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July 10, 1989

EDE LTR #89-539

U.S. Nuclear Regulatory Commission
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Licensee Event Report #89-001-1, Docket #050249 is being submitted as required by Technical Specification 6.6, NUREG 1022 and 10 CFR 50.73(a)(2)(iv). This revised report is provided to correct an error concerning nomenclature of the Motor Control Center (MCC) 38-7/39-7 Reserve Feed Breakers and provide an updated status of corrective actions in progress.

E.D. Eenigenburg
Station Manager
Dresden Nuclear Power Station

EDE/jt

Enclosure

cc: A. Bert Davis, Regional Administrator, Region III
File/NRC
File/Numerical

(0609k)

IE22
1/1

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Dresden Nuclear Power Station, Unit 3	0 5 0 0 0 2 4 9	1 of 3 3

Title (4) Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss of Offsite Power

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Facility Names	Docket Number(s)
									Unit 2	0 5 0 0 0 2 3 7
0 3	2 5	8 9	8 9	0 0 1	0 1	0 7	1 0	8 9	N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 8 9

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

___ 20.402(b)	___ 20.405(c)	X 50.73(a)(2)(iv)	___ 73.71(b)
___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify in Abstract below and in Text)
___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER AREA CODE	
Rob Whalen, Technical Staff Mechanical Systems Group Leader Ext. 2462	8 1 5	9 4 2 - 2 9 2 0

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	F K	C A P	I 0 0 5	N	X	E C	5 2	G 0 8 0	Y
X	E A	5 2	G 0 8 0	Y	X	B J	M 0	G 0 8 0	Y

SUPPLEMENTAL REPORT EXPECTED (14)

___ Yes (If yes, complete EXPECTED SUBMISSION DATE) X NO

Expected Submission Date (15) Month Day Year

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

At approximately 0133 hours on March 25, 1989, while Unit 3 was operating at 89% rated core thermal power, a fault occurred within 345 KV switchyard power circuit breaker (PCB) 8-15. Local Breaker Backup logic circuitry then automatically isolated PCB 8-15; this de-energized Unit 3 reserve auxiliary transformer (TR) 32, causing a loss of offsite power (LOOP) to Unit 3. The automatic transfer of 4 KV Bus 32 from TR 32 to Unit 3 auxiliary TR 31 did not occur quickly enough to prevent undervoltage trips of the 3B reactor feed pump (RFP) and the 3B reactor recirculation pump. When the standby 3C RFP automatically started, reactor water level rose to the main turbine and RFP trip setpoint and a reactor scram on turbine stop valve closure resulted. The Main Steam Isolation Valves (MSIVs) were manually closed to conserve reactor inventory and the Isolation Condenser was used for reactor pressure control. Mildly contaminated condensate was initially used to supply the Isolation Condenser shell side because the clean demineralized water supply valve was unavailable. This resulted in low level contamination to the area surrounding the Isolation Condenser vent. Cold shutdown conditions were achieved by 2230 hours on March 25, 1989. Corrective actions included inspection, testing and repair of various breakers and logic circuits and surveys/cleanup of the areas affected by the Isolation Condenser vent. Conservative calculations found the release was less than 0.01% of 10CFR20 Appendix I Quarterly Objectives. Safety significance was minimal as the Automatic Depressurization and Core Spray Systems were available. A previous LOOP event involving Unit 2 was reported by LER 85-34/050237.

LICENSEE EVENT REPORT (LER) FAILURE CONTINUATION

Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6): Year	Sequential Number	Revision Number	Page (3)
Dresden Nuclear Power Station	0 5 0 0 0 2 4 9	8 9	- 0 0 1	- 0 0	0 2 OF 3 3

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	I A	0 J X	5 2 5 0	N					

NRC Form 366B (9-83)

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2527 MWt rated core thermal power.

Nuclear Tracking System (NTS) tracking code numbers are identified in the text as (XXX-XXX-XX-XXXXX).

EVENT IDENTIFICATION:

Turbine [TA] Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During a Loss of Offsite Power Event.

A. CONDITIONS PRIOR TO EVENT:

Unit: 3 Event Date: March 25, 1989 Event Time: 0133 hours

Reactor Mode: N Mode Name: Run Power Level: 89%

Reactor Coolant System (RCS) Pressure: 972 psig

B. DESCRIPTION OF EVENT:

At approximately 0133 hours on March 25, 1989, while Unit 3 was operating at 89% rated core thermal power, an internal fault occurred within 345 KV power circuit breaker (PCB) 8-15 [FK] located in the 345 KV switchyard [FK]. The configuration of the 345 KV switchyard is shown in Figure 1. Reactor Feed Pumps (RFPs) [SJ] 3A (powered from 4 KV Bus 31 [EA]) and 3B (powered from 4 KV Bus 32 [EA]) were operating. The 3C RFP was selected as the standby RFP (4 KV Bus 32 was selected as the standby power source). A simplified Unit 3 electrical arrangement is provided in Figure 2. The 3A feedwater regulating valve (FWRV) [JB] was operating in the automatic mode, and the 3B FWRV was operating in the manual mode at approximately 25% open. A detailed sequence of events is provided in Table 1.

Significant occurrences during this event that were investigated are as follows:

1. Power Circuit Breaker (PCB) 8-15 Fault.

   A phase-to-ground fault occurred and gave a trip signal for PCB 8-15. Because the fault did not clear, Local Breaker Backup logic circuitry automatically tripped additional breakers to isolate 345 KV Busses 8 and 15. Because reserve auxiliary transformer (TR) 32 [EA] is fed from 345 KV Bus 8, power to TR 32 was lost.

2. Slow Transfer of Bus 32 from TR 32.

   Bus 32 should have promptly transferred to TR 31 [EA] (see Figure 2). During this event approximately 14 seconds elapsed between the tripping of Bus 32 feed breaker 152-3205 from TR 32 to the closing of Bus 32 feed breaker 152-3201 from TR 31.

3. Open Annunciator Panel Fuses.

   At 0435 hours with Unit 2 in the Run mode at 97% rated core thermal power, the Nuclear Station Operator (NSO) discovered that alarm F-12, Alarm Potential F-9 Failure, on the 902-3 annunciator panel [JF] was illuminated. This alarm, which corresponds to an open F-9 fuse and subsequent loss of power to the 902-3 annunciator panel, is believed to have existed since 0134 hours when the Unit 3 main generator tripped. The 902-6 annunciator panel fuse is also believed to have opened at 0134 hours.

Loss of the 902-3 annunciator panel for longer than 30 minutes should lead to the declaration of a Generating Station Emergency Plan (GSEP) Alert condition in accordance with Emergency Plan Implementation Procedure (EPIP) 200-T1, Classification of GSEP Conditions. The loss of the 902-6 annunciator panel did not require entry into the GSEP emergency action levels.

4. Feedwater Control System [JB] Behavior.

When the Bus 32 undervoltage condition occurred due to the slow transfer of Bus 32 from TR 32 to TR 31, the 3B RFP automatically tripped. This caused feedwater flow through the 3A RFP to exceed 5.6 E6 lb/hr, thereby initiating the Feedwater System runout flow control mode [JB]. Runout flow control mode is a feature of the feedwater level control system designed to automatically limit feedwater flow such that RFP trips on overcurrent or low suction pressure are prevented. Runout flow control mode is entered at 5.6E6 lb/hr feedwater flow or below +20 inches reactor water level (instrument zero reference). Normally, at the initial power level, loss of a single RFP without automatic start of the standby RFP would have caused a reactor scram on low water level (setpoint: +8 inches above instrument zero). (Note: instrument zero reference is 143 inches above the top of active fuel). However, since the loss of the 3B RFP was accompanied by a trip of the 3B reactor recirculation [AD] pump (also powered via Bus 32), reactor power decreased and the resultant reactor water level swell minimized the reactor level descent caused by loss of the 3B RFP. Reactor water level dropped to approximately +16 inches above instrument zero; however, the standby 3C RFP failed to start immediately due to Bus 32 being de-energized. After approximately 11 seconds the Bus 32 transfer process completed; this energized the standby 3C RFP. Since reactor water level was still less than +20 inches the runout flow control mode was still in effect, resulting in two RFPs supplying 11.2E6 lb/hr feedwater flow to the reactor vessel. Attempts by the NSO to close the feedwater regulating valves (FWRVs) at this time were thus prohibited by the runout flow control feature. As reactor water level increased rapidly and passed the +20 inches level, the runout flow control mode automatically reset, allowing the FWRVs to return to their normal operating positions as selected prior to the event. As the FWRVs closed, water level continued to rise until at +55 inches reactor water level the main turbine and RFPs automatically tripped. A reactor scram on turbine stop valve closure then resulted.

5. Spurious Trip of Bus 39 [EC] to Motor Control Center (MCC) 38-7/39-7 [EC] Breakers.

Feed Breakers 252-3971 and 252-3972 [EC], from 480 V Bus 39 to the Low Pressure Coolant Injection (LPCI) [BO] swing bus [Motor Control Center (MCC) 38-7/39-7] [EK], spuriously tripped. This was abnormal since a transfer of the power feed to the LPCI swing bus from 480 V Bus 39 to 480 V Bus 38 should not occur until an undervoltage condition exists on Bus 39 [EL] for 15 seconds. Undervoltage on Bus 39 existed for only seven seconds (elapsed time between loss of TR 31 to loading of the Unit 3 Diesel Generator [EK]).

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to close.

Following the spurious trip of feed breakers 252-3971 and 252-3972, reserve feed breaker 252-3872 [EC] failed to close. Consequently, MCCs 38-7 and 39-7 remained de-energized.

7. Use of Contaminated Condensate [KA] Isolation Condenser [BL] Shell Side Supply.

During the first initiation of the Isolation Condenser, the Nuclear Station Operator (NSO) observed that the clean demineralized water [KC] shell side supply valve MO3-4399-74 was de-energized (see Figure 3). Consequently, the NSO initiated use of the mildly contaminated condensate Isolation Condenser shell side supply under direction of Shift Supervision.

During the second initiation of the Isolation Condenser, valve MO3-4399-74 had been opened, but the available clean demineralized water pump could not keep up with demand. Therefore, the NSO supplemented the clean demineralized water supply with the mildly contaminated condensate supply.

8. High Pressure Coolant Injection (HPCI) [BJ] Lube Oil Cooling Problem.

   At approximately 0400 hours while using the HPCI System for reactor pressure and water inventory control, annunciator D-10, HPCI High Pressure Bearing Oil Drain High Temperature, on the 903-3 panel alarmed. The NSO then immediately began to perform the operator actions listed in Dresden Operating Annunciator Procedure (DOA) 920(3)-3 D-10, HPCI High Pressure Bearing Oil Drain High Temperature. The annunciator continued to alarm (setpoint: 180°F increasing temperature). The NSO then reviewed the HPCI System valve alignment and noted that the MO3-2301-49 valve, HPCI Lube Oil Cooling Water Test return valve to the condensate storage tank, was open. The NSO also noted that the MO3-2301-48 valve, HPCI lube oil cooling water normal return valve to the HPCI booster pump discharge, was closed. The NSO proceeded to close the MO3-2301-49 valve and open the MO3-2301-48 valve after which annunciator D-10 reset.

   The HPCI System subsequently tripped due to a +48 inches (instrument zero reference) reactor water level signal. Discussions with the NSO indicated that his concern with the lube oil cooling problem allowed reactor water level to attain the +48 inch HPCI trip setpoint earlier than expected.

9. Bus 34-1 to Bus 34 Breaker Problem.

   When the initial attempt was made to backfeed Bus 34 [EA] from the Unit 3 Diesel Generator (DG 3), the Bus 34-1 [EK] to Bus 34 feed breaker 152-3403 [EA] tripped open when the breaker was initially closed at approximately 0405 hours. Operations Department personnel succeeded in closing breaker 152-3403 at approximately 0530 hours.

10. HPCI Turning Gear Motor Failure.

    The HPCI turning gear was unavailable following the trip of the HPCI turbine because of turning gear motor failure. Consequently, Operations Department personnel turned the HPCI turbine manually to insure proper HPCI turbine cooldown.

11. Open fuse for Security [IA] Multiplexer (MUX) 8.

    Security MUX 8 was unavailable for approximately one hour during the event due to an open power supply fuse. The Security force promptly initiated appropriate compensatory measures upon loss of MUX 8 in accordance with the security plan.

12. Security Uninterruptible Power Supply (UPS) Failure.

    The security computer was without power for approximately 17 minutes during the event when the Security System UPS failed during an attempt to switch the security bus back to main power. The Security force promptly initiated appropriate compensatory measures upon failure of the Security System UPS in accordance with the security plan.

13. Primary Containment [NH] Oxygen Analyzer [IK] Unavailability.

    The Primary Containment oxygen analyzer read zero at each sample point for a short period following restoration of power.

14. Instrument Air System [LD] Behavior.

Upon loss of the Unit 3 Instrument Air System at approximately 0148 hours, the main turbine turning gear was rendered inoperable until 0510 hours at which time the Unit 3 Instrument Air System was supplied by the Unit 1 Instrument Air System.

Additionally, operator action was required to prevent depressurization of the Unit 2 Instrument Air System via the 3C Instrument Air Compressor, which may be aligned to Unit 2 or Unit 3. The 3C Instrument Air Compressor was manually isolated from the Unit 2 Instrument Air System.

C. APPARENT CAUSE OF EVENT:

This report is submitted in accordance with 10CFR50.73(a)(2)(iv), which requires the reporting of any uplanned Engineered Safety Feature (ESF) actuation, including the reactor protection system (RPS).

The Shift Engineer promptly notified Station Management and the Operations Duty Supervisor of this event; a support team was then assembled to assist with root cause evaluation, repairs, testing, and other corrective actions. The root cause of the reactor scram has been attributed to the slow transfer of 4 KV Bus 32 from TR 32 to TR 31, causing a reactor water level transient which resulted in an automatic main turbine trip on high reactor water level and a subsequent turbine stop valve closure reactor scram signal. Cause analyses of the significant occurrences observed during this event are provided below.

1. Power Circuit Breaker (PCB) 8-15 Fault.

Inspection of PCB 8-15 revealed that a ground capacitor in the A phase of the circuit breaker had failed and that a phase-to-ground fault had occurred across an adjacent insulated support column (see Figure 4). The phase compartments of PCB 8-15 are pressurized with sodium hexafluoride gas (SF_6). The failed ground capacitor (which was mounted within the A phase pressure vessel) utilized a mineral oil dielectric fluid which contained no polychlorinated biphenyls. As the phase compartment pressure vessels remained intact, no release of SF_6 gas or ground capacitor dielectric fluid occurred. Debris from the capacitor included pieces of insulation and metal plates. Most of the oil and debris from the failed capacitor remained in the A phase pressure vessel, but some passed through a connecting duct to the B and C phase pressure vessels. The apparent cause of the phase-to-ground fault within the A phase circuit breaker was the capacitor failure and resultant debris.

2. Slow Transfer of Bus 32 from TR 32 to TR 31.

The proximate cause of the slow closure of breaker 152-3201 was attributed to dirty contacts on the breaker up/down position switch. The maintenance history for this breaker indicates that the last overhaul of this breaker was on February 11, 1982, and was next due by December 30, 1989. The root cause of this breaker problem is attributed to the long interval between breaker overhauls.

3. Open Annunciator Panel Fuses.

The probable cause of the open annunciator panel fuses was an apparent spike within the 125 VDC System following the loss of offsite power on Unit 3.

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The failure of the NSO to discover the 902-3 annunciator panel problem until 0435 hours is attributed to personnel error. The NSO incorrectly identified the "Alarm Potential F-9 Failure" alarm (Panel 902-3; Alarm F-12) as an adjacent Primary Containment Nitrogen Inerting Makeup System high flow alarm (Panel 902-3; Alarm G-13) and determined that the alarm did not require immediate operator action. Contributing to this error was the need to clear numerous annunciator alarms following the loss of offsite power on Unit 3 and the lack of distinctive backlighting of annunciator windows for loss of annunciator panel alarms.

4. Feedwater Control System Behavior.

Loss of an RFP without automatic start of the standby RFP at initial conditions of 89% rated thermal power would normally be expected to result in an automatic reactor scram on low reactor water level (setpoint: +8 inches above instrument zero). However, in this event a concurrent trip of the 3B reactor recirculation pump occurred. This caused a reactor power decrease and reactor water level swell such that the minimum reactor water level prior to the reactor scram was approximately +16 inches.

The feedwater level control system was unable to prevent a rapid reactor water level increase to the automatic main turbine and RFP trip setpoint (+55 inches above instrument zero) due to inherent design aspects of the runout flow control feature, which operated as designed to prevent loss of the RFPs on overcurrent and/or low suction pressure trip signals. However, review of this event indicates that additional operator training on the runout flow control feature would assist the reactor operators during this type of event. Additionally, design setpoint changes to the runout flow control feature may be postulated to provide improved feedwater level control in this type of event.

5. Spurious Trip of Bus 39 to MCC 38-7/39-7 Breakers.

A General Electric (GE) CR122AT Time Delay on Energization (TDOE) relay transfers the power feed to the LPCI swing bus from Bus 39 to Bus 38 (see Figure 2). The root cause of the spurious trip of breakers 252-3971 and 252-3972 has been attributed to an original construction design deficiency in that the model TDOE relay used was not suitable for this application. This conclusion is based on the investigation discussed below.

When an undervoltage condition exists on Bus 39, the UV contacts (see Figure 5) pick up and the "HFA" (227B39X1) relay becomes energized. HFA (227B39X1) contacts 11-12 and 5-6 close sealing in the coil while contact 3-4 closes starting the 15 second timer on the TDOE relay. If the undervoltage on Bus 39 remains for 15 seconds, TDOE contacts 3-4 and 1-2 close, tripping feed breakers 252-3971 and 252-3972 while closing reserve feed breakers 252-3871 and 252-3872. If voltage is restored to the bus before the 15 second time delay expires, the OVX contact closes, the OVX coil energizes, and the OVX contact opens. With the OVX contact open, power to the TDOE is lost and the timer should reset. During this event an undervoltage existed on Bus 39 for only seven seconds; nevertheless, the circuit responded as if the 15 second delay had been reached.

The OVX and TDOE relays were tested in accordance with Work Request 83559. The OVX contact was verified to open properly for simulated undervoltage conditions of two, five, seven, and 10 seconds. The TDOE relay was then tested for the same simulated undervoltage conditions by monitoring the voltage across TDOE contacts 3-4 and 1-2. The results of the test are contained in Table 2.

When a simulated undervoltage condition existed for greater than 15 seconds, breaker 252-3971 tripped and breaker 252-3871 closed as expected. When the simulated undervoltage condition existed for two seconds, the breakers were unaffected and the TDOE relay reset as expected. However, when the simulated undervoltage condition was present for five, seven, or 10 seconds, breakers 252-3971 and 252-3871 did not respond as expected.

Subsequently, a review of a GE catalog description revealed that inputs to the GE CR122AT relay for over 1/3 of the time setting will produce a momentary output from the timer upon removal of the input signal prior to completion of the delay. The momentary output from the timer explained the simulated undervoltage test results obtained for the GE CR122AT TDOE relay. Based on the test results and the catalog description, it was determined that the GE CR122AT TDOE relay was unsuitable for this application.

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to Close.

The proximate cause of the failure of breaker 252-3872 to close was attributed to a breaker linkage that was found to be sticking intermittently. Breaker 252-3872, which is located at MCC 38-7, is not currently included in the preventative maintenance program. A modification had been approved for replacement of Breaker 252-3872 with an improved contactor assembly; this modification work is scheduled for completion during the upcoming Unit 3 D3R11 refuel outage. The root cause of the Breaker 252-3872 failure was therefore attributed to the lack of a periodic preventative maintenance requirement.

7. Use of Contaminated Condensate Isolation Condenser Shell Side Supply.

The clean demineralized water shell side supply valve MO3-4399-77 is powered by MCC 39-3 (see Figure 2). The reason that this valve was initially de-energized during this event is that MCC 39-3 is designed to automatically trip during undervoltage conditions to limit loads on the emergency Diesel Generators.

After power was restored to MCC 39-3, the one available clean demineralized water pump could not keep up with the Isolation Condenser demand. Based on this event and previous experience with operation of the Isolation Condenser for reactor pressure control following a Unit scram, the clean demineralized water supply to the Isolation Condenser is judged to be undersized; the root cause of the need to use contaminated condensate Isolation Condenser shell side supply is therefore attributed to design deficiency.

8. HPCI Lube Oil Cooling Problem.

During a HPCI System automatic initiation, the MO3-2301-48 valve is automatically opened and the MO3-2301-49 valve is automatically closed (see Figure 6). This allows lube oil cooling water to be supplied by the HPCI booster pump discharge and returned to the suction. During normal operation with HPCI in the standby mode, the MO3-2301-48 valve is closed and the MO3-2301-49 valve is open. This allows a flow path to the Condensate Storage Tank [KA], through the MO3-2301-15 valve for the Gland Seal Leak Off Drain pump.

During this event, the HPCI System was manually initiated primarily as a means of pressure control and secondly as a means of inventory control. Therefore, according to Dresden Operating Procedure (DOP) 2300-3, HPCI System Manual Startup and Operation, the NSO manually initiated HPCI and utilized the MO3-2301-10 valve and the manual flow controller to adjust HPCI flow. Subsequent steps of DOP 2300-3 direct the NSO to open the 3-2301-48 valve and close the 3-2301-49 valve. DOS

2300-3 did not instruct the NSO to perform these subsequent steps in rapid succession, however. Therefore, since the NSO's primary concern was maintaining the reactor in a safe condition, he remained at the HPCI flow adjustment step and did not immediately close the 3-2301-49 valve and open the 3-2301-48 valve. Not performing these steps caused the lube oil cooler flow to be dead-headed against the 3-2301-21 check valve. (The downstream side of the 3-2301-21 check valve experiences full HPCI pump flow and pressure). During this event HPCI discharge pressure was approximately 800 psig.

In conclusion, the root cause for HPCI lube oil cooling problem is attributed to procedural deficiency as DOP 2300-3 did not require prompt respositioning of the MO3-2301-48 and MO3-2301-49 valves upon manually initiating the HPCI system for purposes of reactor pressure control.

9. Bus 34-1 to Bus 34 Breaker Problem.

The proximate cause of the failure of breaker 152-3403 to trip open following its closure was attributed to pitted overvoltage contacts found on undervoltage relay 127-2-B34. Because the overvoltage contacts did not close upon Bus 34 voltage restoration by DG 3, undervoltage relay 127-2-B34 could not be de-energized and reset; consequently, the trip signal to breaker 152-3403 remained. The maintenance history for this relay indicates that this relay was last cleaned on May 15, 1988. Normal wear since the last relay cleaning is therefore attributed as the root cause of this breaker problem.

10. HPCI Turbine Gear Motor Failure.

Subsequent to the removal of the HPCI turning gear motor, total disassembly and inspection revealed that the motor commutator was excessively pitted and worn. An inspection of the motor brushes indicated that one of the two brushes was installed slightly out of alignment. Figure 7 shows the correct and as found brush installation configurations. The misaligned installation allowed less brush surface area to come in close proximity of the motor commutator. This is believed to have allowed excessive arcing and heat generation, ultimately resulting in degradation of the motor commutator.

A review of Dresden Electrical Procedure (DEP) 8300-4, Unit 2/3 Inspection of DC Motors and Brushes, indicated that there are no cautions that state the brushes must be reinstalled to match the commutator contour. Therefore, the root cause of these event is attributed to procedural deficiency. DEP 8300-4 was last performed on the HPCI turning gear motor on May 12, 1988.

11. Open Fuse for Security Multiplexer (MUX) 8.

No abnormal conditions were identified that would have caused the fuse to open. The root cause of this failure is therefore attributed to normal end-of-life of this component.

12. Security UPS Failure.

The Security UPS failed during an attempt to switch the security bus back to main power. No formal procedure existed to guide the operator in this evolution. The proximate cause of the failure is attributed to an inappropriate switching sequence. The root cause of this failure is attributed to procedural deficiency in that a detailed procedure for switching the security UPS was not available.

13. Oxygen Analyzer Unavailability.

The abnormal readings of the oxygen analyzer are attributed to normal cooldown of the oxygen analyzer following loss of power. The calibration of the oxygen analyzer is temperature sensitive, and the abnormal readings upon restoration of power resulted.

14. Instrument Air System Behavior.

The proximate cause of the main turbine Turning gear engagement problem was determined to be the fact that the turning gear assembly requires instrument air for automatic engagement.

Investigation revealed that the main turbine turning gear can be manually engaged without instrument air supply. However, Dresden Operating Abnormal (DOA) Procedure 4700-1, Instrument Air System Failure, did not include instructions concerning manual engagement of the main turbine turning gear. Therefore, the root cause of the turning gear engagement problem was attributed to procedure deficiency. The root cause behind the unexpected need for operator action to manually isolate the 3C Instrument Air Compressor from the Unit 2 Instrument Air System was also attributed to procedure deficiency as DOA 4700-1 did not include appropriate instructions.

D. <u>SAFETY ANALYSIS OF EVENT</u>:

A safety analysis of each significant occurrence associated with this event is provided below.

1. Power Circuit Breaker (PCB) 8-15 Fault.

The failure of PCB 8-15 led to the reactor scram and loss of offsite power. The safety significance of this failure was minimized by the fact that the Unit 3 and 2/3 DGs started and loaded and were capable of carrying the necessary safety system loads.

2. Slow Transfer of Bus 32 from TR 32 to TR 31.

The slow closure of breaker 152-3201 resulted in the trip of the 3B RFP, the trip of the 3B reactor recirculation (recirc) pump motor generator (MG) set, the delayed automatic start of the 3C RFP (in standby), and the subsequent Unit scram and loss of offsite power. The safety significance of this slow closure is minimized by the fact that the Unit 3 and 2/3 DGs started and loaded and were capable of carrying the necessary safety system loads.

3. Open Annunciator Panel Fuses.

The safety significance of the open annunciator panel fuses is minimal since only the alarm functions were lost. If any of the systems were required during the time of the event, they would have functioned properly and their operation would have been detected from the operational indicators on the panel.

4. Feedwater Control System Behavior.

The safety significance of the feedwater control system behavior can be described as minimal because the runout flow control feature functioned as designed, preventing loss of the RFPs on overcurrent and/or low suction pressure trip signals. Reactor water level reached a minimum of approximately +16 inches above instrument zero prior to the reactor scram (+159 inches above the top of active fuel) and was maintained well above the setpoint for automatic initiation of the emergency core cooling systems (ECCSs) at all times (Setpoint: -59 inches, instrument zero reference).

5. Spurious Trip of Bus 39 to MCC 38-7/39-7 Breakers.

The unsuitability of the GE CR122AT TDOE relay for its application resulted in the de-energization of the LPCI swing bus (MCC 38-7/39-7). The safety significance was minimized by the fact that the Isolation Condenser, which is sized to provide the necessary decay heat removal following a reactor trip with loss of offsite power, was available and operated satisfactorily throughout the event. In the unlikely event that a design basis loss of coolant accident (LOCA) had also occurred, the failure of the swing bus power feed transfer would be equivalent to the assumed worst case single failure of the LPCI injection valve. Both the Unit 3 and the 2/3 DGs were operable during the event; therefore, both Core Spray loops had emergency power available to provide the necessary core cooling for a LOCA.

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to Close.

The failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to close contributed to the de-energization of the LPCI swing bus (MCCs 38-7 and 39-7). The safety significance was minimized by the fact that the Isolation Condenser, which is sized to provide the necessary decay heat removal for a reactor trip with loss of offsite power, was available and operated satisfactorily throughout the event. In the unlikely event that a design-basis LOCA had also occurred, the failure of the swing bus power feed transfer would be equivalent to the assumed worst case single failure of the LPCI injection valve. Both the Unit 3 and the 2/3 DGs were operable during the event; therefore, both Core Spray loops had emergency power available to provide the necessary core cooling following a design-basis LOCA requiring low pressure ECCS injection.

7. Use of Contaminated Condensate Isolation Condenser Shell Side Supply.

The event resulted in approximately 250,000 square feet of contamination to grounds and building roofs below and adjacent to the Unit 3 Isolation Condenser vent, which penetrates the south wall of the Unit 3 reactor building. Levels of contamination ranged from 25 disintegrations per minute (dpm)/100 square centimeters south and east of the Station Administration Building to 60,000 dpm/100 square centimeters just below the Isolation Condenser exhaust (see Figure 8). All contaminated areas were controlled and posted as contaminated to reduce the chance of personnel contamination events and the spread of contamination to non-contaminated areas; as a result, there were no external or internal personnel contaminations from the event.

By reviewing the event, personnel from the Operations and Technical Staffs were able to estimate that 16,000 gallons of contaminated condensate storage water were added to the Isolation Condenser shell side. The estimate of 16,000 gallons was used in conjunction with an isotopic analysis of samples collected from the nearby storm sewer drains on March 25, 1989 at 0910 hours to calculate the activity released during the event. Based on results of the March 25, 1989, isotopic analysis of the storm sewer drain, activity per isotope released was calculated and is listed in Table 3.

Based on the results in Table 3, 10CFR20 Appendix I calculations were completed. A conservative assumption was utilized in the calculation, namely that 100% of the activity released drained to a storm sewer. If 100% of the activity was released via a liquid pathway, the release would result in less than 0.01% of the Appendix I quarterly objective.

Isotopic analyses were performed on several other samples collected on March 25, 1989, i.e., a water puddle under the Unit 3 Isolation Condenser exhaust vent, condensate storage water, and the Unit 3 Isolation Condenser shell side. Activity concentration of these samples were less than that of the storm sewer samples. Therefore, the storm sewer isotopic data was utilized as it was most representative of the actual release. For the above reasons, the safety significance of this event was minimal.

8. HPCI Lube Oil Cooling Problem.

During this event the HPCI System was being utilized primarily as a means of reactor pressure control and secondly as a means of reactor water level control. During the HPCI turbine trip, reactor water level was at +191 inches above TAF and the HPCI system was primarily being utilized as a means of pressure control.

Subsequent to the HPCI turbine trip, reactor pressure was maintained by utilizing the Isolation Condenser. Additionally, the Automatic Depressurization System (ADS) was at all times available for reactor pressure control if necessary. The core spray system was also available to support reflood of the reactor vessel following use of the ADS for reactor pressure control. For these reasons the safety significance of this event is deemed minimal.

9. Bus 34-1 to Bus 34 Breaker Problem.

The initial failure of breaker 152-3403 to remain closed delayed the backfeeding of Bus 34 from Bus 34-1, thus delaying the re-establishment of the main condenser [SG] as a heat sink. The safety significance of this delay is minimized by the fact that the Isolation Condenser remained available for reactor pressure control. Additionally, the ADS valves were available for reactor pressure control if necessary. The core spray system was also available to support reflood of the reactor vessel following use of the ADS.

10. HPCI Turning Gear Motor Failure.

Failure of the HPCI turning gear motor would not have affected the continued manual operation or auto initiation of the HPCI system. The HPCI turning gear motor is provided to adequately prewarm the turbine to minimize turbine vibrations on system startup during surveillance testing. It also provides protection against possible rotor bowing following turbine operation. During this event the turbine shaft was rotated manually to insure that rotor bowing would be prevented.

For these reasons the safety significance of this event is minimal.

11. Open Fuse for Security Multiplexer (MUX) 8.

Because the Security force responded to this failure and promptly initiated appropriate compensatory measures in accordance with security plan, this failure is deemed to have minimal safety significance.

12. Security UPS Failure.

Because the Security force responded to this failure and promptly initiated appropriate compensatory measures in accordance with the Security Plan, this failure is deemed to have minimal safety significance.

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13. Primary Containment Oxygen Analyzer Failure.

Because the primary containment atmosphere remained properly inerted during this event, this failure is deemed to have minimal safety significance.

14. Instrument Air System Behavior.

The safety significance of this event was minimal because the main turbine was placed on turning gear by supplying the Unit 3 Instrument Air System via the Unit 1 Instrument Air System; depressurization of the Unit 2 Instrument Air System was prevented by prompt operator action.

E. CORRECTIVE ACTIONS:

1. Power Circuit Breaker (PCB) 8-15 Fault.

The immediate corrective action was to open the 345 KV bus tie 8-15 Bus 8 and Bus 15 disconnects and to re-energize reserve auxiliary TR 32 at approximately 0800 hours on March 25, 1989.

All three phases of PCB 8-15 will be cleaned and repaired as necessary prior to returning PCB 8-15 to service. As part of the repairs, the internal ground capacitors will be removed. This change will lower the rated capacity of PCB 8-15 from 63 KVA to 50 KVA, however, and ground capacitors may be added in the future (possibly external to PCB 8-15) should system requirements dictate.

A study will also be performed by the Station Electrical Engineering Department (SEED) to determine the feasibility of removing the ground capacitor on 345 KV PCB 6-7, the only other Dresden circuit breaker of the same type as PCB 8-15 (249-200-89-01901).

2. Slow Transfer of Bus 32 from TR 32 to TR 31.

Feed breaker 152-3301 was tested under Work Request 83564 and repaired under Work Request 83572 prior to Unit startup. Repairs to obtain proper operation consisted of switch linkage lubrication and contact cleaning. Also, refer to additional general corrective actions involving circuit breakers listed at the end of Section E.

3. Open Annunciator Panel Fuses.

As immediate corrective action, fuse F-9 was replaced to restore power to the 902-3 annunciator panel. The fuse to restore power to the 902-6 panel was also replaced. A walkdown of the remaining Control Room and Auxiliary Electrical Equipment Room panels identified no additional open fuses related to this event. This event was also reviewed with the NSO involved. As long-term corrective actions, the backlighting of alarm windows for the loss of annunciator panels will be changed from white to red and Dresden Administrative Procedure (DAP) 7-23, Control Room Annunciator Status Book, will be revised as appropriate by the Operations Staff (249-200-89-01902). Various operating annunciator procedures are also being revised as part of a procedure upgrade program to include references to the GSEP emergency action levels as appropriate.

4. Feedwater Control System Behavior.

Potential design setpoint changes to the runout flow control feature are currently under evaluation by the Technical Staff (249-200-89-01903). The GE Site representative is also assisting with this review. These potential setpoint changes include lowering the +20 inch reactor water level (instrument zero reference) runout flow control mode initiating setpoint to preclude a reactor water level increase to the +55 inch (instrument zero reference) automatic main turbine and RFP trip setpoint during this type of event.

The Training Department will review this event during an upcoming Licensed Operator training cycle in order to increase awareness of runout flow control operation (249-200-89-01904). The Operations Staff will also review appropriate feedwater level control procedures and implement improvements as appropriate regarding reset of the runout flow control feature (249-200-89-01905).

5. Spurious Trip of Bus 39 to MCC 38-7/39-7 Breakers.

The immediate corrective action was to replace the GE CR122AT TDOE relay with an Agastat ETR14D3C002 time delay relay as a temporary alteration. The Agastat relay will be removed during refuel outage D3R11 under LPCI Swing Bus Modification M12-3-88-005 (249-200-89-01906). A walkdown was conducted to determine if a GE CR122AT relay was being used in any other applications for Unit 3; none were found. A GE CR122AT TDOE relay was previously removed from Unit 2 under LPCI Swing Bus Modification M12-2-88-005. Based on the close similarity of Units 2 and 3, it was concluded that a walkdown of Unit 2 was unneccessary.

6. Failure of MCC 38-7/39-7 Reserve Feed Breaker 252-3872 to Close.

Breaker 252-3872 was repaired by lubricating and testing the breaker under Work Request 83568 prior to Unit startup. Breaker 252-3872 is scheduled to be replaced with an improved contactor assembly under Modification M12-3-88-5 during the upcoming D3R11 outage (249-200-89-01907). The corresponding breaker on Unit 2 has also been replaced with a contactor under Modification M12-2-88-5.

7. Use of Contaminated Condensate Isolation Condenser Shell Side Supply.

During the event and after the completion of the event, areas were surveyed; as a result the contaminated areas were controlled by ropes and posted as contaminated. Decontamination efforts began outside the gatehouse/security fence and were followed by areas inside the security fence. Areas outside the gatehouse were cleaned by sweeping with sweeping compound and cars were decontaminated by wiping with wet rags. Inside the security fence, walkways were set up from the gatehouse to the mechanical maintenance shop, the storeroom, and the administration building, in addition to change areas being set up to accommodate decontamination efforts.

Various decontamination methods were subsequently utilized in the effort to release areas, i.e., sweeping with sweeping compound, scrubbing with mops and water, floor scrubbing machines, wet and dry vacuum cleaners, and wet wipedowns; however, relatively few areas were released by these methods although the levels of contamination were reduced. At this point a determination was made to utilize fire hoses to spray down the remaining low level contamination to the storm sewers. Prior to the initiation of the spray down, a composite sampler for the storm sewer was set up along with sampling frequencies, and a phone call was made to the NRC for notification of the decision to utilize the fire hoses in low level areas.

The majority of the low level contaminated areas have been released and the higher level contaminated area (under the isolation condenser exhaust vent) has been partially decontaminated to reduce the level of contamination. Decontamination efforts will continue until the remaining contaminated areas are released.

The Operations Staff has also implemented short term revisions to Isolation Condenser operating procedures regarding limiting the use of contaminated condensate to supply the Isolation Condenser shell side. These revisions concern use of alternate systems for decay heat removal (e.g. ADS, HPCI, RWCU) and/or use of service water to supply the Isolation Condenser shell side) (249-200-89-01908).

The Technical Staff and the Boiling Water Reactor Engineering Department (BWRED) are also evaluating design improvements to the clean demineralized water isolation condenser shell side supply system (249-200-89-01909).

8. HPCI Lube Oil Cooling Problem.

   The Operations Staff will revise DOP 2300-3 to ensure that the MO2(3)-2301-48 valve is opened and the MO2(3)-2301-49 valve is closed promptly after manually initiating the HPCI System for pressure control (249-200-89-01910).

9. Bus 34-1 to Bus 34 Breaker Problem.

   Undervoltage relay 127-2-B34 was repaired by burnishing relay contacts under Work Request 83552 prior to unit startup. Also, refer to additional general corrective actions involving circuit breakers listed at the end of Section E.

10. HPCI Turning Gear Motor.

    The motor was replaced under Work Request 83553. Additionally, to prevent this event from recurring the Electrical Maintenance Staff will revise DEP 8300-4 to incorporate a caution to insure that brushes are replaced so that their contours match the commutators contour (249-200-89-01911).

11. Open Fuse for Security Multiplexer (MUX) 8.

    The fuse was replaced by Operations personnel. A Problem Analysis Data Sheet was also initiated by Electrical Maintenance concerning this event to evaluate additional corrective actions.

12. Security UPS Failure.

    The immediate corrective action was to switch the security computer back to security diesel power. Subsequently, the security computer was switched back to the normal power supply. The security UPS was repaired. To prevent future recurrence of this event, the Operations Staff is implementing a detailed security UPS switching procedure (249-200-89-01912).

13. Primary Containment Oxygen Analyzer Failure.

    The immediate corrective action was for Operations personnel to calibrate and test the analyzer by performing Dresden Operating Surveillance (DOS) 1600-14, Oxygen Analyzer and Sampling System Calibration and Functional Test. As long term corrective action, the oxygen analyzer procedures will be reviewed by the Operations Staff to determine if further guidance on resetting the analyzer is warranted (249-200-89-01913).

14. Instrument Air System Behavior.

The Operations Staff has initiated a revision to DOA 4700-1 to include appropriate instructions concerning manual engagement of the main turbine turning gear and isolation of the 3C Instrument Air Compressor (249-200-89-01914).

As a general corrective action to the several problems with circuit breakers during this and other events, the preventive maintenance schedule for 4 KV circuit breakers will be reviewed via the Problem Analysis Data Sheet (PADS) program by the Maintenance Department and accelerated as warranted (249-200-89-01915). Maintenance procedures for 4KV circuit breakers will be reviewed by the Maintenance Department (249-200-89-01916). The maintenance history program will be used to track individual 4 KV breakers in addition to 4 KV breaker cubicle (249-200-89-01917). The preventive maintenance schedule for 4 KV and 480 V circuit breaker relays will also be reviewed by the Maintenance Department and accelerated as warranted (249-200-89-00918).

F. PREVIOUS OCCURRENCES:

1. Loss of Offsite Power (Unit 2).

LER Number	Title
85-34/050237	Low Reactor Water Level Scram During Loss of Offsite Power.

A fault on TR 12 [EA] resulted in the isolation of 138 KV Bus 3 [FK] which was also feeding the Unit 2 reserve auxiliary transformer, TR 22. Due to a design deficiency, Bus 22 [EA] and Bus 24 [EA] failed to automatically transfer to Unit 2 auxiliary transformer, TR 21. Because of the loss of offsite power, the Isolation Condenser clean demineralized water supply valve, MO2-4399-74, could not be opened. Use of contaminated condensate supply to the Isolation Condenser resulted in low levels of contamination on the ground outside the Reactor Building.

2. Activity Release from Isolation Condenser.

LER Number	Title
Non-Reportable Event No. 12-3-85-5	Isolation Condenser Radiation Release.

Use of the Isolation Condenser following a scram resulted in a maximum activity release of 320 pCi/l (Co-60) in an unrestricted area. As a corrective action, the shell side of the Unit 3 Isolation Condenser was cleaned and recoated with epoxy during the 1985-86 Recirculation Piping Replacement (RPR) outage. In addition, the shell side of the Unit 3 Isolation Condenser was cleaned and recoated with epoxy during the 1986-87 refueling outage.

LER Number	Title
84-12/050237	Reactor Scram.

Use of the Isolation Condenser following the scram resulted in an activity concentration of 330 pCi/l on the ground below the Isolation Condenser vent.

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LER Number	Title
Non-Reportable Event No. 12-2-83-173	Unit 2 Ground Contamination Due to Unit 2 Isolation Condenser Initiation.
	Use of the Isolation Condenser following a scram resulted in activity concentration of 2000 pCi/l in the upper layer of snow near the Reactor Building.
Non-Reportable Event No. 12-3-83-14	Opened MO3-1301-10 Valve on Unit 3 Isolation Condenser
	Use of approximately 22,400 gallons of contaminated condensate Isolation Condenser shell side supply during a scram recovery resulted in a release of approximately 0.7 millicuries of activity from the Unit 3 Isolation Condenser vent.
Non-Reportable Event No. 12-2-81-14	Unexpected Radioactive Release to the Environment.
	Low levels of contamination were deposited on the ground outside the Reactor Building during the five-year Isolation Condenser heat removal test.

3. Failure of Power Circuit Breaker.

PCB 6-7 (see Figure 1) previously failed in a similar manner to the failure that initiated the March 25, 1989, Unit 3 scram. PCB 6-7 is the same type of circuit breaker as PCB 8-15. Because of the 138 KV bus configuration, power to TR 22 was not lost during that previous event; however, as a corrective action the ground capacitors on PCB 6-7 and PCB 8-15 were replaced with a different model.

4. HPCI Turning Gear Motor Failure.

LER Number	Title
12-3-87-10	Failure of HPCI Turning Gear to Engage Due to Foreign Material on Turning Gear Motor Brushes.
	Spray painting in the area resulted in paint coating the brushes and commutator.

G. COMPONENT FAILURE DATA:

Industry-wide Nuclear Plant Reliability Data System (NPRDS) search information is provided below each component reportable to the NPRDS data dase.

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
I.T.E	Power Circuit Breaker	362 GA 63-20C	N/A

This component is not reportable to the NPRDS data base.

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
General Electric Co.	4 KV Circuit Breaker	AMH-16-350-1H	N/A

A review of the NPRDS data base revealed 27 failures of this model component attributed to dirty contacts.

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
General Electric Co.	480 V Circuit Breaker	Type AK-2-25-2	Serial No. 224A3510-59FF

A review of the NPRDS data base revealed six failures of this model circuit breaker due to linkage binding.

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
General Electric Co.	Voltage Relay	12IAV69A1A	N/A

No similar failures were listed in the NPRDS data base.

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
General Electric Co.	250 VDC Motor	5CD14D19A111620	N/A

A review of the NPRDS data base revealed 12 failures of this model motor. One of these failures was caused by a brush/commutator failure.

Manufacturer	Nomenclature	Model Number	Mfg. Part Number
Solid State Controls, Inc.	Three Phase Uninterruptible Power Supply (Security)	3SV12300	N/A

No similar failures were listed in the NPRDS data base.

TABLE 1

UNIT 3 - MARCH 25, 1989 SCRAM

SEQUENCE OF EVENTS

The following is a chronological listing of the significant events leading up to the scram, scram recovery, and cooldown to cold shutdown conditions. The times listed are approximations. The initiating event was an internal fault within 345 KV power circuit breaker (PCB) 8-15 at 01:33:32 hours on March 25, 1989; cold shutdown conditions were achieved at 2230 hours on March 25, 1989.

<u>TIME</u> (Hour:Minute:Second.Millisecond)	<u>EVENT DESCRIPTION</u>
01:30:00	Unit 3 is operating at 89% power (780 MWe). Reactor feed pumps (RFPs) 3A (powered from 4 KV Bus 31) and 3B (powered from 4 KV Bus 32) are running. The 3C RFP is selected as the standby RFP (lined up in power from 4KV Bus 32). (See Figure 2 for a simplified Unit 3 electrical arrangement). The 3A feedwater regulating valve (FWRV) is operating in the automatic mode, and the 3B FWRV is operating in the manual mode at approximately 25% open.
01:33:32.045	Internal fault occurs within 345 KV PCB 8-15. (See Figure 1 for 345 KV switchyard arrangement). As the fault does not clear, Local Breaker Backup logic circuitry automatically trips 345 KV oil circuit breaker (OCB) 8-9, 345KV OCB 11-14, and isolates 345KV line 8014 by tripping a 345KV line 8014 circuit breaker located at the Pontiac transmission substation (TSS). This isolates the internal fault within PCB 8-15 and de-energizes Unit 3 reserve auxiliary transformer (TR) 32. A Security Officer on patrol behind the plant hears a loud noise. This was reported to the Control Room, and the fire siren [IC] was then sounded and the fire brigade leader immediately reported to the area. No damage or fire was observed in the area of Unit 3 main power transformer TR 3 [EA], Unit 3 Auxiliary Transformer TR 31, or TR 32. The Security officer indicated the noise may have come from the south end of the 345 KV switchyard; the noise heard is believed to have been the opening of OCBs 8-9 and 11-14 (this type of noise during OCB trips is normal).
01:33:32	Automatic transfer of Auxiliary power loads from transformer TR 32 to TR 31 commences. See Figure 2.
01:33:32.104	Bus 32 feed breaker (3205) from TR 32 trips.
01:33:32.123	4KV Bus 34 feed breaker (3411) from TR 32 trips.
01:33:33.393	Bus 34 feed breaker (3401) from TR 31 closes.
01:33:35	The 3B RFP and the 3B reactor recirculation (Recirc) pump motor generator (MG) set (fed from Bus 32) trip due to a Bus 32 undervoltage condition. This was caused by the Bus 32 transfer from TR 32 to TR 31 not occurring quickly enough. The Nuclear Station Operator (NSO) then attempted to restart the 3B RFP. Reactor water level was approximately +16 inches at this time.

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TABLE 1 (Cont'd)

01:33:46	Bus 32 feed breaker (3201) from TR 31 closes, re-energizing Bus 32. The standby 3C RFP immediately starts automatically as designed. Reactor water level increases sharply. NSO attempts to close FWRVs to control reactor water level increase; however, a reactor level increase to the +55 inch main turbine and RFP trip setpoint could not be prevented (instrument zero reference).
01:34:38	Automatic main turbine trip occurs from +55 inches reactor water level.
01:34:39	Automatic reactor scram on main turbine stop valve closure occurs.
01:34:46	Main generator trip.
01:34:51	The 3A RFP automatically trips on the +55 inches reactor water level signal.
01:34:52	The 3C RFP automatically trips on the +55 inches reactor water level signal. The main turbine and RFP high reactor water level trip logic circuitry is comprised of relays HFA-A and HFA-B, initiated by sensors LITS 3-263-59A and LITS 3-263-59B, respectively. Either relay HFA-A or HFA-B picked up will trip the main turbine; however, automatic trip of the RFPs requires pick up of relays HFA-A and HFA-B. For this reason a slight time delay between the automatic main turbine and RFP trips is not unexpected.
01:34:54	The Unit 2/3 and Unit 3 Diesel Generators (DGs) automatically start and load onto 4 KV Busses 33-1 and 34-1 respectively. Feed Breakers (3971 and 3972) from Bus 39 to motor control centers (MCCS) 38-7/39-7 spuriously trip. This was abnormal as the DGs had started and loaded properly. Also, reserve feed breaker (3872) from Bus 38 to MCCs 38-7/39-7 failed to automatically close. Unit 2 Control Room annunciator panel 902-3 and 902-6 fuses are also believed to have opened at this time.
01:34:54	The Security System DG starts and loads to power the Security System, which had automatically shed from Bus 34-1.
01:35:20	An NSO closes the Main Steam Isolation Valves (MSIVs) to conserve reactor inventory.
01:38	NSO initiates Isolation Condenser for reactor pressure control. Reactor pressure peaks at approximately 1053 psig. The NSO prepares to open clean demineralized water supply to Isolation Condenser shell side valve MO3-4399-74 (powered by MCC 39-3) but observes that the valve is de-energized. The NSO also observes that low pressure Coolant Injection (LCPI) valves powered by MCCs 38-7/39-7 are de-energized (no position indication). The NSO notified the Station Control Room Engineer (SCRE) and Shift Engineer that these valves were de-energized. When the Isolation Condenser level decreased to five feet, the NSO initiated use of the contaminated condensate Isolation Condenser shell side supply under direction of Shift Supervision.
01:48	Main turbine turning gear trips due to loss of instrument air.
02:05	Isolation Condenser secured by NSO.
02:15	High Pressure Coolant Injection (HPCI) System manually initiated to control reactor level and pressure.

TABLE 1 (Cont'd)

03:40	The A Shutdown Cooling (SDC) heat exchanger was filled and vented and Reactor Building Closed Cooling Water (RBCCW) supplied.
04:00	Bus 33-1 to Bus 33 breaker was closed in order to backfeed Bus 33 from DG 2/3.
04:05	Containment Cooling Service Water (CCSW) pump 3A was started (powered from Bus 33). NSO operating HPCI noticed high HPCI lube oil temperature and began restoring cooling water flow to HPCI lube oil cooler. Bus 34-1 to Bus 34 breaker would not stay closed when trying to backfeed Bus 34 from DG 3.
04:10	The 3A LPCI pump was started for torus cooling. HPCI turbine trips on +48 inches reactor water level (instrument zero reference) while NSO was restoring HPCI lube oil cooler cooling water. HPCI turning gear unavailable due to turning gear motor failure.
04:13	The NRC operations center is notified of the Unit 3 scram and loss of offsite power by the SCRE in accordance with 10CFR50.72.
04:25	Isolation Condenser manually initiated by NSO. Clean demineralized water pump could not keep up with demand. Clean demineralized water was therefore supplemented with contaminated condensate.
04:35	Unit 2 NSO discovers loss of Unit 2 Control Room Panel 902-3 and 902-6 annunciators. Open annunciator panel fuses replaced immediately.
05:10	Reactor vessel water level drops below +48 inches and would have permitted restarting HPCI. Decision to leave HPCI off, however, was based on HPCI turbine turning gear motor failure. Operations personnel were dispatched to turn the HPCI turbine manually in order to insure proper turbine cooldown. Unit 1 instrument air compressor (IAC) was started to backfeed Unit 3 instrument air. Main turbine turning gear is restored upon receipt of normal instrument air pressure.
05:25	The NRC Operations Center is notified by the SCRE of the earlier loss of Unit 2 Control Room panel 902-3 annunciator.
05:30	Bus 34-1 to Bus 34 breaker was closed in order to backfeed Bus 34 from DG 3.
05:40	Bus 34 to Bus 37 tie closed.
05:45	3B Turbine Building Closed Cooling Water (TBCCW) pump started.
05:50	Opened valve 2-4705-330 (isolation valve between Unit 2 instrument air and Unit 3 Reactor Building instrument air) and closed valve 3-4705-503 (isolation valve between Unit 3 instrument air and Unit 3 Reactor Building instrument air). Status of Instrument Air Systems:

TABLE 1 (Cont'd)

	Unit 1 service air tied to Unit 1 instrument air.
	Unit 1 instrument air tied to Unit 2 instrument air.
	Unit 2 service air tied to Unit 2 instrument air.
	Unit 2 instrument air tied to Unit 3 Reactor Building instrument air.
	Unit 3 instrument air isolated.
05:57	TR 3 345 KV disconnects were opened.
06:00	3B Control Rod Drive (CRD) pump was started to provide makeup water to reactor vessel.
06:10	Line 8014 line disconnects were opened in preparation for re-energizing TR32.
06:14	345 KV bus tie 10-11 and 9-10 circuit breaker were closed.
06:40	Security computer multiplexer (MUX) 8 lost when power supply fuse opened.
06:45	Isolation Condenser manually initiated for third time. Clean demineralized water used for makeup.
07:41	Security computer MUX 8 restored.
07:50	The 3A CRD pump was started to provide reactor vessel head spray.
07:58	Isolation Condenser secured by closing valves MO3-1301-3 and MO3-1301-4.
08:00	345 KV bus tie 8-15 Bus 8 and Bus 15 disconnects were opened.
08:08	345 KV bus tie 8-9 circuit breaker was closed to re-energize TR32.
08:36	Manual turning of the HPCI turbine was secured.
08:40	TR 32 to Bus 33 and 33-1 breakers were closed and DG 2/3 was unloaded and secured.
08:55	TR 32 to Bus 34 and 34-1 breakers were closed and DG 3 was unloaded and secured.
09:00	Torus lined up to pump to Unit 2 hotwell in accordance with DOP 1600-2.
09:05	TR 32 to Bus 31 and 32 feed breakers were closed; Bus 35 and 36 were re-energized.
09:15	Reactor vessel blowdown was established through reactor water cleanup (RWCU) system.
10:00	The 3A and 3C circulating water pumps were started, thus restoring circulating water flow to the Unit 3 main condenser.

TABLE 1 (Cont'd)

10:20	Unit 3 service air compressor on.
10:25	3A instrument air compressor on and service/instrument air cross-tie closed.
10:45	The MSIVs were equalized and re-opened.
11:15	3C instrument air compressor on.
12:50	During attempts to switch security bus back to main power, security computer lost due to a failure of the security system uninterruptible power supply (UPS) inverter.
12:53	The 3D condensate/booster pump [SD] was started.
13:07	Security computer restored.
13:48	The 3B RFP was started allowing reactor vessel level and pressure control using the feedwater control system.
14:06	Normal (unregulated) power to security bus restored.
14:11	Security computer lost.
14:13	Security computer re-booted.
16:30	RWCU system on.
16:45	Main condenser mechanical vacuum pump on.
18:30	Security system testing began.
18:35	Scram was reset.
19:35	Mechanical vacuum pump was secured.
19:51	The 3A Shutdown Cooling pump [BO] was started.
22:05	Security system testing completed.
22:30	Cold shutdown conditions achieved.

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TABLE 2

Simulated Undervoltage Test of GE CR122AT TDOE Relay

Test	Undervoltage Condition Time	Tripping of Breaker 252-3971	Closing of Breaker 252-3871	Correct Breaker Response
1	> 15 seconds	Yes	Yes	Yes
2	2 seconds	No	No	Yes
3	5 seconds	Yes	No	No
4	7 seconds	Yes	Yes	No
5	10 seconds	Yes	Yes	No

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

TABLE 3

Calculated Activity Release from Isolation Condenser Vent

Isotope	Concentration	Total Released
Mn-54	2.9E-6 µCi/ml	1,756.37 µCi
Co-60	6.0E-5 µCi/ml	3,633.88 µCi
Fe-59	1.1E-6 µCi/ml	66.62 µCi
Co-58	3.0E-7 µCi/ml	18.17 µCi

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Dresden Nuclear Power Station	0 5 0 0 0 2 4 9	8 9	-	0 0 1	-	0 1	2 6 OF 3 3

TEXT   Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

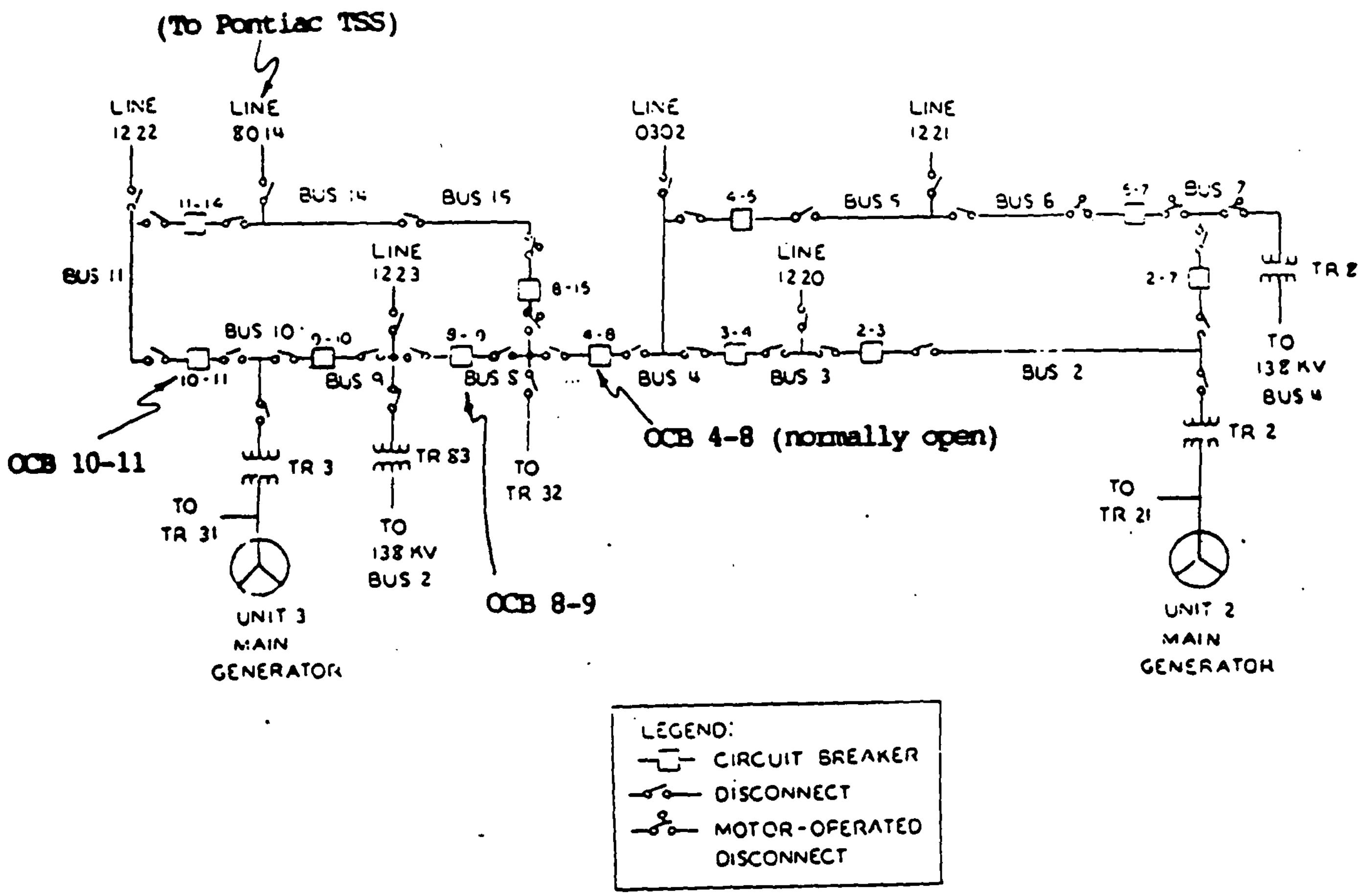


Figure 1.   345 KV Switchyard Configuration

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

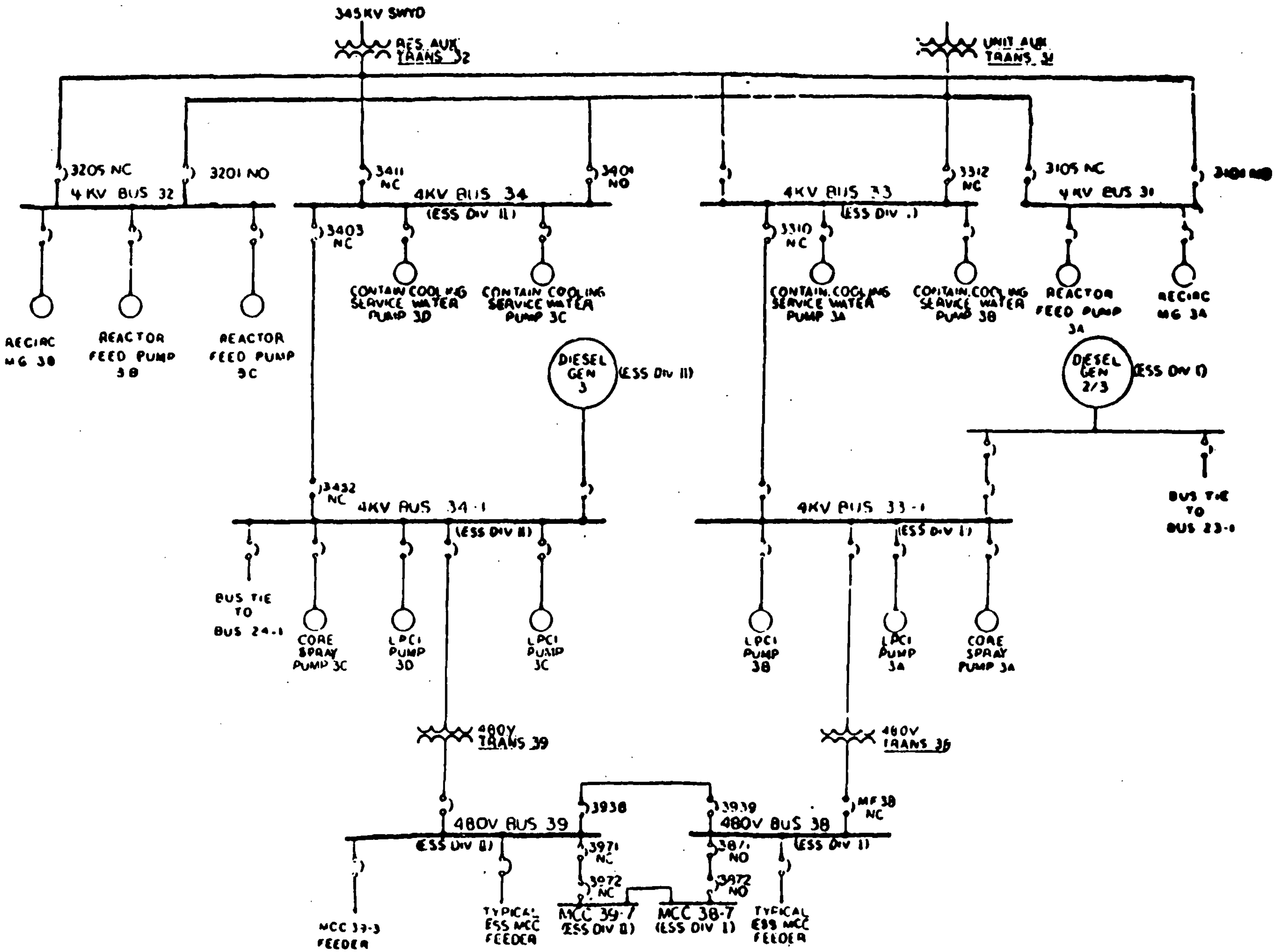


Figure 2. Unit 3 Electrical Configuration Simplified Schematic

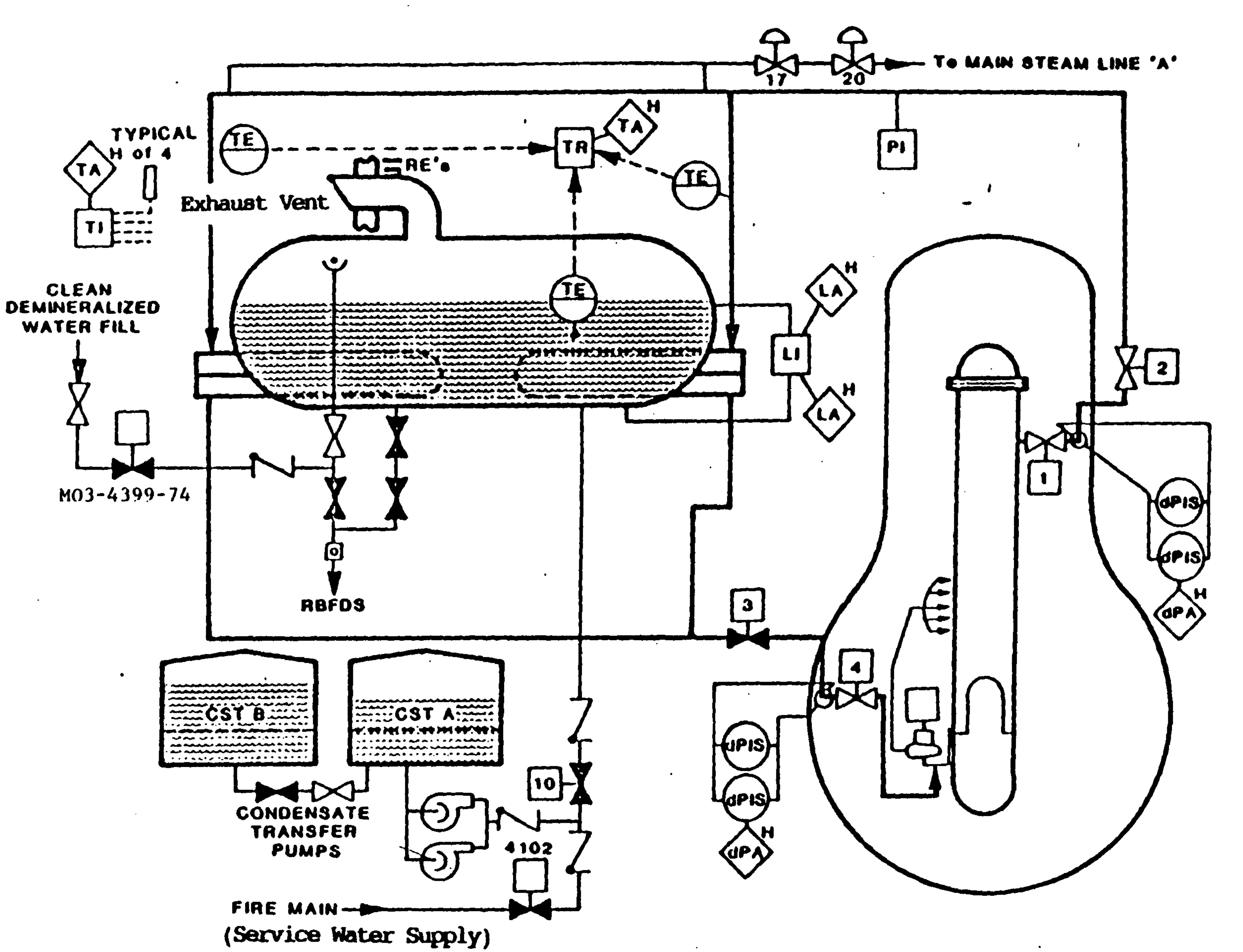


Figure 3. Isolation Condenser System

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

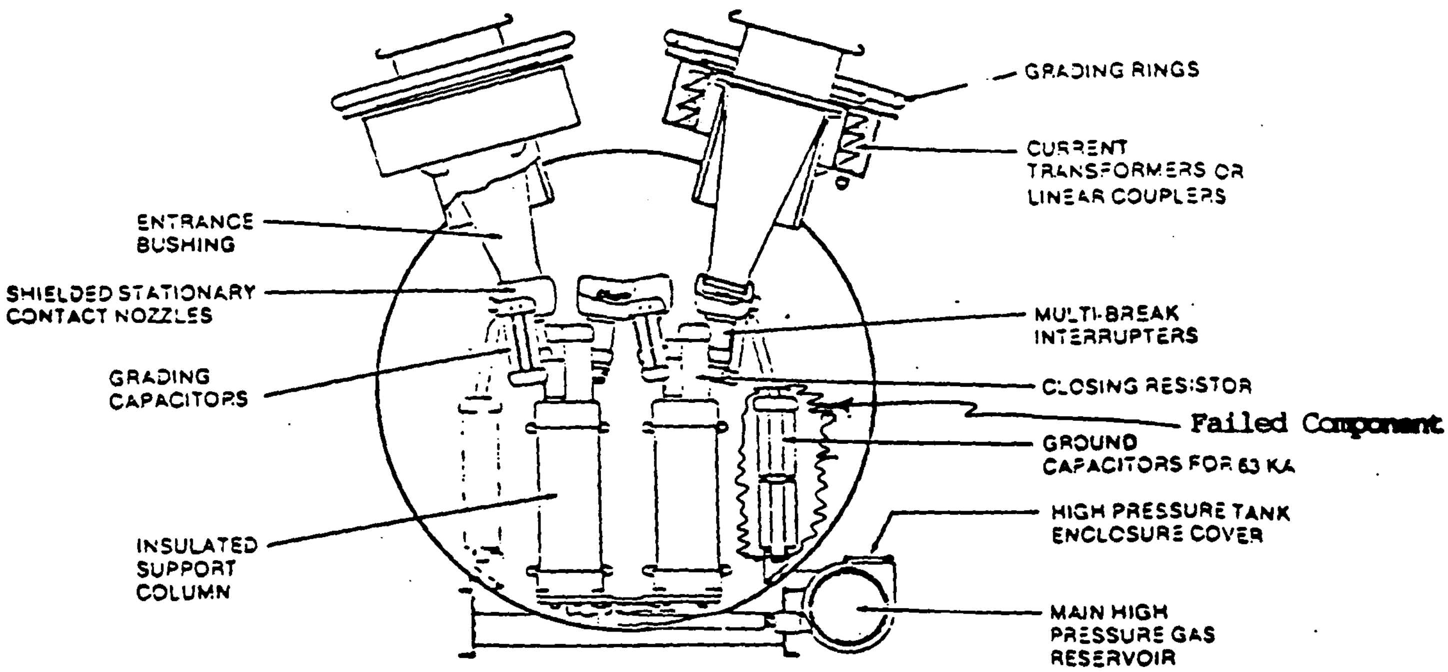


Figure 4. Cross Section View of PCB 8-15

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

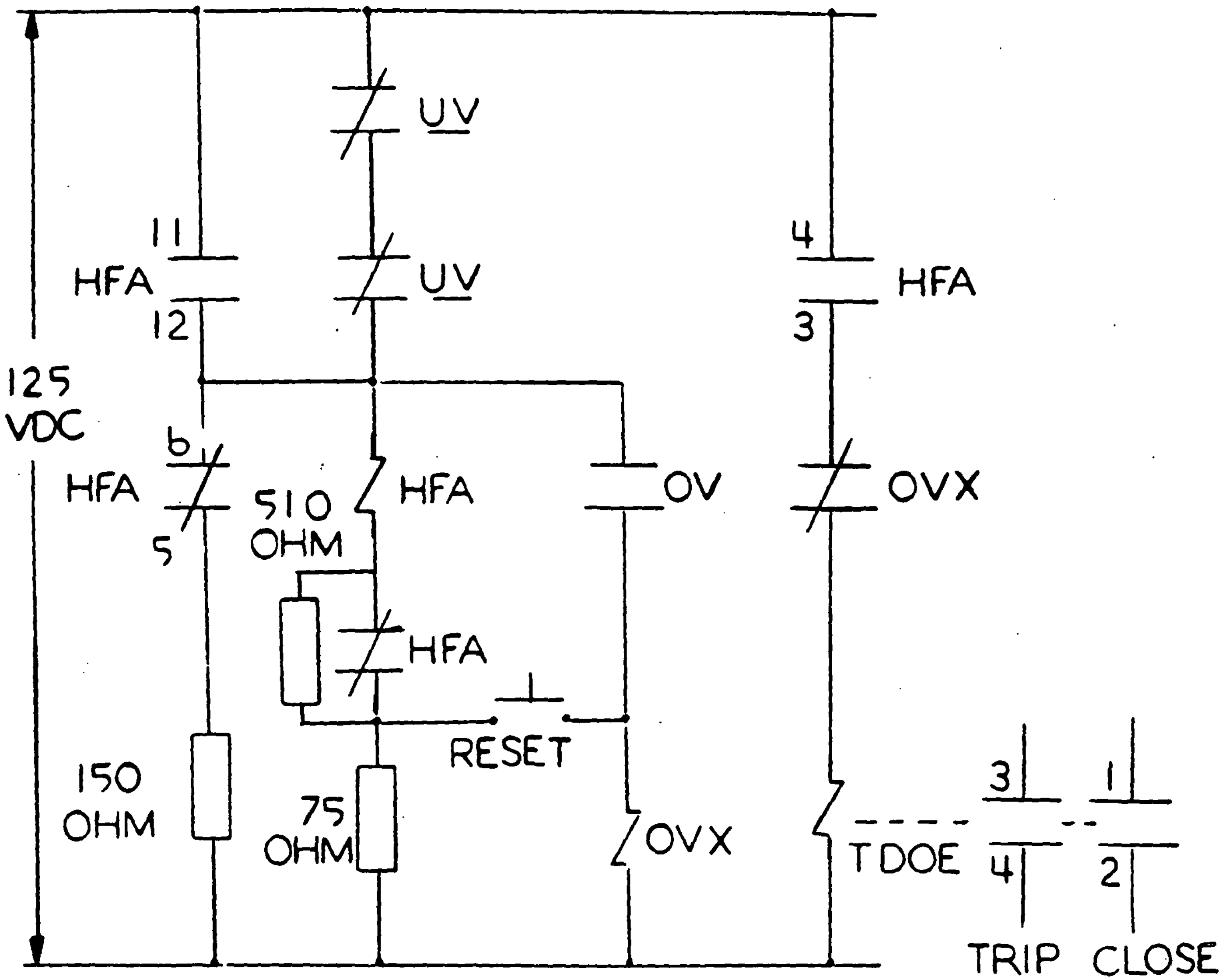


Figure 5. Simplified MCC 38-7/39-7 Logic Diagram

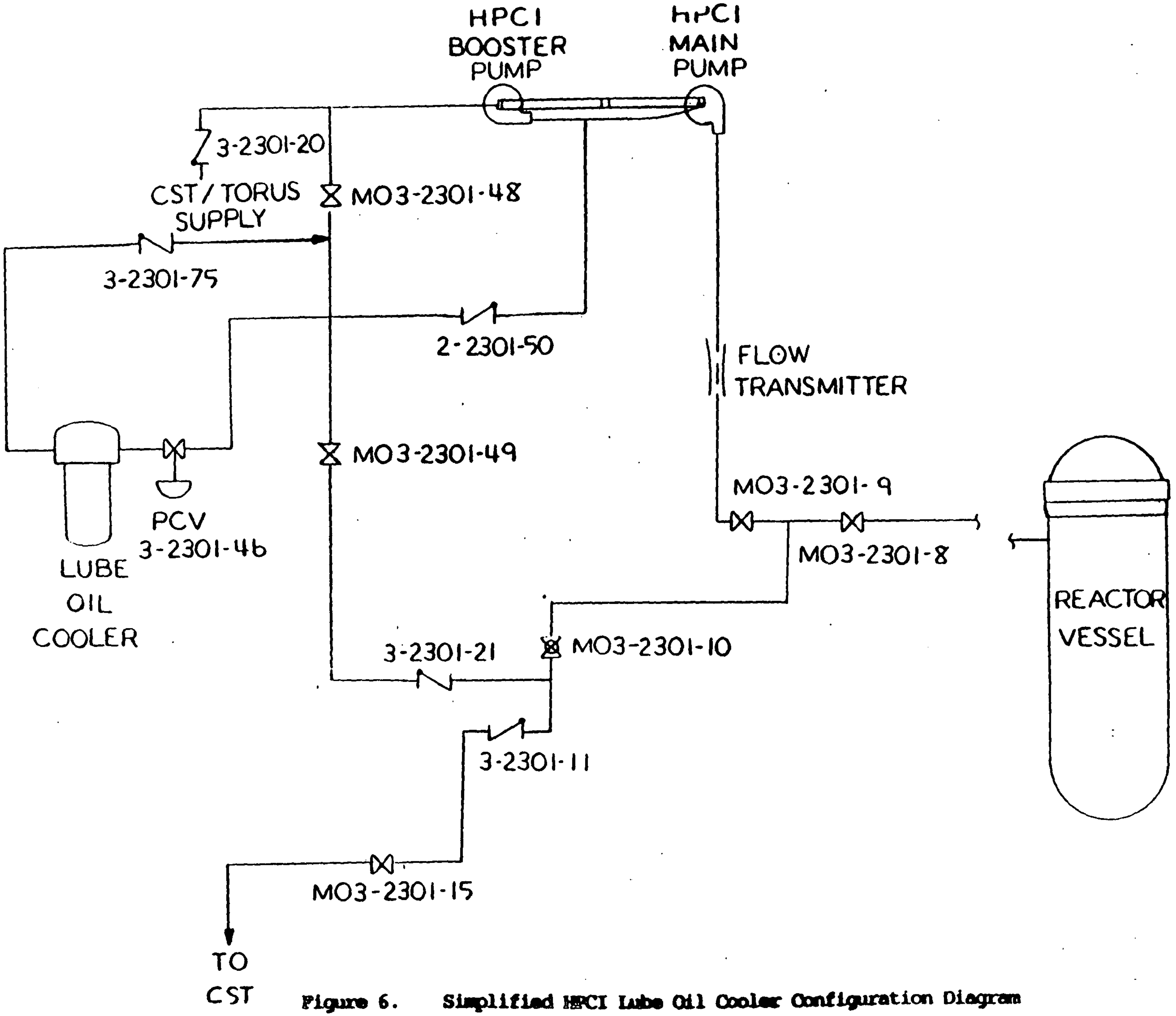


Figure 6. Simplified HPCI Lube Oil Cooler Configuration Diagram

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	Page (3)
Dresden Nuclear Power Station	0 5 0 0 0 2 4 9	8 9	- 0 0 1 -	0 1	3 2 OF 3 3

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

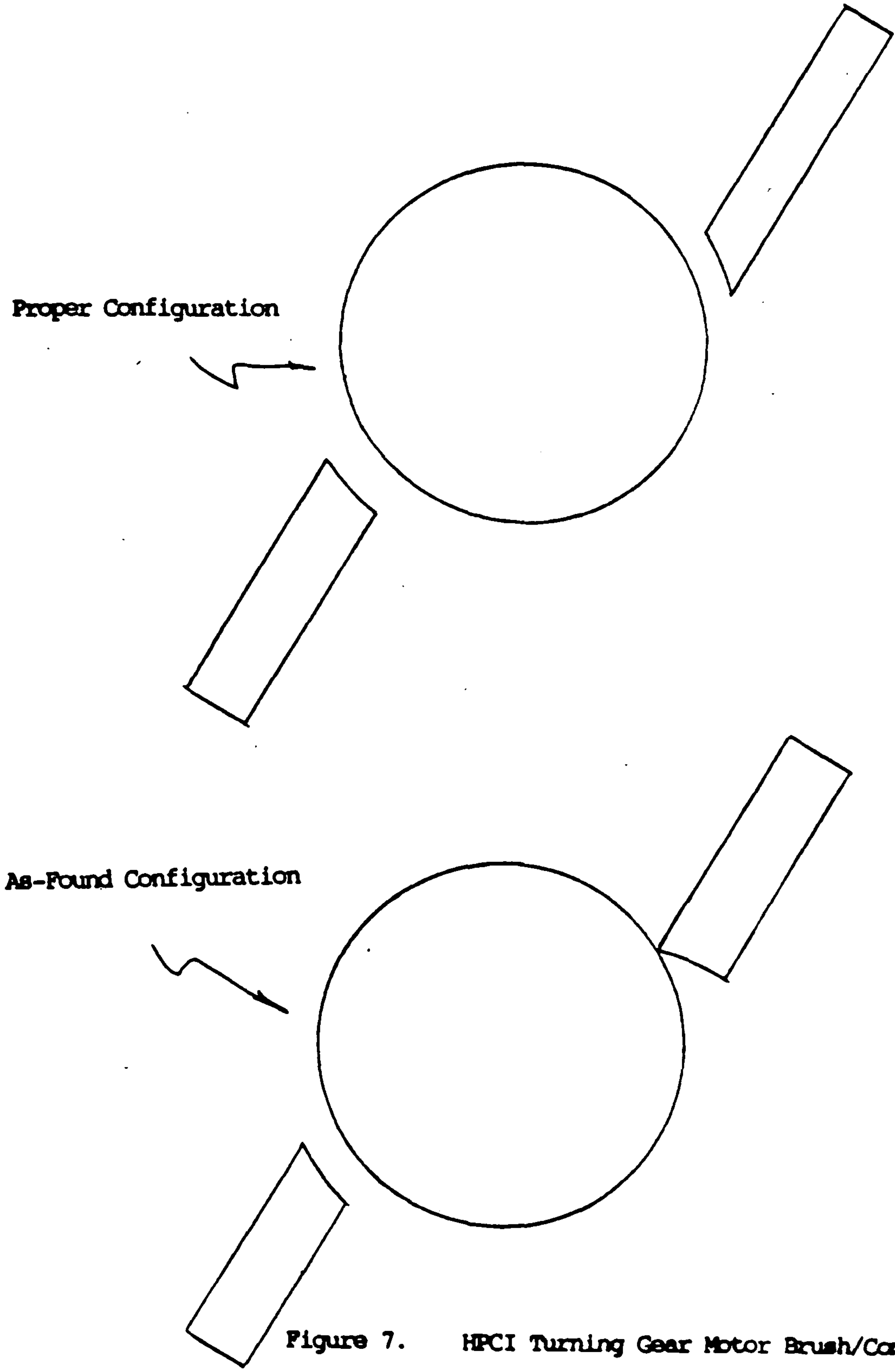
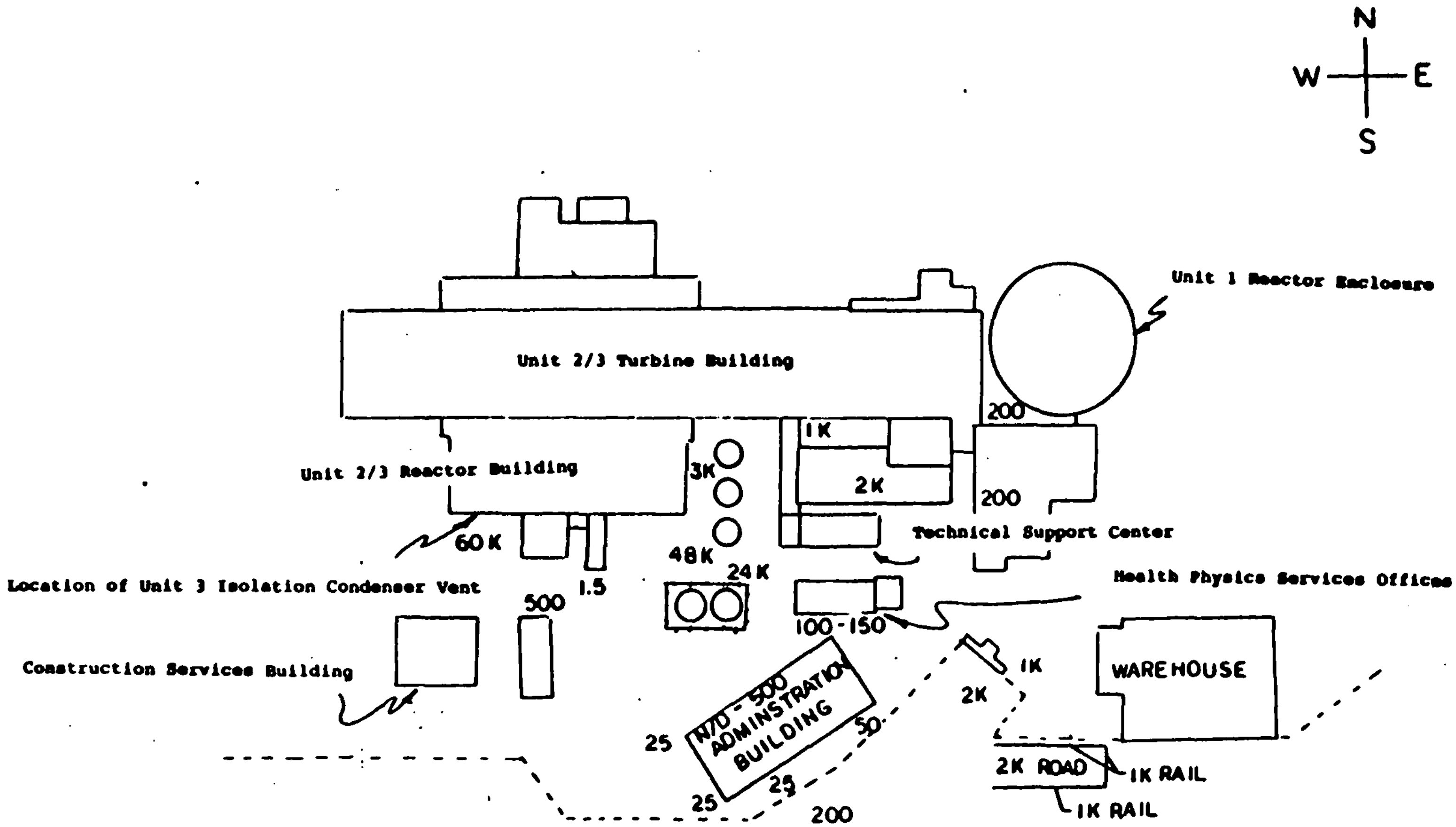


Figure 7. HPCI Turning Gear Motor Brush/Commutator Configuration



Note: Initial contamination levels observed on March 25, 1989 following operation of the Isolation Condenser are listed in Units of Disintegrations Per Minute (DPM)/ 100 square centimeters.

Figure 8. Diagram of Plant Grounds Affected by Isolation Condenser Vent