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June 22, 1995

TPJLTR 95-0069

U.S. Nuclear Regulatory Commission
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Washington, D. C. 20555

Licensee Event Report 95-008, Docket 50-249 is being submitted as required by Technical Specification 6.6 and 10CFR50.73(a)(2)(iv).

Sincerely,

T. P. Joyce

Thomas P. Joyce
Site Vice President

TPJ/PKG:pt

Enclosure

cc: J. Martin, Regional Administrator, Region III
NRC Resident Inspector's Office
File/NRC
File/Numerical

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NRC FORM 366 (5-92)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER)		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Dresden Nuclear Power Station, Unit 3	05000249	1 OF 10

TITLE (4)
Unit 3 Scram From Main Turbine Stop Valve Closure Due to Turbine Trip On High Vibration

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
									None	
05	28	95	95	-- 008 --	00	06	26	95	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.2201(b)		20.2203(a)(3)(i)		50.73(a)(2)(iii)		73.71(b)
POWER LEVEL (10)	000		20.2203(a)(1)		20.2203(a)(3)(ii)	X	50.73(a)(2)(iv)		73.71(c)
			20.2203(a)(2)(i)		20.2203(a)(4)		50.73(a)(2)(v)		OTHER
			20.2203(a)(2)(ii)		50.36(c)(1)		50.73(a)(2)(vii)		(Specify in Abstract below and in Text, NRC Form 366A)
			20.2203(a)(2)(iii)		50.36(c)(2)		50.73(a)(2)(viii)(A)		
			20.2203(a)(2)(iv)		50.73(a)(2)(i)		50.73(a)(2)(viii)(B)		
			20.2203(a)(2)(v)		50.73(a)(2)(ii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Paul Garrett, Plant Engineering Ext. 2713	(815) 942-2920

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

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE).		NO		09	22	95

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

On May 28, 1995, at 0923, during steady state power operation at approximately 2527 MWT, Unit 3 scrammed from Main Turbine Stop Valve closure due to Main Turbine High vibration. Journal Bearing 7 on the C Low Pressure (LP-C) Turbine experienced radial vibration displacement of 14.4 MILS, exceeding the high vibration trip setpoint of 10.0 MILS. The high vibration was caused by the failure of a blade in the LP-C Turbine Rotor. Subsequent to the scram, a feedwater transient was experienced resulting in the Reactor Feed Pump automatically tripping at 48 inches level, causing water to enter the High Pressure Coolant Injection steam line. The root cause of the Turbine blade failure has not yet been determined. The feedwater transient was caused by the Feedwater Control System's failure to properly control the Reactor Level following the scram. The root cause of the Feedwater Control System failure has not yet been determined. The root cause of the Turbine blade and Feed Water Control System failure will be supplied in a Supplemental report. The safety significance of this event was evaluated and determined to be moderate.

EVENT IDENTIFICATION:

Unit 3 Scram From Main Turbine Stop Valve Closure Due to Turbine Trip On High Vibration

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 3 Event Date: 05/28/95 Event Time: 0923

Reactor Mode: N Mode Name: Run Power Level: 100%

Reactor Coolant System Pressure: 1004 psig

B. DESCRIPTION OF EVENT:

On May 28, 1995, at 0923, during steady state power operation at approximately 2527 MWT, Unit 3 scrammed from Main Turbine Stop Valve [TA] closure due to Main Turbine High vibration [IT]. Journal Bearing 7 on the C Low Pressure (LP-C) Turbine experienced radial vibration displacement of 14.4 MILS, exceeding the high vibration trip setpoint of 10.0 MILS. No prior indication of trouble with the Main Turbine vibration level was experienced. The alarm on high vibration was received in the Control Room (CR) and the Main Turbine tripped, resulting in the scram of Unit 3.

Reactor Vessel water (vessel) level remained at (+)31 inches for about 1 second after the reactor scram signal was received and then rapidly descended to a level of (-)18 inches (below instrument zero). This level decrease occurred over a period of about 3 seconds due to normal mass inventory shift in the vessel from core void collapse. At time (+)4 seconds, downcomer level started to recover due to mass addition from the two operating (A and C) Reactor Feed Pumps (RFP) [SJ], pumping at approximately 9.4 Mlbs/hr. At (+)8 seconds the 3D Condensate Booster pump [SD] automatically started to maintain suction pressure for the RFPs. At time (+)12 seconds the Nuclear Station Operator (NSO), seeing the vessel level recovering to the Reactor Level Setdown Setpoint of (+)15 inches and the level still trending up, properly elected to secure the C RFP by manually tripping the pump. At approximately the same time, the Feedwater Level Control System transferred to the flow control mode of operation, with the A RFP supplying in excess of 6Mlb/hr to the Vessel. After an initial decrease in indicated vessel level due to closure of the Turbine Bypass Valves (due to steam void collapse), level began to rapidly increase.

At (+)41 seconds the vessel level reached (+)20 inches (flow control level setpoint) at which time the NSO began to manually close the B Feed Water Regulation Valve (FWRV). However, pressure indication from the A RFP discharge header indicates that the FWRV(s) (A and/or B) did not begin to close until (+)47 seconds and (+)32 inches level. From time (+)23 seconds to (+)55 seconds, vessel level rapidly increased at a rate of about 1.75-2.0 inches/second, until the high level RFP trip setpoint was reached (+)48 inches at time (+)55 seconds. When the A RFP tripped, the rate of level rise decreased to about 0.34 inches/second.

Indicated vessel level continued to rise until the (nominal) lower lip elevation ((+)55 inches indicated) of the High Pressure Coolant Injection (HPCI) [BJ] and

Isolation Condenser [BL] nozzles were reached at time(+)65 seconds. The vessel level continued to increase, going off scale (60 inches) high on all operating instruments at time (+)90 seconds to (+)200 seconds. Data from the upper wide range level column indicates that the vessel level continued to rise another 5 inches over the 9+ minutes before subsiding from inventory loss due to steam flow to the Turbine Bypass Valves and other Unit auxiliary loads. Water entered the HPCI and Isolation Condenser steam nozzles during this period. The HPCI Turbine Drain Pot level high alarm was received in the CR at time (+)19 minutes and cleared at (+)41 minutes.

Other problems identified during this event:

The Steam Jet Air Ejectors (SJAE) [SH] were manually isolated approximately 20 minutes after the scram without proper communication. The Field Supervisor (FS) was in the CR and was told by the NSO that an RFP needed to be started, 3-way (repeat back) communication was used. The FS told the NSO and Unit Supervisor that after checking the RFP he would also valve out the SJAEs, but no 3-way communication was used. The FS went out and checked on the RFP for the NSO and it was started. The FS then went to the SJAEs and valved them out, but did not notify the CR prior to doing so. The NSO, seeing the CR panel indication that the SJAE had isolated, contacted the FS. The Unit NSO notified the FS that the SJAEs should not have been isolated. The FS then restored the SJAEs.

Following the scram, 4 Intermediate Range Monitors (IRM) [IG] (monitors 13, 14, 15 and 16) exhibited erratic indication in the CR, until approximately 1700 on May 28, 1995. Resetting of the scram was delayed due to the IRM erratic indication.

The 3-203-1A Main Steam Isolation Valve (MSIV) [JM] then showed a dual indication on the CR Switch indicating lights. Operator response to this indication was to isolate the A main steam line. No valid Group I isolation signal was received.

Upon the automatic trip of the A RFP, the 3A and 3C Condensate Booster Pumps experienced seal failure.

C. CAUSE OF EVENT:

This report is being submitted in accordance with 10CFR50.73(a)(2)(iv), which requires reporting of any event that results in an unplanned manual or automatic actuation of any engineered safety feature, including the Reactor Protection System.

Main Turbine Trip:

Visual and Non Destructive Examination (NDE) inspections were performed by ComEd and Original Equipment Manufacture (OEM) personnel on the failed LP-C Rotor blade. The visual inspection revealed an apparent fatigue fracture near the leading edge of the blade, running halfway across the width of the blade which lead to the failure. Bulk hardness testing showed typical values and no differences between the failed blade and the other blades checked.

Preliminary analysis results indicate that the fatigue crack originated near the leading edge of the blade, in the stellite erosion shield. There was no evidence on the fracture surface to suggest that foreign object impact played a role in the failure.

All 38" blades on the LP-C rotor are being removed and will be examined. Several blades in the failure quadrant were found to have damage in the vicinity of the tie wire holes. This damage is believed to be the result of the initial blade failure. The tie wire arrangement, locations of the damaged blades and NDE results of the remaining blades necessitates removal of all end row blades regardless of how many may be replaced or reused.

The last stage diaphragm was found to have normal erosion and minor impact damage attributed to the blade failure. No cracks were detected in the diaphragm from NDE inspection. Erosion damage repair on other diaphragms and the casing is also underway.

Rotor and diaphragm repairs are in progress along with coupling and bearing maintenance and reinstallation. No significant coupling or bearing damage, wear, or alignment problems were noted as a result of this failure.

Florescent penetrant testing of the non-magnetic stellite erosion shields and inconel welds on the LP-C rotor was completed. A total of 24 blades in the Turbine end row and 23 blades in the generator end row were found to have cracks, some blades had multiple cracks. All of the cracks were located in the stellite strip on the convex side of the leading edge of the blade, running perpendicular to the length of the blade. The cracks ranged in size from pin holes to approximately 1/2 inch long, extending from the inconel weld fusion area in the stellite strip. No cracks were found by NDE to run through the welds. No cracks were found in the blade material or attachments by florescent mag particle testing. The number of blades effected represents approximately 25% of the blades with stellite erosion shields and all were ABB reverse engineered GE design blades. The significance of the cracks is being investigated by metallurgical and fracture mechanics specialists under the direction of Nuclear Engineering. The one end row GE blade on this rotor was found not to be cracked.

Two of the cracked blades' pieces were removed, and shipped to Argonne National Laboratory for analysis. Blade centerline checks were performed and preliminary results indicate a deviation from the normal GE acceptance limits on some blades. These results are being evaluated to determine relevance. Based on the discovery of these cracks, plans have been made to inspect the LP A and B rotors. Preparations are in progress for selected in-place inspections of LP-B rotor blades as soon as access is available. Preparations are also in progress for removal of the LP-A rotor, which is virtually identical to the C rotor, for blast cleaning and examination. These inspections will help determine whether or not the LP-B Rotor will need to be removed for further inspections and what scope of inspections is appropriate for Unit 2.

These inspections will also serve to positively identify where the ABB blades are installed. Analysis is being performed on used ABB and GE blades for comparison to quantify variations in fabrication. Additionally, 13 spare ABB and 11 spare GE blades were penetrant inspected with no cracks found. An ABB blade design engineer from Switzerland will be on site to assist in the investigation.

The apparent cause of the LP-C Turbine, high vibration signal, which caused the reactor scram, was the result of a failed blade. The root cause of the failed blade has not been determined. The blade failure requires further evaluation and analysis to determine the root cause.

Level Transient:

The vessel level and feed water flow transient were normal for a scram from high power until the C RFP was manually tripped by the NSO. When the C RFP was tripped, and with vessel level below (+)20 inches and the A RFP flow rapidly increasing to 5.6 Mlbs/hr, the Feedwater Control System changed control modes from level control to flow control. The shift from Level to flow control mode was automatic and consistent with the design setpoints in the system. Analysis of the Sequence of Events Recorder (SER) [IQ] and the Transient Analysis Display System (TADS) [IP] data shows that the subsequent Feedwater Control System operation was not satisfactory for most of the remainder of the post scram level/feed flow transient.

At the time of the transition from level to flow control, the B FWRV was in manual at some intermediate position and the A FWRV was opening in automatic control. When in the Flow Control mode, both valves will follow commands from the Flow Controller. The Flow Controller will command both valves to move to a position where feedwater flow will match the set point installed in the Controller. For a single pump, the flow set point is 4.9 Mlbs/hr. Hence, with a flow control initiation setpoint of 5.6 Mlbs/hr, feedwater flow should have decreased to match the setpoint. However, the FWRVs ramped open rather than closing to meet the setpoint. Feedwater flow rapidly increased to a value in excess of 6.0 Mlbs/hr. ((+)12 seconds), thus accelerating the rate of level rise.

The Feedwater Control System remained in the flow control mode of operation until approximately (+)40 seconds when a vessel level of (+)20 inches was attained. At this time the Feedwater Control System is believed to have automatically reverted to level control mode. The NSO began closing the B FWRV; however, the TADS trace for the RFP discharge header pressure does not indicate that either the A (automatic) or B FWRV started closed until time (+)47 seconds and (+)32 inches level. The delay in valve closure caused the transient level to reach the automatic RFP trip setpoint of (+)48 inches at time (+)55 seconds.

After the A RFP automatically tripped, the rate of level rise was drastically reduced to about 0.3 inches/second. This rate of level rise is greater than can be attributed to a single Control Rod Drive (CRD) pump [AA], even at high pump flow conditions. However, concurrent with the time of the A RFP trip, the Reactor Recirculation Pumps [AD] were running back to their minimum speed in accordance with automatic action of the Low Feedwater Flow Run Back Interlock. This action of reduced Core Recirculation flow causes a swell in the Vessel downcomer which is greater than can be attributed to mass input from the CRD pump alone.

Analysis of feedwater system performance has determined that the system did not perform properly in the following manner:

Feedwater level Setpoint Setdown did not actuate immediately upon receipt of the scram signal as per design. Proper operation of this feature would have resulted in an immediate decrease in feedwater flow upon receipt of a scram signal.

Flow control mass flow rate for one RFP is 4.9 Mlbs/hr; however, the A RFP maintained a flow rate greater than 6 Mlbs/hr after the C RFP was manually tripped.

The Feedwater Control System did not respond to vessel level rising above the flow control reset setpoint for approximately 5 seconds.

The cause of the level transient was the result of the improperly functioning Feedwater Control System. The root cause of the improperly functioning Feedwater Control System has not been determined. The improperly functioning Feedwater Control System requires further evaluation and troubleshooting to determine the root cause.

SJAE Isolated:

The root cause of the SJAEs being isolated is due to lack of three way communication between the Unit NSO and the FS prior to removing the SJAEs, which is contrary to Operations standards and Management's expectations. The FS was concentrating on the numerous jobs and tasks that are required after a Reactor scram and the call back to the CR was not performed.

Erratic IRM Response:

Upon inspection of the erratic indicating IRMs 13-16, IRMs 13 and 16 were found with water in the connector area. No anomalies were identified on IRMs 14 and 15.

The water intrusion into the connectors for IRMs 13 and 16 lowered resistance and provided additional conduction paths which generates spurious signals in the IRM logic. The root cause of the water intrusion has not been determined and will require further troubleshooting and evaluation.

Performance history of the IRMs show that some IRMs provide sporadic signals during temperature changes (vessel cooldown) in the high temperature region. Upon inspection of IRMs 14 and 15 no additional problems were found. The spiking of IRM 14 and 15 is attributed to the performance of some IRMs during the temperature change.

3-203-1A MSIV Dual Indication:

On May 30, 1995, a Drywell entry was made to inspect the A inboard (3-203-1A) MSIV. During the inspection, it was found that there was insufficient wipe of the 3-203-1A MSIV Limit Switch arm on the 1A Limit Switch. It is believed that the Limit Switch activated during the scram, but the valve remained open. The root cause of the 3-203-1A MSIV dual indication is insufficient wipe of the 1A

Limit Switch due to improper Electrical Maintenance Department work practices. It is believed that the improper setpoint adjustment was installed during the last adjustment of the 3-203-1A MSIV during the previous refueling outage.

3A and 3C Condensate Booster Pump Failure:

Initial assessment has determined that the 3A and 3C Condensate Booster pumps' seal failures were due to deadheading the pumps after the trip of the C RFP. Additional troubleshooting is required to determine the root cause.

D. SAFETY ANALYSIS:

Upon receipt of the Turbine bearing high vibration signal, the Turbine trip and resultant Reactor scram took place as per design. Receipt of the Turbine Stop Valve closure caused a sudden increase in Reactor Vessel pressure which was controlled by rapid opening of the Turbine Bypass Valves. The Turbine Stop Valve closure took place in order to protect the Turbine and lessen the affects of the pressure increase on the Reactor Vessel and fuel. The limiting factor in a Turbine trip from power is the effect on the fuel cladding safety limit. Operating MCPR limits are imposed to preclude violation of this limit. A Turbine trip from power is analyzed in section 15.2.3 of the UFSAR as bounded by a trip without bypass availability. Since Turbine Bypass Valves were available during this event, there is not considered to be any challenge to fuel integrity.

The level transient which was experienced during this event resulted in putting water in to the HPCI steam supply lines. At the time this event occurred, vessel level was in excess of the Reactor Water Level high level HPCI Turbine trip setpoint ((+)48 inches), thus, preventing an automatic or manual start of the HPCI system. The water was drained out of the HPCI steam supply lines by the action of the HPCI system Drain Pots per design. During the 22 minutes the Inlet Drain Pot Alarm was active, Reactor water level was always greater than the (-)59 inch HPCI initiation setpoint. In addition, based on Operator training and Dresden Annunciator Procedure (DAN) 902-3 B-11, High Water Level In The HPCI Inlet Drain Pot, a manual start of the HPCI system during the time the alarm was active was improbable. In addition, if make-up to the Vessel would have been required, the Automatic Depressurization System (ADS) was available to reduce the Vessel pressure to allow the Core Spray [BM] or Low Pressure Coolant Injection (LPCI) [BO] to provide the needed make-up inventory. However, a further evaluation of water in the HPCI steam lines will be performed.

Water intrusion into the Isolation Condenser steam line would drain down to the condensate leg. This would increase the level in the condensate leg, with minimal impact on the system operation or performance.

The isolation of the SJAEs, without proper communication, had minimal impact on the plant response to this transient. This event took place several minutes after the turbine trip and scram. Reactor pressure was able to be controlled during this time period using the Turbine Bypass Valves. However, additional indication and required actions in the CR challenges the Operators.

The erratic behavior of IRMs resulted in the generation of several spurious trip signals to the Reactor Protection System (RPS). At the time of this failure, the RPS system had already performed its safety function. Had this event occurred during a reactor startup or controlled shutdown, the potential existed for the erratic operation of the IRMs to generate a spurious Reactor scram signal. An Operability Assessment will be performed for the IRMs prior to Unit 3 startup.

The failure of the 1A MSIV indication did not affect the consequences of the Reactor scram or recovery actions. The A MSIV line was isolated by Operator action as a precautionary action pending investigation into the cause of failure. The isolation of one steam line did not affect the ability to control Reactor pressure using the Turbine Bypass Valves. However, additional indication and required actions in the CR challenges the Operators.

The 3A and 3C Condensate Booster Pumps' seal failure resulted in a 1-2 gallon per minute leak. These leaks were well within the capacity of the pumps to maintain adequate RFP suction pressure.

Based on the above discussion, the overall significance of this event is considered to be moderate.

E. CORRECTIVE ACTIONS:

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

Note: Prior to Unit startup, the Plant Operating Review Committee will assure that all applicable corrective actions have been implemented. Actions which are identified upon the completion of the Unit 3 root cause investigation which are applicable to Unit 2, will be implemented on Unit 2.

LP-C Turbine

1. Visual and Non Destructive Examination (NDE) inspections were performed by ComEd and Original Equipment Manufacture (OEM) personnel on the failed blade.
2. Macro photography and chemical oxide removal was performed on the blade and there was no evidence on the fracture surface to suggest that corrosion or foreign object impact played a role in the failure.
3. Analysis was performed on used ABB and GE buckets for comparison to quantify variations in fabrication.
4. 13 spare ABB and 11 spare GE blades were penetrant inspected with no cracks found.
5. Florescent penetrant testing of the non-magnetic stellite erosion shields and inconel welds on the LP-C rotor was completed. A total of 24 blades in the Turbine end row and 23 blades in the generator end row were found to have cracks, some blades had multiple cracks.

6. The blade failure requires further evaluation and analysis to determine the root cause, if possible. The results of the evaluation and analysis, including corrective actions, will be provided in a subsequent supplement. (249-180-95-00801)

Feed Water Transient

1. The improperly Functioning Feedwater Control System requires further evaluation and troubleshooting to determine the root cause. The results of the evaluation and troubleshooting, including corrective actions, will be provided in a subsequent supplement. (249-180-95-00801)

2. A further evaluation of water in the HPCI steam lines will be performed prior to Unit 3 startup. (249-180-95-00802)

SJAE Isolated

1. The Operations Field Supervisor involved was counseled and understands his failure to perform 3-way communication (prior to the SJAEs being isolated) did not meet Operations standards and expectations. He has learned from this event and has amended his work practices to prevent future occurrences.

2. The Operations standards and expectations will be reviewed and emphasized to all Licensed Operators. (249-180-95-00803)

Erratic IRM Response

1. IRM 13 has been replaced. Water was identified inside the connector cover. Drying and cleaning the connectors and cables did not provide satisfactory results, thus the IRM detector was replaced.

2. IRM 14 was inspected and found to be performing satisfactory.

3. IRM 15 was inspected and found to be performing satisfactory.

4. IRM 16 was inspected. Water was identified inside the connector cover. The water was removed and the connectors and cables were cleaned and dried. IRM 16 is now performing satisfactory.

5. The water intrusion will require further troubleshooting and evaluation to determine the root cause, if possible. The results of the evaluation and troubleshooting will be provided in a subsequent supplement. In addition, an action plan to resolve the erratic behavior of the IRMs will be provided in the supplement. (249-180-95-00801)

6. An Operability Assessment will be performed for the IRMs prior to Unit 3 startup. (249-180-95-00804)

3-203-1A MSIV Dual Indication

1. The proper setting techniques for the 1A and 1B Limit Switches on MSIVs was reviewed and emphasized to the Electrical Maintenance Department on June 7, 1995.

2. The remaining MSIVs on Unit 3 have been inspected by System Engineering for similar problems.

3. The MSIVs on Unit 2 will be inspected by System Engineering for similar problems. (249-180-95-00805)

4. The 3-203-1A MSIV Limit Switch 1A incorrect setting was corrected.

5. Since the MSIVs' limit switches were last adjusted, during the previous refuel outage, the Electrical Maintenance Department has received additional training on the setting of limit switches. This training included the personnel performing the limit switch adjustment on a new training model using Dresden Electrical Procedure (DES) 0200-38, MSIV Limit Switch Adjustment and Scram Setpoint Check.

3A and 3C Condensate Booster Pumps

1. The 3A and 3C Condensate Booster Pumps' seal failure will require further troubleshooting and evaluation to determine the root cause, if possible. The results of the evaluation and troubleshooting will be provided in a subsequent supplement. (249-180-95-00801)

F. PREVIOUS OCCURRENCES:

LER/Docket Numbers	Title
94-005/050237	Manual Reactor Scram Due to Loss Of Instrument Air Upon a manual scram due to loss of Instrument Air, Vessel level increased above the HPCI nozzle and water entered the HPCI steam lines. The Feedwater Control System appeared to function properly. The RFP high level trip setpoints were re-evaluated and were changed to a lower value.

G. COMPONENT FAILURE DATA:

An LER Supplement will be submitted with the failed components.