U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-237/89012(DRP); 50-249/89011(DRP)

Docket Nos. 50-237; 50-249 License Nos. DPR-19; DPR-25

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Dresden Nuclear Power Station, Units 2 and 3

Inspection At: Dresden Site, Morris, IL

Inspection Conducted: March 25 through May 26, 1989

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6-16-89
Date

Inspection Summary

Inspection during the period of March 25 through May 26, 1989
(Report Nos. 50-237/89012(DRP); 50-249/89011(DRP))
Areas Inspected: Unannounced special inspection of the March 25, 1989 loss of offsite event and scram on Unit 3.
Results:

- No violations of regulations were identified.
- The operator's action during the event mitigated the plant upset conditions and achieved a known safe shutdown condition.
- Several individual components failed to respond during the event. The slow bus transfer of Bus 32, due to a dirty contact, resulted in tripping of a recirculation pump and a feedwater pump.
- Onsite and corporate management responded during the event by fully manning the Technical Support Center.

- The licensee anticipated release of contamination from the isolation condenser due to the use of contaminated makeup for the isolation condenser. Preparations were made and barriers implemented; however, these actions were mitigated by weather conditions, resulting in a large area of the station being contaminated.

- Several long term corrective actions were initiated due to the licensee's review of the event. These involved revising operating procedures for instrument air and annunciator panels, reviewing and accelerating preventive maintenance schedules for breakers, and evaluating alternate makeup supplies for the isolation condenser.

50-237/89012 and 50-249/89011

Table Of Contents

		Page No.
1.	Introduction	1
	A. Synopsis of Event	1
	B. Persons Contacted	1
2.	Description and Details of the Event	2
	A. Narrative of the Event	2
	B. Sequence of the Event	3
3.	Review of the Licensee's and Equipment Response	6
	A. Equipment Malfunction	6
	1. Circuit Breaker 8-15	6
	2. LPCI Swing Bus Failure	7
	3. Reactor Feed Pump Failure	9
	4. Open Annunciator Panel Fuses	9
	5. HPCI High Pressure Bearing	10
	6. Bus 34-1 to Bus 34 Breaker Trip	11
	7. Slow Transfer of Bus 32	11
	8. Instrument Air Behavior	12
	B. Radiological Aspects of the Event	12
	C. Licensee's Response During the Event	14
4.	Event Summary	15
5.	Exit Interview	15
6.	Enclosure:	
	A. Licensee Event Report 249/89-001-0	
	B. Unit 3 Electrical Configuration	
	C. 345KV Switchyard Configuration	
	D. Simplified MCC 38-7/39-7 Logic Diagram	
	E. Diagram of Plant Grounds Affected by Isolation Condenser Vent Operation	
	F. Isolation Condenser Systems	
	G. Cross Section View of PCB 8-15	

1. Introduction

A. Synopsis of Event

While Unit 3 was operating at 89% power, an internal fault occurred on a 345 KV circuit breaker within the Unit 3 345 KV switchgard. The fault and failure of the circuit breaker to open automatically tripped several other 345 KV circuit breakers, isolating the internal fault and the Unit 3 reserve auxiliary transformer from the 345 KV switchyard. This resulted in a loss of offsite power to Unit 3 and an automatic transfer of the house loads to the Unit 3 auxiliary transformer. During the bus transfer, one of the 4 KV busses did not transfer quickly enough to prevent an undervoltage condition from occurring. This resulted in the tripping of one reactor feed pump and a recirculation pump. After the affected bus completed the transfer, the Standby Reactor Feedwater pump automatically started, resulting in reactor water level increasing to the main turbine and feedwater pump trip setpoint prior to the closing of the feedwater regulating valve by the unit operator. An automatic reactor scram occurred due to the closure of the main turbine stop valve (main turbine trip). The emergency diesel generators automatically started and loaded onto the emergency busses. The unit operator closed the Main Steam Isolation Valves to conserve vessel inventory and initiated the Isolation Condenser for vessel pressure control. Because the clean de-mineralized water makeup valves were de-energized, makeup to the Isolation Condenser was subsequently supplied by the contaminated condensate system. This resulted in a release of contaminated steam from the Isolation Condenser which condensed and contaminated a large area within the site protected area and a smaller area within the owner controlled area. The release did not threaten the general public. Subsequent makeups to the Isolation Condenser were accomplished by using clean de-mineralized water. Additionally, several individual components malfunctioned or experienced unexpected behavior. These are discussed within the details of this report.

B. Persons Contacted

Commonwealth Edison Company (CECo)

*E. Eenigenburg, Station Manager
*L. Gerner, Production Superintendent
*C. Schroeder, Technical Superintendent
N. Kalivianakis, Manager, BWR
*K. Peterman, Regulatory Assurance Supervisor
*D. VanPelt, Assistant Superintendent - Maintenance
J. Kotowski, Assistant Superintendent - Operators
M. Strait, Technical Staff Supervisor
R. Stachniak, Assistant Technical Staff Supervisor
D. Saccomando, Health Physics Services Supervisor
D. Booth, Master Electrician
D. Gulati, Master Instrument Mechanic

J. Achterberg, Assistant Superintendent - Work Planning
J. Mayer, Security Administrator
C. Allen, Administrative Service Superintendent
*T. Lewis, Regulatory Assurance - Staff
*D. Barnett, Senior Quality Assurance Inspector
*R. Meadows, Staff Engineer
*R. Janecek, Nuclear Safety
*R. Leonas, Electrical Maintenance Staff

General Electric (GE)

J. Nash, Site Field Engineer

*Denotes those in attendance at the exit on May 26, 1989.

2. Detailed Description of the Event

A. Narrative Description

On March 25, 1989, while Unit 3 was operating at 89% power, the unit 345KV switchyard experienced a fault on a Power Circuit Breaker (PCB) 8-15. The faulted PCB 8-15 failed to open and protective relays of the Local Breaker Backup (LBB) logic associated with the 345KV switchyard caused additional Oil Circuit Breakers (OCBs) to open. This resulted in the isolation of the affected offsite line from the other two offsite lines in the switchyard and the Reserve Auxiliary Transformer (RAT) TR 32. The loss of the RAT resulted in a rapid transfer of 4KV busses from the RAT to the unit Auxiliary Transformer (UAT) TR 31. During the 4KV bus transfer, the 3B Reactor Feed Pump (RFP) and the 3B Reactor Recirculation Motor-Generator tripped and the standby RFP 3C automatically started. Both the running (RFP 3A) and standby (RFP 3C) reactor feed pumps immediately entered runout flow control upon the completion of the bus transfer and the automatic control Feedwater Regulating Valve (FRV) fully opened to allow maximum flow.

Since both RFPs were in runout and the FRV was fully open, reactor vessel level rapidly increased. Although the Nuclear Station Operator (NSO) had taken manual control of tne FRV in an attempt to regain control of vessel level, the level increased to the main turbine trip setpoint (+55 inches) and, consequently, the reactor scrammed as a result of turbine stop valve closure while above 45% power.

The generator subsequently tripped because of the turbine trip which resulted in no available normal offsite or onsite AC power. Both the Unit 3 and 2/3 diesel generators automatically started and loaded onto their respective emergency busses.

The NSO subsequently manually closed all of the Main Steam Isolation Valves (MSIVs) to conserve reactor vessel water inventory. This action resulted in the ability in maintaining

vessel level well above the top of the active core without requiring vessel depressurization and the use of the low pressure Emergency Core Cooling Systems (ECCS). However, as the event progressed, vessel pressure began to increase because of the stored energy and the isolated vessel condition. Prior to vessel pressure reaching the high pressure lift setpoint of the vessel relief valves, the NSO manually initiated the Isolation Condenser (IC) to control vessel pressure. The NSO was able to control vessel pressure with the IC and manually initiated the High Pressure Coolant Injection (HPCI) system for vessel level control. However, because of the NSOs earlier actions to maintain vessel inventory, HPCI rapidly increased level to the HPCI turbine trip level (+48 inches). Eventually, condensate storage water was required for makeup to the IC because electrical power was not available to the motor operator valves (MOVs) on the clean makeup system. Because condensate storage water was used as makeup to the IC, the atmospheric exhaust from the IC contaminated portions of the site.

Initially, the licensee made preparations for the potential release of contamination. However, these efforts were nullified by weather conditions and shifting wind directions, which spread the contamination from a defined small area within the site protected area to a larger area, including a location outside of the protected area but within the owner controlled area. The release did not threaten the public or result in contamination of personnel.

Approximately seven and a half hours after the initiation of the event, the affected PCB was disconnected and a 345KV feed was returned to the RAT. Once offsite power was restored, the diesel generators were secured and the unit was placed in cold shutdown.

B. Sequence of Events

Time (Hour:Min:Sec MilliSec)	Description
Initial	Unit 3 at 89% reactor power. RFPs 3A and 3B operating with FRV A in automatic and FRV B in manual at 25% open. Units 2 and 3 345KV Ring Busses separated with OCB 4-8 open.
1:32:45	Fault on Unit 3 345KV switchyard (offsite line 8014).
	PCB 8-15 trip.
	PCB 8-15 trouble alarm (indicating that PCB 8-15 failed to open). OCB 8-9 tripped (isolating the RAT from the fault and resulted in a loss of offsite power to Unit 3).

1:33:32	OCB 11-14 tripped (isolating the fault from the remaining portions of the Unit 3 Ring Bus).
1:33:32.104 to 1:33:32.123	4KV Busses 32 and 34 feed breakers to RAT 32 trip (isolating the RAT from the 4KV busses and initiating the 4KV bus transfer to the UAT).
1:33:33.393	4KV Bus 34 transfer to UAT 31.
1:33:35	RFP 3B reactor recirculation pump 3b trip from undervoltage condition on 4KV bus (due to a failed auxiliary contact on the 4KV bus feed breaker) and vessel level rapidly decrease.
1:33:46	Bus 32 completes transfer to UAT. RFP 3C (standby pump) automatically start and enters runout condition. FRV A automatically fully opened because of the rapidly decreasing vessel level after RFP 3B tripped (steaming rate was still equal to 89%). The NSO was manually closing FRV B after RFP 3C started. Vessel level began to rapidly increase.
1:34:38	Vessel level reached +55 inches, turbine trip/reactor scram. The NSO had taken manual control of FRV A but was unable to regain vessel level control.
1:34:39	NSO placed the reactor mode select switch into shutdown per procedures, initiating a manual scram and ensured all control rods in.
1:34:46	Main transformer isolated (Generator trip) due to turbine trip.
1:34:50	Standby Gas Treatment (SBGT) A train automatically started.
1:34:51	3A RFP trips on the +55 inches followed by 3C RFP trip.

1:34:54	Diesel Generators 3 and 2/3 automatically started and loaded. Breaker 3872 failed to close.
1:35:20	NSO manually closed MSIVs for inventory control.
1:39:10	NSO manually initiated the IC for pressure control.
2:05:00	IC secured by NSO.
2:15:00	NSO manually initiated HPCI for level control.
04:00:00	Bus 33 was energized from Bus 33-1 to start Containment Cooling Service Water (CCSW) pump 3A.
04:10:00	3A LPCI pump was started for torus cooling. HPCI turbine trips on +48 inches. HPCI turning gear motor failed preventing placing HPCI on the turning gear.
04:13:00	NRC operations center is notified per 10 CFR 50.72.
04:25:00	IC manually started by NSO. Clean de-mineralized water pump could not keep up with demand and IC feed is supplemented with contaminated condensate.
05:10:00	Vessel level drops below +48 inches for permissive to use HPCI, however, HPCI is not used because of the turning gear failure.
05:25:00	NRC operations center is notified of the discovery of the Unit 2 loss of control panel annunciators. The discovery was made at 04:35 and a fuse was replaced restoring annunciators immediately. However, notification of the Unit 2 control panel condition was not immediately made by the NSO because of activities on Unit 3.
05:57:00	Preparations to restore the 345KV switchyard were initiated.

06:45:00	IC manually initiated for the third time. Clean de-mineralized water used for makeup.
07:58:00	IC secured.
8:08:00	Offsite power was restored to RAT 32 through OCB 8-9 and diesel generators secured at 08:55:00.

3. Review of the Licensee's and Equipment Response

A. Equipment Malfunctions

The following equipment was determined by the NRC Special Inspection Team to have malfunctioned or demonstrated unexpected behavior during the event and required additional inspection. Each of these were reviewed in detail by both the licensee and the NRC to determine the root causes. These efforts are described in the proceeding paragraphs of this report.

- CB 8-15.
- Low Pressure Coolant Injection (LPCI) Swing Bus 38-7 to 39-7.
- RFP 3B.
- Open Annunciator Panel Fuses (Unit 2 only).
- HPCI High Pressure bearing oil temperature high.
- Bus 34-1 to Bus 34 breaker.
- Blow Transfer of Bus 32
- Instrument Air behavior

(1) Circuit Breaker 8-15

PCB 8-15 is located in the Unit 3 345KV (Red) Ring Bus connecting offsite line 8014 through Bus 15 to the RAT through Bus 8. OCB 4-8 is the tie between the Red ring bus and Unit 2 345KV (Blue) ring bus. The initial lineup of the two 345KV switchyards had OCB 4-8 open and all busses on each of the switchyards energized (Enclosure C). A fault developed on the A phase of PCB 8-15 and the breaker received a trip in an attempt to protect the RAT and the remainder of the switchyard from the fault. Immediately after receiving a trip, a trouble alarm was received indicating that the circuit breaker had failed to open on all three phases. OCBs 11-14, 8-9 and 4-8 were interlocked or affected by either the fault or CB 8-15 and opened to further protect their respective portions of the 345KV switchyard. OCB 4-8 only received a trip (the breaker was previously open). OCB 8-9 opened to protect offsite line 1223 and Bus 9. The opening of OCB 8-9 completely isolated the RAT from all offsite sources.

OCB 11-14 also received a trip to protect the offsite line 1222 and the remainder of the Red System (including the

main transformer TR 3). The Blue system (Unit 2 345KV switchyard) was unaffected throughout the event because of the normal separation between the Red and Blue systems via OCB 4-8 being open. The fault on CB 8-15 initially began at 1:33 a.m., and remained on the system until approximately 8:00 a.m. The licensee had decided not to resolve the switchyard fault until after the unit had been placed in a stable hot shutdown condition and cold shutdown had been initiated. This was based upon unexpected system response (RFP 3B trip), malfunctions (LPCI Swing Bus failure to transfer) and reactor scram. The licensee decided that these conditions required resolution and that the unit conditions were to be stabilized prior to resolving the switchyard fault (the fault had been isolated and did not have any additional threat to offsite lines or the remainder of the two switchyards).

Inspection of PCB 8-15 revealed that a ground capacitor in the A phase pressure vessel of the circuit breaker had failed resulting in a phase-to-ground fault (Enclosure G). The phase compartments of PCB 8-15 are pressurized with sodium hexufluoride gas (SF6). The failed ground capacitor uses a mineral dielectric oil. Neither the SF6 gas or dielectric oil leaked during the event. However, some of the debris associated with the failed A phase ground capacitor did communicate through the connecting duct to the B and C phase pressure vessels, however, the phase-to-ground fault was caused by the resultant debris contained within the A phase pressure vessel only.

(2) Failure of the LPCI Swing Bus to Transfer From 38-7 to 39-7.

A General Electric (GE) CR122AT Time Delay on Energization (TDOE) relay transfers the power feed to the LPCI swing bus from either Bus 39 or Bus 38. The normal lineup of power feed for the LPCI Swing bus (Motor Control Centers (MCC) 39-7 and 38-7) is through normally closed breakers 3971 and 3972 to Bus 39 (480 volts). Upon a loss of 480 volt electrical power, 480V transformer TR 39 (indicating undervoltage on Bus 39) will normally transfer by opening breakers 3871 and 3872 while closing onto 480V Bus 38 by closing breakers 3971 and 3972. This transfer from Bus 39 to 38 is controlled by the TDOE relay (reference Enclosure D). When an undervoltage condition exists on Bus 39, the UV (undervoltage) contacts in the MCC 39-7/38-7 logic close and the HFA relay energizes. HFA contacts 11-12 and 5-6 close to seal in the relay coil while contact 3-4 closes to start the 15 second timer associated with the TDOE relay. The purpose of the 15 second time delay is to prevent unnecessary transfers of the LPCI swing bus upon momentary power drops. If power to Bus 39 is not restored before the TDOE times out, TDOE contacts 3-4 and 1-2 close, tripping breakers 3971 and 3972 while closing breakers 3871 and 3872, restoring power

to the LPCI swing bus from Bus 38. If voltage is restored to Bus 39 prior to the TDOE timing out, the OVX contact closes, the OVX coil energizes, and the OVX contact opens. This sequence de-energizes the TDOE and the 15 second timer resets.

During the event, an undervoltage condition existed on Bus 39 for only seven seconds and the transfer logic completed its attempt to transfer to Bus 38. This occurred even though the 15 second timer had not timed out. In addition, the transfer failed to restore power to the LPCI swing bus because breaker 3872 failed to close (breakers 3871 and 3872 are in series from Bus 38). Power to the LPCI swing bus was lost even though Bus 39 was restored with seven seconds because the transfer did succeed in opening both breakers from Bus 39 (breakers 3971 and 3972). Both the premature transfer to Bus 38 (at seven seconds) and the failure of breaker 3872 to close were considered to be abnormal behavior.

The cause of the failure of breaker 3872 to close was attributed to the breaker linkage intermittently sticking. Breaker 3872 is a 480 volt General Electric AK 2A-25-1 circuit breaker. A review of the industry data base by the licensee revealed six failures of this model due to linkage binding. As corrective actions, the licensee repaired, lubricated and tested the breaker. Additionally, Breakers 3872 and 3972 equivalents on Unit 2 (breakers 2872 and 2972) were recently removed via a modification to improve the reliability of LPCI swing bus transfer. Unit 3's breakers are scheduled to be modified in November 1989.

The TDOE was tested under simulated undervoltage conditions by monitoring the voltage across TDOE contacts 3-4 and 1-2 for intervals of two, five, seven and ten seconds. The results of the test indicated that when the simulated undervoltage conditions existed for greater than 15 seconds, the LPCI swing bus transfer occurred as expected. The test also demonstrated that for undervoltage conditions existing for two seconds, the transfer did not occur and the TDOE reset as designed. However, for undervoltage conditions existing for five, seven, or ten seconds, the transfer logic did not respond as expected by either attempting or completing the transfer. A review of the GE design for the TDOE revealed that if undervoltage conditions existed for 1/3 of the time setting (5 seconds) a momentary output or current discharge would be produced by an internal capacitor upon resetting of the TDOE. This capacitor's current discharge was large enough to make up the transfer logic contacts to initiate a transfer. Based upon the test results and design review, the licensee determined that the GE model CR122AT TDOE relay was unsuitable for this application and the root cause of the de-energization of the LPCI swing bus.

The corrective action was to replace the TDOE relay with an Agastat ETR14D3C002 time delay relay as a temporary alteration. A permanent modification (M12-3-88-005) was scheduled for the refueling outage in November 1989. The TDOE had been previously removed from Unit 2 per modification M12-2-88-005 in January 1989. Additionally, both GE and the Quad Cities station were notified of the unsuitability of the TDOE in the LPCI swing bus logic.

A review of Dresden Licensee Event Reports (LERs) since 1981 revealed that no previous failures of the LPCI swing bus logic (TDOE or breaker types AK2A-25-1) had occurred. Additionally, a review of the industry Nuclear Plant Reliability Data System (NPRDS) data base revealed no documented failures of the TDOE relay.

(3) Reactor Feed Pump (RFP) 3B Tripped on Undervoltage.

During the automatic rapid transfer of 4KV busses from the RAT to UAT, both the RFP 3B and the 3B recirculation motor-generator (Reactor Recirculation (RR) pump 3B) tripped on undervoltage conditions. The automatic transfer is designed to transfer 4KV loads from either the RAT or UAT to the unaffected transformer during conditions of loss of offsite (RAT) or loss of the unit (UAT) without these loads sensing undervoltage conditions (Enclosure B). However, during the loss of the RAT, the transfer of BUS 32 to the UAT did not occur without undervoltage being sensed by a feed pump and a recirculation motor-generator resulting in tripping of RFP 3B and RR 3B.

The licensee found that an auxiliary contact on the feeder breaker switch (52H2) was fouled and caused the transfer of Bus 32 to the UAT (TR31) to momentarily stall. This stalling of the transfer was long enough for the recirculation motor-generator and feed pump to sense undervoltage and trip prior to the completion of the transfer of Bus 32 to TC 31.

The auxiliary contact was cleaned and successfully passed several post maintenance tests.

(4) Open Annunciator Panel Fuses (Unit 2 Only)

During the event on Unit 3, the Unit 2 NSO discovered that the Alarm Potential F-9 Failure Annunciator was illuminated on the Unit 2 Control Panel. Initially, the operator had believed that the illuminated annunciator was an adjacent annunciator associated with the primary containment nitrogen inerting. The annunciator indicated that fuse F-9 had opened resulting in loss of power to the annunciator panel for control room panel 902-3. Because the fuse was not replaced within 30 minutes, the Generating Station Emergency Plan (GSEP) Alert condition was declared and

determined per the Emergency Plan Implementation Procedure (EPIP) 200-T1.

Several conditions contributed to the requirement to enter an Alert Condition. The operator's failure to recognize the annunciator was the most significant and is considered to be an operator error. Additionally, the annunciator illumination was not highlighted to alert the operator of the significance of the annunciator to adjacent annunciators. As long-term corrective actions, the backlighting of the annunciator was changed to indicate red illumination to provide additional recognition to the operator. These actions appear to be appropriate and no further concerns exist with this issue.

(5) HPCI High Pressure Bearing Oil Temperature

During the event recovery, the high oil temperature setpoint for the HPCI High Pressure Bearing was reached and prevented the HPCI turbine from being placed onto the turning gear. The NSO immediately began to perform the operator actions per the required procedure and discovered that the Lubrication Oil Cooling Water Test Return valve (M03-2301-49) was open and that the normal return valve (M03-2301-48) to the HPCI booster pump discharge was closed. The NSO immediately opened M03-2301-48 and closed M03-2301-49. Because of the valve misalignment, cooling flow for the turbine turning gear oil was diverted to the condensate storage tank. The re-alignment of the valves decreased the oil temperature to below the alarm setpoint. HPCI was not inoperable during the event, maintaining the ability to inject, but the oil temperature did prevent the operator from placing the turbine onto the turning gear during periods when injection was not required. Because of this, the HPCI system was administratively declared inoperable until the turbine was manually placed onto the turning gear.

Normally, during a HPCI automatic initiation, the M03-2301-48 valve is automatically opened while M03-2301-49 closes. This allows cooling water to be supplied by the HPCI booster pump discharge and returned to the pump suction. During the normal Standby Mode of HPCI, M03-2301-48 is closed and M03-2301-49 open. This allows a flow path to the Condensate Storage Tank for the Gland Seal Leak Off (GSLO) drain pump.

During the Unit 3 Loss of Offsite Power event, HPCI was manually initiated primarily for pressure control and as inventory control only if needed. The operating procedure for using HPCI as pressure control directs the NSO to open M03-2301-48 and close M03-2301-49 as subsequent steps. The procedure did not instruct the operator to perform these subsequent steps in a rapid succession or caution the

operator on extended operation of HPCI without performing these steps. Since the primary concern of the NSO during the event was maintaining pressure control with the use of the Isolation Condenser and HPCI (inventory control had been achieved for most of the event by the closure of the MSIVs and the automatic start of the Standby Feedwater pump), the operator had not proceeded beyond the HPCI flow adjustment step of the procedure and did not perform the subsequent steps pertaining to the cooling water valve alignment.

The root cause of achieving the HPCI high oil temperature alarm setpoint was determined to be an inadequate operating procedure. The HPCI Operating Procedure (DOP 2300-3) was revised to ensure that cooling flow will be established during all operations of the HPCI system. No further concerns exist with this issue.

(6) Bus 34-1 to Bus 34 Breaker Tripping

During the event, the NSO attempted to backfeed Bus 34 from the Unit 3 Emergency Diesel Generator (EDG) through Bus 34-1. The first attempt resulted in the Bus 34-1 to Bus 34 breaker (152-3403) tripping. A subsequent attempt to close 152-3403 was successful.

The cause of breaker 152-3403 to trip during the first attempt was determined to be attributed to pitted overvoltage contacts found on the breaker's undervoltage relay. The root cause of the pitting was determined to be normal wear since the last relay cleaning on May 15, 1988. The next relay cleaning was scheduled for November 1989. The relay contact was cleaned and successfully tested on March 26, 1989.

(7) Slow Transfer of Bus 32

During the event, Bus 32 did not rapidly transfer from the RAT to the UAT. This resulted in the tripping of an feedwater and recirculation pump. The actual transfer lasted approximately 14 seconds.

The root cause of the slow transfer was determined to be a dirty contact on the breaker. The licensee's review of machinery history revealed that the last overhaul of the breaker was conducted on February 11, 1982, and that the next overhaul was scheduled on December 30, 1989. The long interval between overhauls contributed to the failure. As corrective actions, the breaker was overhauled and the preventive maintenance schedule was reviewed and accelerated.

(8) Instrument Air Behavior

During the event, the Unit 3 Instrument Air (IA) System was rendered inoperable due to the de-energizing of the air compressor. The operator isolated the Unit 2 IA System from the 3C Instrument Air Compressor to prevent depressurization of the Unit 2 IA System because of the automatic crossconnection between the Units' IA System upon low air pressure in either IA system. The Unit 3 IA System was subsequently restored by the NSO by crossconnecting to the Unit 1 IA System.

The licensee's review of the IA System behavior revealed that the operating procedure did not contain instructions for crossconnecting to Unit 1 and isolating Units 2 and 3 during a loss of Offsite Power to one unit while the other operated at power. The procedures were revised and no other concerns exist (none of the equipment required for safe shutdown was affected by the IA System behavior).

B. Radiological Aspects of the Event

Two Region III Division of Radiation Safety and Safeguards representatives were dispatched to the site on March 25, 1989, the day of the event, to observe the licensee's health physics response to the event.

The licensee estimated that 16,000 gallons of condensate storage tank (CST) water was fed to the isolation condenser (IC) during the incident. The gross activity in the CST was about 7E-6 uCi/cc (most cobalt-60 and manganese-54) and the licensee estimated the total radioactivity released from the isolation condenser vent in steam and entrained water was about 0.5 millicuries. However, there are uncertainties in the volume of CST water actually released which could affect the activity release quantification. Also, samples from the isolation condenser during the event were about ten times higher in concentration than the CST samples so the released activity could have been an order of magnitude greater than the licensee's estimate. The licensee is continuing to evaluate this matter.

The IC was activated three times between 0130 and 0800. The licensee believes that the first activation released no radioactivity because the secondary side of the IC initially contained clean deionized (DI) water. However, the IC was refilled with contaminated water from the CST causing releases of radioactive material during the subsequent two activations. Only the third activation, occurring around 0700-0800, appeared to result in contamination beyond the protected area fence.

The licensee roped off potentially contaminated outdoor areas and surveyed these areas to establish the extent of contamination. The licensee found that the area contaminated was mostly within the protected area fence; minor quantities of contamination

(approximately 100 dpm/100cm^2 removable were found outside the fence near the guardhouse and in part of the management parking lot adjacent to the guardhouse (Enclosure E). The area outside the fence and several affected cars were decontaminated by the afternoon of the day of the event.

Areas contaminated within the fenced area included blacktop roadways, graveled and soil areas, and the roofs of some nearby buildings. The highest levels of contamination found, near the reactor building below the IC vent, were about 8000 dpm/100cm^2 removable. Most of the remaining areas appeared to be below 500 dpm/100cm^2 removable and 5000 dpm/100cm^2 fixed plus removable. Samples of liquid from the IC and from puddled water near the reactor building below the isocondenser vent were collected and analyzed by the licensee; the concentrations of isotopes present were about ten percent of the restricted area maximum permissible concentrations.

The licensee used various scrubbing and flushing methods to decontaminate hard surfaces; contaminated soil and gravel were being collected in 55-gallon drums for later radwaste disposal. The initial focus was on decontamination of asphalt roadways and pedestrian walkways. Currently, these have been cleared but some contaminated soil and gravel within the protected area remain to be dealt with by the licensee.

The licensee calculated that the concentration of radioisotopes flushed into the storm sewer system would be below regulatory limits for discharge to unrestricted areas. As a precaution, the licensee also placed liquid samplers near the storm sewer outfalls to independently quantify the release in progress. The licensee is continuing the decontamination of outdoor areas. Regional radiation specialists will further review cleanup activities during a future inspection. (Open Item 249/89010-01).

Releases via the IC vent have occurred on several occasions since 1980, including two with activity beyond the protected area fence similar to this event. These previous IC releases were caused by residual low level contamination in the shell side of the IC dating from an earlier period (pre-1980) when contaminated water from the CST was the primary makeup water source to the IC. Although the makeup water source had been switched to clean DI water tanks, the residual contamination on the walls of the shell side of the IC remained available for mobilization whenever the IC was used. After a 1985 IC vent release which deposited contamination beyond the protected area fence, the licensee cleaned the secondary side by hydrolazing to remove the residual activity. However, the licensee did not correct another known weakness wherein loss of offsite power (in conjunction with loss of the plant turbine-generator) causes

loss of the DI water source and the CST once again becomes the primary makeup water source to the IC. This is what occurred in the present event.

On March 28, 1989, the licensee again hydrolazed the shell side of the isolation condenser. Although this may preclude future releases under normal conditions, use for an extended time without power would likely result in another release. The licensee is in the process of evaluating alternatives to mitigate this weakness and has agreed to describe in a written response to this report, the corrective actions it plans to take. (Open Item 249/89010-02).

No violations or deviations were identified.

C. Licensee's Response During the Event

The licensee's onsite and corporate management quickly responded to the event by fully manning the Technical Support Center (TSC) throughout the event and recovery. The licensee effectively used the TSC as a central location for gathering information, evaluating the event and directing the recovery. Additional support was also obtained from various corporate technical and engineering organizations and the GE onsite field engineer. Communications were maintained with outside organizations, such as the NRC, throughout the event.

The licensee's initial recovery from the loss of offsite power was delayed by the unexpected behavior of several individual components, such as breaker 3872 and the TDOE in the LPCI Swing Bus Logic. The licensee approached these behaviors from a safety standpoint by determining the causes of the behaviors prior to initiating recovery. These actions were determined to be very good since the upset plant conditions had been mitigated by the operators and management recovery team, and the plant was in a known safe condition. However, the delay did affect the operation of the isolation condenser. Initially, the isolation condenser was operated using clean non-contaminated makeup. But because the makeup supply valves were inoperable due to the loss of electrical power, makeup was required from contaminated sources. This resulted in contamination of a large portion of the site (the general public was not threatened by the release). Due to the licensee's initial preparations resulted during the event or the recovery.

In general, the station personnel, management and outside organizations responded very good to the event and demonstrated good control of the recovery.

4. Event Summary

The event demonstrated several weaknesses in the licensee's procedures and preventive maintenance schedules. The procedure weaknesses pertained to subsequent actions during a long term event, such as the manual initiation of HPCI oil cooling and the manual separation of Units 2 and 3 instrument air. Additionally, breaker preventive maintenance was evaluated because of the various behaviors that contributed to the 4 KV bus slow transfer, LPCI Swing Bus failure to transfer and the problems associated with closing onto Bus 34. The licensee's evaluation of all of these and others was detailed and effective in resolving these technical issues.

Additionally, the event demonstrated very good actions on the parts of operators and management in dealing with the event and contributing equipment behaviors. The event demonstrated both the ability of the station personnel and the difficulty associated with a long term loss of offsite electrical power.

The site recovery was well planned and implemented. The handling of the site contamination was good with most of the cleanup currently completed. During the event and site cleanup, good personnel precautions were taken such that no personnel contaminations occurred.

The safety significance of the event was low because of the actions of personnel and management in mitigating the plant upset conditions and rapidly achieving a known safe condition. As the event progressed, the station addressed each of the equipment behaviors in a conservative approach from a safety standpoint. This detailed and conservative approach appeared to delay the restoration of offsite power but demonstrated the management's commitment to achieve complete knowledge of all plant conditions prior to restoration.

5. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on May 26, 1989, and informally throughout the inspection period, and summarized the scope and findings of the inspection activities.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary. The licensee acknowledged the findings of the inspection.