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Beaver Valley Power Station, Unit No. 1
Docket No. 50-334 License No. DPR-66
LER 97-005-00

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

In accordance with Appendix A, Beaver Valley Technical Specifications, the following Licensee Event Report is submitted:

LER 97-005-00, 10 CFR 50.73(a)(2)(i), 10CFR50.73(a)(2)(iv), "Inadvertent Operation of 345 KV Bus Backup Timer Relay Results in Dual Unit Reactor Trips."

Ronald L. LeGrand
R. L. LeGrand

IE22

LB

Attachment

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NRC FORM 366 (4-95) | U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Beaver Valley Power Station Unit 1	05000334	1 OF 7

TITLE
Inadvertent Operation of 345 KV Bus Backup Timer Relay Results in Dual Unit Reactor Trips

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
03	19	97	97	005	00	04	14	97	Beaver Valley Power Station Unit 2	05000412

OPERATING MODE (9)	1		20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	100%		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER
			20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		(Specify in abstract below and in Text NRC Form 366A)
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (include Area Code)
R. L. LeGrand, Vice President Nuclear Operations and Plant Manager	(412) 393-7622

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	BA	V	E334	Y						

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (if yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limited to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On March 19, 1997, at approximately 0606 hours, while operating at 100% nominal power, Beaver Valley Power Station (BVPS) Units 1 and 2 experienced simultaneous reactor trips due to the opening of the output breakers for both units. The event was initiated by an inadvertent operation of the Bus Backup Timer relay on the #3-345 KV bus in response to a phase to ground fault which occurred on the Ohio Edison system's Mansfield-Hoytsdale 345 KV line. An Emergency Notification System (ENS) report was made pursuant to the requirements of 10CFR50.72(b)(2)(ii) at 0922 hours on March 19, 1997. This event is also reportable pursuant to the requirements of 10CFR50.73(a)(2)(i) and 10CFR50.73(a)(2)(iv).

Operations responded to the dual unit trip by entering the appropriate plant Emergency Operating Procedures (EOPs). Stabilization of Unit 1 was completed at approximately 0608 hours on March 19, 1997, with the mitigating equipment operating in the expected manner to control the transient. Unit 1 Emergency Diesel Generator (EDG) EE-EG-1 started due to momentary undervoltage on 4 KV emergency bus AE, but was not required to load, since bus AE did not lose power. Unit 1 EDG EE-EG-2 did not start and was conservatively declared inoperable as of 0606 hours on March 19, 1997, until testing was completed which demonstrated that the undervoltage condition on bus DF was of insufficient duration to start EDG EE-EG-2. Both Unit 1 EDGs functioned as designed.

Stabilization of Unit 2 was completed at approximately 0610 hours on March 19, 1997, with the mitigating equipment operating in the expected manner to control the transient with the exception of "B" Steam Generator Auxiliary Feedwater (AFW) flow indicating lower than normal. Subsequent investigation indicated that this was due to the concurrent event failure of a check valve in the "B" AFW injection header. The "B" AFW injection header was declared inoperable at 1206 hours on March 19, 1997, and, pursuant to the requirements of Technical Specifications (TS), Unit 2 commenced a boration and cooldown towards Mode 4 at 1210 hours on March 19, 1997. An update to the ENS notification pursuant to the requirements of 10CFR50.72(b)(1) (i)(A) was made at 1302 hours. Unit 2 entered Mode 4 at 1731 hours on March 19, 1997. Evaluation of the AFW check valve failure pursuant to the requirements of 10CFR21 is ongoing.

The root cause of the dual unit trip event was inadequate implementation of design specifications and design review which resulted in incorrect wiring between the Unit 2 Static Breaker Failure Unit Relay and its associated Static Relay Unit Bus Backup Timer. Both units were safely shut down in accordance with the applicable procedures. There were no implications to the health and safety of the public as a result of this event.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

PLANT AND SYSTEM VERIFICATION

Westinghouse Pressurized Water Reactor (PWR)

345 KV Switchyard Static Relay Unit (SRU) Bus Backup Timer Relay 62-J143 {FK/62/A500}

345 KV Switchyard Static Breaker Failure Unit (SBFU) Relay 50-J140 {FK/50/A500}

AFW to Steam Generator Nozzle Check Valves 2FWE-99, 2FWE-100, and 2FWE-101, Enertech Model DRV-Z {BA/V/E334}

Unit 1 Emergency Diesel Generator (EDG) EDG EG-EE-1 {EK/GEN/E147}

Unit 1 Emergency Diesel Generator (EDG) EDG EG-EE-2 {EK/GEN/E147}

*Energy Industry Identification System (EIIS), component function identifier, and manufacturer codes appear in the text as (SS/CCC/MMMM).

CONDITION PRIOR TO OCCURRENCE

Unit 1: Mode 1, 100% Reactor Power
Unit 2: Mode 1, 100% Reactor Power

DESCRIPTION OF EVENT

On March 19, 1997, at approximately 0606 hours, while operating at 100% nominal power, Beaver Valley Power Station (BVPS) Units 1 and 2 experienced simultaneous reactor trips due to the opening of the output breakers for both units. The event was initiated by an inadvertent operation of the Bus Backup Timer relay 62-J143 {FK/62/A500} on the #3-345 KV bus. A phase to ground fault occurred on the Ohio Edison system's Mansfield-Hoytsdale 345 KV line which was detected by the BVPS switchyard protection equipment, and began shedding various loads through the opening of line breakers. An Emergency Notification System (ENS) report was made pursuant to the requirements of 10CFR50.72(b)(2)(ii) at 0922 hours on March 19, 1997.

Operations responded to the dual unit trip by entering the appropriate plant Emergency Operating Procedures (EOPs). Stabilization of Unit 1 was completed at approximately 0608 hours on March 19, 1997, with the mitigating equipment operating in the expected manner to control the transient. Unit 1 Emergency Diesel Generator (EDG) EE-EG-1 {EK/GEN/E147} started due to momentary undervoltage on 4 KV emergency bus AE, but was not required to load, since bus AE did not lose power. Unit 1 EDG EE-EG-2 {EK/GEN/E147} did not start and was conservatively declared inoperable as of 0606 hours on March 19, 1997, until testing was completed which demonstrated that the undervoltage condition on bus DF was of insufficient duration to start EDG EE-EG-2. Both Unit 1 EDGs functioned as designed.

Stabilization of Unit 2 was completed at approximately 0610 hours on March 19, 1997, with the mitigating equipment operating in the expected manner to control the transient with the exception of "B" Steam Generator Auxiliary Feedwater (AFW) flow indicating lower than normal. Subsequent investigation indicated that this was due to the concurrent event failure of check valve 2FWE-100 {BA/V/E334} in the "B" AFW injection header. A later inspection of the check valve revealed that the seat ring had moved out of its design position, partially blocking the flow stream. The "B" AFW injection header was declared inoperable pursuant to the requirements of Technical Specification (TS) Limiting Condition for Operation (LCO) 3.7.1.2.b at 1206 hours on March 19, 1997. The action statement for TS LCO 3.7.1.2.b requires that the plant be in at least hot standby (Mode 3) within 6 hours and in hot shutdown (Mode 4) within the following six hours. Hence Unit 2 commenced a boration and cooldown towards Mode 4 at 1210 hours on March 19, 1997. An update to the ENS notification was made at 1302 hours. Unit 2 entered Mode 4 at 1731 hours on March 19, 1997.

CAUSE OF EVENT

The root cause of the dual unit trip event was inadequate implementation of design specifications and design review which resulted in incorrect wiring between the Unit 2 Static Breaker Failure Unit Relay and its associated Static Relay Unit Bus Backup Timer.

Evaluation of the Unit 1 Emergency Diesel Generator (EDG) operation during the event demonstrated that both diesel generators functioned as designed. Due to design differences in autostart circuitry and the difference in duration of the undervoltage signals on their respective emergency buses, EDG #1 autostarted and EDG #2 was not required to start.

The root cause of the reduced AFW flow in the "B" injection header was a thermal gradient across the valve body experienced as relatively cold AFW was injected into the system through the hot valve. This allowed the seat ring to lose its interference fit within the valve body bore and move into the flow stream, partially blocking AFW flow.

ANALYSIS OF EVENT

Dual Unit Trip

On March 19, 1997, the Vice-President of Nuclear Operations assigned an Event Review Team (ERT) for each unit. Team members were assigned from various departments to collect and review information and thoroughly investigate this event in accordance with Site procedures. The Nuclear Engineering Department (NED), with the support of the Relay Group, evaluated the cause of the 345 KV system disturbance and performed the associated root cause analysis. The following dual unit trip analysis information was provided by the ERT Report.

Prior to the event on March 19, 1997, BVPS Units 1 and 2 were operating at 100% nominal power supplying power to the 345 KV electrical grid. The outputs of 345 KV buses #3 and #4 were connected to buses #5 and #6, respectively, which is the normal configuration. The primary line protection for the Mansfield Substation that includes the Mansfield-Hoytdale 345 KV line was out of service due to a communications difficulty. The substation's secondary line protection was in service.

At 0606 hours, a phase to ground fault occurred on the Ohio Edison system, Mansfield-Hoytdale 345 KV line. The fault was detected by BVPS switchyard protection equipment which began shedding various loads through the opening of line breakers. During the 13.5 cycle time that the fault was detected, the following eight (8) BVPS switchyard 345 KV breakers opened:

PCB-341	PCB-331	PCB-362	PCB-333
PCB-366	OCB-93	PCB-346	PCB-352

The opening of Unit 1 and 2 output breakers PCB-331, PCB-341, PCB-352 and PCB-362 resulted in the concurrent unit trips.

The BVPS bus protection scheme consists of differential relays, Static Breaker Failure Unit (SBFU) relays and Static Relay Unit (SRU) timers. The SBFU relays and SRU timers are used as part of a backup protection scheme and are designed to operate on the detection of a stuck (failed) breaker. This combination of relays and timers serves as a backup to the various bus differential relays. Normally, the bus differential relays operate for a fault on the affected bus by clearing (opening) breakers that feed the affected bus. However, if any of the breakers fail to trip, the breaker failure scheme with SBFU relays and SRU timers is used.

The breaker failure scheme assumes one breaker that feeds the affected bus has failed to clear. If so, it then trips the next breaker(s) in the circuit in a continuing attempt to isolate the fault from the bus. The backup protection scheme operates with a time delay following bus differential relay initiation. The SRU timer is automatically reset if the detected fault is cleared within the established time delay period. The breaker failure scheme consists of one SBFU relay for each breaker on the bus and one SRU Bus Backup Timer for the entire bus. The SRU Bus Backup Timer has two (2) inputs for each breaker on the bus as sensed through each individual SBFU relay. These inputs consist of a differential relay operation and a breaker overcurrent condition. If the SRU timer times out and the fault has not yet been cleared by the differential relays, then the timer will operate.

Operation of the timer will, in turn, trip the next breaker(s) in the circuit for any of the lines on the bus that are indicating an overcurrent condition in an attempt to isolate the fault and an apparent stuck breaker.

Various sequence of events logs were reviewed by the ERT to determine if unexpected conditions existed prior to, or in response to, the plant trips at Units 1 and 2. In addition, the Relay Group performed an investigation which included the switchyard fault recorder and conducted equipment tests to determine the reasons for the unanticipated switchyard breaker and relay actuations.

The investigation identified a wiring discrepancy with the current interlock of the #3-345 KV Bus Backup Timer. This discrepancy involved the incorrect wiring between the Unit 2 SBFU current interlock relay (50-J140) {FK/50/A500} for PCB-352 and its associated SRU timer (62-J143). Two (2) outputs of the SBFU were cross-connected. This cross-connection resulted in a current interlock inputting into the relay portion of the timer. The relay output of this SBFU relay was connected to the current input of the SRU timer and the current output of the SBFU relay was connected to the relay input of the SRU timer.

With the SRU timer scheme wired with these SBFU outputs reversed, two (2) conditions were needed for the timer to operate. First, there needed to be a current condition greater than the setpoint of the SBFU relay (providing a false differential input to the SRU timer). Second, a sufficient fault current duration was needed to operate the timer. The ground interlock setting of the SBFU relay was set for 400 amps. The measured ground current on the Mansfield-Hoytdale line at the time of the fault was approximately 2800 amps. The SRU timer was set for eight (8) cycles. With a fault duration of 13.5 cycles, both conditions were met for the timer to operate.

The backup protection scheme for Unit 2 was wired in accordance with wiring diagrams that were issued in 1984. The scheme was checked satisfactorily when testing each breaker's interlock individually, which is the typical testing mode for both trip checking and for routine relay calibration. Based on the results of the reviews and investigative efforts completed, the functions of the protection scheme operated during the event as would be expected, based upon the identified (incorrectly) as-installed wiring configuration.

As described above, when the fault on the Mansfield-Hoytdale line occurred, the primary line protection for the Mansfield Substation was out of service due to line communications difficulties. The secondary line protection was in service. The 13.5 cycle fault duration was the normal secondary line clearing time. Even with this line protection scheme, BVPS should not have tripped any of the eight (8) breakers.

The 345 KV bus backup protection scheme, as identified on the electrical schematic diagram, correctly identified the SBFU relay and SRU wiring connections. However, this wiring was not properly reflected in the associated electrical wiring diagram. The as-installed wiring configuration for the Unit 2, PCB-352 SBFU relay and SRU timer matched the (incorrect) wiring diagram. The design review process in effect at the time of installation did not detect the design errors between these two (2) diagrams.

Unit 1 Emergency Diesel Generator Operation

During the Unit 1 trip, EDG EE-EG-1 autostarted but EDG EE-EG-2 did not autostart. Subsequent review of the Sequence of Events Recorder (SER) showed an undervoltage diesel generator start permissive existed for 0.200 seconds on 4 KV bus AE (EDG EE-EG-1) and 0.166 seconds on 4 KV bus DF (EDG EE-EG-2). EDG EE-EG-2 was declared inoperable as of 0606 hours on March 19, 1997, because it appeared the EDG had failed to autostart.

The SER printout indicated that the undervoltage start permissive for EE-EG-2 did actuate, but for a very short period of time. The most probable cause for the diesel generator not to autostart, was that the start permissive actuated for too short a period of time, which did not allow all of the relays in the auto start circuit to actuate. In order to prove this hypothesis, functional testing of EDG EE-EG-2 undervoltage autostart circuit was performed on March 20, 1997.

The testing demonstrated that the start actuate time for EDG EE-EG-2 on Start Circuit No. 1 was 0.198 seconds and 0.194 seconds on Start Circuit No. 2. The 4 KV Bus DF undervoltage diesel generator start signal which existed during the plant trip on March 19, 1997, was 0.166 seconds. Based on the measured start actuate times being longer than the start signal which existed during

the plant trip, EDG EE-EG-2 should not have autostarted, and responded as designed in response to the plant conditions that existed during the plant trip transient.

Undervoltage autostart testing was also performed on EDG EE-EG-1 on March 22, 1997. The start actuate time for EDG EE-EG-1 on Start Circuit No. 1 was 0.170 seconds. The 4 KV Bus AE undervoltage diesel generator start signal which existed during the plant trip was 0.200 seconds. The start actuate time for EDG EE-EG-1 is faster that EDG EE-EG-2, due to one less relay in the start circuit. An interposing relay for Appendix R separation is used on EDG EE-EG-2 and not used on EDG EE-EG-1. Based on the measured start actuate time being less than the duration of the start signal which existed during the plant trip, EDG EE-EG-1 started, as designed, in response to the plant conditions that existed during the plant trip transient.

Unit 2 Auxiliary Feedwater Low Flow to "B" Steam Generator

Automatic AFW actuation occurred at Unit 2 due to the trip. Computer data showed that AFW flow to the "B" steam generator increased to at least 244 GPM initially and then decreased to 150 GPM with no changes in system controls. This low flow ultimately led to declaring the "B" AFW injection line inoperable and entry into Technical Specification 3.7.1.2.b at 1206 hours on March 19, 1997. The action statement for TS LCO 3.7.1.2.b requires that the plant be in at least hot standby (Mode 3) within 6 hours and in hot shutdown (Mode 4) within the following six hours. Unit 2 commenced a boration and cooldown towards Mode 4 at 1210 hours on March 19, 1997. One steam generator and one motor-driven AFW pump were sufficient to meet the decay heat removal requirements for the reactor trip event.

Low flow to "B" steam generator was indicated on two separate flow indicators (same flow element with different taps). The first computer data point for the "A" and "C" AFW lines was approximately 245 GPM, but then increased (as expected) to 280 GPM. All three AFW lines should indicate similar flows when all of the throttle valves (2FWE-HCV100A-F) are open. All AFW throttle valves were open during at least the first nine (9) minutes after AFW actuation. Control Room benchboard indication and local valve position indication verified the "B" steam generator throttle valves (2FWE-HCV100C and D) to be fully open, while "B" steam generator post-trip level recovery lagged behind the "A" and "C" steam generators. This indicated a possible flow restriction downstream of the junction of the "A" and "B" AFW headers.

A calibration check of one of the two flow instruments for the "B" AFW line was performed with satisfactory results, indicating that the flow instruments were accurate in indicating reduced flow. Reverse flow leakage was measured on AFW check valves 2FWE-99, 100, and 101 with satisfactory results. Flow elements 2FWE-FE100B and 2FWE-FE101B and adjacent piping were inspected for foreign material with a boroscope. No foreign material was identified, indicating that the obstruction was not in the flow elements or adjacent piping. Test pressure gauges were installed at key locations throughout the "B" AFW lines and the Motor Driven AFW Pump Full Flow Test was performed to determine the location of the restriction. This test indicated a high differential pressure between flow element 2FWE-FE101B and 2FWE-100 with flow of 180 GPM through the line. The test data pointed to 2FWE-100 as the likely cause of the flow restriction. Valve 2FWE-100 was removed from the system and inspected. The seat ring was observed to have backed out of its position approximately 9/16". The total travel of the disc and stem is 5/8". The backing out of the seat ring pushed the disc back 90% of its travel. Approximately 1/16" of disc travel was observed when stroked by hand indicating that the seat and disc were not bonded.

Check valves 2FWE-99 and 2FWE-101 were also removed from their respective lines and inspected. No significant anomalies were noted for these valves.

All three AFW check valves were sent to the vendor (Enertech) for further analysis and corrective modifications. Examination by Enertech confirmed that the seat for valve 2FWE -100 had moved out of its body position by 9/16". A 1/16" to 1/8" band was observed around the seat ring. This indicated that the seat ring may have moved out 1/16"-1/8", possibly as a result of the Unit 2 trip on January 6, 1997, which was the last time the AFW lines experienced flow. High magnification using microscopy (400X) indicated damage (spalling) to the seat ring, with the seating surface found to be work hardened. It is postulated that the disk experienced chatter after the March 19, 1997 trip when the seat moved the additional 7/16". The cycling of the disk work hardened the seat ring. This would also explain the spalling noted under high magnification. No anomalies were noted for 2FWE-99 and 2FWE-101.

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TEXT CONTINUATION

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Analysis by Enertech concluded that thermal gradient conditions created by introducing low temperature AFW through the hot valve 2FWE-100 caused rapid cooling of the seat ring, allowing it to displace. The thermal gradient is established as follows. 2FWE-100 is 20.25 inches from the Main Feedwater (MFW) pipe in the horizontal direction, whereas 2FWE-99 and 2FWE-101 are a much greater distance from their respective MFW lines. 2FWE-100 is exposed to 430°F MFW on the downstream side which thermally expands the body including the seat ring. The temperature of AFW flowing into the valve is significantly lower. After the trip, indicated AFW temperature was 60°F. The as-found body/seat ring interference for valve 2FWE-100 was 0.006". Calculations show a differential temperature ("delta-T") of approximately 370°F is necessary to free the seat ring, which corresponds to the delta-T observed for 2FWE-100.

CORRECTIVE ACTIONS

Completed Corrective Actions:

Dual Unit Trip

1. On March 19, 1997, the Vice-President of Nuclear Operations assigned an Event Review Team (ERT) for each unit. Team members were assigned from various departments to collect and review information and thoroughly investigate this event in accordance with Site procedures.

2. A modification was completed to resolve the incorrect wiring between the Unit 2 SBFU current interlock relay for PCB-352 and its associated SRU timer, including field proof testing, on March 22, 1997.

3. DLC Substations Department completed an investigation of operations of the SBFU relays versus measured fault currents and rechecked the calibration of the fault recorder on March 25, 1997.

4. The Nuclear Engineering Department (NED), with the support of the Relay Group, evaluated the cause of the 345 KV system disturbance that initiated the relay protective actuation that initiated the event and completed the root cause analysis March 25, 1997.

5. The ERT Reports were completed and presented to the Nuclear Safety Review Board (NSRB) on March 26-27, 1997.

6. DLC Substations Department completed testing of the 345 KV Bus Backup Timer relays, including tests of the SRU timers with multiple inputs, on March 31, 1997.

7. A review of BVPS switchyard protection drawings to determine if additional discrepancies between elementary diagrams and wiring diagrams exist was completed March 31, 1997. Identified discrepancies are addressed below under additional corrective actions.

Unit 1 EDG Operations

1. Functional testing of EDG EE-EG-2 undervoltage auto start circuit was performed on March 20, 1997.

2. Functional testing of EDG EE-EG-1 undervoltage auto start circuit was performed on March 22, 1997.

3. An evaluation of the EDG test data and the March 19, 1997 response to the trip was finalized March 24, 1997.

Unit 2 AFW Low Flow to "B" Steam Generator

1. A calibration check of flow instrument 2FWE-FE100B for the "B" AFW line was performed on March 19, 1997.

2. Reverse flow leakage was measured on AFW check valves 2FWE-99, 100, and 101 on March 20, 1997.

3. Flow elements 2FWE-FE100B and 2FWE-FE101B and adjacent piping were inspected for foreign material with a boroscope on March 21, 1997.

4. Test pressure gauges were installed at key locations throughout the "B" AFW lines and the Motor Driven AFW Pump Full Flow Test was performed to determine the location of the restriction on March 22, 1997.

5. AFW check valves 2FWE-100, 2FWE-99 and 2FWE-101 were sent to the Enertech for further analysis and corrective modifications on March 23, 1997.

6. Enertech-modified AFW check valves 2FWE-100, 2FWE-99 and 2FWE-101 were reinstalled March 27, 1997.

Additional Corrective Actions:

1. DLC Substations Department will test the 138 KV Bus Backup Timer relays, including tests of the SRU timers with multiple inputs, within 30 days of achieving 7 days continuous stable operation at 100% power for both units.

2. BVPS NED, DLC Power Delivery Support Services Department, and DLC Substations Department will review, and, if necessary, revise, the post-modification testing practices to ensure that future modifications are adequately tested for proper operation by July 1, 1997.

3. BVPS NED will review the current switchyard modification and work processes to ensure that adequate requirements and design controls are in place by July 1, 1997, to prevent a similar design event recurrence.

4. DLC Substations Department will provide documentation to BVPS of their current training requirements for conducting switchyard work activities at BVPS. An evaluation of this information will be conducted by BVPS management and the Training Department to determine the level and control of training that would be adequate for BVPS switchyard workers by April 30, 1997.

5. Resolution of identified drawing discrepancies (Dual Unit Trip item 7, above) will be tracked via the Condition Report process.

REPORTABILITY

An Emergency Notification System (ENS) report was made pursuant to the requirements of 10CFR50.72(b)(2)(ii), "Any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF) including the Reactor Protection System (RPS)..." at 0922 hours on March 19, 1997. An update to the ENS notification pursuant to the requirements of 10CFR50.72(b)(1) (i)(A), "The initiation of any nuclear plant shutdown required by the plant's Technical Specifications," was made at 1302 hours on March 19, 1997. This event is also being reported herein pursuant to the requirements of 10CFR50.73(a)(2)(iv) as "Any event or condition that resulted in a manual or automatic actuation of any Engineered Safety Feature (ESF) including the Reactor Protection System (RPS)..." and 10CFR50.73(a)(2)(i)(A), "The completion of any nuclear plant shutdown required by the plant's Technical Specifications." Evaluation of the AFW check valve failure pursuant to the requirements of 10CFR21 is ongoing.

SAFETY IMPLICATIONS

Both Units were safely shut down in accordance with applicable procedures. Adequate decay heat removal capability was afforded by both AFW systems during the event. There were no implications to the health and safety of the public as a result of this event.

SIMILAR EVENTS

LER 2-97-001-00, "Reactor Trip Due to Main Transformer Ground Protection Relay," dated February 3, 1997.