Docket File

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

June 10, 1993

Docket Nos. 50-327
and 50-328

Tennessee Valley Authority
ATTN: Dr. Mark O. Medford, Vice President
Technical Support
3B Lookout Place
1101 Market Street
Chattanooga, Tennessee 37402-2801

Dear Dr. Medford:

SUBJECT: PRELIMINARY ACCIDENT SEQUENCE PRECURSOR (ASP) ANALYSIS FOR SEQUOYAH NUCLEAR PLANT UNITS 1 AND 2

Enclosed are preliminary Accident Sequence Precursor (ASP) evaluations for two Sequoyah events that occurred in 1992. One event was the dual unit trip and loss of offsite power to the safeguards buses on December 31, 1992, and the other was inoperability of a Residual Heat Removal pump when an emergency diesel generator was out of service. The Licensee Event Reports that formed the basis for the analysis are also enclosed. This information is included as Enclosure 1.

Your review and comment on the analyses of these events would be appreciated. In particular, comments on the characterization of possible plant responses, given the occurrence of the events, is sought. We are also interested in comments concerning whether the individual descriptions and analyses reasonably represent plant safety equipment configurations and capabilities that existed at the time of the events. In addition, comments on the analyst's assumptions regarding equipment recovery probabilities are also sought.

We recognize that the enclosed analysis for the loss of offsite power event is different from an analysis that was performed for previous discussions on this event, in that the enclosed analysis does not consider the consequences of loss of cooling water to the reactor coolant pump seals. For this analysis it is felt that, since offsite power was lost for such a short duration in relation to the time that seal damage would have occurred, seal damage would not have occurred before compensatory action was taken. Therefore, the enclosed analysis more closely represents the conditional core damage probability for a loss of offsite power event. See Enclosure 2 for a more thorough discussion.

As discussed with Mr. Jim Smith of your staff, we are requesting that your comments be provided in writing by June 25, 1993. We will review your comments and revise the final ASP analysis as appropriate. If you have any questions regarding this matter, please contact me at (301) 504-1472.

DF01
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This request is covered by Office of Management and Budget Clearance Number 3150-0011, which expires June 30, 1994. The estimated average number of burden hours is 80 person hours per owner response, including the time required to assess the new recommendations, search data sources, gather and analyze the data, and prepare the required letter. Comments on the accuracy of the estimate and suggestions to reduce the burden may be directed to the Desk Officer, Office of Information and Regulatory Affairs (3150-0011), NEOB-3019, Office of Management and Budget, Washington, DC 20503, and to the U.S. Nuclear Regulatory Commission, Information and Records Management Branch (MNBB 7714), Division of Information Support Services, Office of Information and Resources Management, Washington, DC 20555.

Sincerely,

Original signed by:

David E. LaBarge, Senior Project Manager
Project Directorate II-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. ASP Reports
2. RCP Seal LOCA Modeling For LOOP Analysis

cc w/enclosures:
See next page

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DOCUMENT NAME: ASP.LTR

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PRELIMINARY

B.18 LER Number 327/92-027

Event Description: Loss of Offsite Power to Safeguards Busses at Sequoyah

Date of Event: December 31, 1992

Plant: Sequoyah 1 & 2

B.18.1 Summary

Shortly after a switchyard breaker was installed, it faulted and caused an undervoltage condition in the switchyard. This resulted in the tripping of both units from 100% power on loss of offsite power (LOOP). Because of the momentary undervoltage condition on the safeguards buses, the emergency diesel generators started and loaded. The conditional core damage probability estimated for this event is 1.8×10^{-4} per unit. The relative significance of this event compared to other postulated events at Sequoyah is shown in Fig. B.36.

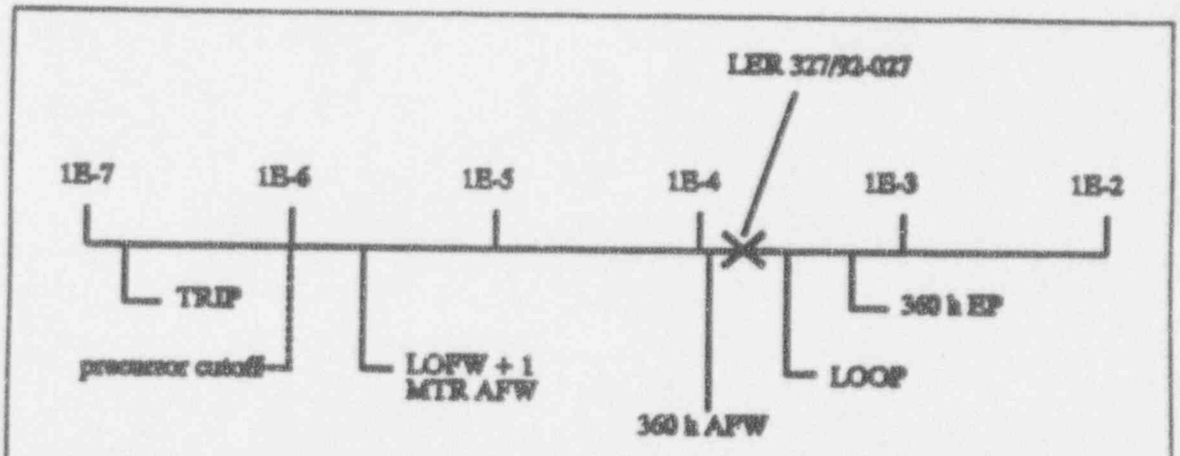

Fig. B.36. Relative event significance of LER 327/92-027 compared with other Sequoyah 1 & 2 potential events.

B.18.2 Event Description

On December 31, 1992, with both units at 100% power, work was progressing on the installation of a 500-kV/161-kV switchyard inter-tie breaker. For testing purposes, the primary relay protection for the breaker was disabled. At 2148 hours, 11 min after the breaker was placed in service, both units tripped because of a reactor coolant pump undervoltage signal. The undervoltage was caused by an internal fault in the inter-tie breaker that resulted in decreased voltage throughout the entire switchyard. After the switchyard fault was cleared (in 88 cycles), offsite power was available to the station.

Following the plant trips and the clearing of the switchyard fault, loads automatically transferred from the unit station service transformers to the common station service transformers, as designed. However, because of the undervoltage sensed on the shutdown (safeguards) buses, the emergency diesel generators started and loaded. At 2313 hours the safeguards buses were realigned to offsite power. By 0013 hours on January 1, 1993, both units were stabilized in hot shutdown.

B.18.3 Additional Event-Related Information

The Sequoyah switchyard consists of a 500-kV section and a 161-kV section. Unit 1 is directly connected to the 500-kV switchyard and unit 2 is directly connected to the 161-kV portion of the yard. The two sections are joined by the inter-tie transformer. Power circuit breaker 5058 connects one of the 500-kV buses to the inter-tie transformer. During startup and shutdown, power to both units is supplied by the 161-kV system via the common station sevice transformers.

B.18.4 Modeling Assumptions

Since the LOOP was caused by a substation fault, this event was modeled as a plant-centered LOOP. Probabilities for LOOP nonrecovery (short term), failure to recover ac power prior to battery depletion, and reactor coolant pump seal LOCA probabilities were revised to reflect values associated with a plant-centered LOOP (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989). The event was modeled for a single unit. The event sequence was essentially the same for both units.

B.18.5 Analysis Results

The conditional probability of core damage estimated for this event is 1.8×10^{-4} per unit. The dominant core damage sequence, highlighted on the event tree in Fig. B.37, involves failure of emergency power restoration resulting in a reactor coolant pump seal LOCA.

PRELIMINARY

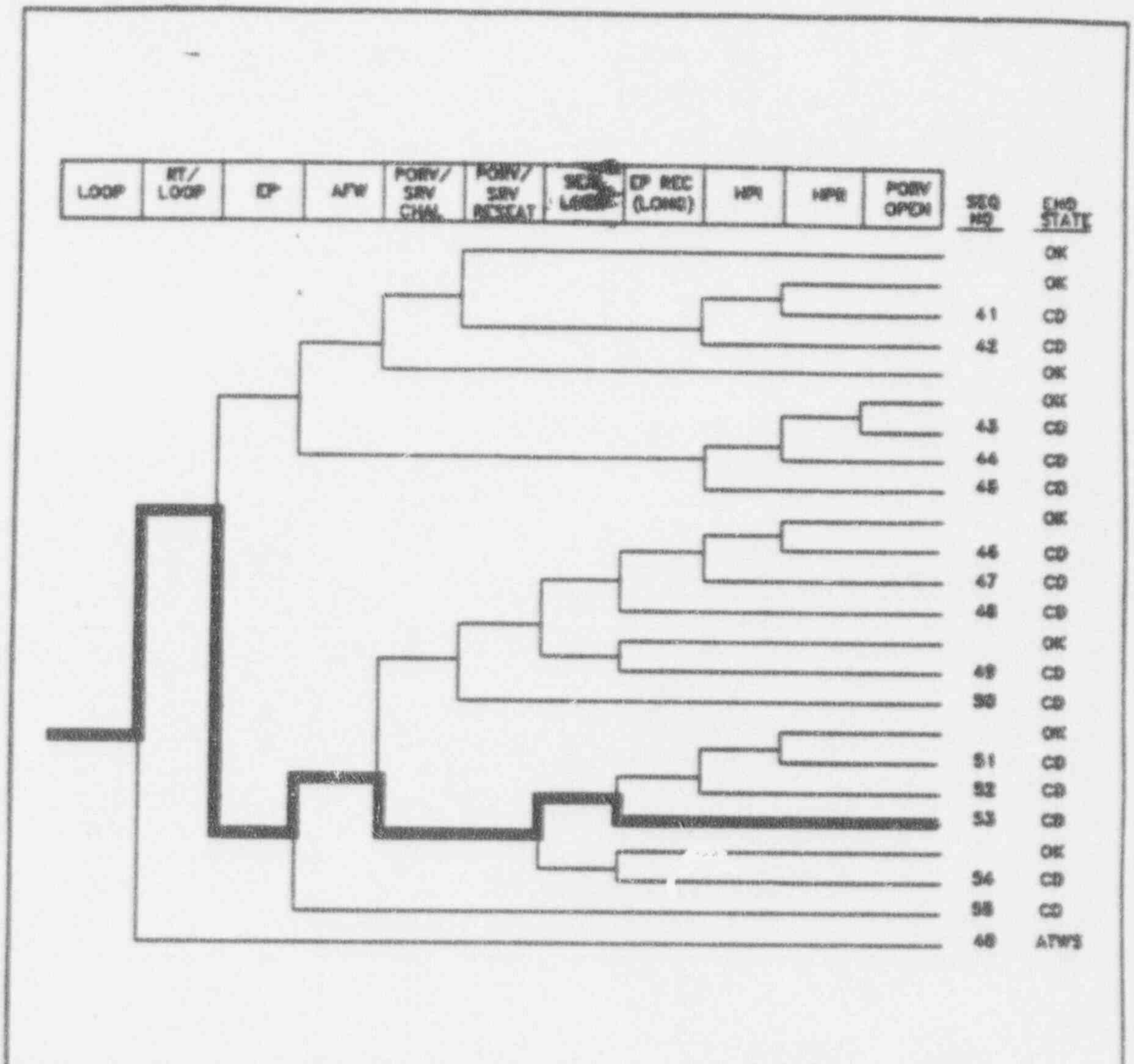

Fig. B.37. Dominant core damage sequence for LER 327/92-027.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 327/92-027
Event Description: Loss of Offsite Power
Event Date: 12/31/92
Plant: Sequoyah 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	1.8E-06
Total	1.8E-06
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.2E-06	4.0E-01
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	3.6E-07	4.0E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.9E-07	1.4E-01
48	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD	6.8E-08	4.0E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
48	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD	6.8E-08	4.0E-01
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.2E-06	4.0E-01
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	3.6E-07	4.0E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.9E-07	1.4E-01

** non-recovery credit for edited case

SEQUENCE MODEL: C:\sapppre\models\pwrbseal.cmp
BRANCH MODEL: C:\sapppre\models\sequoyah.sll
PROBABILITY FILE: C:\sapppre\models\pwr_bsll.pro

Event Identifier: 327/92-027

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.7E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	5.3E-01 > 5.0E-01	
Branch Model: INITOR - Initiator Freq:	1.6E-05		
loop	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
SEAL.LOCA	2.7E-01 > 2.3E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.7E-01 > 2.3E-01		
EP.REC(SL)	5.7E-01 > 4.8E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.7E-01 > 4.8E-01		
EP.REC	7.0E-02 > 4.3E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	7.0E-02 > 4.3E-02		
hpi	1.0E-03	8.4E-01	
hpi(f/b)	1.0E-03	8.4E-01	1.0E+00
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 327/92-027

PRELIMINARY

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Sequoyah Nuclear Plant, Unit 1 DOCKET NO: 327

TITLE: Reactor Trips as a Result of a Switchyard Power Circuit Breaker Fault and a Unit 2 Entry Into Limiting Condition for Operation (LCO) 3.0.3 When Both Centrifugal Charging Pumps Were Removed From Service

EVENT DATE: 12/31/92 LER #: 92-027-00 REPORT DATE: 02/01/93

OTHER FACILITIES INVOLVED: Sequoyah, Unit 2 DOCKET NO: 05000328

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i)
50.73(a)(2)(iv)
50.73(a)(2)(v)

LICENSEE CONTACT FOR THIS LER: Jan Bajraszewski, Compliance Licensing
TELEPHONE: (615) 843-7749

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EL COMPONENT: 52 MANUFACTURER: B455
REPORTABLE NPRDS: N

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On December 31, 1992, at approximately 2148 Eastern standard time (EST), with Units 1 and 2 in power operation at approximately 100 percent, both units received a reactor trip signal because of reactor coolant pump bus undervoltage. The reactor trips were followed by turbine trips. Undervoltage on the 6.9-kV shutdown boards initiated board load stripping, diesel generator (D/G) starts, and D/Gs tying onto their respective shutdown board. Electrical loads were appropriately sequenced back to the boards. Main feedwater isolated and auxiliary feedwater pumps started. Loss of power to a radiation monitor resulted in an auxiliary building isolation. With limited staffing in the Unit 2 main control room, recovery evolutions for Unit 2 resulted in isolation of centrifugal charging pump suction and removal of both centrifugal charging pumps from service. Unit 2 entered LCO 3.0.3 for approximately one minute until a suction flow path was reestablished. The cause of the event was an internal fault in a switchyard power circuit breaker resulting from inappropriate testing methodology. Corrective actions include strengthening of switchyard controls and increasing minimum Operations control room staffing.

I. PLANT CONDITIONS

Units 1 and 2 were in power operation at approximately 100 percent power.

II. DESCRIPTION OF EVENT

A. Event

On December 31, 1992, at approximately 2148 Eastern standard time (EST), both units received a reactor trip signal because of reactor coolant pump bus undervoltage (EIIS Code EA). The undervoltage condition resulted from an internal fault in a new switchyard power circuit breaker (PCB) (EIIS Code FK) that had been in service approximately 11 minutes. Before the event, switchyard crews were in the process of placing the PCB in service. The PCB (PCB 5058) was in the 500-kV switchyard to intertie transformer position. Primary protective relays applicable to the PCB had been disabled by opening the associated trip cutout switches to facilitate differential relay circuit phasing.

The reactor trips were followed by turbine trips. Undervoltage on the 6.9-kV shutdown (S/D) boards (EIIS Code EB) initiated diesel generator (D/G) (EIIS Code EK) starts and loading onto their respective S/D boards. The S/D board loads were stripped and upon D/G loading, loads were appropriately sequenced back to the boards with the exception of the thermal barrier booster pumps (TBBPs), which did not restart. Main feedwater isolated and auxiliary feedwater (AFW) (EIIS Code BA) pumps started. Loss of power to a radiation monitor (EIIS Code IL) resulted in an auxiliary building isolation. The fault was cleared within 88 cycles, and offsite power to the start busses was restored. Following the trip the reactor coolant pumps (RCPS) transferred from the unit station service transformer (USST) to the common station service transformer (CSST) as designed; forced reactor coolant flow was maintained.

During the transient, Unit 2 recovery evolutions resulted in isolation of centrifugal charging pump (EIIS Code CB) suction and both pumps being removed from service. Unit 2 entered Limiting Condition for Operation (LCO) 3.0.3 for approximately one minute until a suction flow path was reestablished. Normal charging seal flow was not in-service during this time. Approximately 20 seconds into that minute, the TBBPs were manually started to provide RCP seal flow cooling.

The transmission system network consists of a 500-kV and a 161-kV switchyard at Sequoyah Nuclear Plant (SQN). Unit 1 is connected to the 500-kV network and Unit 2 is connected to the 161-kV network. These two networks are joined by the intertie transformer (Intertie Bank 5 - see page 16 of LER). PCB 5058 can be used as an intertie-transformer PCB and/or a spare-line PCB. Preferred electric power to the emergency busses and to start up and shut down the generating units at SQN is supplied by circuits from the 161-kV switchyard.

B. Inoperable Structures, Components, or Systems That Contributed to the Event

The handswitches for the TBBPs of both units were in the A-Auto position (in accordance with procedure) instead of the A-P-Auto position (in accordance with design). The TBBPs were shed following the loss of offsite power indication, as designed. However, as a result of the handswitch position, the TBBPs did not reload upon D/G loading.

C. Dates and Approximate Times of Major Occurrences

LER NO: 327/92-027

November 20, 1992	Switchyard PCBs inadvertently tripped during tests to locate a ground on the 250-volt direct current control wiring. Two phases of one PCB closed automatically because of a malfunction and loss of air pressure. The remaining phase did not close. The PCB then failed.
November 23, 1992	The decision was made to replace PCB 5058 with a new 550-PM type ABB breaker. A PCB that had been purchased for the Jackson, Tennessee 500-kV substation was chosen as the replacement PCB. ABB was contacted to obtain the necessary information to install the breaker at SQN.
November 30, 1992	The replacement PCB arrived at SQN from Jackson, Tennessee. A design change notice and work order were prepared and approved to install the breaker.
December 14, 1992	PCB 5058 installation began under the guidance of a TVA-ABB factory-trained power maintenance specialist.
December 29, 1992	The Chickamauga load coordinator was informed that PCB 5058 would be ready to be placed in service on December 31, 1992. The breaker was satisfactorily factory and field tested (the breaker had not been energized) as required by the work order.
December 31, 1992 at 2137 EST	Following review and approval of the switching order and testing methodology by the main control room (MCR) staff, PCB 5058 was placed in service to be followed by verification of phasing on the differential relay circuit. The primary trip cut-out switches were placed in the open position and provided no primary relay protection for PCB 5058 during this timeframe. Secondary delayed relay protection was available and did operate after approximately 88 cycles.
December 31, 1992	PCB 5058 faulted internally, resulting in breaker failure. From the annunciator printout, the first alarms to come in indicated oscillograph operation and opening of PCB 5074 (Plant Bowen line). The condenser circulating water pump motors tripped followed by alarms for overcurrent on Generator 1 exciter field, 161-kV supply voltage failure, station frequency excessive error, and undervoltage on the RCP bus.

Additional events during this first minute included:

1) Opening of the 500-kV switchyard PCBs and the intertie PCBs in the 161-kV switchyard.

2) Undervoltage on the 6.9-kV S/D boards resulted in the appropriate relays stripping the major equipment from the boards. This included the centrifugal charging pumps (CCPs) on both units, which subsequently resulted in letdown isolations.

3) Both units received a reactor trip signal because of RCP bus undervoltage. The reactor trips were followed by turbine trips and 161-kV bus voltage-failure alarms. Automatic transfer from USST

to CSST was successful, and the 6.9-kV unit boards remained energized from offsite power. Undervoltage on the four 6.9-kV S/D boards initiated transfer to the D/Gs. The four D/Gs started; feeder breakers closed and energized their respective S/D boards.

4) An engineered safety feature (ESF) auxiliary building isolation actuated because of a loss of power to 0-RM-90-101.

5) The alarm for the Unit 1 ice condenser lower inlet doors opening was received.

6) Nonaccident equipment sequenced back on the S/D boards. Both CCPs restarted on each unit.

Unit 1 at 2150 EST	The operator took manual control of AFW (minimum average temperature [T sub avg] was 542 degrees Fahrenheit [F]) by reducing the speed of the turbine-driven auxiliary feedwater pump (TDAFWP) and manually throttling the motor-driven auxiliary feedwater pump (MDAFWP) level control valves (LCVs). The letdown orifices were reopened followed by reestablishing the steam-dump operation. After the instrument mechanics (IMs) checked the P-4 contacts for the reactor trip breakers, the feedwater isolation was reset and steam generator blowdown was established.
Unit 2 at 2151 EST	The operator took manual control of the TDAFWP to bring the pump to minimum speed.
Unit 2 at approx. 2155 EST	The T sub avg temperature had decreased to less than 540 degrees F. The assistant shift operations supervisor (ASOS) determined that boration was required. He directed boration through the blender at greater than 10 gallons per minute (gpm) with high concentration boration. The operator then took manual control of the MDAFWP LCVs to control the temperature decrease.
Unit 2 at 2208 EST	Suction to the CCPs swapped over from the volume control tank (VCT) to the refueling water storage tank (RWST) because level in the VCT had decreased to 7 percent. At that time, the ASOS realized that letdown had been previously isolated. The ASOS directed that one CCP be stopped. Since the blackout relays were sealed in, the pump was placed in pull-to-lock (P-T-L).
Unit 2 at 2209 EST	Letdown was reestablished.
Unit 2 at 2211 EST	After the reactor operator (RO) and ASOS verified sufficient VCT level, the VCT outlet valves were opened. The operator then closed the RWST valves. The operator observed that the VCT outlet valves were traveling closed. The second CCP was stopped and letdown automatically isolated. With both CCPs not in service, LCO 3.0.3 was entered. Approximately 20 seconds after the second CCP was stopped, the shift operations supervisor (SOS) started the TBBPs. The Unit 1 TBBPs were then started after the Unit 2 TBBPs.

Unit 2 VCT at 2212 EST — valves were opened, the second CCP was started, and letdown was reestablished. The handswitches for both the VCT and RWST valves were either placed in or verified to be in AP-AUTO position. LCO 3.0.3 was exited.

Unit 2 at 2313 EST — The 6.9-kV S/D boards were returned to normal offsite power.

January 1, 1993 at 0011 EST — Unit 2 was stabilized in Mode 3.

January 1, 1993 at 0013 EST — Unit 1 was stabilized in Mode 3.

D. Other Systems or Secondary Functions Affected

The low voltage condition resulted in the Units 1 and 2 condenser circulating water (CCW) pumps tripping. The loss of these pumps is not considered abnormal for this event. The unit boards sustained a voltage drop that would cause a drop in excitation voltage and result in a speed deviation trip or a power-factor deviation trip. CCW flow is necessary to maintain condenser vacuum and to provide an enable signal for steam dump controls.

E. Method of Discovery

The switchyard buzzers, reactor trips, and blackout sequence alarms were annunciated on the MCR panels. Oscillograph charts identified that a fault had occurred in the C-phase of PCB 5058, which was in the process of being placed in service.

F. Operator Actions

The operators promptly diagnosed the plant conditions and took actions necessary to stabilize the units in the hot standby condition (Mode 3).

Unit 1 MCR personnel (one ASOS and two ROs) responded as prescribed by emergency procedures. The secondary side of the plant was secured, and the operators took manual control of the TDAFWP and placed the motor-driven auxiliary MDAFWP LCVs in manual bypass mode. The plant responded as expected and the operators performed the designated actions of the procedures.

Unit 2 MCR personnel (one ASOS and one RO) proceeded through the actions described by the emergency procedure. With only one RO, securing of the secondary side was delayed. The RO took manual control of the TDAFWP and reduced its speed to minimum. The MDAFWP LCVs were left in the auto position resulting in twice the AFW flow of that in Unit 1, resulting in a greater cooldown rate. With blowdown isolated, feedwater pumps tripped, main turbine tripped, and steam dumps not available, the effect of the higher AFW flow caused Unit 2 to cooldown to about 537 degrees F. The ASOS recognized that RCS boration was required if T sub avg was less than 540 degrees F and made the decision to leave the MDAFWP LCVs in auto and borate first. The ASOS and RO discussed which flow path was to be used. The normal boration path was chosen because it was considered to require less operator intervention and monitoring than the emergency path. The ASOS made the decision to borate through the blender and directed the RO to initiate 135 gallons of high concentration (20,000 parts per minute) boration at greater than 10 gpm. The ASOS did not read the procedure and believed that the procedure allowed boration through the path chosen. The procedure required boration through the emergency boration path. The normal boration path was allowed only if flow could not be achieved through the emergency boration path. The decision to borate through the normal rather than emergency path, as required by the procedure, set up the sequence of events ultimately leading to the loss of both CCPs and charging RCP seal injection.

The ASOS had noted early in the transient that the component cooling system (CCS) TBBPs did not automatically start after the D/Gs energized the S/D boards. The ASOS did not direct manual starting of the TBBPs at that time because he did not have the resources available to evaluate the impact on D/G loading.

At the time of the reactor trip, the undervoltage condition had resulted in load stripping of the 6.9-kV S/D boards. The load shedding tripped off the running CCP. With no CCPs running, a letdown isolation automatically occurred. After the ASOS initiated boration and manual control of the MDAFP LCVs, an automatic swapover from the VCT to the RWST occurred as the level in the VCT reached 2 percent. At this time, the ASOS realized that letdown was isolated, and normal boration was only providing approximately 10 gpm makeup. After swapover, the ASOS directed the operator to stop the one CCP. The handswitch was placed in the P-T-L position to ensure that it would not immediately restart, since the blackout relays had not been reset. The SOS, ASOS, and RO had verified that no condition existed that would indicate the need for operation of both CCPs. Stopping the CCP was based on adequate RCS inventory, letdown isolation, and potential for equipment (CCPs and subsequently RCP seals) damage as a result of low indicated oil pressure on the CCPs and no running TBBPs. The ASOS directed the RO to reestablish letdown flow to restore VCT level.

The RO and ASOS observed VCT level indication increase and agreed that the VCT was capable of supporting sustained transfer of the CCP suction from the RWST back to the VCT to restore normal conditions. Handswitches for the VCT outlet valves were taken to A-Auto, to the OPEN position. When the RO observed the valves reaching the full open position (red lights), he took the handswitches to the AP-Auto position. The RO then took the RWST outlet valve handswitches to A-Auto and to the CLOSED position. The RO observed the valves reaching the full closed position (green lights). It is believed that the RWST valve handswitches were left in the A-Auto position. This evolution took place in approximately 18 seconds based on printouts.

At this point, the RO recalled the RWST valves being closed and the VCT valves being open. The RO stated that as he looked away from the handswitches, he noticed green and red lights on the VCT valves, indicating the valves traveling closed. The RWST valves remained closed with green lights. With the RWST valve handswitches left in the A-Auto rather than the AP-Auto position, automatic transfer back to the RWST did not occur when the VCT valves traveled closed. The RO called out the condition to the ASOS. Not knowing whether the VCT valves were partly closed or almost fully closed, the RO prepared to stop the running 2A-A CCP. With concern for potential imminent failure of the CCP on loss of suction, the ASOS directed the RO to stop the 2A-A CCP. The RO held the pump handswitch in the STOP position (not in P-T-L). When told by the ASOS that the second CCP was being stopped, the SOS manually started the TBBPs approximately 20 seconds after the 2A-A CCP was stopped. The VCT outlet valves were reopened and remained open, the handswitch for the 2A-A CCP was released, and the pump restarted approximately one minute after being stopped. Letdown was reestablished and the system stabilized.

G. Safety System Responses

Safety systems performed and plant parameters responded as expected for the reactor and turbine trips. Details of specific safety system responses are as follows: Upon receipt of the trip signals, the S/D and control bank rods for both units dropped into the core and reactor power rapidly decreased as expected.

The RCPs for both units were in service during the transient and forced flow was maintained.

Main feedwater flow for both units terminated on the reactor trips. The AFW pumps for both units started as designed, and steam flow continued to the TDAFW pumps. The operator of each unit took manual control of the TDAFW pumps and MDAFW pumps as the transient progressed.

The auxiliary building vent radiation monitor lost power at the start of the event. This equipment is powered from the instrument power distribution panel, which is not backed by the ENTIRE vital inverters. This condition resulted in a control room alarm "Auxiliary Building Vent Monitor Hi Rad" and was not a result of an actual high radiation condition. The equipment performed as expected.

The normal feeder to the 6.9-kV S/D boards is designed to open when its undervoltage relays sense less than 80 percent voltage for more than 0.5 seconds. After the 6.9-kV S/D board voltage had decreased to less than 70 percent undervoltage, a D/G start signal was generated. The load shedding occurred as expected. After each D/G reached the appropriate speed and voltage, the breaker that connects each D/G to the S/D board closed, and the load sequencing timers started. Loads were then automatically reconnected for a nonaccident loading sequence. During this event, the load shed/load sequence logic functioned as designed on the four S/D boards, with the exception of the TBBPS.

The TBBPs failed to start following S/D board reloading. The SOS took manual action to restart the TBBPS. Further investigations into the failure to start revealed that the handswitches for the pumps had been placed in the A-Auto position in accordance with procedure. With the handswitch in this position, the pumps will not start upon actuation of the blackout relays. The handswitch position described by procedure was found to be incorrect relative to design.

During the time that the S/D boards were without power, a control power alarm was received on D/G 1A-A and a low lube oil pressure alarm was received on the four D/Gs. The low lube oil pressure alarm was expected for the event and was cleared. The control power alarm was reviewed and found to be the result of the test pushbutton being depressed or momentarily shorted. This condition was evaluated and no D/G operability concerns were identified.

During this transient, Unit 1 RCS temperatures remained above the analysis value of 540 degrees F, relative to S/D margin. The FSAR or technical specification (TS) requirements were not violated.

During this transient, Unit 2 RCS temperatures dropped to approximately 537 degrees F. The cooldown on Unit 2 was greater than Unit 1 because of a delay in taking manual control of AFW as described in Section F. A boration of 10 gpm through the blender was initiated and was replaced by RWST water on VCT swapover. Calculations show that approximately 600 ppm boron was required to maintain adequate S/D margin for an RCS temperature of 537 degrees F. Boron concentration before the event was 735 ppm. The FSAR or TS requirements were not violated.

Unit 1 pressurizer level was constant at approximately 57 percent before the event, sharply decreased to 33 percent (expected for the reactor trip while under load), and then settled to approximately 29 percent. The 29 percent level was reasonable for pressurizer level with two CCPs running, and letdown initially isolated. Actual and programmed levels returned to agreement upon stabilization of the plant and return to normal hot standby conditions.

Unit 2 pressurizer level was constant at approximately 59 percent before the event and then decreased upon the reactor trip to approximately 33 percent. Level subsequently increased to approximately 48 percent. Letdown was isolated when both CCPs were stopped as a result of S/D board load stripping and again later when both CCPs were stopped by operator action. Actual levels, posttrip, remained well above programmed levels principally because of the operation of both CCPs and the duration for which letdown was isolated. No challenges to any FSAR analysis limits were observed.

Except for a temporary upward trend on the Unit 1 upper containment radiation monitors, no perturbations were observed in containment pressure, temperature, or radiation. The exact cause for the increase in the particulate count rate could not be determined. Two plausible explanations of the rate increase are: (1) preexisting particulate activity that was disturbed upon restart of the radiation monitor (RM) pump, or (2) the restart of the upper compartment cooling fans after reloading on the S/D boards. Additionally, three Unit 1 lower ice condenser doors opened during the transient. The most likely cause for ice condenser door operation is the restart of the three lower compartment coolers (LCCS) after loading back on the S/D boards. The Unit 2 doors did not open; however, only two LCCs were restarted.

When the Unit 2 CCPs started, the red low oil pressure light illuminated on each of the pump handswitches. These low oil pressure lights remained illuminated when the CCPs were running. These lights cleared after the blackout relays were reset. An operator was dispatched to check the oil pressure on the CCPs locally. When he arrived, one CCP was in service and the oil pressure for that pump was normal. Troubleshooting verified that the circuitry associated with the low oil pressure light was installed in accordance with design requirements, and the auxiliary oil pump and light for the CCP worked as designed. An independent review was performed and no existing equipment deficiency was identified that could impact CCP operability.

III. CAUSE OF EVENT

A. Immediate Cause

The immediate cause of the event (ESF and RPS actuations) was an internal fault with the C-phase of the PCB that was being placed in service. This fault dropped bus voltages for both units through the intertie transformer below the undervoltage protection setpoints.

The immediate cause of the LCO 3.0.3 entry was the loss of CCP suction and the removal of both CCPs from service.

B. Root Cause

The root cause analysis for the internal fault of the PCB determined that the fault was the result of particle contamination of the gas insulating system. During breaker timing tests, the breaker appears to have been "pumped" (the breaker was in motion toward opening with a closure signal initiated). The pumping action results in the production of metallic particles that allowed flashover in the resistor assembly area. Breaker timing test methodology did not provide guidance to ensure that breaker pumping would be prevented. The system configuration and testing methodology of bypassing primary breaker protection was the cause of the extent of subsequent undervoltage conditions on both units. This undervoltage condition resulted in activation of undervoltage protection, precipitating the dual unit trips, load shedding, and D/G start.

Although minimum TS staffing was maintained, effective control of the transient for Unit 2 was hampered by the fact that only one licensed operator was on duty. The other scheduled operator had called in sick and the Operations superintendent made the decision not to hold another operator over. As a result of the extent of the specific event (i.e., reactor trips and undervoltage on both units combined with a major upset to the offsite electrical distribution system), other MCR personnel were not available to assist in the Unit 2 response. During the transient, the Unit 2 operator was delayed in securing the secondary plant and taking manual control of the MDAFW LCVs. This action precipitated the unit cooldown, boration evolution, and eventual LCO 3.0.3 entry.

C. Contributing Factors

The removal of primary breaker protection relays (trip cut-out relays) before placing the new PCB in service prevented early breaker actuation (3.5 cycles) for protection of switchyard busses and the generating units. Before placing the breaker in service, an assessment was made for disablement of relay protection, and it was determined that failure of the new PCB was highly unlikely. This was founded on successful factory and field testing. Also, it was considered that the potential for an intertie trip resulting from miswiring or improper phasing might exist without the trip cut-out relays removed. It is concluded that the testing methodology did not appropriately assess potential risks involved and that alternatives were not adequately evaluated. Communication between the Transmission and Power Service organization and site management was inadequate for assessing acceptability of inherent risk.

Additionally, the testing documents did not contain sufficient detail for site management to understand or assess the potential risks involved.

The Unit 2 operators failed to follow procedures regarding alignment of the emergency boration path. This set up the sequence of events ultimately resulting in loss of CCP suction and removing both CCPs from service for approximately one minute. It also appears that operator error resulted in mispositioning the VCT and RWST outlet valve handswitches directly resulting in loss of CCP suction. Staffing factored into key decisions made during these evolutions as described in Section II.F. The magnitude of the event, compounded by having only one licensed operator, resulted in challenges to the operators (RO and ASOS). From a human factors standpoint, this situation heightened the potential for inadvertent/unrecognized operator action "in the heat of the battle." Investigation results conclude that the RWST handswitches were incorrectly left in A-Auto and that inadvertent operator action appears to have resulted in reclosure of the VCT valves. While not recalled, the action could have taken place under the urgency/pressure of the situation and not have been consciously recognized. While the effect of minimum staffing on this event was apparent, it is considered that recovery evolutions could have been successfully performed had procedures been explicitly followed.

IV. ANALYSIS OF EVENT

A C-phase to ground fault on the 500-kV system caused both Units 1 and 2 to trip. The fault caused the C-phase voltage in the 500-kV switchyard to drop to zero and the 161-kV switchyard C-phase voltage to dip to approximately 50 percent. The fault caused the 161-kV voltage to dip because of the intertie transformer being in service at the time of the fault. The intertie transformer ties the 161-kV switchyard to the 500-kV switchyard; therefore, the 161-kV switchyard was supplying power to the fault, which caused its voltage to dip. With a fault of this nature and the intertie transformer in service, the 161-kV switchyard responded as expected. The reduced voltage on both the 500-kV and 161-kV switchyards is reflected back to the auxiliary power system (APS). The undervoltage relays on the RCPs initiate a reactor trip signal in seventeen and one-half cycles when the voltage goes below 5022V (approximately 73 percent). Therefore, each unit's reactor protection system responded to the degraded voltage and tripped. The undervoltage relays on the 6.9-kV S/D boards' normal feeder breakers trip the breakers if the voltage dips to 80 percent or less for one-half second. This would cause the 70 percent loss-of-voltage relays to start the D/Gs and sequence the loads onto them. The RCPs did not trip since an underfrequency signal of less than 56 Hertz on the RCP bus did not occur.

The Unit 1 unit boards fast transferred from the USST to the CSST because of the loss of the 500-kV switchyard. The Unit 2 boards did not transfer immediately from the USSTs to the CSSTs since there was not a fault in the Unit 2 main generator or any of the 161-kV sources tied to the generator. The Unit 2 unit boards transferred approximately 30 seconds after the reactor tripped as designed. The reaction of the APS to the undervoltage for 90 cycles was as expected and as designed. The response to the event is part of the design basis for SQN.

In addition, both units' TBBPs were shed following the loss of offsite power indication as designed. However, upon D/G reloading, they were not reloaded because of the position of the handswitches. The RCP thermal barrier heat exchanger functions as a backup to the seal injection system to ensure that hot

RCS water will not enter the RCP bearings and seals in the event of a loss of seal injection. While the thermal barrier heat exchanger provides a backup function; operation of the RCPs with reduced or no CCS flow to the thermal barrier heat exchanger will not result in damage to the RCP seals or bearings as long as normal seal injection flow is maintained. The operator recognized during the event that the TBBPs had not restarted and waited until D/G loading could be verified to start the TBBPS. Therefore, the operator at this point maintained the primary cooling source for the seals (i.e., charging pumps). Later in this event, both CCPs for Unit 2 were removed from service approximately 20 seconds before manual start of the TBBPS.

Evaluation indicated that there is approximately 50-55 gallons of cold water contained in the shaft alley area of the reactor coolant pumps. With a nominal leak-off rate of 3 gpm, it is estimated that it would take 10 to 20 minutes for hot RCS water to contact the seals. Although there would be some increase in temperature of the water in the seal area as it leaks through, any loss of flow for a period of less than 10 minutes is not considered to have adverse effects on seal condition or performance. The period of time without normal charging seal injection or normal thermal barrier cooling was approximately 20 seconds. No TBBP high-temperature alarms were present during this event. There was no RCS inventory loss outside of the RCS or to interfacing systems. The capability to provide adequate long-term core cooling remained unimpaired.

Unit 1 was S/D and stabilized in Mode 3 with no other anomalies. Plant parameters associated with the trip function responded as designed and operator actions were considered appropriate via the emergency procedures.

During the event response, Unit 2 RCS T sub avg trended below 540 degrees F and emergency procedures required emergency boration to compensate for potential reduction in S/D margin. Given the actual amount of boration required and the fact that all rods inserted upon reactor trip, no challenge to the FSAR or TS requirements occurred.

During the loss of power, low oil pressure indications were received in the MCR for both of the Unit 2 CCPS. Under S/D board load sequencing, the CCP auxiliary oil pump is started immediately when power is returned to the S/D board. The CCP starts two seconds later regardless of oil pressure. Assuming that the low oil pressure indicating lights were a true indication that no auxiliary oil pump start had not occurred, the effects of operating the CCPs with low oil pressure were evaluated. It was concluded that:

1. The low oil pressure condition would have only existed during pump startup. Once the pump was up to full speed, sufficient oil pressure would have existed to adequately lubricate the pump bearings.

2. If one of the charging pumps was in normal operation when the event occurred, sufficient bearing lubrication would have been provided if the time interval for which the charging pump was without power was short (i.e., within the start-up and wind-down times). Sufficient pressure would have existed to bathe the pump bearings with lube oil.

An investigation was performed on the lube oil light anomaly and no equipment deficiency was found.

In conclusion, primary safety systems responded as designed during this transient. Adequate S/D margin, well within prescribed safety analysis limits, was maintained for both units. No primary safety system component was faulted or degraded during this event. Safety parameters remained within the design basis of the plant. This event did not result in adverse consequences to plant personnel or the public.

V. CORRECTIVE ACTION

A. Immediate Corrective Actions

The control room staff promptly diagnosed the plant conditions and took actions to stabilize the unit in a safe condition. Additionally, the motor-operated disconnects for PCB 5058 were opened, which completely isolated the PCB from the bus. Follow-up investigations were initiated for identified anomalies and appropriate corrective actions were identified.

B. Corrective Action to Prevent Recurrence

The transmission and Power Service field test manual has been revised to provide specific guidance for breaker timing testing. This guidance ensures that the field timing test does not bypass the anti-pumping circuit within the breaker. Additional controls have been established to strengthen communications between the Transmission and Power Service organization and the site, increase plant visibility of switchyard work, implement improved risk assessment for disablement of protective relays, and change testing methodology to minimize disablement of protective relays.

Administrative controls have been implemented to ensure that control room staffing will be maintained at two ROs for each operating unit. The need for additional training at diluted staffing levels (i.e., common MCR staffing such as shift technical advisor/SOS not available) is being evaluated.

The operators involved in the Unit 2 recovery evolutions have been counselled on procedure adherence and are providing the lessons learned from this event to other operators. Operations management has met with the operator crews and discussed this event focusing on procedure adherence and operator actions outside procedural steps.

The procedure used to position the TBBP switches was revised to be in agreement with design requirements. Other MCR handswitch positions were reviewed against design requirements to ensure proper positioning. A broader effort is in progress to provide overall improvements in the control of configuration of plant equipment. This effort includes specific improvements in the configuration control process, review to properly identify components needing configuration control, and to ensure that appropriate administrative controls are in place to reflect the required configuration. This broad effort is complemented by a field configuration verification.

The lube oil light anomaly on the Unit 2 CCP lube oil system was investigated. The investigation recommendations are under evaluation for further action.

VI. ADDITIONAL INFORMATION

A. Failed Components

The failed component of this event was an Asea Brown Boveri 550-PM power circuit breaker.

B. Previous Similar Events

A review of previous events did not identify an LER associated with failure to provide adequate relay protection during breaker testing, VCT isolation/CCP suction isolation, or operator staffing. No additional previous events were identified relative to operator error or failure to follow procedures during a transient. A previous event (LER 50-328/88010) was identified associated with an operator taking the CCP to the P-T-L position. In that event, the responsible RO did not recognize that placing the CCP handswitch in the P-T-L position would result in the CCP being inoperable during plant operation in Mode 3. Two LERs (50-327/92018 and 92025) were identified that addressed single system/component failure affecting both units. Those LERs provided information on water intrusion into the station non-essential control air system and station air compressor selector-switch failure. The causes and corrective actions of those events would not have prevented the event described by this LER. LERs were identified (LERs 327/92006, 90009, and 328/90009) associated with procedure noncompliance involving failure to properly verify RCS flow, failure to adhere to a precaution resulting in an automatic start of the AFW system, and failure to properly implement a surveillance requirement. The broader issues of human performance and control of work are being evaluated under the site improvement plan that is currently being developed.

VII. COMMITMENTS

None.

Figure omitted. (no title available)

B.19 LER Number 328/92-010

Event Description: EDG Removed from Service with RHR Pump Inoperable

Date of Event: July 17, 1992

Plant: Sequoyah Nuclear Plant, Unit 2

B.19.1 Summary

During performance of a surveillance procedure on the 2B-B Residual Heat Removal (RHR) pump, it was found that the miniflow control valve continuously cycled open and closed when it should have remained opened. While the pump was inoperable, the 2A-A emergency diesel generator (EDG) was inoperable for 17 h and the 2A-A centrifugal charging pump was inoperable for 6 h. The conditional core damage probability estimated for this event is 8.6×10^{-4}. The relative significance of this event compared to other postulated events at Sequoyah, Unit 2 is shown in Fig. B.37 Fig. B.38.

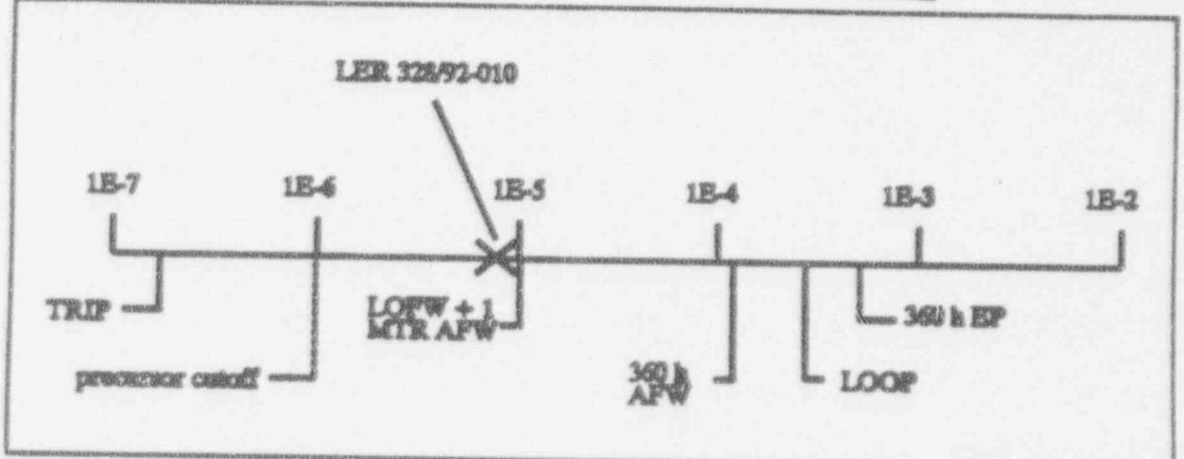

Fig. B.38. Relative event significance of LER 328/92-010 compared with other Sequoyah 2 events

B.19.2 Event Description

On July 17, 1992, with the unit at 100% power, a quarterly surveillance procedure on the 2B-B RHR pump was conducted. During the test, it was discovered that the pump's miniflow line motor control valve was continuously cycling open and closed when it should have remained open.

Further investigation revealed that the valve had been miswired on July 1, 1992, during performance of the flow switch quarterly preventive maintenance procedure. Between July 1, 1992 and July 17, 1992, there were 10 instances where Train A safety equipment had been out of service. Only two of these instances were of a significant duration; EDG 2A-A was out of service for 17 h, and centrifugal charging pump (CCP) 2A-A was out of service for 6 h.

The wiring for the other RHR trains was verified to be correct.

B.19.3 Additional Event-Related Information

The Sequoyah Units have miniflow lines for each of the RHR pumps. This flow path consists of the pump, a flow sensor, the RHR heat exchanger, and a recirculation line that returns to the pump suction. The recirculation line contains a motor-operated flow control valve that varies its position, based on the pump discharge flow signal, to maintain total pump flow between 500 and 1500 gal/min. Manual control and indication of the valve's position is available in the control room.

During an accident, the pump would be aligned for reactor coolant system (RCS) injection. However, the pump would be in the recirculation mode until RCS pressure drops below the pump deadhead pressure, or the system is realigned to the safety injection pump suction during the recirculation phase.

The valve does not have any thermal overloads and may fail after 15 min of continuous operation. With the valve closed and RCS pressure greater than the RHR pump deadhead pressure, insufficient flow through the pump results, which could possibly damage the pump because of overheating. With the valve fully open, flow to the RCS would be insufficient to ensure accident mitigation. Because the valve continuously cycled opened and closed, the actual time to failure of the RHR pump is more difficult to predict.

The two CCPs fulfill part of the emergency core cooling system (ECCS) function. The discharge pressure of the pumps (2670 psig) is greater than normal RCS pressure. The two high pressure safety injection (HPSI) system pumps have a discharge pressure of 1650 psig. All four pumps are used during initial injection and during long term recirculation cooling.

B.19.4 Modeling Assumptions

The event was modeled assuming the 2B-B RHR train and the 2A-A EDG are inoperable for 17 h. The Accident Sequence Precursor (ASP) models do not account for separate high head and intermediate head systems that Sequoyah uses for the ECCS function. The models have a single high pressure injection system. Therefore the centrifugal charging pump (CCP) inoperability was modeled as high-pressure injection system failure. This is equivalent to rendering the CCP and HPSI pump in the same train inoperable.

Three cases were run. For all cases, one train of high-pressure recirculation was inoperable because of the RHR pump failure. The first two cases were run for the EDG inoperability. The first was for the loss-of-offsite power (LOOP) initiator and the second was for the transient and loss-of-coolant (LOCA) initiators. For the LOOP case the equipment associated with the train 2 EDG is rendered inoperable due to loss of electrical power. For the other two initiators, transients and LOCAs, only the EDG is inoperable since the associated equipment will receive power from offsite. The third case was run for the CCP unavailability. In this case one train of high pressure injection, recirculation and feed and bleed are inoperable due to the loss of the CCP, while the other recirculation train is inoperable due to the RHR pump being inoperable.

B.19.5 Analysis Results

The conditional probability of core damage estimated for this event is 8.6×10^{-6}. This consists of 8.3×10^{-6} for the EDG inoperability and 6.3×10^{-6} for the CCP inoperability. It should be noted that since the CCP inoperability was modeled as an inoperability of both the CCP and HPSI pump in the same train, the result is very conservative for this case. The dominant sequence, highlighted on the event tree in Fig. B.39, involves a LOCA followed by the failure of high pressure recirculation.

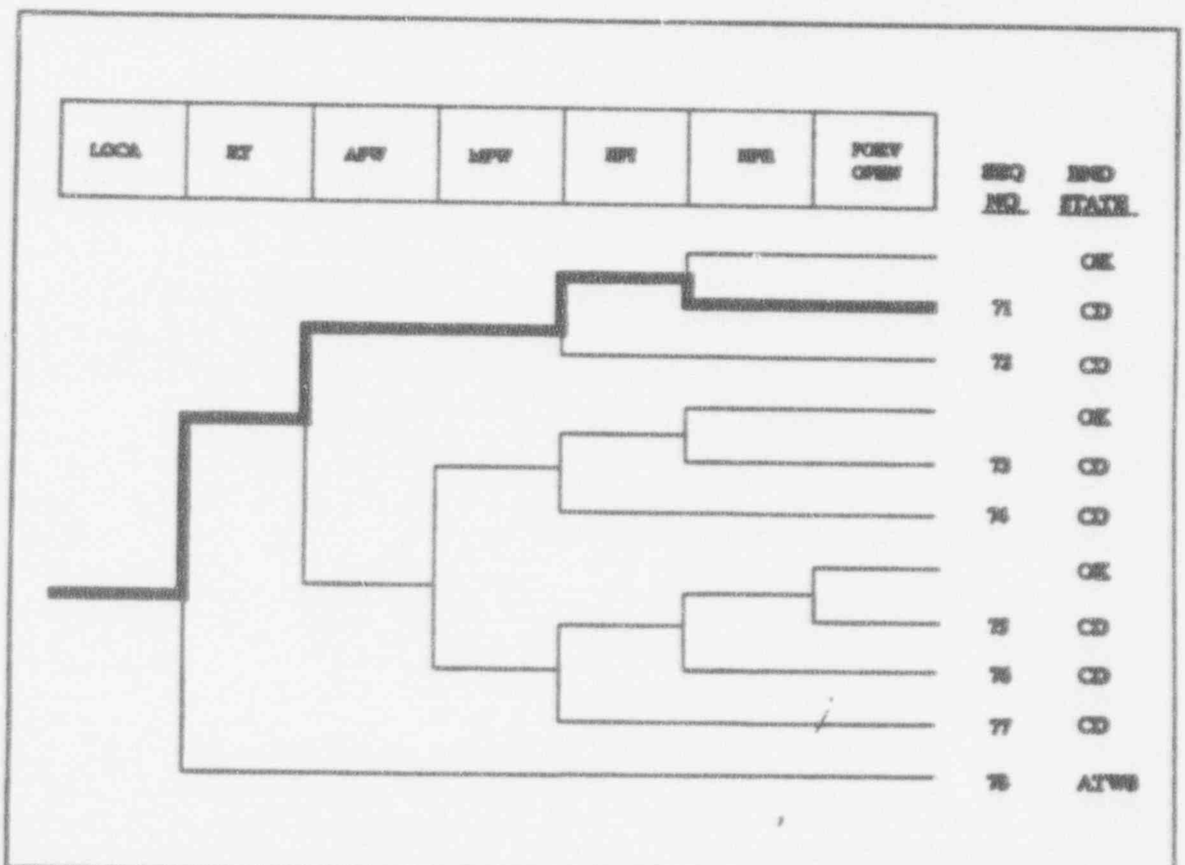

Fig. B.39. Dominant core damage sequences for LER 328/92-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 328/92-010
Event Description: EDG removed from service with 1 RHR pump inoperable (LOOP only)
Event Date: 07/17/92
Plant: Sequoyah 2 (Case 1)

UNAVAILABILITY, DURATION= 17 Hours
NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.5E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.0E-06
Total	2.0E-06
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	8.0E-07	4.2E-01
51	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	6.4E-07	4.2E-01
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	2.7E-07	4.2E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	9.4E-08	1.4E-01
44	loop -rt/loop -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	8.2E-08	1.4E-01
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.3E-09	4.2E-01
46	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	2.6E-09	4.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
44	loop -rt/loop -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	8.2E-08	1.4E-01
46	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	2.6E-09	4.2E-01
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.3E-09	4.2E-01
51	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	6.4E-07	4.2E-01
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	8.0E-07	4.2E-01
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	2.7E-07	4.2E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	9.4E-08	1.4E-01

** non-recovery credit for edited case

Event Identifier: 328/92-010

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk
compared to a similar period without the existing failures.

SEQUENCE MODEL: C:\asppra\models\pwrbseal.cmp
BRANCH MODEL: C:\asppra\models\sequoyah.sll
PROBABILITY FILE: C:\asppra\models\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.7E-06	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.0E-02	8.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02 > Failed		
AFW	3.8E-04 > 2.3E-03	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02 > Failed		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.7E-01	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
HPI	1.0E-03 > 1.0E-02	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Failed		
HPI(F/B)	1.0E-03 > 1.0E-02	8.4E-01	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Failed		
HPR/-HPI	1.5E-04 > 1.0E+00	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.5E-02 > Failed		
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 328/92-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 328/92-010
Event Description: EDG removed form service with 1 RHR pump inoperable (TRANS & LOCA only)
Event Date: 07/17/92
Plant: Sequoyah 2 (Case 2)

UNAVAILABILITY, DURATION= 17 Hours
NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.3E-02
LOCA	1.8E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.0E-08
LOCA	2.6E-07
Total	2.6E-07
ATWS	
TRANS	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
71 loca -rt -afw -hpi HPR/-HPI	CD	2.6E-07	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
71 loca -rt -afw -hpi HPR/-HPI	CD	2.6E-07	4.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: C:\asppre\models\pwrbseal.cmp
BRANCH MODEL: C:\asppre\models\sequoyah.sl1
PROBABILITY FILE: C:\asppre\models\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 328/92-010

Branch	System	Non-Recov	Opr Fail
trans	7.7E-04	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.0E-02	8.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02 > Failed		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.7E-01	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
hpi	1.0E-03	8.4E-01	
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
HPR/-HPI	1.5E-04 > 1.5E-02	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.5E-02		
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 328/92-010

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Sequoyah Nuclear Plant, Unit 2 DOCKET NO: 328

TITLE: Residual Heat Removal Pump Inoperable due to a Miswired Flow Switch for the Miniflow Valve

EVENT DATE: 07/17/92 LER #: 92-010-00 REPORT DATE: 08/17/92

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION: 50.73(a)(2)(i), 50.73(a)(2)(ii)

LICENSEE CONTACT FOR THIS LER: C. H. Whittemore, Compliance Licensing
TELEPHONE: (615) 843-7210

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On July 17, 1992, with Unit 2 in Mode 1 at 100 percent power operations, personnel performing a surveillance instruction identified a Residual Heat Removal (RHR) Pump 2B-B miniflow valve to be malfunctioning. Operations personnel declared the RHR pump inoperable, and Limiting Conditions for Operation (LCOs) 3.5.2 and 3.6.2.1 were entered at 1100 Eastern daylight time (EDT) on July 17, 1992. An investigation determined the problem to be an incorrectly terminated wire on the flow switch. The wire was correctly terminated and the flowswitch was functionally tested and returned to service. LCOs 3.5.2 and 3.6.2.1 were exited at 2249 EDT on July 17, 1992. A subsequent investigation into the event identified the root cause of the mislaid wire as being inattention to detail with an inadequate second-party verification. Maintenance personnel have been briefed on specific problems identified in this event. A less than adequate post maintenance test (PMT) also contributed to the event. On July 28, 1992, during the review of the event by the Plant Event Review Panel (PERP), it was discovered that a potential issue existed involving the RHR systems being outside of design basis of the plant. A one-hour telephone call notifying NRC of the issue was made at 1928 EDT on July 28, 1992.

I. PLANT CONDITIONS

Unit 2 was operating at approximately 100-percent reactor thermal power.

II. DESCRIPTION OF EVENTS

A. Event

On July 17, 1992, with Unit 2 in Mode 1 and 100-percent power, Operations personnel performing a quarterly residual heat removal (RHR) pump surveillance instruction, identified the 2B-B RHR (EIIS Code BP) pump (EIIS Code P) miniflow valve (EIIS Code FCV) to be malfunctioning. The miniflow valve was cycling open and closed instead of remaining open. Operations personnel declared the RHR pump inoperable, and Limiting Condition for Operation (LCOs) 3.5.2 and 3.6.2.1 were entered at 1100 Eastern daylight time (EDT). An investigation revealed the flow switch for the miniflow valve had been miswired on July 1, 1992. It should be noted that between July 1 and July 17, 1992, there were 10 instances where Train A safety equipment, i.e., centrifugal charging pump (CCP), safety-injection pump, diesel generator (D/G), and 6.9 kilovolt shutdown boards were inoperable for short periods of time. With the exception of two instances that are described in the following paragraph, the periods of inoperability were of short duration.

B. Inoperable Structures, Components, or Systems That Contributed to the Event

On July 8, 1992, D/G 2A-A was inoperable for 17 hours.
On July 9, 1992, CCP 2A-A was inoperable for six hours.

C. Dates and Approximate Times of Major Occurrences

June 30, 1992	Flowswitch quarterly preventive maintenance (PM) 0600 EDT was started.
June 30, 1992	A work request (WR) was written to replace a 0820 EDT flowswitch when a problem was found that prevented calibration and testing.
July 1, 1992	A WR was completed (flowswitch replaced). 0627 EDT
July 1, 1992	A PM was completed and the RHR pump was declared 0730 EDT operable.
July 8, 1992	Diesel Generator (D/G) 2A-A was inoperable - 0600 EDT LCO 3.8.1.1 was entered.
July 8, 1992	D/G 2A-A was operable - LCO 3.8.1.1 was exited. 2301 EDT
July 9, 1992	CCP 2A-A was inoperable for maintenance, LCOs 1841 EDT 3.5.2, 3.1.2.4, and 3.1.2.2 were entered.
July 10, 1992	CCP 2A-A was operable, and LCOs 3.5.2, 3.1.2.4, 0059 EDT and 3.1.2.2 were exited.
July 17, 1992	Quarterly operability surveillance instruction 1100 EDT test for RHR pump 2B-B identifies miniflow valve cycling open and closed. LCOs 3.5.2 and 3.6.2.1 were entered.
July 17, 1992	Miniflow valve flowswitch was found to be 1830 EDT miswired - the wiring was corrected.
July 17, 1992	LCOs 3.5.2.1 and 3.6.2.1 were exited for 2B-B 2249 EDT RHR pump.
July 18, 1992	The wiring on Unit 1 Train A and both trains of 0015 EDT Unit 2 RHR pump miniflow switches was verified as correct.
July 28, 1992	Following management's review of the event in 1928 EDT the Plant Event Review Panel (PERP) meeting, NRC was notified of the condition under 10 CFR 50.72 as potentially having placed the plant outside of design basis, because of Train A safety equipment and/or components out of service between July 1 and July 17, 1992.

D. Other Systems or Secondary Functions Affected

None

E. Method of Discovery

Operations personnel performing a quarterly operability test on the 2B-B RHR pump identified the abnormal operation of the miniflow valve. Investigation into the cause of the abnormal operation of the valve revealed the flowswitch that controls the miniflow valve had a field wire incorrectly terminated.

F. Operator Actions

Operations personnel identified that the miniflow valve was malfunctioning and took appropriate action by declaring the 2B-B RHR pump inoperable and for entering LCOs 3.5.2 and 3.6.2.1. A WR was initiated to investigate and troubleshoot the cause. After corrective action was concluded and the miniflow valve was functionally verified as being able to perform its intended function, LCOs 3.5.2 and 3.6.2.1 were exited.

G. Safety System Response

No safety system responses were required.

III. CAUSE OF EVENT

A. Immediate Cause

The immediate cause of this event was the incorrectly terminated wire for the miniflow valve, which rendered the 2B-B RHR pump inoperable. The inoperability of opposite train equipment contributed to the event.

B. Root Cause

There were three root causes for the event:

1. Inadequate self-checking and inattention to detail was the cause for the craftsmen to incorrectly terminate the field wire. There was only one wire removed and reterminated during the July 1, 1992, flowswitch calibration PM.
2. Secondary-party verification was not effectively implemented. The verifier did not identify that the field wire was terminated on the correct terminal. The terminal block was correctly labeled and the label corresponded to the procedure and drawing. The wire was misterminated on a terminal that was not labeled.
3. A third root cause for this event was that the postmaintenance test (PMT) for the maintenance activity was ineffective. The WR did not clearly specify requirements necessary to verify that the miniflow valve functioned properly after the flowswitch was replaced in conjunction with the PM.

The PMT as stated in the WR was to properly calibrate and functionally check the flowswitch. The ambiguity in the PMT led the craftsmen to belief that a system functional test or independent verification was not required.

IV. ANALYSIS OF EVENT

This event involves a wiring error that resulted in the miniflow recirculation valve cycling when the valve should have remained open.

The flowswitch that was miswired controls closure of the recirculation valve when the RHR pump discharge exceeds a setpoint of approximately 1,250 gallons per minute (gpm). (This setpoint accounts for instrument inaccuracies.) The basis for the valve closure is to ensure adequate flow goes to the core whenever reactor coolant system (RCS) pressures are low enough to allow RHR to inject.

The design logic requires the valve to be open at 500 gpm (decreasing) through the pump to protect the pump from heating damage, and for the valve to close at 1,500 gpm (increasing) to assure adequate flow to the reactor core for accident mitigation. The recirculation valve, which is motor operated, is part of the safety injection logic; therefore, it does not use thermal overloads. The actuator motor is rated for intermittent duty and can fail after approximately fifteen minutes of continuous operation. The pump recirculation requirement of 500 gpm is a continuous operation value. The continuous cycling of the valve ramped the flow from zero to approximately 750 gpm with each valve cycle. This may meet the cooling requirements for continuous flow through the pump, but the action puts a thrust cycle on the pump impeller and motor bearings that creates additional wear on the pump.

During an accident situation, the pump normally would be in recirculation mode during the injection phase of the accident. The pump is then used for net positive suction head (NPSH) boost during the recirculation phase until the RCS pressure drops below the pump deadhead pressure. With the recirculation valve open, the pump would operate normally and complete the accident mitigation task as designed.

The worst-case scenario involves a small break loss of coolant accident with the miniflow-valve motor failing in the fully closed position. Failing in the closed position, the RHR pump is subject to overheating and ultimate failure. This scenario, coupled with opposite train safety component unavailability, results in a condition outside design basis.

Further investigation and computer-simulated scenarios revealed that no damage would result from the valve cycling for approximately 25 minutes. It is fully expected that operators in the main control room would detect the abnormal operation from annunciators signaling the rapid change of position of the valve, and the fluctuation of the motor amperage. Upon detection, the RHR pump would then be turned off. This expectation was demonstrated by submitting the problem to operators during requalification training. These simulations did not cycle the miniflow valve, stopping the RHR pump relied on normal SI termination criteria contained in emergency procedures. The times ranged between 21 and 25 minutes before the RHR pump was removed from service. Therefore, the added indications of position status lights and motor amps should prompt the operators to earlier intervention.

V. CORRECTIVE ACTIONS

A. Immediate Corrective Actions

Operations personnel immediately entered LCOs 3.5.2 and 3.6.2.1 for Unit 2.

Operations personnel exited LCOs 3.5.2 and 3.6.2.1 for Unit 2 after the misplaced wire was correctly terminated and the functional test verified the miniflow valve performed as designed.

B. Corrective Actions to Prevent Recurrence

1. Wiring on the other miniflow switches for Unit 1 and Unit 2 was checked and verified as being correctly terminated.
2. The instrument PMs data packages associated with the RHR miniflow valve switches have been revised to require independent verification for wire connections and also for jumpers.
3. Maintenance craftsmen, planners, and procedure writers have been briefed on this event with an emphasis on the need for an adequate PMT or specifying an independent verification in lieu of a PMT.
4. Maintenance planners will be trained on the proper way to specify acceptance criteria for verifying that components can perform their intended functions. This will be accomplished by September 14, 1992.

VI. ADDITIONAL INFORMATION

A. Failed Components

None

B. Previous Similar Events

A review of the licensee event report data base was conducted to identify any previous or similar events, and if so, to determine if corrective actions had been unsuccessful in preventing recurrence. Several events were identified that were caused by or had contributing factors similar to those noted in the investigation of this event, i.e., inattention to detail, inadequate verification, and inadequate PMT. Actions have been taken in response to previous events to ensure that expectations of management were clearly conveyed, understood, and concurred with by working-level personnel. Following this event, an independent team was assembled to evaluate the verification and PMT processes and their implementation. Corrective actions from this evaluation will be pursued as part of the overall SQN performance improvement efforts.

VII. COMMITMENT

Maintenance planners will be trained on the proper way to specify acceptance criteria for verifying that components can perform their intended functions. This will be accomplished by September 30, 1992.

ASP Reactor Coolant Pump Seal LOCA Modeling for the Sequoyah LOOP
(LER 327/92-027, 12/31/92)

General LOOP Modeling

The ASP EVNTEVAL computer code is used to determine the conditional core damage probabilities (CCDPs) of events for the ASP program. For LOOP events the ASP BLACKOUT computer code is used to modify the following parameters used in the EVNTEVAL code:

- LOOP non-recovery probability
- seal LOCA probability (PWRs only)
- emergency power recovery (given no seal LOCA for PWRs)
- emergency power recovery given a seal LOCA has occurred (PWRs only)

To determine these values the ASP BLACKOUT computer code uses the following plant and event dependent data as inputs:

- Type of LOOP (Event dependent)
  - Plant Centered
  - Grid Related
  - Severe Weather Related
  - Extremely Severe Weather Related
- Core Uncovery Time (plant dependent)
- Battery Depletion Time (plant dependent)
- Diesel Generator Mean Repair Time (plant dependent)
- Reactor Coolant Pump Seal design (plant dependent - PWRs only)

The type of LOOP which is used is dependent on the type of fault that causes the LOOP. The frequency and duration of a LOOP event are dependent on the type of LOOP used in the evaluation. The LOOP types are listed above in decreasing frequency and increasing length. The seal LOCA probability for PWRs is determined using the attached figure which shows the cumulative seal failure probability distribution[1].

Seal LOCA Considerations for Sequoyah LOOP (LER 327/92-027)

Shortly after this event occurred, the licensee determined a conditional core damage probability (CCDP) of 6.3E-3 for this event[2]. This value was based on the assumption that the reactor coolant pump (RCP) seals would fail whenever the thermal barrier booster pumps (TBBPs) and the charging pumps were simultaneously lost. During recovery from this particular event both of the TBBPs and the charging pumps were lost for a period of 21 s (The component cooling pumps continued to run and provide some flow to the thermal barrier heat exchangers). The CCDP value initially obtained by the licensee was highly dependent on the seal failure assumption. Subsequently, they performed an analysis which demonstrated that the flow to the thermal barrier heat exchangers from the Component Cooling Pumps

1 Based on NUREG-1150.

2 The information was presented to the NRC by the licensee at a March 3, 1993 enforcement conference. It was provided to ORNL by the NRC for consideration during this evaluation.

alone is sufficient to prevent seal failure. Thus it was concluded by the licensee that the assumption of seal failure was overly conservative. Reevaluation by the licensee determined a CCDP value of 1.0E-4.

The ASP event evaluation methodologies do not consider RCP seal failure likely until seal cooling (component cooling and seal injection) have been lost for about an hour[3]. In this event, seal cooling was provided throughout the event. During the 21 s when the TBBPs and charging was lost, thermal barrier cooling flow was reduced to 70% of the normal value (based on the licensee analysis). This flow was provided by the component cooling pumps. The TBBPs were restarted 21 s after they were stopped and one charging pump was restarted 41 s later. Therefore the reduction in seal cooling for a brief period time (21 s) would not impact the seal failure probability used in the ASP evaluation of this event. This is consistent with the reevaluation of the event by the licensee.

3 Based on NUREG - 1150 data.