SRV was closing.

Time and Event	Section Reference	Contributing Cause and Comment
01:53 a.m.		
Racked in feeder breaker to the 4.16KV ESS bus 2C from the Unit 1 ESS transformer 111; closed associated "DC CONTROL" knife switch in the cubicle.	5.13 and 6.1	
The preferred feeder breaker closed to energize the dead 4.16 KV ESS bus 2C from T10;		When the "DC CONTOL" switch was closed, the associated 2C bus logic circuitry recovered its DC control power, and closed the preferred source feeder breaker.
"C" EDG continued to idle.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	GETARS traces indicated that the reactor dome pressure peaked at 1055 psig when the "J" SRV was lifting, and that the pressure decayed to 970 psig when the SRV was closing.
01:54 a.m.		
Racked in feeder breaker to 4.16KV ESS bus 2A from the Unit 1 ESS transformer 101; closed associated "DC CONTROL" knife switch in the cubicle.	5.13 and 6.1	
The preferred feeder breaker closed to energize the dead 4.16 KV ESS bus 2A from T10;		When the "DC CONTROL" switch was closed, the associated 2A bus logic circuitry recovered its DC control power, and closed preferred source feeder breaker.

Time and Event	Section Reference	Contributing Cause and Comment
"A" EDG started automatically.		When power was restored, the control operator monitored the reactor water level using wide range level indication (-150" to 60") on the standby information panel.
01:55 a.m.		
4.16 KV ESS busses 2A and 2C source feeders were remote manually transferred to unit 2 ESS transformers 201 and 211 from unit 1 ESS transformers 101 and 111.		All 4.16 KV ESS busses were energized from T20.
GETARS was taken out of services for down-loading the disk.		
Operator noted that "A", "B" and "D" EDGs had "High Priority" alarms energized and remote manually shut down the three EDGs.	5.4, 5.5 and 5.14	A probable high vibration trip on the previous shutdown of the "A" EDG and the automatic trips of the of the "B" and "D" EDGs had never been reset. These specific trips will prevent remote or local manual starts, but are bypassed on an automatic start, and the alarms remain energized.
Operator attempted to reset the alarms locally: "A" trip and alarm was reset; "B" and "D" trip and alarms were not reset.	5.14	Operators were not aware of the sequence of steps necessary to reset the electrical trips.

Time and Event	Section Reference	Contributing Cause and Comment
01:58 a.m.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	
02:03 a.m.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	
02:09 a.m.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	
02:17 a.m.		
"J" SRV opened at 1055 psig and closed at 970 psig.	5.9	
02:18 a.m.		
Operator manually initiated RCIC when the reactor water level reached -34"; the operator used the wide range indicator on the standby information panel.	5.10 and 6.2	"J" SRV openings to limit the reactor pressure depleted the reactor water inventory, resulting in steady decrease of the reactor water level.
RCIC flow into the reactor was 600 gpm in automatic mode.		

Time and Event	Section Reference	Contributing Cause and Comment
The Safety Parameter Display System (SPDS) level indication was -27"; local level indicators showed that one channel at -34" and other three at -28".		RCIC initiation setpoint was set at -30". Since the auto initiation required 2/4 logic and three channels were reading -28", RCIC did not start automatically. Even though TS required setpoint was >-38" for RCIC and HPCI initiations, the RCIC setpoint was conservatively selected at -30" to compensate for instrument drifting and accuracy, and was higher than the HPCI initiation setpoint in order to minimize high capacity HPCI injections during the transients.
<u>02:20 a.m.</u>		
Unit 1 entered Technical Specification Action Statement with "B" and "D" EDGs inoperable.	5.14, and 5.17	Two diesel generators "B" and "D" were inoperable because of the inability to reset "High Priority" trips and alarms.
<u>02:28 a.m.</u>		
GETARS was back in service. The reactor water level reached +19" and increasing, on narrow range indicator. RCIC was still injecting 600 gpm water into the reactor.		

Time and Event	Section Reference	Contributing Cause and Comment
02:29:13 a.m.		
When the indicated reactor water level on narrow range indicator reached +20", operator manually reduced the RCIC flow to 430 gpm.		
02:30 a.m.		
Terminated "UNUSUAL EVENT"	6.2	Plant control operator log showed that the "Unusual Event" was terminated at 02:34 a.m. based on plant stability.
"High Priority" alarms on "B" and "D" EDGs cleared by operators.	5.14	
02:32 a.m.		
Wide range level, +33";		
Narrow range level, +38";		
Reactor dome pressure, 960 psig.		
02:33 a.m.		
Operator manually reduced RCIC flow to 250 gpm when the narrow range level indicator showed +36".		

Time and Event	Section Reference	Contributing Cause and Comment
02:41 a.m.		
Operator manually tripped RCIC when the narrow level indicator was showing +53".		Turbine protection trip setpoint was +54".
Reactor dome pressure, 900 psig.		
02:50 a.m.		
Operation staff concluded that the problems were traced to the opening of the wrong DC knife switches in the 4.16KV ESS bus 01 cubicles.		
02:55 a.m.		
Reactor dome pressure, 910 psig.		
04:30 a.m.		
RHR loop "A" in suppression pool cooling; Reactor Water Cleanup System pumps restarted; Isolation cleared.	6.2	Plant operation was proceeding in accordance with the normal shutdown and cooldown procedures.
04:41 a.m.		
Unit 1 was out of Technical Specification Action Statement	5.14 and 5.17	"B" and "D" EDGs "High Priority trips and alarms had been cleared at 02:30 a.m.

Time and Event	Section Reference	Contributing Cause and Comment
05:45 a.m. Operation restored all breakers to normal configuration per startup test procedure ST 31.1., except 4.16KV ESS Busses 2A and 2C being fed from ESS transformers 201 and 211.		
07:20 a.m. Swapped 4.16 KV ESS busses 2A and 2C from alternate to normal supply of ESS transformers 101 and 111.		

5. Plant and Equipment Response Details

5.1 4.16KV Feeder Circuit Breaker Auto Opening Failure

When the Unit 2 4.16KV ESS busses were deenergized per the test procedure, the Plant Control Operator (PCO) at the electrical distribution panel noted that the four Unit 2 ESS transformer feeder breakers to the 4.16KV ESS busses remained closed.

The 4.16KV ESS bus feeder breakers are designed to automatically open on a loss of voltage to their associated 4.16KV busses. (See Section 3.2.3). The feeder breakers did not automatically trip open because the open knife switch to the bus auxiliary relay control circuitry prevented the bus undervoltage auxiliary relays (27AX) from energizing and providing a trip signal to the feeder breakers.

The four Unit 2 ESS transformer feeder breakers to 4.16KV ESS bus functioned as expected in accordance with the design (with the knife switch open) and no corrective action for this item was required, with the exception of returning the knife switch to normal. The breakers functioned properly on the next performance of startup test ST 31.1. on August 7, 1984.

5.2 Emergency Diesel Generator (EDG) Auto-Start Failure

When the Unit 2 4.16KV ESS busses were de-energized the PCO noted that the four EDGs did not start automatically as designed.

As discussed in Section 3.2.5, the EDGs are designed to automatically start on total loss of all sources of power to the 4.16KV ESS bus of either unit to which the diesel generator can be connected, and starting is initiated by sensing the simultaneous open condition of the two associated offsite power feeder breakers and the diesel generator breaker. The failure of the EDGs to start initially was due to the fact that Unit 2 ESS transformer to 4.16KV ESS bus feeder breakers remained closed on the dead ESS busses (See Section 5.1), therefore not satisfying the start logic.

The PCO then manually opened the four feeder breakers, but again the EDGs did not start, because the open knife switch to the bus auxiliary relay control circuit removed power from the time delay relay (62A) which must energize to provide the EDGs with an automatic start signal.

The EDGs would have automatically started on a Unit 1 or Unit 2 LOCA signal, but the EDG output breakers for Unit 2 would not have been able to automatically close on the bus with the incorrect knife switch open.

The circuit functioned as designed (with the knife switches open) and no corrective action was required. The automatic start feature was demonstrated successfully on the next performance of the startup test on August 7, 1984.

5.3 Full Core Display Problems

Following the reactor scram, the full core display showed a "checkerboard" pattern with about one half to two thirds of the rods indicating "full in" (See Section 6.2). The full core display, the four rod display on the Standby Information Panel (SIP) and Rod Position Indication System (RPIS) are powered from Uninterruptible Power Supplies (UPS) and remained powered throughout the event. The Rod Sequence Control System (RSCS) is powered by instrument AC power which was lost. Rod position information to the full core and four rod display systems is fed through the AC powered RSCS. As a result, the full core display and four rod display, the normal sources of rod position information in the control room, may not be reflective of actual rod position on loss of AC power. When power to RSCS is restored and the full core display is reset, accurate rod position information is displayed. Since the RPIS on Unit 2 is powered by UPS, rod position information to the Performance Monitoring System (PMS) computer is unaffected by a loss of all AC power and hence, rod position can always be verified by performing the OD-7 program.

NOTE: The RPIS on Unit 1 is not powered by UPS and no reliable source of rod position information exists on Unit 1 during a loss of all AC power.

5.4 Overvoltage Trip of "B" and "D" Emergency Diesel Generators During Manual Start

The Susquehanna facility uses four emergency diesel generators (EDGs) that are common to Unit 1 and 2. During the event, when the EDGs failed to automatically start, the operator manually started all four EDGs. The "D" EDG tripped on overvoltage and the "B" EDG tripped on overvoltage and underfrequency. It is believed that the underfrequency trip was received as a result of the "B" EDG shutdown and will not be further discussed.

Review of the EDG overvoltage trip disclosed that two Licensee Event Reports (82-050/03L and 83-004/03L) were submitted by the licensee during previous overvoltage trips of the "C" and "D" EDG's.

The LER's discuss the fact that the overvoltage relay is frequency sensitive and that the manual voltage adjust was originally routinely set at 4350 volts when the EDG's were shutdown after monthly operability surveillance. The corrective action discussed by the licensee in the subject LER's was (1) reduce the manual voltage adjust to 4250 volts at EDG shutdown, (2) consider a modification to auto position the voltage regulator on a EDG shutdown and (3) consider replacing the frequency sensitive overvoltage sensing relay. Items 2 and 3 are still under consideration by the licensee.

During review of the monthly surveillance SO-024-004, it was noted that when the EDG is started, its manual voltage regulator setting is reduced to 4160V in preparation for paralleling with the 4.16KV ESS bus, but when it is secured, the setting is raised to 4250 volts. When questioned, the licensee could not initially determine why the regulator was normally left set at 4250 volts. Further records search indicated that the manual voltage adjust was set at 4250 to match the auto regulator, which is used during an auto start of the EDG. The same motor driven potentiometer is used in both circuits (auto and manual). By setting the manual adjustment at 4250 the auto adjust would not have to move to obtain 4250 volts on an emergency start. The auto adjust is set at 4250 volts to ensure that ECCS equipment (RHR and Core Spray pumps) will receive at least 80 percent of their rated voltage on an emergency start of the ECCS equipment when fed from the EDGs. The licensee subsequently performed a test to determine the length of time necessary for the auto regulator to drive from 4160 volts to 4250 volts. The time required was 2 seconds, well within the 10 seconds allowed for the EDG to reach rated speed and voltage. Based on the above, the licensee has modified the monthly surveillance procedure to require the manual voltage adjust to be set at 4160 volts when the EDG is shutdown. The appropriateness of this change is under review and is an unresolved item (388/84-34-04).

The overvoltage trip setpoint is set at 4480 volts to prevent EDG operation at voltage more than 110 percent of the design voltage (4000 volts) of equipment fed by the 4160 volt ESS busses. A review of calibration records for the overvoltage relays indicated proper adjustment had been completed during February 1984.

The above action (setting of manual voltage adjust to 4160 volts) should preclude overvoltage trips of the EDGs during manual starts. However, the licensee plans to review other options to further reduce the possibility of an overvoltage trip. Reference Attachment A Item No. 2-84-04-09.

5.5 Frequency Oscillations on "A" Emergency Diesel Generator (EDG)

When the EDGs did not automatically start the operator manually started all four EDGs. The "A" EDG exhibited large (reported between 57 and 63 hertz) frequency oscillations and was subsequently remote manually tripped by the operator. When DC power was restored to the 2A bus auxiliary relay circuit, the EDG automatically started, no frequency oscillations were observed; however, a high priority alarm was noticed by the operator and the diesel was again remote manually tripped.

The licensee subsequently, (July 29, 1984), performed seven successful manual test starts from the control room. Testing was observed by the NRC inspector. During the test starts, the output of the electronic governor control was recorded then varied until oscillations in speed control were obtained. These measurements were taken to determine if the previous setpoint was close to those that would produce oscillation. The measurements showed the electronic governor to be stable. The settings were returned to the original condition. The licensee also recorded the hydraulic actuator setting and then varied its setpoint. No oscillations were produced and the setting was returned to the original value. The original temperature conditions were duplicated as much as possible by running Emergency Service Water prior to initial engine start. All seven starts were normal with no oscillations observed.

The licensee is conducting a review of the "A" EDG performance records to determine if there have been any previous problems with "A" EDG oscillations. (See Appendix A, Item No. 2-84-04-21)

5.6 Emergency Diesel Generator "C" Failure to Manually Load onto Bus 2C

During the event, after manually starting the four EDGs, the plant control operator attempted to manually close the "C" EDG output breaker onto the 4.16KV ESS bus 2C, but the breaker did not close.

The breaker did not automatically close, as designed, because the open DC knife switch removed power to the bus undervoltage auxiliary relay (27AX), which must energize for the breaker to be signalled to close. With the "C" EDG running and bus 2C de-energized, the EDG output breaker should have the capability to close manually on the dead bus. For the operator to manually close the 2C bus EDG feeder breaker from the control room, the operator must turn the 2C bus EDG feeder breaker keylocked synchronizing switch to the "ON" position and place the 2C bus EDG feeder breaker control switch to the close position. Additional permissives in the closing circuit include auxiliary relay V1 contacts which close on loss of 4.16KV bus and auxiliary relay V2 contacts which close when EDG output voltage is present. The inability to close the breaker manually could not be explained and should not have been affected by the incorrectly open knife switch.

The licensee concluded that wiring scheme checks were needed to verify the various contact operations. The scheme checks were performed on July 26, 1984, on the "A" and "C" EDG breaker closing circuits. The scheme checks verified operation of the necessary contacts and the breakers were successfully operated manually from the control room with the breaker in the test position. The inspectors reviewed the work documents and discussed the test with licensee personnel, and no unacceptable conditions were identified.

On July 31, the licensee performed special test procedure TP-24-004, Revision 1, "Diesel Generator "C" Emergency Start and Remote Manual Loading" test to demonstrate the "C" EDG would auto-start and close in on ESS bus 2C upon loss of bus voltage, and that the "C" EDG could be started manually from the control room and closed in on ESS bus 2C using the remote breaker control switches on control room panel.

The test placed the bus in the identical configuration that was present during the July 26 startup test, with the exception of the maintaining capability of bus lockout protection (86 relays). The inspectors witnessed the performance of the test and verified that the test was completed satisfactorily and the breakers operated as designed.

Since the test was completed satisfactorily, the cause for the breaker not functioning properly on July 26 was probably due to the operator use of the incorrect synchronizing or breaker control switch, thereby not satisfying the closure permissive interlocks (all the synchronizing and breaker control switches are grouped together in a non-alphabetical order).

5.7 Startup Bus Energization Error

At approximately 1:39 a.m., the control room operator attempted to close the supply feeder breaker from Bus 20 to ESS transformer 211. The breaker would not close as designed. The reason for this is that the breakers will not close in on a de-energized startup Bus 20.

Subsequently, at approximately 1:41 a.m., the control room operator closed the 13.8KV breaker between Startup Transformer 20 and Bus 20, enabled the appropriate permissives, allowing the operator to close the ESS transformer supply feeder breakers, and energizing ESS transformers 201 and 211.

5.8 4.16KV Feeder Circuit Breaker Failure to Manually Close

When the operators determined that the emergency diesel generators (EDGs) were not available (See Sections 5.4, 5.5, 5.6), they attempted to manually close the four incoming feeder breakers to the 4.16KV ESS busses from the Unit 2 ESS transformers, but they would not close. With the bus de-energized, and the alternate feeder breaker and EDG breaker open, the breaker should have closed automatically. Since the DC auxiliary relay and bus control knife switch was incorrectly open, the bus undervoltage auxiliary relay scheme (27AX) was de-energized. The feeder breaker control circuit contains a bus undervoltage relay permissive contact. Since the 27AX relay must energize to close this contact to provide the close permissive, the breaker could not be closed.

The breaker control circuit operated in accordance with the existing design (with the knife switch open) and no corrective action beyond restoring the knife switch to its correct position was required. When the knife switches were restored, the preferred feeder breakers automatically closed as designed.

5.9 Safety/Relief Valves (SRV) Setpoint Drift

The facility has 16 SRV's to protect the nuclear steam supply system from overpressurization. Six of these valves provide for automatic depressurization of the nuclear system during small breaks (if needed) to allow low pressure coolant injection (LPCI) and core spray (CS) systems to inject cooling water to protect the fuel. The 16 valves can be actuated by two means: (1) Self actuated by nuclear system pressure against spring pressure at the code (ASME Boiler and Pressure Vessel Code) safety setting, and (2) by power assist (not safety related) via an air piston which will open the valve at a preset pressure which is below the code safety setting. In addition, six of the sixteen valves can be operated through the Automatic Depressurization System (ADS), which is safety related and opens the valve via the power assist air piston.

During the event on July 26, 1984, the "J" SRV lifted a total of eight times at pressures between 1050 and 1060 PSIG. The licensee had calculated that an SRV would lift nine times via the power assist mode. The "B" or "E" SRV's have the lowest power assist setpoint; however, there are a total of ten (including B and E) SRV's that are set to relieve prior to the "J" SRV.

Subsequent review of General Electric Transient Analysis Recording System (GETARS) traces indicate the lifting of one or all SRV's in the No. 4 SRV group. Review of SRV tail pipe temperature traces indicate that only the "J" SRV lifted. The individual SRV did not indicate lifting on the GETARS trace due to the loss of signal input when AC power was lost.

Review of previous alignment data (May 1983) of power assisted SRV actuation points indicated that each SRV had been set to within ± 6 PSIG of the design actuation pressure plus head correction.

As a result of the event, the licensee conducted calibration checks of all 16 SRV's. Of those checked, three including the "J" SRV required recalibration ("J", "L" and "M" SRV's). Setpoint checks and recalibration activities for all SRV's were completed on July 27, 1984. The above calibration records were reviewed by the inspector. The inspector also reviewed the following relating to SRV's:

-- General Electric Publication No. GEK-73602, Automatic Depressurization System;

-- Mechanical (spring) setpoint data sheets for all SRV's;

-- Relief Valve Inspection Records;

-- Previous calibration data sheets for power assisted SRV setpoints (completed May 1983); and,

-- Crosby Engineering Procedure for Installation, Operation and Maintenance Instruction for Crosby Style 6XRX10 HB-BP Self Actuated Nozzle Type Safety Valves With Air Cylinder Actuated (Pneumatically Operated) Auxiliary Lifting Gear.

The apparent cause of early actuation of the "J" SRV was instrument setpoint drift. Due to the limited operating time of the Susquehanna units there is no setpoint trending data available to determine if instrument drift is a problem.

5.10 Reactor Pressure and Level Instrumentation Availability

While power was lost, the only reactor pressure and level instrumentation available to the control room was HPCI and RCIC steam line pressure instruments, B and C narrow range (0 to +60 inches) reactor vessel water level instruments and one Upset range reactor vessel water level instrument (0 to +180 inches). The availability of the Upset range reactor vessel water level instrument was determined post test since it was not realized it was also DC powered (indicator only, the recorder drive motor is AC). The 125V AC instrument busses at Susquehanna are not backed by DC power supplies and hence, all instruments powered from these sources were lost. Computer systems, such as, the Performance Monitoring System, the Display Control System and the Safety Parameter Display System (SPDS) still retained power, but all AC instrumentation which provide inputs to the computer systems were lost, rendering this equipment unusable for monitoring reactor pressure and level.

Within seconds after the reactor scram, reactor vessel level dropped below zero and remained below zero until RCIC restored level about one hour later. Hence, the operators had no usable control room indication of reactor vessel water level instrumentation from the start of the event until power was restored. (Local panel indication was available and level information was communicated to the control room by personnel stationed at these panels during the conduct of ST 31.1). As noted in Appendix A, Item No. 2-84-04-30, the licensee is evaluating the adequacy of instrumentation available to the operators in the event of a loss of AC power.

5.11 Suppression Pool Response and Temperature Instrumentation

When all AC power is lost, the MSIV's shut and the heat sink for removal of core decay heat is the suppression pool via the safety relief valves (SRV). During this event, one SRV lifted eight times to control reactor pressure. Suppression pool temperature only increased from 80 degrees to 90 degrees Fahrenheit before suppression pool cooling was initiated about one hour after the event started. AC power is needed to run RHR and RHR service water pumps to cool the suppression pool. For this event, the suppression pool was easily able to absorb core decay heat without approaching temperature limits. Technical Specifications (TS) permit a maximum average suppression pool temperature of 120 degrees F following a scram with MSIV closure. TS bases indicate that 170 degrees Fahrenheit suppression pool temperature is conservatively assumed to be the limit for complete condensation to assure sufficient Net Positive Suction Head for low pressure ECCS pumps.

If this event had occurred following operation at high power levels, suppression pool temperature would have increased more rapidly. A station blackout analysis provided by PP&L to the NRC on June 10, 1982, indicated that 170 degrees Fahrenheit suppression pool temperature would be reached in about three hours and the design limit of 220 degrees Fahrenheit would be reached in about eight hours, if suppression pool cooling were unavailable.

Average suppression pool temperature is displayed in the control room by two microprocessor display systems called SPOTMOS. Each SPOTMOS channel averages eight resistance temperature detectors (RTDs) in various locations in the suppression pool to determine average temperature. SPOTMOS is powered by instrument AC and was lost when AC power was lost. When power was restored, an operator was unsuccessful in trying to reset SPOTMOS and average suppression pool temperature instrumentation was unavailable for about one hour. An I&C technician restored SPOTMOS. A review of the SPOTMOS procedure indicated that time and date must be entered in the display system to reset it after power restoration. The proper method of resetting SPOTMOS was reemphasized in the training conducted prior to Unit 2 restart. (See Appendix A, Item No. 2-84-04-27)

5.12 Standby Gas Treatment System Performance

The Standby Gas Treatment System (SGTS) started as designed when the RPS MG sets coasted down causing a primary and secondary containment signal. The SGTS fans were aligned to Unit 1 power supplies and thus, did not lose power. Both fans started since they are both normally aligned in "Auto Lead." Since SGTS sees a Unit 2 isolation signal, ventilation dampers should open to allow SGTS to drawdown Zone II (Unit 2 Reactor Building) and Zone III (common refueling floor). These dampers lost power on the loss of the 4KV busses and thus, did not open. Hence, SGTS fans could not drawdown Zones II and III and they tripped on low differential pressure between inside and outside the reactor building.

If after the SGTS fans tripped, a Unit 1 LOCA signal was received, the fans would not have restarted. If an operator turned the fan control switches to "STANDBY," the fans would have restarted. Although one unit losing all AC power followed by a LOCA in the other unit is beyond the SGTS design basis, the licensee is evaluating the desirability of the low differential pressure trip signal (see Appendix A, Item No. 2-84-04-13).

5.13 Auxiliary Relay DC Power Restoration

Following the inability to close the feeder breakers from the Unit 2 ESS transformers to the 4.16KV ESS busses, the unit supervisor instructed the reactor building plant operator to rack in the feeder breakers from the Unit 1 ESS transformers 101 and 111 to the Unit 2 4.16KV ESS buses. As the feeder breakers from the Unit 1 ESS transformers were racked in and the DC auxiliary relay and bus control circuit knife switches closed, the preferred feeder breaker to the ESS bus closed, reenergizing the bus. At the same time, the associated emergency diesel generator (EDG) automatically started.

At the instant the DC auxiliary relay and bus control circuit knife switch for the 4.16KV ESS bus auxiliary relay control circuit power was closed, the control circuits sensed a dead bus condition and activated the three-way transfer logic. The circuit as described in paragraph 3.2.1, operated as designed.

5.14 Emergency Diesel Generator (EDG) Priority Alarm Reset Problem

Subsequent to the operator manually tripping the "B" and "D" EDGs, the operator at the diesel control panels (EDG Bay) could not reset the "B" and "D" EDG overvoltage trips (control room Hi Priority Alarm).

The Overvoltage alarm/trip on the "B" and "D" EDG's could not be reset because the operator was not aware that the trip was a seal-in alarm/ trip and required the protection relay seal-in reset button to be operated prior to the system reset push button. In addition the alarm response procedures (AR-ODA, B, C and D 521) were not available at the local EDG control panels and the procedures did not specifically require reset of the protective relay seal-in before the system reset. This combination of factors placed Unit 1 into an Action Statement, because 2 EDGS were considered inoperable. The licensee by reviewing the EDG control schematic diagrams determined that the protective relay seal-in must be reset prior to system reset. It took the licensee 35 minutes to discover and correct this situation.

As a result of this event, the licensee developed a new Off-Normal Procedure (ON-024-001) which requires specific steps to be taken to reset EDG trips and alarms. In addition the new procedure has been placed at the local EDG control panel and operator training has been conducted on EDG alarm/trip reset procedures.

5.15 Scram Discharge Volume (SDV) Drain Valve Failure

Following the event, when the operator reset the scram condition, the SDV would not drain. Licensee investigation showed that the upstream SDV drain valve (one of 2 in series) air operator stem had pulled free from the drain valve stem to operator stem coupling. Since the valve seats with system pressure it remained closed. The coupling is made from a solid block of metal 2 1/8" long (all dimensions approximate) by 1 1/8" square. Both ends are threaded (female) to match the valve and valve operator stem threads (male). A hole is drilled through the center of the coupling face to accommodate the coupling bolt which holds the coupling halves against the valve and operator stems. The block is then cut in half lengthwise and perpendicular to the coupling bolt hole. This results in 2 coupling halves 2 1/8" long X 1/2" thick with internal threading. Two additional holes are then drilled in the center of the small (1/2") face on one side of each coupling half to accommodate the valve position indicating assembly. These additional holes significantly weakened the original coupling and contributed to its failure.

A new coupling was fabricated using ASTM 193 Grade B-7 steel (stronger than original). The 2 holes used to mount the position indication assembly were made 1 size smaller to minimize their weakening effect and dimensional checks were made at the top, middle and bottom of the coupling when it was installed. Valve stroking was performed successfully after installation.

Investigation by the licensee and the NRC determined that failure was the result of overtorquing the coupling halves together. The overtorquing caused the coupling to bow in the center and forced the upper and lower portions of the coupling to move away from the valve and operator stem allowing the valve operator stem to pull free.

In addition a records search was conducted by the licensee to identify other valves with similar couplings. A total of 16 valves (eight per unit) were identified including the failed valve. Four of the valves in each unit are Q listed, the two SDV drain valves and two SDV vent valves. The Non-Q valves are in the control rod drive hydraulic system. All valves in Unit 2 were inspected with no discrepancies identified. The Unit 1 valves will be inspected when they are more readily accessible. (See Appendix A, Item No. 2-84-04-07).

5.16 Communications Problem

During the event the licensee experienced minor communication difficulties. Difficulties existed because both Unit 1 and Unit 2 were using the same radio frequencies. This made communication very difficult between Unit 2 operators in the field and the Unit 2 control room if Unit 1 was using the radio and vice versa.

In addition the station Maintenance and Instrumentation and control (I&C) departments also used the same radio frequency although this did not impact licensee action during the event.

Subsequent to the event all Maintenance and I&C radios were collected. All single channel radios used by operations were collected and new multi-channel radios were issued with separate frequencies for Unit 1 and Unit 2. Security utilizes a separate frequency. Further action is addressed in Appendix A, Item No. 2-84-04-38.

5.17 Unit 1 Event Response

Unit 1 was not directly affected by this event. The emergency diesel generators (EDGs) would have auto started and supplied Unit 1 loads if they received a Unit 1 auto start signal. Although the EDGs would have auto started if required for Unit 1, Unit 1 entered an LCO Action Statement for two inoperable EDG's after the operator was unable to reset the H Priority trips (which are bypassed on an auto start) on the "B" and "D" EDG's. Proper actions were taken in accordance with the TS and the LCO was cleared after EDG surveillance tests were successful.

The Standby Gas Treatment System, which is common to both units, was also affected as noted in Section 5.12 above.

6. Operator Response to Event

The operator actions during this event focused on restoring power to the 4.16KV ESS busses, determining and monitoring plant status with available instrumentation and then recovering equipment after power was restored.

6.1 Restoration of Power to 4.16KV Busses

The test began at 1:37 a.m. The operators quickly recognized that none of the emergency diesel generators (EDG) started and noticed that the feeder breakers from ESS transformers 201 and 211 to the 4.16KV ESS busses remained closed. The operators manually opened the feeder breakers and the EDG still did not start. The operators then manually started the "A", "B", "C", and "D" EDGs. The "B" and "D" EDG's had High Priority alarms and immediately tripped (the trips were later verified locally to be generator overvoltage on the "D"

EDG and generator overvoltage and underfrequency on the "B" EDG). The "A" and "C" EDGs started but did not close in on their respective busses. The operator noticed that the "A" EDG had large frequency oscillations so he manually tripped it. He then tried to close the "C" EDG breaker onto the 2C bus after inserting the key in the synchronizing switch and turning it to "on" as required. The "C" EDG breaker did not close.

The operators then tried to restore power from the offsite source. At approximately 01:41 a.m., the operators reenergized Startup Bus 20 and ESS transformers 201 and 211. However, when they tried to close the feeder breakers from the 201 and 211 transformers to the 4.16KV busses, the breakers would not close. At approximately 1:44 a.m., the shift supervisor directed that the test lineup relative to the 4.16KV ESS bus feeder breakers be restored. The NPO who was near the 4.16KV load centers in the reactor building then began racking in the 4.16KV ESS bus feeder breakers. At about 1:48 a.m., the Unit 1 ESS transformer feeder breaker to the 2B 4.16KV ESS bus was racked in and the DC Auxiliary relay and bus control power knife switch was closed. When the knife switch was closed, Unit 2 ESS transformer feeder breaker to the 2B bus, which is the preferred source, closed and the "B" EDG auto started. Similarly, when the NPO racked in the other open 4.16KV breakers and closed the knife switches, the breaker from the preferred source (Unit 1 ESS transformer feeders for busses 2A and 2C and Unit 2 ESS transformer feeders for busses 2B and 2D) closed and the respective EDG auto started (except "C" EDG, which was already running). Power was restored to all 4.16KV ESS busses by 1:55 a.m., within 18 minutes after the power loss. When the EDG auto started, the "A", "B", and "D" EDGs had Hi Priority alarms (Hi Priority alarms are automatic trips when the EDG is manually started, but the trips are bypassed when the EDG's are auto started). Since power had already been restored, the operators shutdown the "A", "B", and "D" EDG's.

6.2 Other Operator Actions

At the start of the test, when the reactor scram occurred, the PCO noticed and reported that all rods did not indicate "full in" on the full core display. The normal indication of all rods in is a completely green display which indicates that all "full in" limit switches for the rods have actuated. During this scram, about one half to two thirds of the green lights were not lit. The PCO took actions in accordance with the Reactor Scram procedure EO-200-001, which includes turning the Mode Switch to SHUTDOWN, arming and pushing the manual scram pushbuttons, inserting the Source Range Monitors (SRM) and Intermediate Range Monitors (IRM) into the core and monitoring nuclear instruments to verify that power was decreasing. The PCO was unable to drive in the SRMs and IRMs because they had no power. The operators were confused by the full core display and were not sure if all rods had inserted. They pulled out the ATWS procedure and thought about initiating those required actions.

The Unit Supervisor decided, based on the negative reactor period and decreasing counts on the SRMs (which still indicate even though they remain out of the core) and the fact that reactor pressure was not rapidly increasing even though the MSIVs were shut, that the reactor was completely shutdown. When AC power was restored, the full core display was reset and showed that all but seven rods indicated "full in" (the seven rods had drifted past the "full in" position because the scram had not been reset). The STA verified that all rods were full in by obtaining an OD-7 printout from the process computer. The indications on the full core display at the time power was lost was not understood until after the event.

After the operators were satisfied that the reactor was shutdown, they began to determine the status of the plant. Because of the power loss, most control room instruments had failed downscale. Because of previous training, the PCO knew which reactor level and pressure instruments would still be working when AC power was lost. HPCI and RCIC steam line pressure instruments (which read reactor pressure whenever the steam isolation valves are open) and B and C Narrow range (0 to +60 inches) reactor vessel level instruments at the Standby Information Panel are DC powered. HPCI and RCIC pressure readings showed that pressure was slowly increasing as expected. Level, however, quickly dropped below zero on the narrow range instruments because of the scram. The operators had no usable level instrumentation in the control room, until AC power was restored. At the start of the test, I&C personnel had indicated that they would be in the Reactor Building at the level and pressure instrument racks. Several minutes after the scram, the PCO contacted I&C personnel who provided the control room with periodic level readings from the instrument racks until power was restored. Level was not decreasing rapidly (after the initial sharp decrease due to the scram). When the first AC bus was restored at 1:48 a.m., level was about -12 inches.

After the initial actions had been taken, the Plant Superintendent declared an Unusual Event in accordance with the Emergency Plan at 1:50 a.m. Operators made the required notifications, the Technical Support Center was manned and additional plant technical staff were called in. At 2:30 a.m., after power had been restored and the plant was stabilized, the Unusual Event was terminated.

After power was restored, operator actions consisted primarily of recovering reactor and balance of plant equipment and monitoring plant status. At about 2:15 a.m., when the scram was reset, the PCO noticed that the scram discharge volume drain valve would not open remotely and an NPO was dispatched to open it with a wrench. At approximately 2:18 a.m., RCIC was manually started to restore level when vessel level reached -28 (-34 on wide range indicator on the standby information panel) inches. Containment isolation logic was reset and isolation valves reopened as necessary. Suppression pool temperature instrumentation was restored at about 2:40 a.m. (the operators were unable to reset SPOTMOS earlier - see Section 5.11) and indicated 90 degrees F. An RHR pump was started and lined up for suppression pool cooling. Other operators and technical staff personnel were dispatched to the "B" and "D" EDG bays to reset the locked in high priority alarms. The alarms were reset (see Section 5.14) and all diesels were tested to verify their operability.

6.3 Appraisal of Operator Performance

In the opinion of the inspectors in the control room during the test, the performance of the control room operators was excellent. They quickly took action to try to restore power to the 4.16KV ESS busses from the diesel generators and offsite and to assure the reactor was adequately shutdown and cooled. Power was restored to the first bus 10 minutes 15 seconds after the event started and all busses were re-energized within 18 minutes. By virtue of previous training, operators knew most of the instrumentation which was available and verified vessel level readings with local instrumentation.

With the exception of the breaker rack out errors and the inability to reset the EDG trips, both a product of inadequate labelling, procedures and training, the nuclear plant operators also functioned extremely well.

7. Administrative Controls

7.1 Station Blackout Procedure

The station blackout procedure, EO-200-030, was not entered for this event because offsite power was not lost to both units. As a result of this event, however, changes were made to the procedure to caution the operator about the full core display after power loss and direct the operator to call up the OD-7 program to verify rods in. The procedure was also revised to include the availability of the upset range level indicator LR-2R601, which is DC powered, and to include terminal specifications for monitoring suppression pool RTDs with portable equipment.

7.2 Operator Rounds/Surveillance Procedure

During the event review, it was determined that the lockout relay indicating lights at the breaker cubicle were the only indication that the knife switches, which supply 4.16KV ESS bus DC auxiliary relay and bus control power, were open. The operator's shiftly surveillance procedures SO-200-006 for Unit 2 and SO-100-006 for Unit 1 have been revised to require verifying once per shift that the lockout relay indicating lights are lit, which verifies that the knife switches are closed.

7.3 Emergency Diesel Generator (EDG) Procedure Availability in the Field

The unavailability of Alarm Response procedures and operating procedures at the local EDG control panels contributed to the operator confusion when attempting to reset the overvoltage trips on the "B" and "D" EDGs. Although the alarm response procedures did not specify a step by step sequence to reset each specific alarm it could have aided the operator, since it did mention the protective relay seal-in-reset.

The licensee has since placed EDG Operating, Alarm Response and Off-Normal procedures at the EDG local control panel and conducted training on the new and revised procedures.

7.4 Electrical Plant and Diesel Generator Operating Procedures

The inspector reviewed selected operating procedures and administrative directives to ascertain the adequacy of the licensee's administrative controls concerning 125V DC control power for various plant systems.

Several procedures did not contain adequate administrative controls to specify the most reliable DC control power source alignments to associated equipment:

-- Operational Procedure OP-024-001, Revision 1, Diesel Generators, dated May 7, 1984, requires positioning of only one "DC Selector Switch" at EDG control panel OC521 (A-D), when actually two selector switches are installed. The two switches select power from either the Unit 1 or Unit 2 DC source for each of the EDG control circuits. Additionally, the DC control power feeder breakers (72DC) to the EDG control circuits in panel OC521 are not listed in this procedure, or any other procedure to ensure proper alignment. The EDG DC power field flash selector switch is also not listed in the procedure.

-- Operational Procedure, OP-203-001, Revision 1, Electrical Plant Lineup, dated March 28, 1984 correctly aligns the 4.16KV ESS bus auxiliary relay and bus control power switches and the breaker control power switches, but the component identification in the procedure is inconsistent with the nameplate installed at the switch. For example, the procedure lists "Bus 2A (2A201) Control Power" and the nameplate stated "D.C. Control". Subsequently the nameplate has been changed to "Bus/Diesel Generator A Auxiliary Relay, Control D.C. Power". Also step 3.1.4 of the procedure contains a note that the "control power switch" located inside the breaker cubicle must be closed before operating the breaker, but does not provide an adequate description or identification of the switch. OP-024-001 contained similar inconsistencies such as the procedure aligns a "DC Selector Switch" in panel 00521, but the actual switch nameplate states "DC Circuit #1 Power Selector".

The inspector identified the above noted discrepancies to the licensee, and the positions of the switches were verified to be in the proper position. OP-203-01 (and OP-103-001) were revised to list the correct component identification, consistent with the new nameplate for the bus and breaker control power knife switches.

The licensee is conducting a complete review of the control of DC knife switches and power transfer switches and the associated operating procedures. Additionally, surveillance and maintenance procedures will be evaluated for adequacy. (See Appendix A, Item No. 2-84-04-24)

7.5 Emergency Diesel Generator (EDG) Off-Normal Operation Procedure

At the time of the event, Off-Normal Procedure ON-024-001, "Diesel Generator Trip" did not exist. Due to the difficulty experienced in attempting to reset the Overvoltage trip on the "B" and "D" EDG's the licensee decided to develop an Off-Normal procedure. The procedure specifies an exact step-by-step sequence to be used to reset any alarm/trip received on the EDG's. The procedure also requires recording of what alarms/trips are received and requires restart of the EDG to adjust the manual voltage regulator to its prescribed value of 4160 volts to prevent overvoltage trips on subsequent manual starts.

7.6 Emergency Preparedness Notification Procedures

During the activation of the Emergency Plan, it was discovered that Emergency Procedure EP-IP-002, Emergency Management Notifications, Revision 3, requires initial notification of an Unusual Event to Pennsylvania Emergency Management Agency (PEMA); Luzurne County Emergency Management Agency (LCEMA), and the NRC. EP-IP-028, Downgrade and Termination, Revision 0, required notification of event termination to the three agencies above and additionally Department of Environmental Resources/Bureau of Radiological Protection (DER/BRP).

The licensee issued a procedure change on July 24, 1984 to change EP-IP-028 to be consistent with EP-IP-002.

7.7 Controlled Drawings and Vendor Schematics

The inspectors reviewed selected licensee controlled drawings to ascertain the adequacy of the licensee's configuration controls concerning DC control power for various equipment and systems.

One drawing was identified that did not correctly reflect the "as built" system configuration. Bechtel Schematic Diagram E-184 Sheet 2, Revision 12, "Diesel Generator Auto-Start Signals", showed that the control power supply to the Diesel Generator "A" Backup Auto-Start circuit was from 125 VDC distribution panel 2D614 breaker No. 5, but it is actually fed from either panel 1D614 breaker No. 20 or panel 2D614 breaker No. 20, through a local selector switch. Similar errors were noted for the other seven auto-start circuits on the schematic.

The discrepancy was identified to the licensee, and a drawing change (DCN) for the document was prepared on July 29 and provided to the inspector. The proposed change correctly reflected the as built condition. No other drawing errors were identified.

8. Corrective Actions

8.1 Licensee Investigation

As a result of the event, the licensee initiated a multi-department evaluation of the event impact. Among the aspects considered were operations, nuclear safety, plant engineering and design, procedural adequacy, human factors and plant response. On July 29, 1984 the licensee presented a detailed briefing of their findings and proposed resolutions to the on-site NRC Investigation Team. The NRC team made several comments concerning corrective actions which were added to the licensee's list of action items. The NRC team was satisfied with the licensee's already implemented short term actions and the proposed long term action items list.

8.2 Action Items

As a result of the NRC:RI and licensee investigation discussed in this report, the licensee compiled an Action Items listing to address and correct identified problems.

The listing denotes the problem, the responsible group, the priority and current status (as of August 13, 1984). The licensee's Action Item listing is included in this report as Appendix A. The incomplete action items are considered unresolved items. Appendix B assigns each action item an unresolved open item control number.

APPENDIX A

UNIT 2 SCRAM NO. 2-84-04

ACTION ITEM

PRIORITY DESCRIPTION

Priority 1	Complete Prior To Startup
Priority 2	Complete Prior To August 13, 1984
Priority 3	Provide Schedule Of Completion To NRC By August 13, 1984
Priority 4	When Required

UNIT 2 SCRAM NO. 2-84-04
ACTION ITEM INDEX

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-01 (SR-1)	Why did the D/G's fail to start? Provide a time line, actions to prevent recurrence and an HFE review of event.
2-84-04-02 (SR-2)	Why did the "J" SRV lift first?
2-84-04-03 (SR-3 & SR-13)	At what level was RCIC manually started? What level instruments were used to determine this level.
2-84-04-04 (SR-4)	Condensate Demineralizer bypass valve requires repair.
2-84-04-05 (SR-5 & SR-22 & NRC-2)	Verify the fuse size and types in the D.C. Control Power circuits for the 13.8 KV and 4KV switchgear in Units 1 and 2.
2-84-04-06 (SR-6)	Should the 4KV Breakers from the D/G's to the ESS busses have been able to be closed remotely?
2-84-04-07 (SR-7)	Repair SCRAM discharge volume drain valve (2F011) operator.
2-84-04-08 (SR-8)	Why did the RFPT 9 and 10 valves fail to close after reenergization of Auxiliary Busses?
2-84-04-09 (SR-9)	Are D/G overvoltage trip procedural controls adequate?

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-10 (SR-10)	Specify the indications available to detect a loss of Control and Trip D.C. Power to 13.8KV, 4KV Switchgear and 480V Load Center Breakers and a Loss of Auxiliary Relay and Control D.C. Power to the 13.8KV, 4KV Switchgear and 480V Load Centers.
2-84-04-11 (SR-11 & NRC-10)	Evaluation and recommendation of testing on 4KV loss of power. D/G auto start to be performed prior to U-2 startup.
2-84-04-12 (SR-12)	Explanation of partial full core display indications immediately after transient.
2-84-04-13 (SR-14 & SR-24)	Evaluation of operation of SGTS during transient.
2-84-04-14 (SR-15)	Evaluation of operation of CREOASS during transient.
2-84-04-15 (SR-16)	Evaluation of operation of Emergency Switchgear Room Cooling during transient.
2-84-04-16 (SR-17)	EP-IP-002 and EP-IP-008 need to be reviewed for coordination. NRC hotline found to be in need of repair.
2-84-04-17 (SR-18)	Conduct operator training as a result of this event.
2-84-04-18 (SR-19)	Conduct Startup PORC.

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-19 (SR-20)	Review 13.8 KV and 4 KV Bkr tagging requests to determine how often we apply tagging to those breakers.
2-84-04-20 (SR-21)	How can an operator get a remote emergency start of the D/G's from the control or relay rooms?
2-84-04-21 (SR-23)	D/G "A" was manually tripped immediately after its manual start due to large frequency oscillation.
2-84-04-22 (NRC-1)	Training Concerns.
2-84-04-23 (NRC-3)	RCIC Flow indication of GETARS
2-84-04-24 (NRC-4)	Use of Wide Range Level During Event
2-84-04-25 (NRC-5)	D/G Reset
2-84-04-26 (NRC-6)	Reg. Guide 1.47
2-84-04-27 (NRC-7)	Suppression Pool Temperature Loss
2-84-04-28 (NRC-8)	08 and 09 Breakers
2-84-04-29 (NRC-9)	Power Transfer Switches

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-30 (NRC-11)	Loss of AC Instrument Indications
2-84-04-31 (NRC-12)	Independent Verification
2-84-04-32 (P-1)	Review of standard electrical operating practices
2-84-04-33 (P-2)	Review of Labeling Blackout Instrumentation
2-84-04-34 (P-3)	Staffing Considerations
2-84-04-35 (P-4)	Procedure Review: 480V, 4KV, & 13.8KV Bkrs.
2-84-04-36 (P-5)	Review of RHR and CS circuit breaker response to various combinations of Motive and Control Power availability.
2-84-04-37 (P-6)	Recorder Pen Colors Discrepancy between Unit 1 and 2 HFE Post Accident Inst. Levels Pressure
2-84-04-38 (P-7)	Communications considerations
2-84-04-39 (P-8)	Pre-test Walk-through

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-01

DESCRIPTION:

Why did the D/G's fail to start? Provide a time line, actions to prevent recurrence and an HFE review of event.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Revise Knife Switch labeling in the 4 kV "01" SWGR CUBICLES listed below: 1A201, 202, 203, & 204 and 2A201, 202, 203, & 204.	Maint	1	C
3. Paint the handle of the knife switch for the "Bus/DG Aux Relay, Control D.C. Power" RED.	Maint	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-02

DESCRIPTION:

Why did the "J" SRV lift first?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Check all SRV Setpoints.	I&C	1	C
3. Recalibrate as required.	I&C	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-03

DESCRIPTION:

At what level was RCIC manually started? What level instruments were used to determine this level?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. What level instrument used/when?	Comp	1	C
3. Explain observed level differences.	I&C	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-04

DESCRIPTION:

Condensate Demineralizer bypass valve requires repair.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Repair Condensate Demin Bypass Valve	Maint	1	C
3. Report on "as found condition" and repairs performed.	Maint	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-05

DESCRIPTION:

Verify the fuse size and types in the D.C. Control Power circuits for the 13.8KV and 4KV Switchgear, 480V Load Centers, 250VDC and 125VDC Load Centers and D/G Cabinets in Units 1 and 2.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Complete the As-Built verification of fuse size, fuse type and labeling in all 4KV, 13.8KV, 480V LC's, and 250VDC and 125VDC Load Centers, and D/G Cabinets. Also, verify knife switch labeling.	Tech	3	C
3. Replace fuses/change labels (for knife switches and fuses) as required.	Maint	3	
4. Establish Fuse Control Policy	Ops	3	
5. Determine proper Control Fuse size/type for: -13.8 breakers - 4.16 breakers -480V Load Centers (not MCC's)	NPE	[illegible]	C
6. Statement that type of fuse is not critical.	NPE	1	C
7. Determine fuse size and types in the 15A and 30A D.C. Control Power circuits for the 13.8KV and 4KV switchgear in Units 1 and 2.	Tech	1	C
8. Replace fuses and relabel Control Fuse nameplates as required (for item No. 7).	Maint	1	C
9. Revise appropriate procedures including COL's (refer to item #2).	Ops	3	
10. Verify that there are no 480V Load Center alarms indicating open D.C. Knife Switches.	Ops	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-06

DESCRIPTION:

Should the 4KV Breakers from the D/G's to the ESS busses have been able to be closed remotely?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Provide copy of results of scheme checks performed by ET.	Maint	1	C
3. Test the "C" D/G's ability to close in on a dead bus with the U/V relay disabled.	S&T	1	C

Note: NRC requested notification regarding test schedule. Intend to witness tests. PP&L will provide notification.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-07

DESCRIPTION:

Repair SCRAM discharge volume drain vlave (2F011) operator.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. What should the valve position be (before the SCRAM)? What position was it in?	Tech	1	C
2. What was the Failure Mechanism?	Tech	1	C
3. Did the valve fail to its proper position? What was the "As-Found" condition?	Maint	1	C
4. What was failure method?	Maint	1	C
5. How did we find SCRAM Discharge Volume Drain Valve failure?	Ops	1	C
6. Inspect similar valves on Unit 2.	Maint	1	C
7. Revise PM's for similar valves.	Maint	3	
8. Inspect similar valves for Unit 1.	Maint	3 (cold shutdown)	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-08

DESCRIPTION:

Why did the RFPT 9 & 10 valves fail to close after reenergization of Auxiliary Busses?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write up.	Tech	1	C
2. Write up design of 9 & 10 valve operation on LOP.	NPE	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-09

DESCRIPTION:

Are D/G overvoltage trip procedural controls adequate?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Why left @ 4250 Volts.	Tech	1	C
3. How do you position D/G voltage required to insure successful starts?	Tech	1	C
4. Determine max T/D on Timing relay.	Maint	3	
5. Recal overvoltage relay (ratio of pickup to dropout - should be as low as possible).	Maint	3	
6. Implement recommendations from Tech/MT on Diesel Generator Voltage Regulator operation (SO's, OP's).	Ops	1	C
7. Adequacy of procedures relating to D/G remote emergency start.	NPE	2	
8. Provide RSCN for relay settings as required.	NPE	3	
9. Optimize O.V. protective scheme - (long term fix).	NPE	3	
10. Provide procedures for remote manual start of the D/G's from the control room to support emergency operations.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-10

DESCRIPTION:

Specify the indications available to detect a loss of Control and Trip D.C. Power to 13.8KV, 4KV Switchgear and 480V Load Center Breakers and a Loss of Auxiliary Relay and Control D.C. Power to the 13.8KV, 4KV Switchgear and 480V Load Centers.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Expand definition to include lights on 13.8KV, 4KV, 480LC.	Tech	1	C
3. Indications available and what it means.	Trng	1	C
4. As result of re-label; incorporate proper terminology into training procedures, etc.	Trng	3	
5. Evaluate changes to procedure as result of re-labeling (procedures, instructions, guidelines).	Ops	3	
6. Revise surveillances and/or rounds to include Supv/Brk Control lights to the 4KV Switchgear.	Ops	1	C
7. Revise guidelines in AD (Permit and Tag).	Ops	1	C
8. Write OI for proper rack out of various breaker types (to include observation/ indication during sequence).	Ops	2	
9. Indications available and what it means.	NPE	1	C
10. Rectify labeling to prints.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-11

DESCRIPTION:

Evaluation and recommendation of testing on 4KV loss of power. D/G auto start to be performed prior to U-2 startup.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Evaluate/Recommend testing. (Identify testing, conditions, and basis for performing the test(s) - discuss safety implications).	S&T	1	C
2. Perform ST31.1 (prior to leaving test plateau No. 2).	S&T	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-12

DESCRIPTION:

Explanation of partial full core display indications immediately after transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Provide discussion of full core display indications following loss of power. Actual indications observed. Provide information to OPS on how to restore.	I&C	1	C
3. Train the operator regarding: Full core display response to loss of power and, how to power-up.	Trng	1	C
4. Revise EO on Station Blackout procedure to address reset of Full Core Display.	Ops	1	C
5. Evaluate and revise as required the ATWS procedure.	Ops	3	
6. Review the differences between Units 1 and 2 relative to the full core display during blackout conditions and make recommendations.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-13

DESCRIPTION:

Evaluation of operation of SGTS during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C
2. (a) Evaluate performance on restart following trip and subsequent LOCA init.	NPE	1	C
(b) Evaluate desirability of modifications for the SGTS based upon review of the trip experienced.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-14

DESCRIPTION:

Evaluation of operation of CREOASS during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-15

DESCRIPTION:

Evaluation of operation of Emergency Switchgear Room Cooling during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-16

DESCRIPTION:

EP-IP-002 and EP-IP-008 need to be reviewed for coordination. NRC hotline found to be in need of repair.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Repair hotline to NRC.	Maint	1	C
2. Revise EP-IP for consistant notification.	Trng	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-17

DESCRIPTION:

Conduct operator training as a result of this event.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Trng	1	C
2. Define who (by position) get training (scope).	Ops	4	
3. Review all action items and determine/ conduct training required prior to startup for Ops.	Trng	1	C
4. Determine and provide additional training required for each group.	Trng	4	
5. Conduct training and incorporate lessons learned into training programs.	Trng	3	

Note: Preparations are being made to commence training activities. The NRC noted that they would like to attend a session.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-18

DESCRIPTION:

Conduct Startup PORC.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Conduct PORC when ready.	Tech	1	C

Note: PP&L will inform the NRC as to when the PORC will take place.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-19

DESCRIPTION:

Review 13.8KV and 4KV Bkr tagging requests to determine how often we apply tagging to those breakers.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Survey Permit and Tag permits over past 6 months.	Ops	2	C
2. What were the actual instructions on the permit?	Ops	2	C
3. Evaluate adequacy of written tag out direction (results may be changed to AD).	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-20

DESCRIPTION:

How can an operator get a remote emergency start of the D/G's from the control or relay room?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Define how to get an emergency start of the Diesel Generators.	Tech	2	C
2. Evaluate manual emergency start of the Diesel Generators.	NPE	2	C
3. Evaluate the necessity of D/G emergency start capability from the Control Room other than by the methods currently available.	NPE	3	

Note: Action item 2-84-04-09 includes related items.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-21

DESCRIPTION:

D/G "A" was manually tripped immediately after its manual start due to large frequency oscillation.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Support MT/IC on evaluation of Diesel Generator "A" Frequency Oscillations.	Tech	1	C
2. From operator interview, how large were frequency oscillations?	Comp	1	C
3. Review records regarding performance of "A" D.G. (i.e., oscillations).	Maint	2	
4. Evaluate testing for "A" D/G.	S&T	1	C
5. Review/evaluate Diesel Generator test program for adequacy with respect to determining Diesel Generator performance.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-22

DESCRIPTION:

Training Concerns.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Describe administrative program to assure required operator training is performed.	Ops	1	C
2. (a) Evaluate present program.	Ops	1	C
(b) Revise program as required.	Ops	2	
3. Review Station Program for methods of assuring Non-Routing Training is performed.	Comp	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-23

DESCRIPTION:

RCIC flow indication on GETARS.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Operator RCIC action.	Comp	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-24

DESCRIPTION:

Use of Wide Range Level During Event.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. What Level Control Instruments were used during event?	Comp	1	C
2. Which level Instrument indicated on GETARS? (Is label correct?)	I&C	1	C
3. Determine which level instruments remain powered. - Notify Ops to correct EO.	Tech	1	C
4. Correct EO as required to 'identify level instruments'.	Ops	1	C
5. Review and revise as required procedure, including ON-117-001 and 002, and ON-217-001 and 002.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-25

DESCRIPTION:

D/G Reset

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write a procedure for reset of D/G on OV trip.	Ops	1	C*
2. Perform training.	Trng	1	C
3. How to reset the trips for various D/G trips AR-ODA-521, ODB, ODC, ODD.	Tech	1	C

* Note: Item 1 closed pending NRC review.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-26

DESCRIPTION:

Reg Guide 1.47

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Does our present design meet the intent of Reg. Guide 1.47 with respect to control power disconnect supervision, specifically the 30A fuse circuit.	NPE	2	
2. Review adequacy of our present design with respect to Reg. Guide 1.47 as associated with Control Power disconnects, specifically the Bus/DG Auxiliary relay, Control D.C. Power Knife Switch.	NPE	2	
3. Review and revise as appropriate monthly Surveillance Maintenance (SM) procedures to incorporate provisions for continuity checks on non-supervised circuits so as to assure full closure.	Maint	4	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-27

DESCRIPTION:

Suppression Pool Temperature Loss

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Was SPOTMOS lost during the event?	Tech	2	C
2. Provide a description of how to reset.	Tech	3	
3. Revise ON-117 & 217.	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-28

DESCRIPTION:

08 & 09 Breakers

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. If the 13.8 Bkrs were open, the 08 & 09 Bkrs could be tripped; but could they be closed again due to the 27 relay (Knife Switch).	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-29

DESCRIPTION:

Power Transfer Switches

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Listing of all Power Transfer Switches. (Manual and Auto)	NPE	3	
2. Determine present lineup of all Power Transfer Switches and how these are checked and controlled.	Ops	3	
3. What is the desired lineup for maximum reliability?	NPE	3	
4. Review labels versus OP's/Col's and revise accordingly.	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-30

DESCRIPTION:

Loss of AC Instrument Indication

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Does the present design provide adequate instrumentation during a loss of AC power. Is the present instrumentation of sufficient range and is it in accordance with the General Design Criterion?	NPE	3	
2. Perform an HFE Review of Instrumentation Locations for instruments used during a loss of AC power.	NPE	3	
3. Are there sufficient instruments available for the operating staff to properly perform their activities during loss of AC power?	Ops	3	

a. Are ranges proper?
b. Are locations proper?
c. Are there a sufficient number of instruments?

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-31

DESCRIPTION:

Independent Verification

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review the Station Program for Independent Verification and provide recommendations (Common Mode Failure Considerations)	Comp	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-32

DESCRIPTION:

Review of standard electrical operating practices.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review of standard electrical practices.	Ops	3	
2. Poll the operators for review of standard electrical operating practices.	Comp	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-33

DESCRIPTION:

Review of Labeling Blackout Instrumentation.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Evaluate advisibility of Labeling Blackout Instrumentation	Tech	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-34

DESCRIPTION:

Staffing

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Given the type of event, was our Operating Staffing adequate? (2 Units worst case)	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-35

DESCRIPTION:

Procedure Review: 480V, 4KV & 13.8KV, 250VDC, 125VDC, and Diesel Generator cubicles.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review for adequacy SM's, PM's, OP's, and SO's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	Ops	3	
2. Review for adequate control, PM's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	Maint	3	
3. Review for adequate control, ST's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	S&T	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-36

DESCRIPTION:

Review of RHR and CS circuit breaker response for various combinations of Motive and Control Power availibility.
Examples: a) Closure of circuit breaker on a "dead bus".
b) Closure of circuit breaker on a "dead bus" with no control power to under voltage relays.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Conduct review	NPE	2	
2. Conduct training	Trng	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-37

DESCRIPTION:

Recorder Pen Colors Discrepancy between Unit 1 and 2
HFE Post Accident Inst. Levels, Pressure.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Resolve recorder pen color differences in Control Room Recorders identified during event.	Tech	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-38

DESCRIPTION:

Communications

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write radio communications procedure. Include unit separation requirements.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-39

DESCRIPTION:

Pre-Test Walk-Through

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Test Director to walk through with Operations and involved primary groups which have an active role prior to major tests.	S&T	4	

APPENDIX B

Unresolved Item List

Unresolved Item Number	Licensee Action Item Number	Action Item Description
388/84-34-5	2-84-04-05 (SR-5 & SR-22 & NRC-2)	Verify the fuse size and types in the D.C. Control Power circuits for the 13.8KV and 4KV switchgear in Units 1 and 2.
388/84-34-6	2-84-04-07 (SR-7)	Repair SCRAM discharge volume drain (2F011) operator.
388/84-34-7	2-84-04-09 (SR-9)	Are D/G overvoltage trip procedural controls adequate?
388/84-34-8	2-84-04-10 (SR-10)	Specify the indications available to detect a loss of Control and Trip D.C. Power to 13.8KV, 4KV Switchgear and 480V Load Center Breakers and a Loss of Auxiliary Relay and Control D.C. Power to the 13.8KV Switchgear and 480V Load Centers.
388/84-34-9	2-84-04-12 (SR-12)	Explanation of partial full core display indications immediately after transient.
388/84-34-10	2-84-04-13 (SR-14 & SR-24)	Evaluation of operation of SGTS during transient.
388/84-34-11	2-84-04-17 (SR-18)	Conduct operator training as a result of this event.
388/84-34-12	2-84-04-19 (SR-20)	Review 13.8KV and 4KV Bkr tagging requests to determine how often licensee applies tagging to those breakers.
388/84-34-13	2-84-04-20 (SR-21)	How can an operator get a remote emergency start of the D/G's from the control or relay rooms?
388/84-34-14	2-84-04-21 (SR-23)	D/G "A" was manually tripped immediately after its manual start due to large frequency oscillation.

Unresolved Item Number	Licensee Action Item Number	Action Item Description
388-84-34-15	2-84-04-22 (NRC-1)	Training Concerns.
388/84-34-16	2-84-04-24 (NRC-4)	Use of Wide Range Level During Event.
388/84-34-17	2-84-04-26 (NRC-6)	Regulatory Guide 1.47.
388/84-34-18	2-84-04-27 (NRC-7)	Suppression Pool Temperature Loss.
388/84-34-19	2-84-04-29 (NRC-9)	Power Transfer Switches.
388/84-34-20	2-84-04-30 (NRC-11)	Loss of AC Instrument Indications.
388/84-34-21	2-84-04-31 (NRC-12)	Independent Verification.
388/84-34-22	2-84-04-32 (P-1)	Review of Standard Electrical Operating Practices.
388/84-34-23	2-84-04-33 (P-2)	Review of Labeling Blackout Instrumentation.
388/84-34-24	2-84-04-34 (P-3)	Staffing Considerations.
388/84-34-25	2-84-04-35 (P-4)	Procedure Review: 480V, 4KV and 13.8KV Breakers.
388/84-34-26	2-84-04-36 (P-5)	Review of RHR and CS circuit breaker to various combinations of Motive and Control Power availability.
388/84-34-27	2-84-04-37 (P-6)	Recorder Pen Colors Discrepancy between Unit 1 and 2 HFE Post Accident Instrument Levels Pressure.
388/84-34-28	2-84-04-38 (P-7)	Communications considerations.