NUREG/CR-4674
ORNL/NOAC-232
Vol. 16

Precursors to Potential Severe Core Damage Accidents: 1991 A Status Report

Appendices B, C, and D

Prepared by
J. W. Minarick, J. W. Cletcher, D. A. Copinger, D. W. Dolan

Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

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*SAIC, Oak Ridge, TN 37831

NOTE

This document is bound in two volumes: Volume 15 contains the main report and Appendix A; Volume 16 contains Appendices B-D.

CONTENTS

LIST OF ACRONYMS

ADS	automatic depressurization system
AEOD	NRC Office for Analysis and Evaluation of Operational Data
AFW	auxiliary feedwater
AIT	augmented inspection team
ASP	accident sequence precursor (program)
ATWS	anticipated transient without scram
BWR	boiling-water reactor
CC	containment cooling
CCW	component cooling water
CD	core damage
CRD	control rod drive
CSR	containment spray recirculation
DG	diesel generator
DHR	decay heat removal
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPS	emergency power system
ESF	engineered safety feature
FWCI	feedwater coolant injection
FSAR	final safety analysis report
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HPI	high-pressure injection
IC	isolation condenser
IIT	incident investigation team
LER	licensee event report
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LOOP	loss of offsite power
LPCI	low-pressure coolant injection
LPI	low-pressure injection
LPR	low-pressure recirculation
LWR	light-water reactor
MFW	main feedwater
MOV	motor-operated valve
MSIV	main steam isolation valve
NRC	Nuclear Regulatory Commission
PCS	power conversion system
PORV	pilot- or power-operated relief valve
PRA	probabilistic risk assessment

PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RHRSW	residual heat removal service water
ROAB	Reactor Operations Analysis Branch of AEOD, NRC
RPS	reactor protection system
RV	relief valve or reactor vessel
RWCU	reactor water cleanup
RWST	refueling water storage tank
SCSS	Sequence Coding and Search System database
SDC	shutdown cooling
SG	steam generator
SI	safety injection
SLB	steam-line break
SLC	standby liquid control
SP	suppression pool
SRV	safety relief valve
SW	service water
TBS	turbine bypass system

LIST OF TABLES

Appendix B

PRECURSORS

Appendix B

PRECURSORS

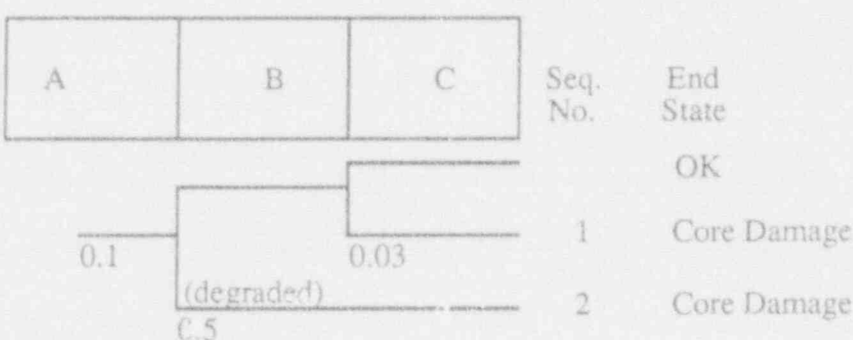
Reactor plant operational events for 1991 were selected for documentation as precursors, containment-related, and other events based on the selection criteria described in this report. Precursors are documented herein.

For each precursor, an event analysis sheet is included. This provides a description of the operational event, event-related plant design information, the assumptions and approach used to model the event, and analysis results.

Two figures are included. The first figure compares the significance of the event from a core damage standpoint with other potential events at the same plant. The second figure highlights the dominant core damage sequence associated with the event.

A conditional core damage calculation is also provided. Included with the conditional core damage calculations are individual sequence probabilities for the more significant core damage and anticipated transient without scram (ATWS) sequences, listed in probability and sequence order; and a listing of the branch probabilities and frequencies utilized (edited branches are in upper case). Individual sequences are listed if their probability is >0.03 times the probability of the dominant sequence for each end state.

Probabilities for sequences that reflect a decrease in conditional probability are enclosed in parentheses. A decrease in core damage or ATWS conditional probability for an individual sequence can occur in sequences containing success branches when an unavailability is modeled. For example, consider two sequences involving an initiator A, an observed degraded system B, plus another system C as shown on the following event tree. Sequence 1 includes success of B; sequence 2 includes failure of B.



The probability of sequence 1 is probability (A) × [1 - failure probability (B)] × failure probability (C); the probability of sequence 2 is probability (A) × failure probability (B).

In assessing the significance of an unavailable system, the likelihood of core damage calculated without any observed failures and over the same period of time is subtracted from the value calculated considering the unavailable system so as to estimate only the additional impact of the unavailability. Applying this procedure to the two core damage sequences with the probability of initiator A assumed to be 0.1, the probability of B failing (given that it had been degraded) assumed to be 0.5, the nominal failure probability assumed to be 0.01, and the probability of C failing assumed to be 0.03, the conditional probability of sequences 1 and 2, respectively, is calculated as follows:

$$[0.1 \times (1 - 0.5) \times 0.03) - [0.1 \times (1 - 0.01) \times 0.03) = -1.47 \times 10^{-3}$$

$$[0.1 \times 0.5] - [0.1 \times 0.01] = 4.9 \times 10^{-2}$$

In this case, the differential probability for sequence 1 is negative, indicating a decrease in probability for that sequence compared with the same time period without the unavailability.

Each event is identified by its unique docket-licensee event report (LER) number. Table B.1 provides an index to the documentation for each precursor event. The LERs associated with each event are included with the precursor description. Note that copies of LERs utilized in the Accident Sequence Precursor (ASP) Program are also used in other Oak Ridge National Laboratory programs and may contain markings made during abstracting and coding in those programs.

Table B.1. Index of precursors

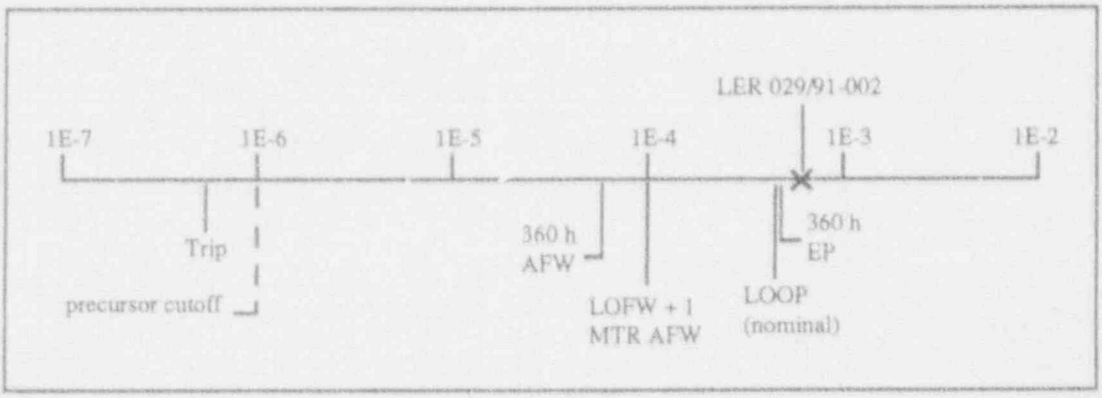
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 029/91-002
Event Description: Loss of offsite power caused by lightning strike
Date of Event: June 15, 1991
Plant: Yankee Rowe

Summary

Yankee Rowe lost offsite power for 24 min due to a lightning strike. All three emergency diesel generators (EDGs) operated as designed. As a result of the lightning, surge protection fuses from the normal DC supplies blew on both vital power supply inverters. Both inverters transferred to their alternate (EDG-backed) AC sources. However, in the event of failure of the EDGs, 120-VAC instrument power would have been lost.

The conditional probability of core damage associated with this event is 6.1×10^{-4}. The relative significance of the event compared to other postulated events at Yankee Rowe is shown below:



Event Description

Yankee Rowe experienced a lightning strike that caused a total loss of offsite AC power on June 15, 1991. The lightning strike (1) destroyed the phase A lightning arrestor on station service transformer (SST) 3, which is connected to the Cabot (Y-177) 115-kV transmission line, and (2) caused a flashover of an insulator on phase A of the Harriman (Z-126) 115-kV transmission line disconnect switch. Offsite AC power was lost for 24 min.

An automatic reactor scram and turbine trip occurred as a result of the loss of offsite power. All three EDGs operated as designed. EDGs 1 and 3 started automatically in response to the deenergization of both offsite transmission lines. EDG 2 was manually started by operators in anticipation of securing the main generator in accordance with plant procedures. Lightning also caused blown surge protection fuses in the normal DC input supplies to both vital buses. Upon deenergization, both vital bus inverters automatically transferred to and were energized by their backup sources (EDGs 1 and 3).

The nonessential uninterruptible power supply (NEUPS) failed to automatically transfer to its backup source after the lightning strike. Consequently, various plant communication systems experienced failures. The plant commercial phone system failed to operate after the NEUPS was reenergized due to lightning-induced failures of two critical circuit packs.

While attempting to realign the emergency buses to offsite power, an inadvertent safety injection (SI) actuation signal was initiated. No actual injection occurred due to adequate main coolant system pressure.

An unusual event was declared due to the loss of offsite power and a fire emergency caused by the smoldering lightning arrestor on SST 3. The unusual event was elevated to an alert based on the continued inoperability of communication systems, the deenergized NEUPS, and the existence of degraded plant equipment.

Additional Event-Related Information

Yankee Rowe has two independent sources of offsite power, the 115-kV Z-126 transmission line from the Harriman station, and the 115-kV Y-177 transmission line from the Cabot station. Normal operation is with both of these lines in service. Z-126 feeds the SST 2 and Y-177 feeds the SST 3. The SST 1 is connected to the outdoor section of the generator bus.

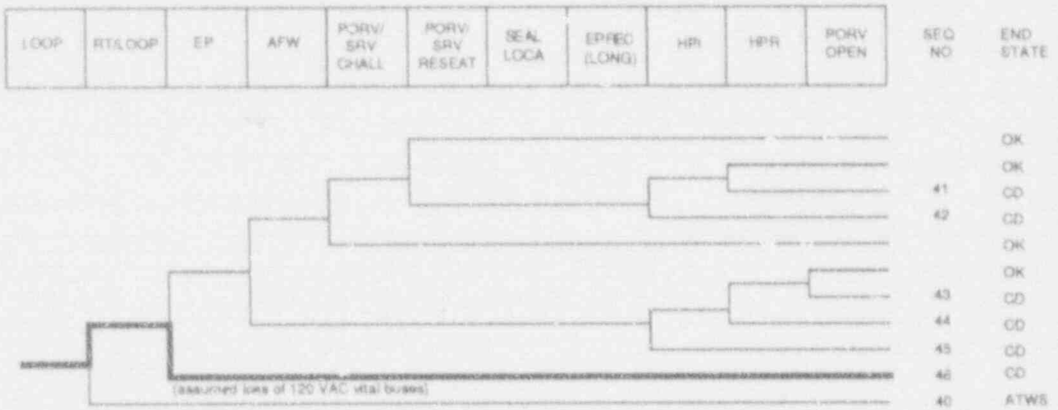
The station service system consists of three 2400-V buses, each supplied from an SST. Each 2400-V bus, in turn, supplies a 480-V station service switchgear bus. Three emergency 480-V buses (vital bus 1, vital bus 2, and transformer A bus) are fed independently from the 480-V station service buses or, upon loss of AC power, from each of the three independent EDGs. Backup DC power consists of three 125-VDC station batteries and three associated battery chargers.

ASP Modeling Assumptions and Approach

The event has been modeled as a plant-centered loss of offsite power (LOOP). Probabilities for LOOP nonrecovery (short term) and failure to recover AC power prior to battery depletion 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). Both trains of 120-VAC vital power were assumed to be unavailable if all three EDGs failed to start or run (only the backup source to the vital buses was available since the DC fuses supplying power to both inverters failed open after the lightning strike). Unavailability of both instrument buses was assumed to proceed to core damage, since steam generator (SG) and reactor coolant system (RCS) parameters would be unavailable for monitoring and control.

Analysis Results

The conditional probability of core damage estimated for this event is 6.1×10^{-4}. The dominant core damage sequence, highlighted on the following event tree, involves a station blackout. In the event that RCS and SG parameters can be successfully monitored without 120-VAC power to allow decay heat removal, the conditional core damage probability estimated for the event is 4.3×10^{-4}.



Dominant core damage sequence for LER 029/91-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 029/91-002
Event Description: LOOP and degraded instrument power caused by lightning
Event Date: 06/15/91
Plant: 029/91-002

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	6.1E-04
Total	6.1E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
46	LOOP -rt/loop emerg.power	CD	2.2E-04	4.0E-01
45	LOOP -rt/loop -emerg.power afw/emerg.power hpi(f/b)	CD	2.0E-04	1.4E-01
43	LOOP -rt/loop -emerg.power afw/emerg.power -hpi(f/b) -hpr/-hpi porv.open	CD	1.7E-04	1.7E-01
44	LOOP -rt/loop -emerg.power afw/emerg.power -hpi(f/b) hpr/-hpi	CD	1.7E-05	1.7E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
43	LOOP -rt/loop -emerg.power afw/emerg.power -hpi(f/b) -hpr/-hpi porv.open	CD	1.7E-04	1.7E-01
44	LOOP -rt/loop -emerg.power afw/emerg.power -hpi(f/b) hpr/-hpi	CD	1.7E-05	1.7E-01
45	LOOP -rt/loop -emerg.power afw/emerg.power hpi(f/b)	CD	2.0E-04	1.4E-01
46	LOOP -rt/loop emerg.power	CD	2.2E-04	4.0E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\02991002.cmp
BRANCH MODEL: c:\asp\1989\yrowe.all
PROBABILITY FILE: c:\asp\1989\pwr_bsl? otc

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 029/91-002

Branch	System	Non-Recov	Opr Fail
trans	2.5E-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		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	5.4E-04	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	1.0E-01	3.4E-01	
mfw	2.0E-01	3.4E-01	
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	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
EP."EC	1.7E-01 > 1.1E-01	1.0E+00	
Branon Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > 1.1E-01		
hpi	3.0E-04	8.4E-01	
hpi(f/b)	2.4E-03	8.4E-01	1.0E-02
hpr/-hpi	1.5E-05	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Minarick
06-11-1992
20:07:53

Event Identifier: 029/91-002

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8-31-85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Yankee Nuclear Power Station, Rowe, MA. 01367	0 5 0 0 0 0 2 9	1 OF 1 1

TITLE (4)
Reactor Scram/Turbine Trip and Loss of Offsite Power Due to Lightning Strike

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 6	1 5	9 1	9 1	0 0 2	0 0	0 7	1 6	9 1		0 5 0 0 0
										0 5 0 0 0

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

OPERATING MODE (9)	1
POWER LEVEL (10)	0 8 8

	20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

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Gregory A. Maret, Technical Director	4 1 3	4 2 4 - 5 2 6 1

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
X	F C	L A R	W 1 2 0	NO	C	E F	I N V T	E 2 0 9	NO
C	E E	U J X	E 3 5 6	NO	C	F I	C B D		NO

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	Month	Day	Year
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On June 15, 1991, at 2350 hours, while in Mode 1 at 88% reactor power, a lightning strike resulted in destruction of a lightning arrestor on the No. 3 Station Service Transformer (SST) and flashover of an insulator on the Z-126 115 kV transmission line disconnect switch. As a result, all offsite AC power was lost, an automatic reactor scram and turbine trip occurred, and all three EDGs operated as designed. On June 16, 1991, at 0010 hours, an UNUSUAL EVENT (UE) was declared based on the loss of offsite power and a fire emergency (smoldering arrestor). At 0014 hours, one source of offsite power was restored. At 0130 hours, an ALERT was declared at the discretion of the Shift Supervisor. While attempting to normalize the emergency busses, an inadvertent SI actuation signal was initiated at 0155 hours. Following restoration of essential communication systems and plant equipment, the ALERT was de-escalated to an UE at 0450 hours. On June 17, 1991, the plant attained a cold shutdown condition at 0755 hours and the UE was terminated at 0925 hours.

The root cause of this event has been attributed to lightning-induced transients. Immediate corrective actions involved repairing and testing of affected electrical and mechanical equipment and plant instrumentation, and returning normal and emergency communication equipment back to service. A Yankee Investigation Team was assembled to evaluate the event and develop immediate and long-term corrective actions. There was no adverse effect to the public health or safety.

NRC Form 366 (9-83)

NRC Form 366A (9-83)
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION
U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Yankee Nuclear Power Station Rowe, MA 01367	0 5 0 0 0 0 2 9	9 1	— 0 0 2 —	0 0	0 2 OF 1 1

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

INITIAL CONDITIONS

The plant was in Mode 1, at 88% reactor power, with a main coolant [EIIS:AB] pressure of 2000 psig, an average temperature of 521 degrees Fahrenheit and a boron concentration of 814 ppm. The plant was operating at a reduced power level to comply with temperature limits on the circulating water system imposed by the National Pollutant Discharge Elimination System (NPDES) Permit. On June 15, 1991, at 2010 hours, the weather alert radio in the Control Room was activated. Sustained winds in excess of 73 MPH were not expected; therefore, no further action was required.

EVENT DESCRIPTION

On June 15, 1991 at approximately 2350 hours, the Yankee Nuclear Power Station experienced a lightning strike which affected both of the independent offsite transmission lines. The lightning strike caused destruction of the Phase A lightning arrestor on the No. 3 Station Service Transformer (SST) [EIIS:XFMR] and flashover of an insulator on Phase A of the Z-126-5 115 kV disconnect switch. Table 1 provides a description of the sequence of important events.

As a result of the lightning strike, all offsite AC power was lost for twenty-four (24) minutes. An automatic reactor scram and turbine trip occurred. All three (3) emergency diesel generators (EDGs) [EIIS:DG] operated as designed. EDGs No. 1 and 3 started automatically in response to the deenergization of the two offsite transmission lines. EDG No. 2 was manually started by operators in anticipation of securing the main generator, during realignment of electrical systems in accordance with plant procedures. The control room operators stabilized the plant in a hot standby (Mode 3) condition and verified natural circulation cooling.

On June 16, 1991, at 0010 hours, an UNUSUAL EVENT was declared based on the loss of offsite power and a fire emergency (due to the smoldering lightning arrestor on the No. 3 SST) lasting greater than ten (10) minutes. Notification to the States of Massachusetts and Vermont was delayed due to lightning-induced damage to plant communication systems [EIIS:FI]. Alternate means for these notifications to the states and the NRC were established using a dedicated outside telephone line.

At 0014 hours, one source of offsite AC power (Harriman, Z-126, line) was restored. Damage to the lightning arrestor on No. 3 SST and failure of a control circuit relay on OCB Y-177 delayed restoration of the second source of offsite AC power (Cabot, Y-177, line) until repairs could be made.

An ALERT was declared at 0130 hours, at the discretion of the Shift Supervisor, who determined that existing plant conditions warranted a precautionary activation of all emergency response centers and a need for additional

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Yankee Nuclear Power Station Rowe, MA 01367	0 5 0 0 0 0 2 9	9 1	— 0 0 2	— 0 0	0 3 OF 1 1

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

manpower. This determination was based on the continued inoperability of communication systems, the deenergized state of the nonessential uninterruptible power supply (NEUPS) [EIIS:UJX], and the existence of degraded plant equipment (see Table 1).

While attempting to realign the emergency busses to offsite power, an inadvertent safety injection actuation signal (SIAS) [EIIS:JE] was initiated at 0155 hours. Main coolant system (MCS) pressure remained above the shutoff head of the safety injection (SI) pumps; therefore, no actual injection was needed and no flow into the MCS from SI occurred.

At approximately 0400 hours, the normal power supply was returned to the No. 1 and 2 vital bus [EIIS:BU]. Emergency electrical busses No. 2 and 3 were realigned to an offsite power source and EDGs No. 2 and 3 were secured. Following the restoration of essential communication systems and plant equipment and with the concurrence of the States of Massachusetts and Vermont, the ALERT was de-escalated to an UNUSUAL EVENT at 0450 hours.

A plant cooldown was initiated at approximately 0700 hours. Plant commercial phone service was restored at 0715 hours, with limited functionality.

On June 17, 1991, the plant attained a cold shutdown (Mode 5) condition at 0755 hours. The UNUSUAL EVENT was terminated at 0925 hours.

A Yankee Investigation Team was assembled to evaluate the event for lessons learned and develop immediate and long-term corrective actions. The Yankee Investigation Team focused on the following areas: plant operations, electrical systems, communication systems and emergency preparedness.

CAUSE OF EVENTS

The root cause of this event has been attributed to lightning impacting equipment on both of the 115 kV transmission lines serving the plant. Subsequent to the lightning strike, the Phase A lightning arrestor [EIIS: LAR] on the No. 3 SST failed to reset and was destroyed; an adjacent lightning arrestor sustained consequential damage. As a result, both sources of offsite AC power were lost and an automatic reactor scram and turbine trip occurred.

The root cause of the failure of various plant communication systems has also been attributed to lightning. Subsequent to the lightning strike, the NEUPS failed to automatically transfer to its backup source; the NEUPS provides power to communication systems equipment at the plant. The loss of NEUPS also caused the failure of other plant instrumentation associated with it. (See Table 1)

The root cause of the sustained loss of the plant commercial phone system (PBX) after the NEUPS was reenergized was a voltage-induced failure of two critical circuit cards [EIIS:CBD]. A possible cause of this failure is a lightning-induced voltage spike that came into the PBX through the telephone lines, independent of the lightning strike affecting the 115 kV transmission lines.

The root cause of the sustained loss of communication systems between the plant and Emergency Operations Facility (EOF) [EIIS:NC] has been attributed to the following:

- Failure of plant PBX causing a loss of tie lines and a reduction in calling capability over local lines. The loss of tie lines continued after the PBX was restored due to lightning-induced New England Telephone (NET) circuit equipment failures at both the plant and NET Central Office in Readsboro, Vermont.

- Loss of control of the Mt. Massamet and Bordon Mountain transmitters from the EOF due to lightning activity separate from that experienced locally at the plant.

- Loss of the YNPS Nuclear Alert System, the preferred means for making emergency notifications to the states, due to NET circuit failure and failure of equipment at the plant.

- Loss of two ring-down circuits due to NET circuit failures.

The root cause of the inadvertent SIAS is unknown. Subsequent to this event, extensive bench testing was conducted using spare instrumentation (bistable and actuation relay) to simulate the actual instrument loop operation and determine the cause of the spurious SIAS. The results of the bench testing were inconclusive and did not definitively identify a root cause. It is suspected that a combination of voltage and frequency reduction experienced by Vital Bus No. 1 during coastdown of EDG No. 1, after it was tripped by the operators when attempting to realign Emergency Bus No. 1 to offsite power, resulted in the inadvertent SIAS. Vital Busses No. 1 and 2 had both automatically transferred to their bypass supplies, EDGs No. 1 and 3 respectively, as a result of lightning-induced surges.

CORRECTIVE ACTIONS

A. Electrical Systems

Immediate corrective actions involved testing the No. 3 SST. All lightning arrestors on both No. 2 SST and No. 3 SST were replaced. Also, one of the three surge arrestors on the main transformer was replaced. Subsequent to the performance of acceptable tests, the No. 3 SST was reenergized. The damaged insulator on the Z-126-5 disconnect switch was replaced. Extensive testing of selected plant protective relays, voltage regulators and oil circuit breakers on the two offsite power transmission lines was also

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conducted. This testing ensured the adequacy of all transmission line relay functions.

An evaluation of other electrical equipment and plant instrumentation which could have been affected by the lightning strike was also performed.

Miscellaneous instrumentation (power supplies, amplifiers, recorders, etc.) was also repaired.

B. Communication Systems

Immediate corrective actions involved returning normal and emergency communication equipment back to service.

At 0235 hours, on June 16, 1991, the following communication systems were returned to service when power was restored by manually bypassing the NEUPS: Emergency Notification System, Nuclear Alert System and plant radio paging system (two out of three transmitters operable). The plant commercial phone system (PBX) was returned to service with limited capability at 0715 hours, after damaged equipment was replaced.

C. Restart Action Items

The following corrective actions were developed by the Yankee Investigation Team and were implemented prior to transition to Mode 4 in preparation for plant restart:

1. Develop and issue a procedure which provides direction for manual bypass of the NEUPS, so that the NEUPS distribution panel can be fed from available power sources.

2. Train operators on performing the NEUPS manual bypass function.

3. Revise procedure OP-3501, "Restoration of Normal AC Power After a Total Loss of AC," to:

   a. Alert operators to check the status of the Vital Bus power supply prior to realigning the Emergency Diesel Generator (EDG) and the Emergency Bus.

   b. Address the realigning of the EDGs and the Emergency Bus when the EDGs are not backfeeding the associated 480V station service bus.

   c. Provide guidance on how to backfeed a deenergized 480V station service bus when only one outside (offsite) line is available.

4. Perform a visual inspection of all solid state equipment that may have been susceptible to lightning strikes and document findings.

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5. Include alternate staff augmentation call-in capability in Emergency Plan Implementing Procedures (EPIPs), which provides appropriate contingency actions to address degradation of plant communications.

6. Revise EPIPs to include log-in time on Emergency Response Facility (ERF) personnel log-in forms.

7. Resolve inadvertent safety injection actuation by identifying plausible actuation cause and implementing actions to avoid recurrence.

8. Revise EPIPs to include identification of backup meteorological data for inclusion in notification to the state of Vermont.

9. Provide guidance on all capabilities of each telephone type at all ERFs.

10. Distribute access control keys to shift operations personnel to assure timely controlled access for equipment operation. Establish appropriate controls over these keys and their turnover.

D. Follow-up Action Items

The following long-term corrective actions were developed by the Yankee Investigation Team

1. Review lightning protection capability of the Cabot (Y-177) and Harriman (Z-126) transmission lines, including the switchyard. Specifically address the absence of a ground wire (static wire, shield wire) on these lines. Provide recommendations of specific enhancements in order of priority.

2. Review lightning protection capability of the station considering ANSI/NFPA-78 and Report NSAC-41. Provide specific recommendations in order of priority.

3. Perform a station ground resistance test and compare the results with those of a previously-conducted test. Make recommendations for improvement as appropriate.

4. Review all solid-state equipment (including communications equipment) to determine if surge protection capability can be enhanced. Provide specific enhancements and priorities.

5. Determine if the station 115 kV protective relaying and its coordination with Cabot and Harriman stations is adequate or in need of improvement. Provide specific improvements in order of priority.

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6. Evaluate parameters requiring verification in procedure OP-3051, "Safety Injection Termination Following Spurious Initiation," and revise procedure as appropriate.

7. Evaluate Emergency Operating Procedures (EOPs) ES-0.1, REACTOR SCRAM RESPONSE, and ES-1.1, SI TERMINATION, to determine the need for adding a check of the status of the Vital Bus power supply prior to realigning the Emergency Diesel Generators (EDGs) and Emergency Busses.

8. Evaluate EOP ES-1.1, SI TERMINATION, to determine the need to direct the operator to realign the Safety Injection System for automatic initiation.

9. Provide improved guidance and training on the use of communications equipment available to emergency response personnel.

10. Evaluate coordination between shift staffing and assigned duties during emergency conditions.

11. Evaluate enhanced diversification of power supplies for emergency assessment equipment.

12. Assemble and stage a telephone equipment repair kit.

SAFETY ASSESSMENT

As a result of lightning, both sources of offsite AC power were lost, and an automatic reactor scram and turbine trip occurred. The exact sequence of relay action leading to the reactor scram is not known, due to the deenergization of the sequence of events recorder during the event. Following the loss of power to the 480V emergency busses, all three EDGs operated as designed. Power continuity to two main coolant pumps was maintained despite the loss of all offsite power during coastdown of the main turbine-generator, as designed. Control room operators stabilized the plant in a hot standby (Mode 3) condition and verified natural circulation cooling.

As a consequence of lightning, both of the vital busses were briefly deenergized by blown surge protection fuses in their normal DC input supplies. Upon deenergization, the vital bus inverters [EIIS:INVT] automatically transferred to their individual backup sources (EDGs No. 1 and 3) and were reenergized by the associated EDG.

Approximately two hours into the event, control room operators attempted to restore normal AC power to Emergency Bus No. 1 from which the No. 1 Vital Bus was energized. In this evolution, EDG No. 1 was secured. A

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SIAS occurred after securing the EDG. The operators immediately restarted the EDG to restore power to the No. 1 Vital Bus. The SIAS was verified to be inadvertent.

Subsequent to the SIAS, all high pressure and low pressure safety injection pumps started as designed. Due to the pressure in the main coolant system, water injection did not occur.

At no time during this event was the plant in an unanalyzed condition or in a condition that was outside the design basis of the plant. All Engineered Safety Feature systems and equipment operated as designed. Therefore, the health and safety of the public were not adversely affected as a result of this event.

SIMILAR EVENTS

Similar events at the YNPS involving lightning disturbances resulting in a plant trip have been previously reported in LER 88-08, Rev. No. 1, LER 86-04, LER 83-22, LER 82-17 and LER 80-21.

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

TABLE 1

SEQUENCE OF EVENTS

6-15-91 2350 Lightnin, strike

Loss of both offsite AC power sources:

- Harriman (Z-126) transmission line
- Cabot (Y-177) transmission line

Automatic transfer of Vital Busses No. 1 and 2 to their backup sources

Automatic reactor scram and turbine trip

Loss of nonessential uninterruptible power supply (NEUPS) and instrumentation associated with it:

- Safety parameter display system (SPDS)
- Sequence of events recorder (SER)
- Steam generator (SG) process recorders
- Radiation monitoring instrument panels
- Loss of emergency feedwater flow indication (all four loops)

Loss of miscellaneous instrumentation (power supplies, amplifiers, recorders etc.)

Loss of selected communication systems:

- Emergency Notification System (ENS)
- Nuclear Alert System (NAS)
- Plant radio paging system
- Plant commercial phone system (PBX)

Loss of selected security system equipment:

- Security Event Report 91-S01 will provide a description of effects of lightning strike on the YNPS physical security system.

Two emergency diesel generators (EDGs) automatically started - one EDG manually started

Rupture discs blown on LP turbine (three out of four)

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

	2355	Initiated procedure OP-3251, "Loss of AC Supply"
		Report of smoke from No. 3 Station Service Transformer (SST) surge arrestor
		Fire brigade activated
6-16-91	0010	UNUSUAL EVENT declared
	0014	Offsite AC power partially restored - Harriman (2-126) transmission line
		Steam-driven emergency boiler feed pump operating/core decay heat removal occurring through emergency atmospheric steam dump valves
		Loss of normal level, pressure and feed indication on No. 2 and No. 4 SG (Channels 2 & 4)
		Main coolant system pressure stable at 2000 psig
	0030	Fire emergency terminated, fire brigade secured and fire watch established
	0035	Initiated procedure OP-2501, "Restoration of Normal AC Power After a Total Loss of AC"
	0047	Commonwealth of Massachusetts notified of UE
	0050	State of Vermont notified of UE
	0052	NRC notified of UE
	0130	ALERT declared
	0141	Commonwealth of Massachusetts notified of ALERT
	0145	State of Vermont notified of ALERT
	0155	Inadvertent safety injection actuation signal (SIAS) while normalizing emergency busses using OP-2501
		Initiated procedure OP-3051, "Safety Injection Termination Following Spurious Initiation"
	02.5	NRC notified of ALERT

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

0235 NEUPS restored

0240 Normal communication lines with NRC (ENS Red Phone) and States (NAS Orange Phone) operational in control room

Plant radio paging system operational

0410 Restored normal power supply to No. 2 vital bus

Secured No. 3 EDG

0413 Restored normal power supply to No. 1 vital bus

0415 Secured No. 2 EDG

0450 Returned 480V Station Service Bus 6-3 to service - power being supplied by No. 1 EDG

De-escalate to UNUSUAL EVENT
(State of Vermont notified and concurred at 0422 hours. Commonwealth of Massachusetts notified at 0422 hours and concurred at 0450 hours.)

0453 Restored power to meteorological monitoring system

0455 NRC notified of de-escalation to UNUSUAL EVENT via ENS Red Phone

0555 SG Channels 2 & 4 returned to service

0625 Preparing for plant cooldown - main coolant system (MCS) stable at 2000 psig and 494 °F

Pressurizer level at 124 inches

SG feed with main feedwater system

Steam released through emergency atmospheric steam dump valves

Preparing to borate MCS and restart main coolant pumps

0715 Operability of plant commercial phone system restored with limited functionality

6-17-91 0755 Plant attained cold shutdown (Mode 5) condition

0925 Termination of UNUSUAL EVENT

NRC FORM 366A

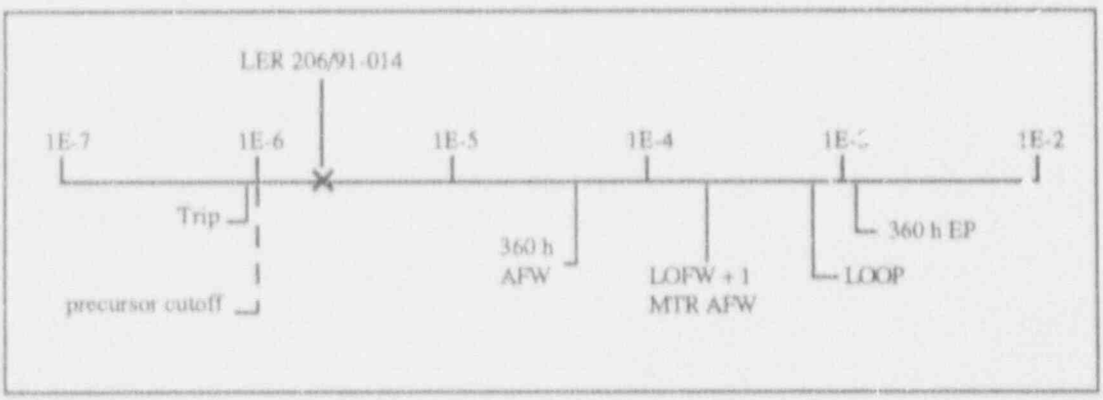
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No:	206/91-014
Event Description:	Inoperable volume control tank level transmitters
Date of Event:	August 7, 1991
Plant:	San Onofre 1

Summary

The automatic actuation for re-alignment of the charging pumps from the volume control tank (VCT) to the refueling water storage tank (RWST) on low VCT level was disabled. In the event of a small-break loss-of-coolant accident (LOCA), and if manual realignment failed, the charging pumps would become gas bound due to hydrogen from the VCT. This condition existed for ~17 h.

The conditional probability of core damage associated with this event is 2.1×10^{-6}. The relative significance of the event compared to other postulated events at San Onofre 1 is shown below:



Event Description

VCT level transmitter LT-1100 was exhibiting erratic indication as compared to the opposite train level transmitter (LT-2550). To avoid inadvertent actuation during corrective maintenance on LT-1110, the automatic actuation functions of both transmitters were bypassed. Both transmitters were bypassed for a period of ~17 h.

Additional Event-Related Information

Level transmitters (LT-1100 and LT-2550) function to realign the charging pumps from the VCT to the RWST when the VCT level becomes low and to provide a protective trip to the charging pumps to avoid the introduction of VCT hydrogen gas to the pump suctions. On a low-low VCT level, each level transmitter (LT-1110 for train A and LT-2550 for train B) initiates opening of its respective RWST isolation valve; when these valves complete opening, limit swiiches initiate closure of the associated VCT isolation valves.

On low-low-low VCT level these transmitters also trip the charging pumps. Two trains of automatic charging pump protection are provided on low VCT level to preclude the VCT hydrogen cover gas from gas binding and potentially damaging the charging pump.

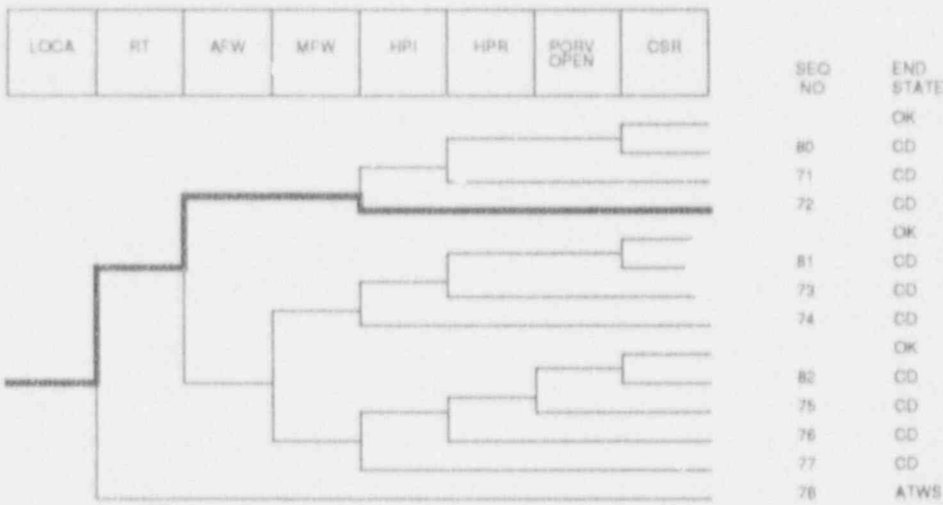
The valves controlled by LT-1100 and LT-2550 were still capable of being repositioned by their safety injection (SI) contacts. However, for certain small LOCAs, the VCT would have drained and the charging pumps would have been damaged before the reactor coolant system depressurized to the SI setpoint.

ASP Modeling Assumptions and Approach

The level transmitters were assumed to be unavailable for 17 h. For the purposes of this analysis, all potential small-break LOCAs were assumed to be small enough to drain the VCT before reaching the SI setpoint. Because the operators were aware that VCT level transmitters were unavailable, a non-recovery probability of 0.12 for high-pressure injection (HPI) was assumed. Feed and bleed was assumed not to be impacted by the unavailability of the level transmitters, since SI is manually actuated when initiating feed and bleed.

Analysis Results

The conditional probability of subsequent core damage estimated for this event is 2.1×10^{-6}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated LOCA with successful reactor trip and auxiliary feedwater initiation with a failure of HPI.



Dominant core damage sequence for LER 206/91-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

```
Event Identifier:  206/91-014
Event Description: Inoperable Volume Control Tank level transmitters
Event Date:        08/07/1991
Plant:             San Onofre 1
```

UNAVAILABILITY, DURATION= 17

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	2.0E-03
LOOP	1.9E-04
LOCA	1.8E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	2.1E-08
LOOP	5.9E-09
LOCA	2.1E-06
Total	2.1E-06
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	2.1E-06	5.2E-02

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	2.1E-06	5.2E-02

** 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:\asp\1989\pwrbseal.cmp
BRANCH MODEL:        c:\asp\1989\sanono1.sll
PROBABILITY FILE:    c:\asp\1989\pwr_bsll.pro
```

No Recovery Limit

Event Identifier: 206/91-014

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.2E-04	1.0E+00	
loop	2.0E-05	5.8E-01	
locs	2.4 -06	4.3E-01	
sgtr	2.3E-04	1.2E-01	
sgtr/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	1.0E-03
afw	2.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.9E-01	3.4E-01	
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	3.2E-01	1.0E+00	
ep.rec(sl)	7.6E-01	1.0E+00	
ep.rec	1.6E-01	1.0E+00	
HPI	1.0E-03 > 1.0E+00 **	8.4E-01 > 1.2E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-03

* branch model file
** forced

Minarick
06-07-1992
21:39:07

Event Identifier: 206/91-014

LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
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Title (4)

ENTRY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO INOPERABLE VOLUME CONTROL TANK LEVEL TRANSMITTERS

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 Names	Docket Number(s)
									NONE	0 5 0 0 0
0 8	0 7	9 1	9 1	0 1 4	0 0	0 9	0 6	9 1		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 0

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

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

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER: AREA CODE	
R. W. Krieger, Station Manager	7 1 4	3 6 8 - 6 2 5 5

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
XX Yes (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 1	2 6	9 2

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

On August 7, 1991 at 1135, with Unit 1 in Mode 1 at approximately 90% power, Volume Control Tank (VCT) level transmitter LT-1100 was exhibiting erratic indication as compared to the opposite train level transmitter (LT-2550). These level transmitters function to realign the charging pumps from the VCT to the refueling water storage tank when the VCT level becomes low, and provides a protective trip to the charging pumps to avoid the introduction of VCT hydrogen gas to the pump suction. To avoid inadvertent actuation during corrective maintenance on LT-1100, the automatic actuation functions of both transmitters were bypassed. At 0440 on August 8th, the automatic protection afforded by LT-2550 was restored since maintenance which could affect both transmitters had been completed.

At about 1700 on August 8th, it was recognized that removal of the automatic actuation feature was contrary to the requirements of TS 3.3.1, "Safety Injection System ... - Operating Status," section A(3) since an applicable action statement governing these components is not provided. As such, shutdown of Unit 1 was initiated at 1800 per TS 3.0.3. SCE requested a temporary 72-hour waiver of compliance from the above TS requirements since a previously submitted TS change provided a 72-hour action statement for this situation. The NRC verbally approved the waiver at approximately 2000. The unit shutdown was then suspended.

LT-1100's erratic indication resulted from loose fasteners in the transmitter which have been corrected and the transmitter restored to service. SCE's investigation into the cause of the loose fasteners is continuing. Resolution of NRC questions on the pending TS change are being expedited. The results of the investigation and any applicable corrective actions will be reported in a supplement to this LER.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

SAN ONOFRE NUCLEAR GENERATION STATION UNIT 1	DOCKET NUMBER 05000206	LER NUMBER 91-014-00	PAGE 2 of 8

Plant: San Onofre Nuclear Generating Station
Unit: One
Reactor Vendor: Westinghouse
Event Date: August 7, 1991
Time: 1135

A. CONDITIONS AT TIME OF THE EVENT:

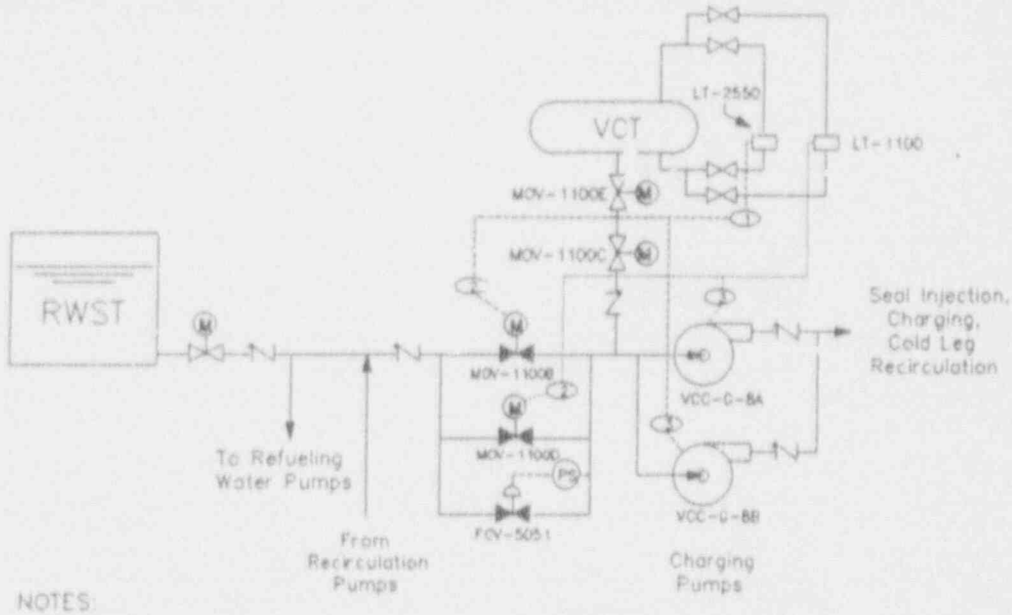
Mode: 1, Power Operation

B. BACKGROUND INFORMATION:

1. Charging Pump Protection on Low Volume Control Tank (VCT) Level:

During normal power operation, one of the two charging pumps provide borated water from the VCT [CB,TK] to the Reactor Coolant System (RCS) [AB] as shown in the following figure. In the event of certain small break Loss of Coolant Accident (LOCA) scenarios, the centrifugal charging pumps [CB,P] could maintain sufficient RCS inventory to prevent initiation of a safety injection actuation signal while emptying the VCT. Two trains of automatic charging pump protection are provided on low VCT level to preclude the VCT hydrogen cover gas from gas binding and potentially damaging the charging pump(s) after the VCT empties during such events. Each train consists of a VCT level transmitter [LT] and an associated control loop, a normally open valve [ISV] in the charging pump suction from the VCT, a normally closed valve [ISV] in the charging pump suction from the Refueling Water Storage Tank (RWST), and trip circuitry for the associated charging pump. On a low-low VCT level, each train's level transmitter (LT-1100 for train "A" and LT-2550 for train "B") initiates opening of its respective RWST isolation valve (MOV-1100D and MOV-1100B, respectively); when these valves complete opening, limit switches initiate closure of the associated VCT isolation valves (MOV-1100C and MOV-1100E, respectively). On a low-low-low VCT level LT-1100 trips charging pump VCC-G3A, and LT-2550 trips charging pump VCC-G3B. LT-2550 also initiates a VCT level low alarm in the control room. LT-1100 also automatically maintains VCT level by controlling makeup.

During surveillance testing or when corrective maintenance is necessary on loop components, it is necessary to block automatic actuation of components whose automatic actuation could upset plant operations (i.e., stop the running charging pump or switch charging pump suction from the VCT to the RWST).



NOTES:
Control Room Alarm on Low VCT Level.
Opens MOV-1100 B & D on Low-Low VCT Level.
MOVs 1100 B & D Open Contacts Initiate Closure of MOV-1100 C & E.
Stops Charging Pump on Low-Low-Low VCT Level.

Figure - Charging Pump Low VCT Level Protection

2. Existing Technical Specifications (TS):

TS 3.3.1, defines the operability requirements for the Safety Injection System (SIS) [BP and BQ]. The objective of the TS is to ensure availability of the SIS while the reactor is critical. TS 3.3.1, A(3) requires, in part, that valves and interlocks associated with the SIS be maintained operable but does not provide an ACTION statement with an Allowable Out-of-service Time (AOT) for many SIS components, including the VCT level transmitters. This specification was written before the Standard TS's which generally allow most Emergency Core Cooling System (ECCS) components having a redundant counterpart (or system) an AOT of 72 hours. This specification applies to the VCT level transmitters LT-1100 and LT-2550 and the associated MOVs.

TS 3.0.3 requires, in part, that when a limiting condition for operation is not met, except pursuant to associated ACTION requirements, unit shutdown shall be initiated within one hour and that the unit be placed in COLD SHUTDOWN in the following 36 hours.

3. TS Amendment Application:

SCE submitted a proposed TS change (letter, H. B. Ray (SCE) to USNRC Document Control Desk, Amendment Application 188, dated August 31, 1990) which among other changes, would modify the existing TS 3.3.1 and add TS 3.3.2 to be generally consistent with the Standard TS philosophy for ECCS. Appropriate action statements provided in the proposed change would permit the removal of one train of certain safety injection components (including the VCT level transmitters) from service for up to 72 hours.

C. DESCRIPTION OF THE EVENT:

1. Event:

On August 7, 1991 at 1135, with Unit 1 in Mode 1 at approximately 90% power, VCT level transmitter LT-1100 was exhibiting erratic indication as compared to the opposite train level transmitter (LT-2550). Maintenance was initiated on LT-1100 at that time and, to preclude potential spurious actuations due to the maintenance: 1) Automatic actuation of the MOVs on low VCT level by LT-1100 and LT-2550 was blocked; and 2) The low VCT level charging pump automatic trip was blocked for both pumps. Since: 1) the valves controlled by LT-1100 and LT-2550 were still capable of being repositioned by their respective safety injection initiated contacts, and 2) a comparison of the level transmitter function to potentially applicable TS did not reveal any TS applicability, no TS was thought to apply. At 0440 on August 8th, both MOVs controlled by LT-2550 were restored to automatic operation and the associated low VCT level charging pump trip was restored since the maintenance which could potentially affect both level transmitters had been completed. The automatic operation of the MOV's associated with LT-1100 and its associated charging pump trip remained blocked, however, since the cause of the erratic operation of the transmitter had not been determined.

At about 1700 on August 8th, it was concluded that operation in Modes 1 or 2 with one inoperable level transmitter (LT-1100) was contrary to the requirements of TS 3.3.1, A(3) (i.e., inoperable valves and interlocks). Therefore, shutdown of Unit 1 was initiated at 1800 per the requirements of TS 3.0.3 and an Unusual Event (UE) was declared in accordance with our Emergency Plan Implementing Procedures. The UE was exited at 1922. SCE requested a temporary 72-hour waiver of compliance from the above TS requirements since a TS change then under NRC review, would have allowed a 72-hour action statement in this circumstance. The NRC verbally approved the waiver at approximately 2000 on August 8th. The unit shutdown was then suspended.

2. Inoperable Structures, Systems or Components that Contributed to the Event:

   Not applicable.

3. Sequence of Events:

DATE - TIME	ACTION
8/7 - 1135	LT-1100 and LT-2550 removed from service. MOVs 1100B, C, D and E placed in manual control; the VCT low level trip for both charging pumps is blocked.
8/8 - 0440	MOVs 1100B and E were restored to automatic actuation by LT-2550; Charging pump VCC-G8B low VCT level trip is restored.
8/8 - 1700	TS 3.0.3 is entered.
8/8 - 1800	Unit shutdown initiated and UE declared.
8/8 - 1922	UE exited.
8/8 - 2000	Waiver of TS compliance granted and the unit shutdown is suspended.
8/9 - 1635	LT-1100 restored to operability, MOVs 1100C and D returned to automatic actuation, and the charging pump VCC-G8A low VCT level trip is restored.

4. Method of Discovery:

   Operators observed differences in the indicated VCT level between the two level channels (LT-2550 and LT-1100) and erratic level indication by LT-1100.

   Due to the erratic behavior of LT-1100, a temporary design change was requested to switch the automatic VCT level control function from LT-1100 to LT-2550. During a feasibility review of the change request, it was recognized that operation with blocked charging pump protection on low VCT level was contrary to the TSs.

5. Personnel Actions and Analysis of Actions:

   Not applicable.

6. Safety System Responses:

   Not applicable.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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D. ROOT CAUSE OF THE EVENT:

1. The problems exhibited by LT-1100 were caused by loose fasteners in the transmitter which allowed some internal parts to bind and others (which should be locked together) to rotate. An investigation has been initiated to determine why the level transmitter fasteners were loose.

2. The safety function of the charging pump suction isolation valves and the charging pump trip was determined to be satisfied with the automatic controls either enabled or blocked since proper automatic operation would occur in the event of a safety injection signal. It was not recognized that for certain small break LOCA events, the VCT could empty and potentially lead to charging pump damage prior to initiation of the safety injection signal which would switch the charging pump suction to the RWST.

E. CORRECTIVE ACTIONS:

1. Corrective Actions Taken:

   LT-1100 has been repaired, calibrated, and returned to service.

2. Planned Corrective Actions:

   a. As noted in Section D.1 above, an investigation to determine the root cause of the loose LT-1100 fasteners is in progress. Appropriate corrective action will be developed and implemented based on the findings of our investigation. The investigation results and our corrective action to prevent recurrence will be provided in a supplement to this LER.

   b. Appropriate procedures will be revised to preclude simultaneously disabling both trains of charging pump low VCT level protection.

   c. Guidance provided to the operators with respect to the equipment governed by TS 3.3.1 is being augmented by a background document intended to correlate the ECCS components to the associated LCOs and action requirements.

   d. A TS change has been proposed which would provide a 72-hour AOT for one train of safety injection components.

F. SAFETY SIGNIFICANCE OF THE EVENT:

1. One VCT level transmitter inoperable.

   Continued operation with a VCT level transmitter inoperable for a period of 72 hours is of no safety significance for the following reasons:

a. Unit 1 is provided with two independent and redundant trains of ECCS (which includes safety injection), including the capability to realign the charging pump suction from the VCT (on low VCT level or safety injection) to the RWST. Either train is capable of mitigating any event requiring the use of the ECCS. These provisions ensure that a single failure could not prevent completion of this aspect of a required safety function. In this regard, SCE has recently completed an ECCS single failure analysis and certain plant upgrades to assure completion of required ECCS functions in the event of a single failure.

b. Consistent with these changes, SCE had previously concluded that a TS change was appropriate to preclude unnecessary entries into TS 3.0.3. In this regard, SCE submitted a proposed TS change which would modify the existing TS 3.3.1 and add TS 3.3.2 to be consistent with the Standard TSs for ECCS as discussed in Section B.3 above.

c. The AOT (72 hours) being proposed is of minimal safety significance when compared to the risks associated with initiating a plant shutdown for the purposes of repairing or testing these level transmitters. The risks for the AOT are also similar to that for any other one-of-two train systems or components having a 72-hour action statement.

Further, the probability of core damage as a result of the inoperability of a VCT level transmitter for up to 72 hours has been calculated to be approximately 5E-7 per year.

2. Operation with Blocked Charging Pump Protection on Low VCT Level:

In the event of a large break LOCA or Main Steam Line Break, MOVs 1100B, C, D and E would be automatically actuated to realign the charging pumps' suction from the VCT to the RWST by the safety injection signal thereby satisfying the safety function of these valves.

For certain small break LOCA scenarios, the operating charging pump would maintain RCS pressure and volume above the SI actuation conditions while drawing down the VCT level. Operators were fully aware of the blocked automatic charging pump protection on low VCT level and the consequences of gas binding the charging pumps. In the event of a small break LOCA, LT-2550 would have initiated a low VCT level alarm in the control room as the VCT was pumped down and the operators would have realigned the charging pump suction to the RWST per procedure.

In the unlikely event that operators were unsuccessful in preventing charging pump damage, the RCS would be depressurized and low head pumps would be used in accordance with procedures to re-establish and

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

SAN ONOFRE NUCLEAR GENERATION STATION UNIT 1	DOCKET NUMBER	LER NUMBER	PAGE
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maintain core cooling. Therefore the conditions described above are of minimal safety significance.

G. ADDITIONAL INFORMATION:

1. Component Failure Information:

LT-1100 is a torque tube displacer type level transmitter manufactured by Masoneilan International, Inc, model number 0120.

2. Previous LERs for Similar Events:

LERs 89-024 and 89-026 (Docket No. 50-206) reported, in part, TS violations which occurred as the result of misinterpretation of the existing TS 3.3.1. The corrective action described in these LERs to address such misinterpretations was preparation of a TS amendment application which would establish appropriate TS requirements and appropriate out-of-service times for ECCS components. Concurrent with preparation of this amendment application, SCE was performing an ECCS single failure analysis which identified needed ECCS single failure enhancements. These enhancements were implemented during the Cycle 11 refueling outage during the last half of 1990. A TS amendment application was submitted to the NRC on August 31, 1990 to provide appropriate ECCS TSs which also address the added single failure enhancements. This TS amendment application is being actively reviewed. Due to the comprehensive nature of the proposed TS change, the review process has not yet been completed. As a result, this corrective action could not prevent recurrence of TS 3.3.1 misinterpretation.

3. Other Additional Information:

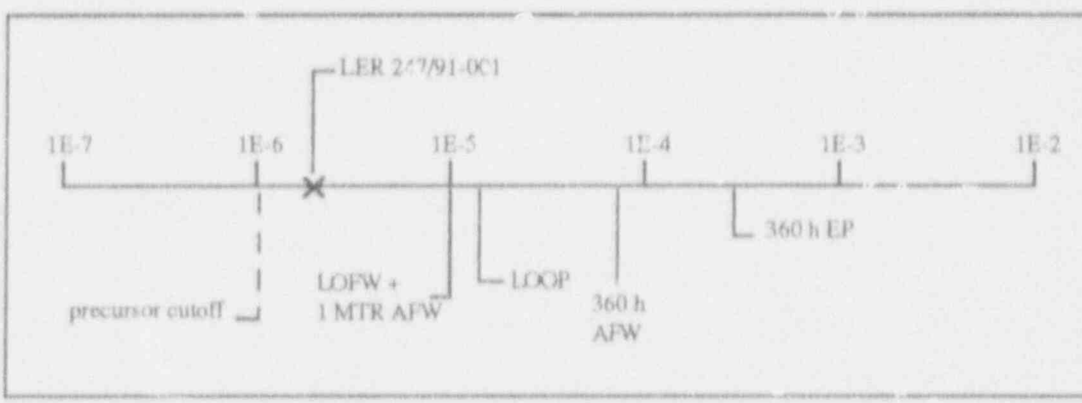
By letter dated August 26, 1991, R. W. Krieger (SCE) to USNRC Document Control Desk, "Level Transmitter Surveillances - Safety Injection," SCE requested a temporary waiver of compliance from the requirements of TS. 3.0.3, without fully complying with the requirements of TS 3.3.1. The purpose of this request was to avoid unnecessary plant shutdowns while the affected level transmitter (LT-1100 or LT-2550) is removed from service for surveillance testing and for the performance of any corrective maintenance which may become necessary. The duration of the requested waiver was from August 28th until issuance of the TS changes proposed by Amendment Application number 188. On August 28, 1991, the NRC verbally approved SCE's August 26th request. Following NRC approval of the waiver request, LT-1100 and LT-2550 were removed from service for performance of the routine monthly surveillance on August 29, 1991 in accordance with the provisions of the waiver.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	247/91-001
Event Description.	Reactor trip and auxiliary feedwater pump failure
Date of Event:	January 7, 1991
Plant:	Indian Point 2

Summary

Maintenance errors resulted in a spurious low pressurizer pressure reactor trip. A subsequent low steam generator (SG) level signal initiated an automatic start of both motor-driven auxiliary feedwater (AFW) pumps. After about two min, faulty protective circuitry caused one auxiliary feedwater pump to trip. The conditional probability of subsequent core damage estimated for the event is 2.0 x 10^{-6}. The relative significance of the event compared to other postulated events at Indian Point 2 is shown below.



Event Description

Indian Point 2 was operating at 97% power when repair work was begun on a leaky compression fitting in a pressurizer pressure transmitter sensing line. The transmitter was isolated and repairs effected. During this time, the affected transmitter falsely indicated a low pressurizer pressure. While the sensing line was being restored to service, a pressure transient in the sensing line resulted that caused a second pressure transmitter to indicate low. Coincidence of low pressurizer pressure indication from the two transmitters caused a reactor trip.

A short time later, low level in the SGs resulted in actuation of the AFW system. Motor-driven AFW pumps 21 and 23 started and began supplying feedwater. About two min later, AFW pump 21 tripped and would not restart. This resulted in a loss of feedwater flow to SGs 21 and 22. Subsequent investigation revealed that the pump motor breaker spuriously tripped on overcurrent as a result of miscalibration of an associated overcurrent protective device. The device, an Amptector, was set to trip at 540 A instead of at 725 A. Normal operating current for the motor is ~530 A. Operators did not initially know that the pump had tripped on overcurrent as faulty relay contacts in the breaker resulted in control room indication that the pump was off, but not that it had tripped. The 22 AFW turbine-driven pump was started and used to supply the affected steam generators.

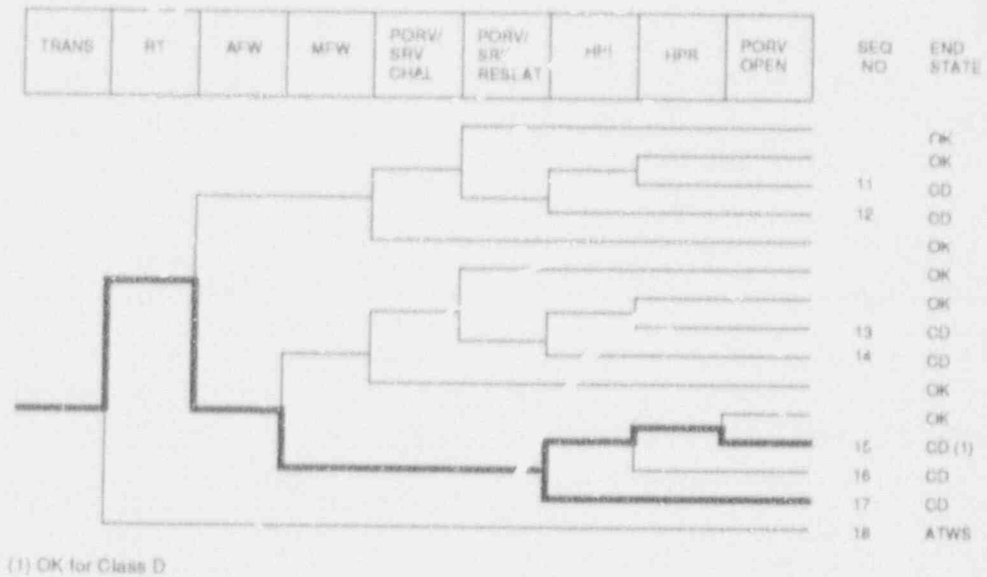
ASP Modeling Assumptions and Approach

This event was modeled as a reactor trip with loss of one motor-driven AFW pump.

Analysis Results

The estimated core damage probability associated with a reactor trip and failure of one motor-driven AFW pump was calculated as 2.0×10^{-6}.

The dominant core-damage sequences involve failure of main feedwater, failure of the remaining AFW systems, and failures in systems required for feed-and-bleed heat removal. The two dominant sequences are shown on the following event tree.



Dominant core damage sequence for LER 247/91-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 247/91-001
Event Description: Reactor trip and AFW pump failure
Event Date: 01/07/91
Plant: Indian Point 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	2.0E-06
Total	2.0E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW mfw -hpi(f/b) -hpr/-hpi porv.open	CD	9.6E-07	8.8E-02
17	trans -rt AFW mfw hpi(f/b)	CD	9.6E-07	7.4E-02
16	trans -rt AFW mfw -hpi(f/b) hpr/-hpi	CD	1.1E-07	8.8E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW mfw -hpi(f/b) -hpr/-hpi porv.open	CD	9.6E-07	8.8E-02
16	trans -rt AFW mfw -hpi(f/b) hpr/-hpi	CD	1.1E-07	8.8E-02
17	trans -rt AFW mfw hpi(f/b)	CD	9.6E-07	7.4E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbasel.cmp
BRANCH MODEL: c:\asp\1989\indpoint.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail

Event Identifier: 247/91-001

trans	4.6E-04	1.0E+00	
loop	3.1E-05	1.7E-01	
loca	2.4E-06	4.3E- 1	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	5.4E-04	8.0E-01	
AFW	3.8E-04 > 5.3E-03	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
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	2.1E-01	1.0E+00	
ep.rec(sl)	6.0E-01	1.0E+00	
ep.rec	5.6E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
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

Minarick
03-11-1992
11:10:46

Event Identifier: 247/91-001

NRC FORM 366 (6-89) — U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	1 OF 0 5

TITLE (4): RPS Low Pressurizer Pressure Logic Actuation

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 NAMES	DOCKET NUMBER(S)
0 1	0 7	9 1	9 1	0 0 1	0 1	0 3	0 5	9 1		0 5 0 0 0
										0 5 0 0 0

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

OPERATING MODE (9): N
POWER LEVEL (10): 0 9 6

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Claude Peart, Senior Engineer	9 1 4 5 2 6 - 5 1 9 0

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	I B	X I		N					
X	B A	B K R	W 1 2 0	N					

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

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

On January 7, 1991 at appro imately 11:02 a.m., with the unit operating at 96.5% power, the reactor ripped. The trip was generated by the reactor protection system (RPS) two out of four coincidence logic for a low pressurizer pressure. The low pressurizer pressure logic actuation occurred as a result of maintenance activity on pressurizer pressure transmitter PT 455. The operators responded to the event in accordance with established plant procedures and the plant systems responded as designed, with the exception of auxiliary feedwater pump No. 21. This pump started and tripped after running for approximately 120 seconds. Consequently, at 11:05 a.m., the plant entered a 72 hour limiting condition of operation (LCO) as required by Technical Specification 3.4.B(1)(a). Also during the event, the isolation of the chemical volume control system normal letdown occurred and the bank "C" rod "L3" bottom light did not illuminate as required by design.

The plant achieved hot shutdown at approximately 11:30 a.m. and restart was subsequently initiated with the generator breakers closed on the grid on January 8, 1991 at approximately 8:36 p.m. No NRC limit was exceeded. Likewise there was no impact on public health and safety.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 1	0 0 1	0 1	0 2 OF 0 5

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

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse 4-Loop Pressurized Water Reactor

IDENTIFICATION OF OCCURRENCE:

Inadvertent Low Pressurizer Pressure Logic Actuation initiating a reactor trip.

EVENT DATE:

January 7, 1991

REPORT DUE DATE:

February 5, 1991

REFERENCES:

Significant Event Reports (SOR) 91-13, 91-14

PAST SIMILAR OCCURRENCE:

None

DESCRIPTION OF OCCURRENCE:

On January 7, 1991 at 11:02 a.m., with the unit operating at 96.5% power, the reactor tripped. Earlier that morning, at approximately 10:58 a.m., a containment entry was made by plant personnel to repair a leak in a compression fitting in the sensing line of pressurizer pressure transmitter PT 455. This sensing line is common to another redundant pressurizer pressure transmitter, PT 474. The repair team, subsequent to communicating with the control room operators, proceeded to effect this repair by manually closing the isolation valve (537 X B2) for PT 455. After the repair was completed the repair team began restoring PT 455 to service by slowly re-opening its isolation valve. This effort caused a momentary depressurization in the common sensing line, ultimately causing a low pressurizer pressure value in pressurizer pressure transmitter PT 474. With both PT 474 and PT 455 reading low, the necessary two out of four reactor protection system (RPS) logic for a low pressurizer pressure reactor trip was satisfied and the reactor tripped, consistent with design.

As required, the plant operators immediately entered emergency operating procedure E-0 "Reactor Trip or Safety Injection" and began to effect the shutdown of the reactor.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 1	— 0 0 1 —	0 1	0 3 OF 0 5

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

DESCRIPTION OF OCCURRENCE: (continued)

Subsequent to the trip, and as is normal for this type of transient, the steam generators narrow range level instrumentation indicated a dramatic decrease in secondary side fluid level (the shrink effect of a trip). At a level of 8%, a signal to the auxiliary feedwater pumps (AFWP) to start is generated. This occurred at approximately 6.5 seconds after the reactor trip signal. Both motor driven AFWP No. 21 and 23 started and commenced feedwater injection at approximately 11:02 a.m. At approximately 11:04 a.m., AFWP No. 21 tripped and feedwater flow to steam generators (SG) No. 21 and 22 was lost. While reviewing the requirement of step 3(d) of emergency operating procedure ES-0.1 "Reactor Trip Response," one manual attempt to start AFWP No. 21 was made by the operators, subsequent to which the pump was declared inoperable. Consequently, at approximately 11:05 a.m., the plant entered a 72 hour limiting condition of operation (LCO) as stipulated by Technical Specification 3.4.B(1)(a). Feedwater flow was re-established to SGs No. 21 and 22 at approximately 11:06 a.m. via the steam driven AFWP No. 22 and the LCO was subsequently terminated at approximately 06:46 p.m.

The immediate determination of the cause for the AFWP No. 21 trip was determined to be overcurrent, as reflected by the pump breaker indicators. Further investigation found no mechanical or electrical problem with AFWP No. 21 or its motor. The overcurrent trip setting of the overcurrent trip device (Amptector long delay pickup) was checked and discovered to have an improper setting. This as found Amptector setting resulted in a decrease in the current setpoint from approximately 725 Amperes to 540 amperes (.9 x rated current of 600 amperes versus 1.25 x rated current). 540 amperes is very close to the expected current when the pump is delivering rated flow (approximately 400 gpm). Subsequent analysis of pump test data indicated that the pump's motor current is approximately 530 amperes when it is delivering 403 gpm. Therefore, the trip of AFWP No. 21 was attributed to the incorrect long delay pickup amptector setting. It was observed that the setpoint could be inadvertently moved if, in the process of breaker handling, plant personnel were to touch the amptector setpoint adjustment wheel.

In regards to the failure of AFWP No. 21 to manually start on demand, the operators were unaware that the pump had previously started and tripped, as indicated during subsequent analysis of computer data. Specific breaker contacts provide pump status indication in the control room. One of these contacts causes the amber breaker "mismatch" light to be energized in the control room. This light, when seen in combination with the green "breaker open" light in the control room,

NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 1	0 0 1	0 0	0 4 OF 0 5

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

DESCRIPTION OF OCCURRENCE: (continued)

would indicate a "trip" condition of the pump breaker. Due to a fault in the AFWP No. 21 breaker "mismatch" contact, the amber light was not energized in the control room. With only the green breaker "open" light energized, the operators believed AFWP No. 21 did not automatically start as required, and proceeded to manually start the pump from the control room during the recovery process.

Consequently, the reason for the failure of AFWP No. 21 to start when given a manual start signal from the control room is therefore attributed to the fact that the pump's circuit breaker, as required following a trip, was not first reset by the operators. This was not done for the reasons discussed previously. The pump breaker was subsequently replaced.

The Chemical Volume and Control System (CVCS) normal letdown isolation occurred because the controlling pressurizer level instrument channel (LT 460) went below the 18% letdown isolation pressurizer level setpoint. It was later observed that this channel value deviated considerably from the other two channel values which were indicating above 20% of pressurizer level at the same time. Data analysis further revealed all channel readings converged approximately 400 seconds later. This appears to indicate instrument recalibration may be necessary. An operational check on instrument channel LT 460 was subsequently performed by Instrument and Control personnel with no identified deficiency. These pressurizer level channels are scheduled to be calibrated during the upcoming refueling outage (February, 1991).

The bank "C" rod "L3" control rod bottom light in the control room did not illuminate. This was immediately attributed to a blown bulb. The defective bulb was subsequently replaced.

Later in the day, the AFWP No. 21 was successfully tested in accordance with approved plant procedures. The pump's circuit breaker was replaced and also tested in accordance with approved plant test procedure and returned to service. Having verified, the operability of AFWP No. 21 and its circuit breaker, and having corrected the incorrect amptector long delay pickup setting, plant restart was initiated and the generator breakers were closed on the grid on January 8, at approximately 08:36 p.m.

ANALYSIS OF OCCURRENCE:

This report is being made since actuation of the reactor protection system (RPS) occurred. Any manual or automatic actuation of the RPS is reportable under 10 CFR 50.73(a)(2)(iv). There were no adverse safety implications for this event. All systems performed as expected with the exception of the components mentioned previously. Equipment design envelopes were not exceeded and identified deficiencies were corrected.

NRC Form 366A (6-89)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 1	0 0 1	0 1	0 5 OF 0 5

CAUSE OF OCCURRENCE:

The reactor trip occurred as a result of a momentary depressurization of pressurizer pressure transmitter PT 474 while another pressurizer pressure transmitter PT 455, on a common sensing line, was being valved back in service. Our review of industry experience, prior to this event, did not reveal the phenomena specifically encountered in this instance.

In regard to the response of AFWP No. 21 to this event it appears that inadvertent instrument setpoint adjustment occurred.

The CVCS normal letdown isolation occurred, as noted previously, as a result of the controlling pressurizer level instrument channel sensing a pressurizer pressure level below 18%, which is the value for CVCS normal letdown isolation. The isolation occurred at the correct time and setpoint value. However, the readings for all channels over time indicate recalibration may be necessary.

The cause for bank "C" rod "L3" control rod bottom light in the Control Room not illuminating was immediately attributed to a blown bulb which was replaced.

CORRECTIVE ACTION:

1) Engineering was requested to evaluate and implement a method to prevent inadvertent amptector setting adjustment by the end of the February, 1991 refueling outage.

2) Calibrate pressurizer level instruments during the February 1991 refueling outage

3) The breaker for AFWP No. 21 was replaced with a spare unit, and subsequently tested in accordance with approved plant procedures.

4) The blown bank "C" rod "L3" control rod bottom light in the control room was replaced.

5) For pressurizer pressure transmitters PT 455 and PT 474, provide enhanced guidance and policy for instrument maintenance that will preclude the possibility of a similar event. Additionally, an engineered solution for the momentary depressurization of these transmitters, is also being evaluated.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

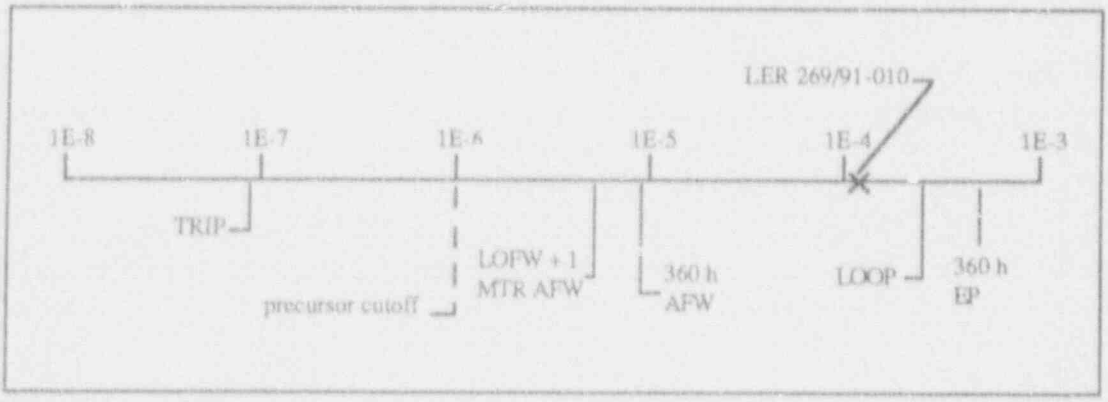
LER No.:	269/91-010, 270/91-003
Event Description:	Potential for hydrogen entrainment in HPI pumps
Date of Event:	September 19, 1991
Plant:	Oconee 1, Oconee 2, and Oconee 3

Summary

During an analysis of the letdown storage tank (LDST) high-pressure alarm setpoint, it was determined that the potential existed for hydrogen entrainment in the high-pressure injection (HPI) pumps during small-break loss-of-coolant accident (LOCA) scenarios involving failure of either of the borated water storage tank (BWST) isolation valves to open.

LDST hydrogen overpressure is normally adjusted so that the BWST will provide flow to the HPI pumps during a safety actuation. In this situation, the higher BWST pressure seats the LDST outlet check valve and prevents hydrogen from expanding into the HPI pump suction piping. During review of a 1971 Babcock & Wilcox curve of maximum LDST pressure as a function of inventory, it was determined that the curve was based on an assumption that the LDST would be isolated within 6.5 min for certain scenarios. This action is not specified in the procedures. In addition, the single valve provided for this purpose is not safety-related nor is it provided with safety-related controls or power.

Subsequent analyses by the utility, which considered flow-related pressure drops, indicated that hydrogen entrainment would only occur if one of the BWST isolation valves failed to open. In this case, the additional pressure drop in the single operating line would allow hydrogen to expand into the HPI pump suction lines and damage the pumps. The conditional core damage probability estimated for this event is 1.2×10^{-4}. The relative significance of the event compared to other postulated events at Oconee 1 is shown below.



Event Description

On April 16, 1991, with Oconee 2 at full power, hydrogen was being added to the LDST. At the completion of this operation, a non-licensed operator observed that the hydrogen supply had not been isolated when the fill-line solenoid valve was closed. After manual isolation, the LDST pressure exceeded procedural limitations, and the excess pressure was vented. Both trains of HPI were declared inoperable for the duration of the overpressurization (~20 min) due to the potential for hydrogen to enter the HPI pump suctions following a LOCA and damage the pumps.

During a review of that event, it was observed that the setpoint for the control room alarm for high LDST pressure exceeded the highest procedurally specified LDST pressure, and a setpoint change was requested.

The setpoint review utilized a draft 1990 limit and precautions document, which included a copy of a 1971 curve developed by Babcock & Wilcox that specified the maximum LDST pressure as a function of BWST level. The curve was based on calculations that, for certain scenarios, assume the operator will isolate the LDST within 6.5 min by closing HP-23, the LDST outlet header isolation valve. HP-23 is not safety-related and does not have safety-related controls or power. Also, Oconee operating procedures did not require HP-23 to be closed.

The 1971 curve was based on calculations that addressed static head differences, but did not consider pressure drops due to flow. Calculations performed by the utility after this problem was discovered, which addressed flow-induced pressure drops, indicated the existing LDST hydrogen pressure curve was adequate for most scenarios without closure of HP-23.

The one exception was a small-break LOCA during which one of the two BWST isolation valves fails to open. In this case, all HPI injection flow would pass through one suction supply line, which would lead to higher pressure losses and lower pressure in the suction supply header, and would result in hydrogen entrainment from the LDST and HPI pump damage.

This problem applied to all three Oconee units. As a short-term corrective action, new pressure curves were developed that provided additional margin to assure hydrogen from the LDST would not expand into the HPI pump suction piping for all scenarios that do not involve a single failure of a valve in the lines from the BWST. In addition, new instructions were provided to the operators to align the HPI system for piggy-back operation (HPI pump suction flow provided by low-pressure injection pumps) if a single failure of a BWST line valve occurred. Use of the piggy-back mode would provide additional suction pressure at the HPI pumps and prevent hydrogen entrainment (provided a failed suction valve could be detected).

Additional Event-Related Information

The HPI system controls the reactor coolant system (RCS) inventory, provides seal water for the reactor coolant pumps, and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control. The HPI system uses the LDST as a surge tank and normal suction source for the HPI pumps. During operation, a hydrogen atmosphere is maintained in the LDST to promote oxygen scavenging. Guidance for establishing and maintaining this hydrogen pressure is given in OP/1, 2, 3/A/1104/02, "High Pressure Injection System," which includes a graph of permissible hydrogen pressure versus LDST level.

The HPI system also serves to mitigate the consequences of a small-break LOCA. The HPI system, during emergency operation, supplies borated water to the RCS from the BWST. The HPI system has three parallel HPI pumps that take suction from the BWST and to discharge through two redundant flow paths into the RCS.

The suction lines from the LDST to the HPI pumps are normally isolated from the BWST supply lines by check valves (HP-101 and HP-102) and motor-operated valves (HP-24 and HP-25). In the event of a safety actuation, the motor-operated valves open, and the pressure due to elevation head in the BWST will overcome the pressure due to LDST level and hydrogen pressure, opening check valves HP-101 and HP-102, closing the LDST outlet header check valve (HP-97), and providing flow from the BWST to the HPI pumps. As BWST level drops, the available pressure from the LDST could exceed the available pressure from the BWST, allowing flow from the LDST as a check valve opens. The hydrogen gas in the LDST could then expand and fill the suction piping, resulting in damage to the HPI pumps. The procedural operating limit curve for LDST hydrogen pressure and volume is intended to assure that LDST pressure does not exceed available BWST pressure, even as BWST level is drawn down during a LOCA.

ASP Modeling Assumptions and Approach

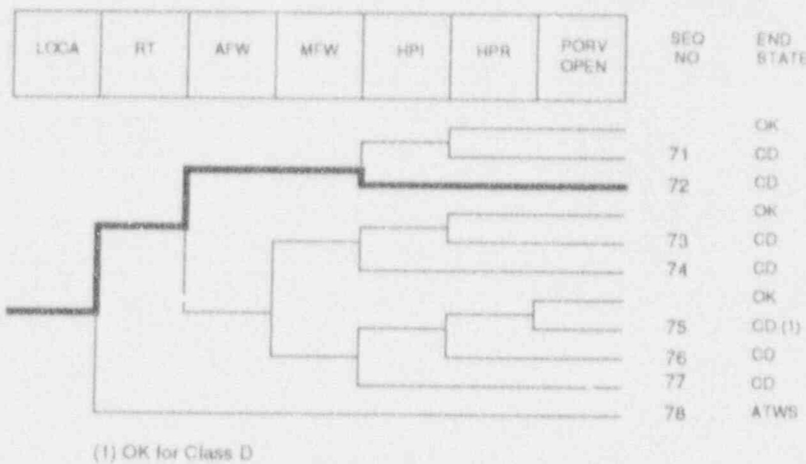
The event has been modeled as an unavailability of HPI and feed and bleed period for situations in which either of the two BWST-to-HPI-pump suction valves (HP-24 or HP-25) fail to open. The probability of HP-24 or HP-25 failing to open was assumed to be 0.02, based on the probability values typically used in ASP calculations.

The potential for hydrogen entrainment existed since initial criticality. To estimate the relative significance of the event within a 1-yr observation period (the interval between precursor reports), a 1-yr unavailability period was utilized in the analysis (6132 h, assuming the plant was critical or at hot shutdown 70% of the time).

Analysis Results

The conditional core damage probability for this event is estimated to be 1.2×10^{-4}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated LOCA with failure of HPI.

If it is assumed that HPI would be failed for all small-break LOCA scenarios, independent of the status of the BWST valves, a conditional probability of 6.3×10^{-3} is estimated. This would be the case if flow-related pressure drops did not have the effect indicated in the utility analysis. Such an event would be considered very significant.



Dominant core damage sequence for LER 269/91-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 2.9/91-010
Event Description: Potential for hydrogen entrainment in HPI pumps after a LOCA
Event Date: 09/19/91
Plant: Oconee 1

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.9E-01
LOOP	2.3E-02
LOCA	6.3E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	9.9E-08
LOOP	4.6E-08
LOCA	1.2E-04
Total	1.2E-04
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	1.2E-04	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	1.2E-04	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:\asp\1989\pwrdseal.cmp
BRANCH MODEL: c:\asp\1989\oconee1.sll
PROBABILITY FILE: c:\asp\1989\pwr_b11.pro

No Recovery Limit

Event Identifier: 269/91-010

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.4E-05	1.0E+00	
loop	1.6E-05	2.4E-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	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
ep.rec	4.5E-01	1.0E+00	
HPI	3.0E-04 > 2.0E-02 **	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
HPI(F/B)	3.0E-04 > 2.0E-02 **	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.3+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Minarick
05-27-1992
10:51:51

Event Identifier: 269/91-010

LICENSEE EVENT REPORT (LER)

FACILITY NAME(1)	DOCKET NUMBER(2)	PAGE(3)
Oconee Nuclear Station, Unit 1	05000 269	1 OF 13

TITLE(4) High Pressure Injection System Technically Inoperable For Some Single Failure LOCA Scenarios Due to Design Deficiency

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 NAMES	DOCKET NUMBER(S)
									Oconee, Unit 2	05000 270
09	18	91	91	010	0	10	21	91	Oconee, Unit 3	05000 287

OPERATING MODE(9): N

POWER LEVEL(10): -0-

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

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text) 50.72(b)(1)(ii)(c)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)	X	50.73(a)(2)(ii)(c)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER(12)

NAME	TELEPHONE NUMBER: AREA CODE	
Henry R. Lowery, Chairman, Oconee Safety Review Group	803	885-3034

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
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

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

On September 19, 1991, at 1225 hours, while reviewing an alarm setpoint change, Design Engineering determined that the operating limit curve or Letdown Storage Tank (LDST) Pressure versus Level was inadequate. Use of this curve could permit operation outside the design basis for the emergency injection function of the High Pressure Injection (HPI) system. It was determined that, under certain small break LOCA scenarios, a single failure could result in hydrogen gas from the LDST expanding into the suction piping of the HPI pumps, causing the pumps to be damaged. This deficiency has existed on all three Oconee units since initial startup. At the time of discovery, Unit 1 was shutdown for refueling and Units 2 and 3 were both at 100 % full power. Corrective actions were to revise the operating limit curve and to provide additional instructions for operator action. The root cause was Design Deficiency.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER			
Oconee Nuclear Station, Unit 1	05000 269	91	010	0	2	OF	13

EVALUATION:

BACKGROUND

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Pumps [EIIS:P], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control. The HPI system uses the Letdown Storage Tank (LDST) as a surge tank and normal suction source for the HPI pumps. During operation, a hydrogen atmosphere is maintained in the LDST to promote oxygen scavenging. Guidance for establishing and maintaining this hydrogen pressure is given in OP/1, 2, 3/A/1104/02, "High Pressure Injection System," which includes a graph of permissible hydrogen pressure versus LDST level.

The HPI System is also a part of the Emergency Core Cooling System (ECCS) which mitigates the consequences of loss of coolant accidents (LOCA). The HPI System prevents uncovering of the core for smaller break sizes, where high RCS pressure is maintained, and delays the uncovering of the core for intermediate break sizes. The HPI System, during emergency operation, supplies borated water to the RCS from the Borated Water Storage Tank (BWST). The HPI System has three parallel HPI pumps that have the capability to take suction from the BWST and to discharge through two redundant flow paths into the RCS, utilizing four injection nozzles (two per flow path). The injection nozzles are located on each of the reactor inlet pipes downstream of the Reactor Coolant Pumps. (See Attachment 1)

The suction lines from the LDST to the HPI pumps are normally isolated from the BWST supply lines by check valves [EIIS:V] (HP-101 and HP-102) and motor operated valves (HP-24 and HP-25). In the event of an Engineered Safeguards [EIIS:JE] actuation, the motor operated valves will open, and the pressure due to elevation head in the BWST will overcome the pressure due to LDST level and hydrogen pressure, opening check valves HP-101 and HP-102, closing HP-97 (LDST outlet header check valve), and providing flow from the BWST to the HPI pumps. As BWST level drops, the available pressure from the LDST could exceed the available pressure from the BWST, allowing flow from the LDST as a check valve opens. If allowed to continue, the hydrogen gas in the LDST could expand, filling the suction piping, until HPI pump suction could be lost, resulting in damage to one or more pumps. Therefore, the required total system flow might not be met and core damage could result. The procedural operating limit curve for LDST hydrogen pressure and volume is intended to assure that LDST pressure does not exceed available BWST pressure, even as BWST level is drawn down during a LOCA.

Technical Specification 3.3.1 requires three HPI pumps and two HPI flow paths to be operable when RCS temperature is greater than 350 degrees with fuel in the core. This is based on considerations of potential small breaks at the Reactor Coolant Pump discharge piping for which two HPI trains (two pumps and two flow paths) are required to assure adequate core cooling.

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EVENT DESCRIPTION

On April 16, 1991, an event occurred during which the pressure in the Letdown Storage Tank (LDST) for Oconee Unit 2 exceeded the procedural maximum limit. One of the design bases for the High Pressure Injection (HPI) system was that the hydrogen in the LDST could not be allowed to expand into the HPI pump suction piping following a LOCA. The pressure versus level curve contained in the Operating Procedures was intended to limit the amount of gas in the tank in order to assure system operability following an accident. Therefore, the event resulted in the HPI system being declared technically inoperable for approximately 20 minutes. That event was reported as LER 270/91-03.

During the review of that event, it was observed that the setpoint for a control room alarm for high LDST pressure exceeded the highest pressure in the normal operating range. Therefore, one corrective action from that event was to lower the alarm setpoint.

On August 20, 1991 a setpoint change request was initiated by Operations Technical Support. Design Engineering (DE) was notified of the change request and began their review. The DE review of the setpoint change included verification of the suitability of the setpoint. Previously, in December, 1990, a Design Basis Document (DBD) was issued for the HPI system. While reviewing the draft of that DBD, the basis of the pressure versus level curve (see Figure 1) contained in the Operating Procedures had been questioned but this item was carried as a open item for future resolution. Therefore, DE decided to document the basis of the pressure versus level curve as part of the setpoint verification.

During this review, the assigned engineer utilized a 1990 draft Limit and Precautions document prepared by Babcock & Wilcox (B&W) for the B&W Owners Group. This document includes a copy of a 1971 curve and states that it is based on calculations which, for certain scenarios, require the operator to isolate the LDST within 6.5 minutes by closure of HP-23, the LDST outlet header isolation valve. HP-23 is considered non-safety related and does not have safety related controls or power. In event of failure of HP-23, the only alternative was to vent the LDST into another non-safety related support system. DE did not consider it appropriate to continue to take credit for non-safety related equipment and operator action within this short time period in order to prevent loss of the HPI system should this scenario occur.

Therefore, DE began their own calculations to determine if the existing curve was adequate to prevent hydrogen gas expansion into the HPI piping under all required accident scenarios. One part of these calculations accounted for pressure drops due to flow in addition to static head due to level differences. The results indicated that the existing curves had not included the effects of losses due to flow. On September 18, 1991, DE initiated a Problem Investigation Report and began discussions with station Compliance and Operations personnel.

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Operations personnel noted that their procedures did not call for isolation of HP-23. They did not understand that the operating curves were based on that action. Operations wished to avoid any requirement to close HP-23. After receiving input from the station, DE continued their evaluation of the situation.

On September 19, 1991, at 1225 hours, it was concluded that the current procedure limits were adequate for most scenarios, but a scenario existed where a single failure might result in total failure of the HPI system. This scenario assumes a small break LOCA with a concurrent single failure of either HP-24 or HP-25, the two Borated Water Storage Tank (BWST) to HPI suction isolation valves. This failure would cause all of the required HPI injection flow to pass through one suction supply line, which would lead to higher pressure losses and therefore lower pressure in the suction supply header, resulting in entrainment of hydrogen from the LDST and eventual pump damage.

This conclusion, which applied to all three Oconee units, was reached while Unit 1 was at cold shutdown for a refueling outage, and Units 2 and 3 were operating at 100 % Full Power.

As immediate corrective action DE provided new curves for use in the affected operating procedures. The new curves are slightly more restrictive so as to provide an additional safety margin to assure that hydrogen gas in the LDST will not expand into the HPI pump suction piping for any scenarios which do not involve single failure of a valve in the path from the BWST. Additionally, new instructions were provided to the operators for an alternative mitigating action if the single failure scenario does occur. Under the new guidance, operators will have at least thirty minutes to realign the HPI and Low Pressure Injection (LPI) [EIIS:BP] systems into "Piggyback" mode if a failure of either HP-24 or 25 is observed after an accident. The flow path would then be from the BWST through the LPI pumps to the HPI pump suction. This path would allow the LPI pumps to supply enough additional head pressure to assure that the hydrogen could not expand into the suction piping. This information was provided verbally to the Operations personnel on shift at the time. Procedure changes to incorporate the revised curves were approved later in the day of September 19, 1991.

Another version of the curve is currently under review. This curve would further restrict the operating range so that operator action would not be required even in the event of single failure. However, at this time it is not certain that operation within its limits would still provide adequate oxygen scavenging during normal operation.

A search of master file documents revealed a draft procedure dated March 24, 1970, which provided a LDST pressure versus level curve and operating guidance. According to an enclosure taken from B&W documentation, the calculations established two limiting curves to

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prevent gas entrainment into the pump suction assuming the BWST had been drained (following the accident) and no operator action was needed to vent or isolate the LDST. Case 1 assumed a LDST level at the bottom instrument tap and Case 2 assumed a LDST level at the physical bottom of the tank. Case 1 was more restrictive.

A Duke Power curve was drawn and included in station operating procedures on 9/30/71. It is virtually equal to the B&W 1970 Case 1 curve for levels less than 55 inches and more conservative at higher levels. Subsequently the curve was redrawn several times as part of general procedure upgrades. No procedure change documentation mentions any intentional changes to the curves, but there are minor differences between the various versions. The 1978 version was less conservative than the 1971 version, especially between 25 to 75 inches, which includes the normal operating range.

CONCLUSIONS

The root cause of this event is Design Deficiency, (Functional Design Deficiency, Mechanical) because the potential for hydrogen entrainment leading to pump damage was recognized, operational guidance was provided, but was based upon inappropriate operator response times and operation of equipment which does not have sufficient provision for single failure. Design Criterion 14 (FSAR 3.1.14) requires automatic actuation of core protection systems. Design Criteria 38 and 41 (FSAR 3.1.38 and 3.1.41) require that the Emergency Core Cooling systems function assuming a failure of a single active component.

The operational curve was provided by Babcock and Wilcox (B&W), the Nuclear Steam Supply System vendor, in the early 1970's, but it is not certain if documentation of the basis was also provided at that time. The documentation found to date still does not adequately document if any consideration was included for dynamic flow losses.

Also, it is noted that "appropriate operator response time" has been open to interpretation and has evolved over the years. The current interpretation at Oconee assumes ten minutes for problem recognition and diagnosis prior to initiation of any manual corrective actions.

It is also noted that, even if the 6.5 minute operator response time had been acceptable, Operations procedures did not contain adequate instructions to perform those actions. This indicates a historical Design Deficiency, deficient documentation because, in the past, design basis documentation was not maintained in a reasonably accessible manner. Station personnel were unable to recognize that the Letdown Storage Tank (LDST) pressure curve was based on prompt operator action. This generic problem was recognized several years ago which resulted in the creation of the Design Basis Documentation (DBD) project. The DBD project is not yet complete, but is being worked on system by system, therefore the appropriate corrective action for this cause is already in progress. While this problem was not

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specifically discovered during the creation of the DBD for the HPI system, the operating curve had been identified as an action item for further evaluation.

An additional, non-causal deficiency was observed and identified as Management Deficiency, (Procedure Control, deficient procedure review and maintenance) because unintentional "minor," but non-conservative, changes occurred in curves during procedure reissues without detection and correction. The best guidance found related to accuracy of graphs is a statement in Operations Management Procedures 4-1, Enclosure 5.6, Operations OP Verification Checklist, which states "Are data on graphs and tables appropriate, correct, and legible." The Nuclear Production Department Procedure Development Guide, used by all groups other than Operations, addresses only the appearance of graphs. Existing guidance on generation of graphs and curves for use in procedures does not address how the necessary data points are generated and controlled. It also does not address how to verify the new curves are correct.

This event is considered recurring. Several Licensee Events Reports have addressed design deficiencies directly related to the design of the High Pressure Injection System. Others have affected other Engineered Safeguards systems. These are listed on Attachment 2. In general, these other deficiencies also occurred during original design of the system and resulted in the affected system being technically inoperable for certain accident scenarios. Since the deficiency in this event has existed since initial startup, no corrective action from previous events could have prevented it. Several of these deficiencies have been discovered through reviews related to the DBD project.

One additional event, documented as voluntary LER 270/89-007, occurred where Oconee Unit 2 was shutdown because it was thought to be operating in an unanalyzed condition due high tilt and imbalance following a dropped rod [EIIS:ROD]. That event also involved Duke Design not having adequate documentation of a vendor analysis. The DBD project is expected to improve the level of documentation of analyses available to Duke Power, but it is recognized that some vendor information will not be readily available.

There were no NPRDS equipment failures, personnel injuries, contamination, over-exposures, or releases of radioactive materials associated with this event.

CORRECTIVE ACTIONS

Immediate

1. Operations personnel were provided verbal guidance for maintaining Letdown Storage Tank (LDST) pressure within the new limits, and for immediate corrective actions to be taken in the event the applicable accident scenario were to occur.

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Subsequent

1. The operating procedure was revised to incorporate the new LDST Pressure Versus Level curve prepared by Design Engineering.

2. Revised Emergency Procedure to include requirement to immediately line up in Piggyback if a single failure of HP-24 or HP-25 occurred during/after a small break LOCA.

Planned

1. Evaluate revision of operating procedure for another, more restrictive, curve which would not require any operator action.

2. Establish Station Directive guidance related to preparation and review of safety significant curves used in station procedures to better assure accuracy. Existing curves will be reviewed when changed or when the procedure is reissued.

SAFETY ANALYSIS

The suction lines from the Letdown Storage Tank (LDST) to the High Pressure Injection (HPI) pumps are normally isolated from the Borated Water Storage Tank (BWST) supply lines by check valves and motor operated valves. In the event of an Engineered Safeguards actuation, the motor operated valves will open, and the pressure due to elevation head in the BWST will overcome the pressure due to LDST level and hydrogen pressure, opening the check valves and providing flow from the BWST to the HPI pumps. As BWST level is drawn down, some of the inventory in the LDST will also be used, but normal letdown flow will be isolated. Therefore, the LDST water level will drop and the hydrogen gas will expand. Procedural limits on the LDST hydrogen pressure and volume are intended to assure that the hydrogen cannot expand enough to enter the HPI pump suction.

Because of the potential for a single failure of one HPI pump suction supply isolation valve, Design Engineering performed an Operability Evaluation which determined that the HPI system had been technically inoperable. The significance was that, had an accident occurred with a concurrent single failure, the hydrogen gas in the LDST would expand as level dropped and could enter the HPI pump suction, cause gas binding and severe pump damage. Due to the system lineup, this potential scenario could lead to damage to all three HPI pumps which would correspond to loss of system function. The probability of such an event actually occurring is low. It is further reduced by the fact that the actual LDST pressure is routinely less than the maximum pressure permitted by the operating curve and would frequently be within the limit of the new curve.

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In the event that this scenario did actually occur, the Babcock and Wilcox, (B&W) 1990 draft Limits and Precautions Document states that the necessary operator response time could be as short as 6.5 minutes. Possible actions would be 1) to isolate the LDST by closing HP-23, the LDST outlet block valve, 2) to make-up to the LDST to maintain minimum level, or 3) to vent the LDST gas volume to the Gaseous Waste Disposal System. However, these activities all depend upon operation of components/systems which are not safety related, are not supplied from emergency power sources, and/or do not have full redundancy. Therefore, while it is probable that some appropriate operator action would have been attempted, if needed, it is possible that HPI system function would have been lost.

If a loss of the HPI System were to occur, the Emergency Operating Procedure would instruct the operators to depressurize the Reactor Coolant System (RCS) using steam generator cooling. This depressurization would allow injection from the core flood tanks (at about 600 psig) and eventually the Low Pressure Injection System. If inadequate core cooling conditions are indicated by superheated core exit thermocouple temperatures, the operators would also open the pressurizer power operated relief valve (PORV) and the reactor vessel and hot leg high point vents to further depressurize the RCS. Although this approach may result in enough Emergency Core Cooling System (ECCS) injection to prevent core damage, the effectiveness of these processes for all small break LOCA scenarios has not been demonstrated.

The analysis for a Maximum Hypothetical Accident (MHA) as described in the Final Safety Analysis Report assumes that some core damage occurs. That analysis shows that 10CFR100 limits would still be met.

Therefore, while it is not expected that the situation would actually result in pump damage, damage is assumed in the low probability event that a small break LOCA occurred simultaneously with single failure of one HPI suction valve from the BWST. The assumed loss of system function is still bounded by FSAR analysis. Therefore, the health and safety of the public was not affected by this event.

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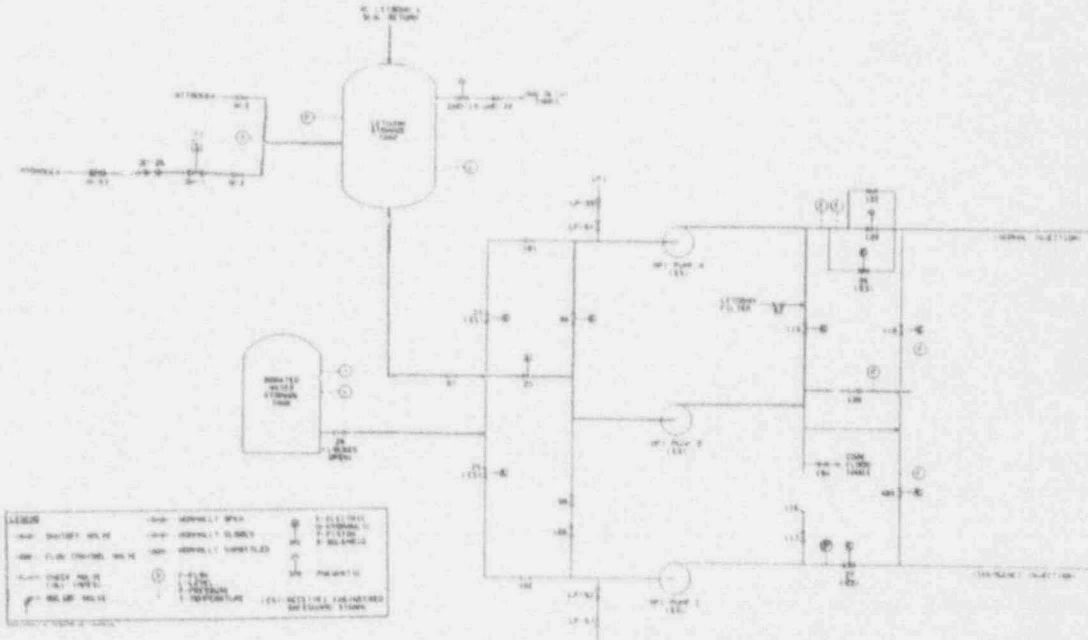
Attachment 1

High Pressure Injection System



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Attachment 2

Recu.ring Design Deficiencies

LER Number	Title/Problem
269/88-06	Inadequate Design Analysis of the High Pressure Injection System in the Emergency Co: Cooling System Sump Recirculation Mode. (Found that Design (B&W) did not calculate/verify required HPI pump NPSH in "Piggyback" mode.)
269/90-04	Unanticipated System Interaction During Undervoltage Condition in the 230KV Switchyard Results in Failure to Comply With Technical Specifications. (Relay setpoints were not coordinated, resulting in a situation where, after a unit trip, the backup power breakers could not close in due to an undervoltage condition, but emergency power would not be initiated. If this occurred, the HPI system (and other Engineered Safeguards systems) could be without power.)
269/90-05	Design Deficiency/Unanticipated Interaction of Systems Results in the Potential Closure of the Startup Transformer "E" Breaker on to a Degraded (Low Voltage) Switchyard. (Protective relay setpoint would permit selection of an under voltage power source, leading to Engineered Safeguards equipment failure.)
269/90-10	Potential Failure of Engineered Safeguards System by Improper Valve Failure Mode Due to Design Deficiency, Deficient Documentation. (During construction, air operated valves were changed to fail closed with out adequate documentation and in conflict with the FSAR. This made the Penetration Room Ventilation System, an Engineered Safeguards system, technically inoperable.)

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Recurring Design Deficiencies

LER Number	Title/Problem
269/90-12	Potential Overload Condition May Result in Inadequate On-Site Emergency Power Source During a LOCA/LOOP Event Due to Design Deficiency. (Two diverse potential single failures would allow an operating Keowee Hydro unit to become overloaded, potentially causing random loss of Engineered Safeguards equipment due to overcurrent protection.)
269/90-15	Unit Operation in an Unanalyzed Condition Due to Design Deficiency, Design Oversight. (Identified a different location for worst case small break. This affected operational requirements for HPI system.)
269/91-01	Potential Single Failure During LOCA/LOOP Event May Result in the Loss of Emergency Power Due to Design Deficiency. (A single failure mechanism was postulated which would allow the two Keowee Hydro units (emergency power generators) to close in out of synchronization, resulting in assumed damage and loss of both units. If this occurred, the HPI system (and other Engineered Safeguards systems) could be without power.)
269/91-03	Technical Inoperability of Oconee Backup Electrical Power Sources Results From Deficiently Designed Circuit Breaker Arrangement of Keowee Hydro Auxiliary Loads. (Breaker co-ordination problem would allow a fault in a non-safety circuit to potentially shut down one emergency power generator. A common mode failure could cause both generators to be lost due to this problem. If this occurred, the HPI system (and other Engineered Safeguards systems) could be without power.)

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Attachment 2

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Recurring Design Deficiencies

LER Number	Title/Problem
269/91-07	Breaker Coordination Problem Due to Design Deficiency Results in Technical Inoperability of Safety Related Equipment. (Failure of non-safety related equipment could cause loss of power to safety-related equipment, including HP-25.)

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Figure 1

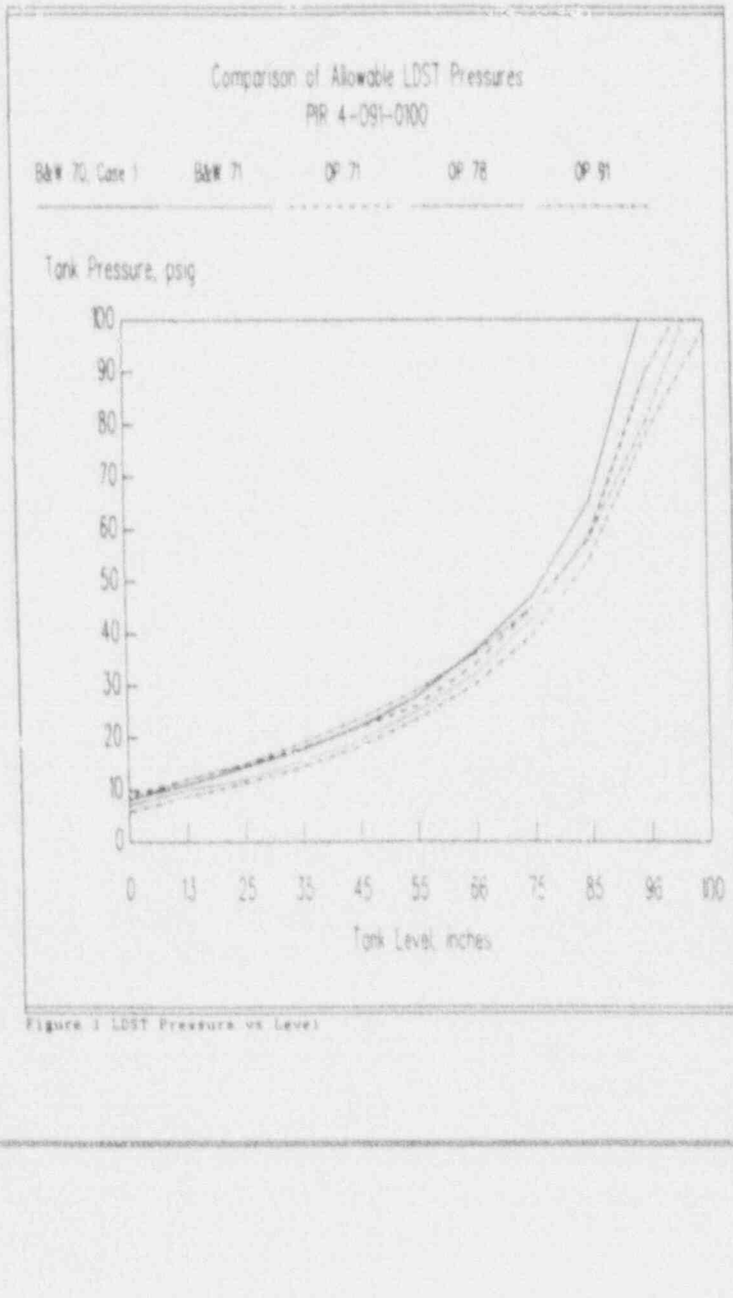

Figure 1 LDST Pressure vs Level

JUN 14 1991

LICENSEE EVENT REPORT (LER)

EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TITLE (4): Excessive Letdown Storage Tank Pressure for Unknown Reason Makes High Pressure Injection System Inoperable

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 4	1 6	9 1	9 1	0 0 3	0 0	0 5	1 6	9 1		0 5 0 0 0
										0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (11)

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

X 50.73(a)(2)(i)(a)

X OTHER (Specify in Abstract below and in Text, NRC Form 366A): 50.72(b)(1)(ii)(a)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Henry R. Lowery, Chairman Oconee Safety Review Group	8 0 3 8 8 5 - 3 0 3 4

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): YES (If yes, complete EXPECTED SUBMISSION DATE) [ ] X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

On April 16, 1991, at 1607 hours, while Unit 2 was operating at 100 % Full Power, a Control Room Operator completed addition of Hydrogen (H2) gas to the Letdown Storage Tank (LDST) by closing a solenoid valve. During subsequent isolation of the H2 fill piping, a Non-Licensed Operator heard additional flow through the pipe. She finished manual isolation and observed that the LDST pressure exceeded the procedural maximum limit. At 1610 hours this was reported to the Control Room Operators, and the excess H2 was vented to the Gaseous Waste Disposal System. At 1628 hours pressure was within the allowed operating range. Both trains of the High Pressure Injection System (HPI), an Emergency Core Cooling System, were declared inoperable for the duration of the overpressurization due to the potential for H2 to enter the HPI pump suction following a LOCA event. This could damage the HPI pumps and make the system inoperable. The root cause is Unknown, Possible Equipment Malfunction. A solenoid valve is believed to have stuck open temporarily during the H2 fill, but this could not be confirmed. A contributing cause is Inappropriate Action, Lack of Attention to Detail. Planned corrective actions include procedure enhancement, inspection of the valve, and counseling of the operator.

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

BACKGROUND

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Pumps [EIIS:P], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control. The HPI system uses the Letdown Storage Tank (LDST) as a surge tank and normal suction source for the HPI pumps. During operation, Hydrogen gas is maintained in the LDST to promote oxygen scavenging. Guidance for establishing and maintaining this Hydrogen pressure is given in OP/0/A/1106/17, "Hydrogen System", which includes a graph of permissible Hydrogen pressure vs LDST level (Attachment A). During normal operation, additional Hydrogen is required every day or two.

The HPI System is also a part of the Emergency Core Cooling System (ECCS) which mitigates the consequences of loss of coolant accidents (LOCA). The HPI System prevents uncovering of the core for smaller break sizes, where high RCS pressure is maintained, and delays the uncovering of the core for intermediate break sizes. The HPI System, during emergency operation, supplies borated water to the RCS from the Borated Water Storage Tank (BWST). The HPI System has three parallel HPI pumps that have the capability to take suction from the BWST and to discharge through two redundant flow paths into the RCS, utilizing four injection nozzles (two per flow path). The injection nozzles are located on each of the reactor inlet pipes downstream of the Reactor Coolant Pumps. (See Attachment B)

The suction lines from the LDST to the HPI pumps are normally isolated from the BWST supply lines by check valves [EIIS:V] and motor operated valves. In the event of an Engineered Safeguards [EIIS:JE] actuation, the motor operated valve will open, and the pressure due to elevation head in the BWST will overcome the pressure due to LDST level and Hydrogen pressure, opening the check valves and providing flow from the BWST to the HPI pumps. Procedural limits on the LDST Hydrogen pressure and volume are intended to assure that LDST pressure does not exceed available BWST head pressure, even as BWST level is drawn down during a LOCA. LDST level and pressure are monitored in the control room and Hydrogen is periodically added, every day or two, to maintain the desir pressure.

Valve 2H-1, (Unit 2 LDST Supply), is a 3/4 inch, solenoid operated valve. It requires power to open and fails closed when the coil is de-energized. The valve position indicating lights and Operator Aid Computer inputs are actuated by contacts on the switch [EIIS:XIS] rather than actual valve stem position.

Technical Specification 3.3.1 requires three HPI pumps and two HPI flow paths to be operable when RCS temperature is greater than 350 degrees with fuel in the core. This is based on considerations of potential small breaks at the Reactor Coolant Pump discharge piping for which two HPI trains (two pumps and two flow paths) are required to assure adequate core cooling.

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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EVENT DESCRIPTION

On April 16, 1991, while Unit 2 was operat at 100 % Full Power, Control Room Operators (CROs) on duty observed th e Unit 2 Letdown Storage Tank (LDST) pressure had decreased to approxima y 35 psig. At the current LDST level, 81 inches, this represented the low pressure boundary of the normal operating range as shown on the Maximum Pressure vs Indicated Level curve in Enclosure 3.13, "Hydrogen Addition to Unit 1, 2, or 3 LDST" of OP/0/A/1106/17, "Hydrogen System" (see Attachment A). Unit 2's main generator [EIIS:GEN] and Unit 1's LDST also required filling. Therefore, the CROs began planning the routine evolution to add Hydrogen. This primarily entailed coordination between the CROs assigned to the two units and assigning Non-Licensed Operators (NLOs) to operate manual block valves at various points in the Hydrogen System.

NLO A was assigned to operate two manual valves in the Unit 2 section of the Auxiliary Building and one in the Unit 1 section. She opened H-93 (LDST LP Control Bypass), 2H-26 (Unit 2 LDST Block), and 1H-26 (Unit 1 LDST Block) while NLO B opened valves at the Hydrogen Storage Tank building to charge the supply header and to supply Unit 2's generator.

Upon receiving confirmation that the portion of the system in the auxiliary building was lined up, CRO A operated the control switch in the Control Room to open 2H-1, (Unit 2 LDST Supply), at 1559:43 hours. At approximately the same time, CRO B operated the switch for 1H-1, (Unit 1 LDST Supply). The Unit 2 Operator Aid Computer (OAC) alarm typer documented that the 2H-1 valve control switch was in the open position three times between 15:59:43 and 16:06:01, for a total duration of five minutes and six seconds. The Unit 1 OAC alarm typer shows that 1H-1 was also operated three times during this period, and was open a total of three minutes, twenty eight seconds. CRO A stated that he kept his hand on the switch while he observed LDST pressure on an adjacent indicator gauge [EIIS:XI]. He watched pressure rise to approximately 39 psig, at which point he operated the switch to close 2H-1. He states that next he observed the position indicating lights change to show the valve closed, and heard the OAC alarm typer print out. He did not walk over to the typer but assumed that the typer entry was documenting the 2H-1 position change. He then observed the pressure indicator again and noted that it was still showing 39 psig.

Since Unit 1 was also finished filling, CRO A contacted NLO A via the page and instructed her to close the block valves. At approximately 1607 hours, he began making an entry in the Reactor Operator's Log to document the Hydrogen fill.

NLO A states that she closed 1H-26 and 2H-26. Next, while closing H-93, she heard the sound of flow through the pipe. The sound stopped when H-93 was fully closed. At this point she checked 2PG-0179, a local pressure gauge located close to, but downstream of, 2H-1. 2PG-0179 indicates the pressure in the LDST. This step is not required by the operating

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TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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procedure, but NLO A states that she and several other NLOs perform this check routinely following Hydrogen addition to the LDST. She observed that this gauge indicated approximately 60 psig, which she recognized as being higher than she had ever observed it previously.

NLO A went promptly to the Control Room, and reported her observation to CRO A at approximately 1610. CRO A immediately looked at the Control Room indication, which now showed 55 psig. At the existing level of 80 inches, this pressure violated the maximum pressure limit on the curve in Enclosure 3.13. CRO A immediately notified the Control Room Senior Reactor Operator, the Unit Supervisor and the Shift Supervisor.

The immediate corrective action was to lower the LDST pressure by venting the excess Hydrogen into the Gaseous Waste Disposal (GWD) header in accordance with OP/1+2/1104/18, "Gaseous Waste Disposal System." At 1628 hours the LDST pressure was reduced to 50 psig, the highest permissible pressure for the existing LDST level. It was lowered further to 45 psig at 1633.

At 1730 the NRC Resident Inspector was notified. At 1735 station Compliance personnel were notified. It was determined that the High Pressure Injection (HPI) system, an Engineered Safeguards Emergency Core Cooling System, had been unable to perform its intended safety function for 18 minutes due to the high LDST pressure. The significance of exceeding the limit was that, in the event of a Loss Of Cooling Accident (LOCA), the Hydrogen gas could enter the HPI pump suction, cause gas binding and severe pump damage. Due to the system lineup, all three HPI pumps could have been damaged during this potential scenario, with the possible result of core damage.

Operations personnel had NLO A repressurize the header to 2H-1 to see if any continued leakage could be observed. No noticeable change in pressure was seen, indicating that 2H-1 had fully closed at some point during the event. CRO A issued Work Request (WR) 28619C at 1745 to "Please investigate and repair 2H-1. The valve leaks past seat when indicating closed."

A caution that 2H-1 may stick open or leak past the seat was added to the Unit 2 CRO's Shift Turnover sheet. This entry requires that an NLO be stationed at 2H-26 when filling the LDST with Hydrogen in order to isolate 2H-1 if it should leak or malfunction.

During the review of the incident, the Shift Technical Advisor referenced OEE 251-23, the electrical schematic drawing of the control circuit for 2H-1, and noted that the position indications for 2H-1 (computer points and lights adjacent to the switch in the control room) are all operated by contacts on the control switch rather than actual valve position.

On April 18, 1991, Instrument and Electrical (I&E) technicians performed a troubleshooting investigation per WR 28619C. At that time 2H-1 operated

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properly, but the valve could not be disassembled for inspection of the seat and plunger due to the fact that the only isolation from the LDST is a single check valve. Due to the potential for leakage past the check valve, the disassembly of 2H-1 has been deferred until a unit shutdown of sufficient duration.

A check of the maintenance history data base of 1H-1, 2H-1, and 3H-1 revealed that the solenoid had been replaced on 2H-1 in 1989 because the valve was believed to be sticking open. On Jan. 25, 1991, WR 28006C was written because the closed indicating light did not illuminate when the control switch was placed in the closed position even though the computer indicated that the switch had operated. Troubleshooting confirmed that the portion of the switch mechanism which includes the contact block for the indicating lights was not changing state. The contact block was replaced. On Feb. 27, 1991, WR 28330C was written because, again, the light did not indicate closed when the switch was moved to the closed position, but the computer did indicate closed. The discrepancy did not recur during troubleshooting. The corrective action was to tighten the same contact block, which was apparently loose. Valves 1H-1 and 3H-1 had no work requests indicated in the data base.

During the investigation of this event, it was observed that Enclosure 3.13, "Hydrogen Addition to Unit 1, 2, or 3 LDST," of OP/0/A/1106/07, "Hydrogen System," does not include a "Limit and Precaution" or "Caution" to warn of the consequences of operation above the maximum pressure, or to provide specific instructions for corrective actions. However, the potential for over pressurization of the LDST to result in damage to the HPI pumps is discussed in Operator training.

It was also observed that a control room alarm exists for both high and low LDST pressure. The high pressure setpoint is 59 psig, which is higher than the highest normal operating range pressure. The alarm setpoint is calibrated at a fixed value, and, with existing hardware, cannot vary with the tank level to follow the maximum allowable pressure curve.

There have been no reports of problems during Hydrogen additions to the LDST subsequent to this event.

CONCLUSIONS

Control Room Operator (CRO) A reports that Letdown Storage Tank (LDST) pressure was 39 psig when he turned the switch to close 2H-1. Non-Licensed Operator (NLO) A reports hearing flow through H-93 at a time when no flow should have been present. Therefore, it is concluded that 2H-1 and 2H-26 were not fully seated following closure and allowed flow of Hydrogen to continue into the LDST until H-93 was closed by NLO A.

It is presumed, for lack of evidence to the contrary, that 2H-1 failed to properly close due to Equipment Malfunction. The mode of malfunction may

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APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 2	0 5 0 0 0 2 7 0	9 1	0 0 3	0 0	0 6 OF 1 0

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

have been an intermittent malfunction of the control switch, similar to two previous malfunctions of the position indication light circuit, or it may have been binding of the valve stem, possibly due to interference of a foreign particle. Because this presumption cannot be proven at this time, this event is assigned a root cause of Unknown, Possible Equipment Malfunction.

It is observed that CRO A did not adequately monitor LDST pressure following closure of 2H-1. He should have monitored to assure that system parameters were responding as expected for the existing condition. Had he properly observed the instrument, he should have identified the continued increase in pressure and instituted corrective action prior to the pressure increasing above the Maximum Pressure curve. For this reason, a contributing cause of Inappropriate Action, Lack of Attention to Detail is assigned.

It is presumed that 2H-26 was not fully seated during closure by NLO A, therefore allowing the leak to continue until H-93 was shut a few moments later. This would also be Inappropriate Action, Lack of Attention to Detail. However, NLO A properly noted the unexpected sound of flow in the line while closing H-93, followed up by investigating to determine if an unexpected condition did exist, and promptly reported the results.

It is also concluded that OP/0/A/1106/17, "Hydrogen System," could be enhanced, although it was not a causal factor in this event.

It is also noted that the control room alarm for LDST high pressure is set such that, at any LDST level less than the maximum allowed tank level, the maximum allowable pressure will be exceeded before an alarm is received. This provides little assistance to the operator, especially considering that the normal operating range has an upper limit of 40 psig compared to an alarm value of 59 psig.

A review of Problem Investigation Reports covering the previous two years indicates that this event is not recurring. No NPRDS reportable equipment failures have been confirmed, pending further inspection during a future outage. There were no injuries, releases of radioactive materials, or personnel over-exposures as a result of this event.

CORRECTIVE ACTIONS

Immediate

1. The excess Hydrogen was vented into the Gaseous Waste Disposal system in order to reduce the Letdown Storage Tank pressure to a point within the allowed operating range.

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LICENSEE EVENT REPORT (LER)
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Subsequent

1. A Work Request was written for investigation and repair of a presumed seat leak on valve 2H-1.

2. An entry was made on the shift turnover sheet to remind subsequent shifts of the potential that valve 2H-1 may malfunction.

3. Both 2H-1 and 2H-26 were functionally leak tested and no pressure change due to seat leakage could be observed.

Planned

1. Valve 2H-1 will be disassembled for inspection of the plunger and seat per Work Request 28619C during the next unit shutdown of sufficient duration.

2. OP/0/A/1106/17, "Hydrogen System", will be enhanced. Operators will receive appropriate training on these changes.

3. The LDST high pressure alarm setpoint will be revised.

4. Appropriate procedure(s) will be revised to document periodic verification that LDST pressure is in the acceptable range. Other operating parameters affecting operability of safety systems will also be considered.

5. CRO A will be counseled about his inappropriate action in this event. The need to anticipate leaking valves and to monitor process parameters following an evolution will be stressed.

SAFETY ANALYSIS

The Letdown Storage Tank (LDST) has a design pressure rating of 100 psig. Overpressure protection is provided by 2HP-79, LDST Relief Valve, which relieves into a Reactor Coolant Bleed Holdup Tank. Therefore, tank integrity was not a concern for this event.

The suction lines from the LDST to the High Pressure Injection (HPI) pumps are normally isolated from the Borated Water Storage Tank (BWST) supply lines by check valves and motor operated valves. In the event of an Engineered Safeguards actuation, the motor operated valves will open, and the pressure due to elevation head in the BWST will overcome the pressure due to LDST level and Hydrogen pressure, opening the check valves and providing flow from the BWST to the HPI pumps. As BWST level is drawn down, some of the inventory in the LDST will also be used, but normal letdown flow will be isolated. Therefore, the LDST water level will drop and the Hydrogen gas will expand. Procedural limits on the LDST Hydrogen

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pressure and volume are intended to assure that the Hydrogen cannot expand enough to enter the HPI pump suction.

Because the procedural limits were exceeded in this event, Design Engineering performed an Operability Evaluation which determined that the HPI system had been inoperable for 18 minutes due to the high LDST pressure. If NLO A had not followed up on the sound of flow in the line, an extended per. .d of time could have passed prior to the discovery of the excessive pressure. The significance of exceeding the limit was that, had an accident occurred prior to the discovery of the excessive pressure, the Hydrogen gas in the LDST would expand as level dropped and could enter the HPI pump suction, cause gas binding and severe pump damage. Due to the system lineup, this potential scenario could lead to damage to all three HPI pumps wh'.ch would correspond to loss of system function.

However, Design Engineering calculations show that the Hydrogen gas would not expand into the pump suction header until the BWST level had been reduced to near the minimum post-LOCA level. This would take several hours, even fc: the largest break sizes for which HPI is required. During this time, LDST level and pressure would be dropping slowly. Although no credit is taken in the Operability Evaluation for operator action, it is probable that the operators would take some prevent.tive action. Possible actions would be 1) to isolate the LDST by closing 2HP-23, the LDST outlet block valve, 2) to make-up to the LDST to maintain minimum ` vel, or 3) to vent the LDST gas volume to the Gaseous Waste Disposal System.

If a loss of the HPI System were to occur, the Emergency Operating Procedure would instruct the operators to depressurize the RCS using steam generator cooling. This depressurization would allow injection from the core flood tanks (at about 600 psig) and eventually the Low Pressure Injection System. If inadequate core cooling conditions are indicated by superheated core exit thermocouple temperatures, the operators would also open the pressurizer power operated relief valve (PORV) and the reac vessel and hot leg high point vents to further depressurize the RCS. Although this approach may result in enough ECCS injection to prevent core damage, the effectiveness of these processes for all small break LOCA scenarios has not been demonstrated, therefore core damage is assumed.

The analysis for a Maximum Hypothetical Accident (MHA) as described in the Final Safety Analysis Report assumes that some core damage occurs. That analysis shows that 10CFR100 limits would still be met.

Therefore, while it is not expected that the situation would actually result in pump damage, damage is assumed in the low probability event that a LOCA occurred simultaneously with h'gh pressure in the LDST. The assumed loss of system function, and resulting core damage, is still bounded by FSAR analysis. Therefore, the health and safety of the public was not affected by this event.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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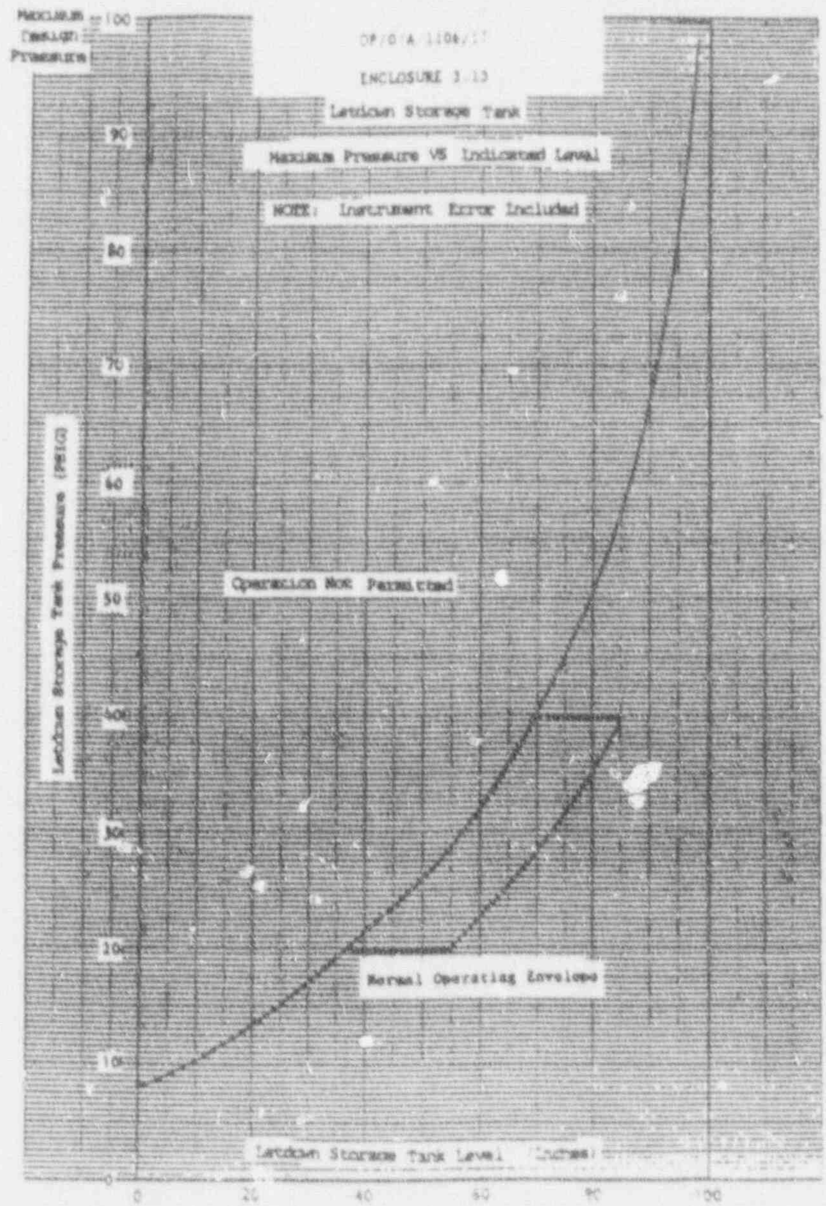
TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT A



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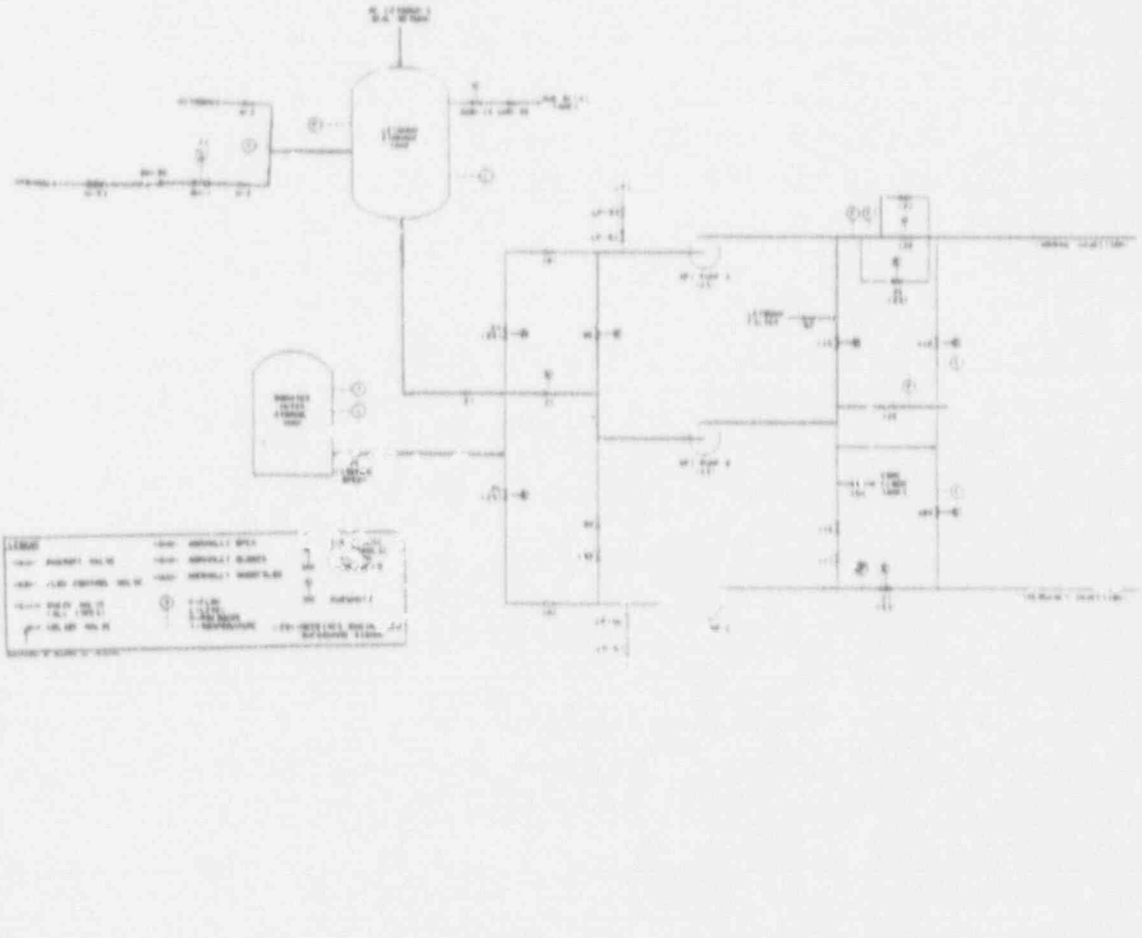
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 2	0 5 0 0 0 2 7 0	9 1	— 0 0 [illegible]	— 0 0	1 0 OF 1 0

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

ATTACHMENT B

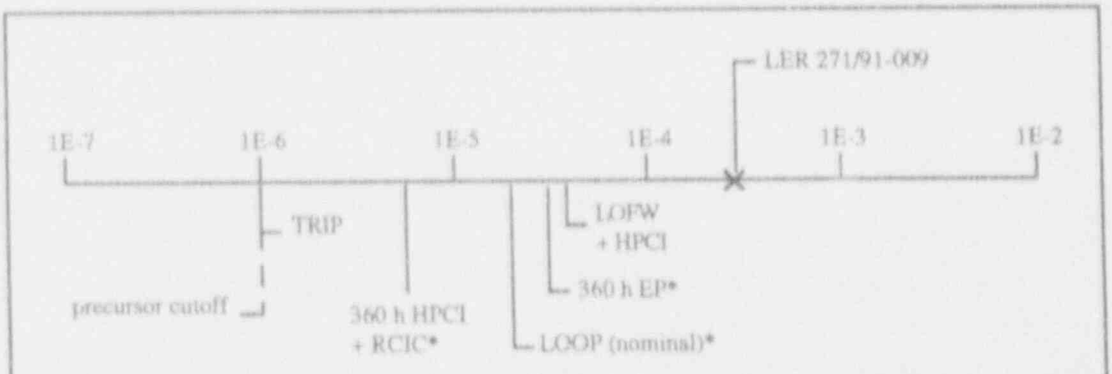


ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	271/91-009, 271/91-012
Event Description:	Extended loss of offsite power
Date of Event:	April 23, 1991
Plant:	Vermont Yankee

Summary

A loss of offsite power (LOOP) occurred at Vermont Yankee during switchyard maintenance activities. Both emergency diesel generators (EDGs) started and provided power to their respective safety-related buses. Recovery of offsite power, which took ~13 h, was complicated by communications and organizational difficulties and travel time for support personnel. The conditional core damage probability estimated for this event is 2.9×10^{-4}. The relative significance of the event compared to other postulated events at Vermont Yankee is shown below.



*these probabilities were developed considering the Vernon tie line as an alternate emergency power source

Event Description

On April 23, 1991, at 1448 hours, during normal operation with the reactor at 100% power, a reactor scram occurred as a result of a generator/turbine trip on generator load reject due to the receipt of a 345-kV breaker failure interlock (BFI) signal. This resulted in a total loss of 345-kV and 115-kV offsite power. Both EDGs provided power for essential safety-related systems during the loss of power until approximately 0430 hours on April 24, 1991, at which point 345-kV offsite power was restored and backfed through the station auxiliary transformer. Restoration of 115-kV power had been accomplished at 1925 hours on April 23, 1991; however, it was decided to continue supplying power to the emergency buses via the EDGs since only one offsite breaker was closed and testing was continuing in the switchyard. A chronological list of activities during this event is provided in Table 1.

Prior to the event, the plant was in the process of completing the replacement of switchyard battery bank 4A. All work, with the exception of restoring the connection of the battery bank to the DC 4A bus, was completed without incident. While performing the final sequence of actions necessary to reconnect the battery bank to DC bus 4A, a voltage transient occurred on the bus when battery charger 4A-5A was disconnected from the DC-5A bus (this rendered the DC-4A bus susceptible to voltage spikes due to the absence of a battery bank). The voltage transient caused the failure of zener diodes in the trip logic cards for several breakers, which initiated the BFI signals.

The recovery of offsite power began with an attempt to restore 115-kV power from the switchyard via 115-kV breaker K186 and the startup transformers. This was determined to be the easiest path in obtaining an offsite power source due to the need to close only one breaker. However, the K1 breaker BFI signal remained locked in due to a failed zener diode on the associated trip card and prevented the closure of K186. At 1925 hours, the BFI signal from the K1 to the K186 breaker was blocked, allowing reclosure of K186 and subsequent restoration of power to 4-kV buses 1 and 2. The K1 BFI trip card was subsequently replaced with an identical card from a spare breaker. Closure of the K186 breaker required 4 h, in part because of the length of time required for New England Power Service Co. (NEPSCO) relay technicians to travel to Vermont Yankee from Providence, Rhode Island.

After 115-kV power was established through the K186 line, efforts to close breaker K1 continued to establish a more reliable source of 115-kV power through the auto transformer. However, due to communication problems between Vermont Yankee and the New England Switching Authority (REMVEC) concerning priorities over breaker testing, a 3-h delay occurred before 115-kV power was made available through the auto transformer.

In a parallel effort, at 1900 hours, operation orders were given to complete backfeeding of the plant from the 345-kV switchyard through the main transformer. This effort was also hampered by communication problems with REMVEC, personnel delays (including a 45-min delay while exiting the radiologically controlled area because of noble gas activity), and equipment malfunctions. Backfeeding was completed at 0410 hours on April 24, 1991. In all, recovery of offsite power took ~13 h.

Reduced EDG and air compressor cooler service water (SW) flow was observed during the event. This was caused by the SW discharge alignment, in which SW was directed to the cooling tower basin instead of to the main discharge structure. Directing SW to the cooling tower basin had been the standard mode of operation since 1987. This "alternate" lineup resulted in higher flow resistance and significant backpressure at the discharge of both EDG heat exchangers. An analysis performed shortly after the event concluded that the EDGs would perform acceptably with the reduced SW flow immaterial of SW temperature. However, this conclusion was later revised (LER 271/91-012 Rev. 1); it was determined that, at maximum SW temperatures, the EDGs would perform acceptably with the loads experienced during the April 23, 1991, event (approximately 33% of rated load: four SW pumps, two residual heat removal (RHR) SW pumps, two RHR pumps, plus lower power loads). The utility apparently concluded that adequate SW margin existed during the event, when SW temperature was 48°F.

During the recovery, the torus volume increased above Technical Specifications limits twice. The volume increase was caused by condensation of steam being used by the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. The second time that torus volume increased above limits, the volume stayed above the limit until all AC power was restored. The torus water volume increased because the radwaste system could not handle the addition of water (condensed steam) used by the HPCI and RCIC systems due to the lack of normal AC power.

Also during the recovery, RCIC tripped when an operator incorrectly matched flow during changeover from manual to automatic operation mode. RCIC was immediately reset and restored to the automatic mode of operation.

Additional Event-Related Information

A simplified diagram of the Vermont Yankee AC power system is shown in Fig. 1. Each EDG is capable of supplying 100% of the emergency loads required under postulated design-basis accident conditions. Each of the EDGs has a continuous rating of 2750 kW and a 7-d rating of 3000 kW. Each EDG is physically and electrically independent of the other and of any offsite power source.

Tables 2 and 3 indicate emergency loads connected to 4.16-kV buses 3 and 4 and the associated 480-V buses. In addition to automatically and manually started loads, the EDGs can supply other loads on buses 3 and 4 and the associated lower voltage buses, if required.

The EDGs receive cooling water via separate SW headers. Each header is supplied by two SW pumps located at the intake structure. The headers are cross-connected on the upstream and downstream side of the in-line mechanical strainers, and normally three of four pumps are operated to remove plant service heat loads. One pump provides sufficient capacity to remove head loads during accident conditions.

If a loss of AC power occurs on emergency bus 3 and diesel generator 1B (connected to bus 3) fails to start or run, then the Vernon Hydroelectric Station 4.16-kV tie line can be connected to bus 3 through a manual switching operation in the control room. If the above described situation arises on emergency bus 4, the Vernon tie line can be connected manually to bus 4.

The 4.16-kV tie from the Vernon Hydroelectric Station to Vermont Yankee is connected through a transformer to the Vernon Hydroelectric Station 2.4-kV bus system. This bus system is connected to the station's ten hydroelectric generators and also is connected through six transformers to the outside 69-kV switchyard. Four 69-kV transmission lines from this switchyard connect the Vernon Hydroelectric Station to the interconnected transmission system of New England. Thus, the Vernon Hydroelectric Station 2.4-kV bus system is normally energized and available whether the Vernon generators are operating or not.

The switching arrangement for connection of the Vernon tie line to a Vermont Yankee emergency bus is shown in Fig. 1. Three circuit breakers are used: 3V, to connect to emergency bus 3; 4V, to connect to emergency bus 4; and 3V4, which is the feeder breaker for the Vernon Hydroelectric Station tie line. The control switches for the three breakers are located on the electrical section of the main control board, and the availability of the Vernon tie line is indicated by a voltmeter and ammeter adjacent to the control switches. In addition, there is a direct telephone circuit between the main control room and the Vernon Hydroelectric Station to allow communications between the two stations.

ASP Modeling Assumptions and Approach

The event has been modeled as a nonrecoverable loss of offsite power. The Vernon tie line was considered to be an alternate power source to one emergency bus; a probability of 0.12 was assumed for failing to connect this power source given both EDGs fail and cannot be recovered in the short term (station blackout scenario). This was included in the model by revising the nonrecovery probability for emergency power from 0.8 to 1.0 [0.8 x 0.12]. Because of the nature of the switchyard failures and the difficulties encountered in recovering from them, the probability of failing to recover AC power prior to battery depletion was assumed to be 1.0, given that emergency power and the Vernon tie line were unavailable.

Because of the temperature of the SW system, adequate EDG cooling was assumed to be available during this event. However, to assess the impact of inadequate EDG cooling at higher SW temperatures, a sensitivity analysis was performed (the EDGs were apparently determined to be operable at all temperatures if loaded as they were during this event). In this analysis, it was assumed that both EDGs would fail if they were fully loaded — for example, if low-pressure coolant injection and core spray were actuated following automatic depressurization. To implement this assumption in the Accident Sequence Precursor LOOP model, the automatic depressurization system (ADS) was assumed failed in sequences associated with emergency power success.

Analysis Results

The conditional probability of subsequent core damage estimated for this event is

2.9×10^{-4}. The dominant sequence, highlighted on the following event tree, involves the loss of offsite power, failure of emergency power (including the Vernon tie line), and failure to recover AC power prior to battery depletion.

The assumption that the EDGs fai. if fully loaded raises the conditional core damage probability to 3.1×10^{-4}.

Additional information concerning this event is included in Augmented Inspection Team report 50-271/91-13, dated June 5, 1991.

Table 1. Chronological listing of activities

Time	Activity
	April 23, 1991
14:48	LOOP from 100% power. Total loss of all 345-kV and 115-kV power. The Vernon Hydrostation was available to provide backup power to one emergency bus, if required.
14:48:45	Both emergency diesel generators started and reenergized safety buses.
14:50	HPCI manually employed to control reactor pressure and level.
15:33	Torus water volume exceeded Tech Spec limit of 70,000 ft^3. Volume was restored to within limit.
15:42	"A" station air compressor tripped due to inadequate service water cooling flow.
16:45	RCIC used for first time during event.
17:31	"B" station air compressor tripped due to inadequate service water cooling flow.
17:36	"B" station air compressor restarted. Instrument air header pressure dropped 15 psig during 5 min of air compressor unavailability.
17:59	Reserve diesel air compressor operable and hooked to outlet of "D" station air compressor. "C" and "D" station air compressors were unavailable due to the LOOP.
19:04	RCIC tripped on overspeed — operator error in the adjustment of RCIC flow controls during process of switching from manual to auto mode of operation.
19:12	RCIC operation resumed.
19:25	115-kV power restored to startup transformers. 4-kV breakers 13 and 23 were closed to reenergize buses 1 and 2, which power the normal station loads. Because testing was continuing in the switchyard with only 1 breaker closed, a decision was made to leave EDGs connected to buses 3 and 4.
21:12	Torus water volume again above 70,000 ft^3 and could not be readily reduced.
	April 24, 1991
04:10	Back-feeding 345-kV power through station auxiliary transformer completed.
04:30	Both emergency diesels secured.
19:25	Torus water volume reduced below 70,000 ft^3.
19:50	Unusual event terminated.

Table 2. Category 1 loads (automatically starting or restarting loads)

Reactor core spray cooling system
Residual heat removal system
Standby gas treatment system
All AC motor-operated isolation valves (momentary load) (except for valves connected to UPS-powered MCC-849A and MCC-89B)
Emergency AC lighting
Instrumentation and control
Service water (1 of 2 pumps)
Diesel auxiliaries, diesel room fan, and diesel air compressor
Reactor building cooling water system
Drywell cooling
Distribution transformers
Reactor building HVAC
Battery chargers

Table 3. Category II loads (manually started shutdown loads)

Standby liquid control system
Turbine turning gear
Service water system
Control rod drive system
Station and instrument air system
Containment air system
Battery chargers
Control valves (as required by above systems but not included as battery load)
Vital AC motor generator system
Residual heat removal — station service water system
Reactor protection motor generator system
Fuel pool cooling system
Control room air conditioning
Torus cooling
Turbine building cooling water
Drywell cooling

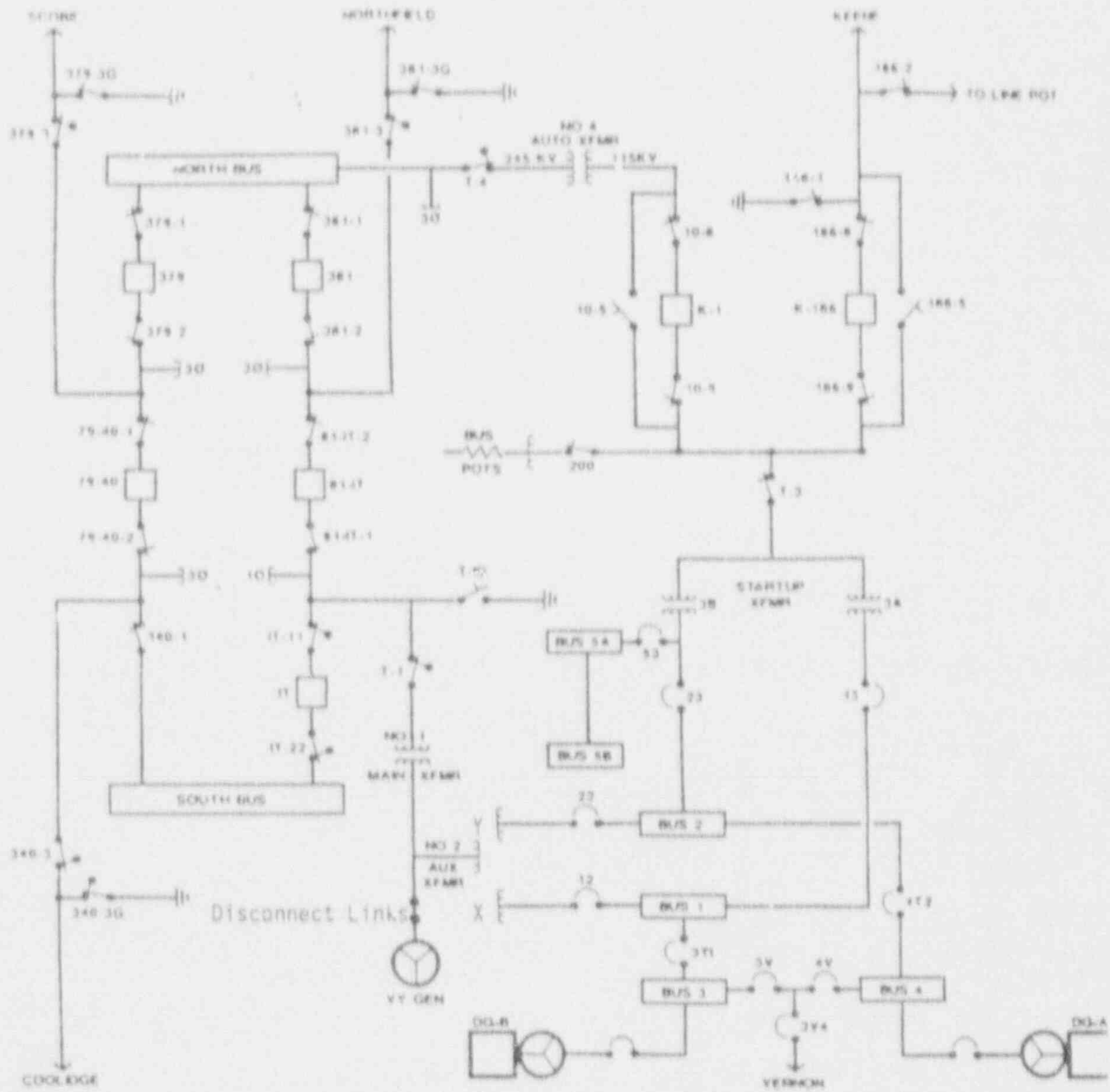
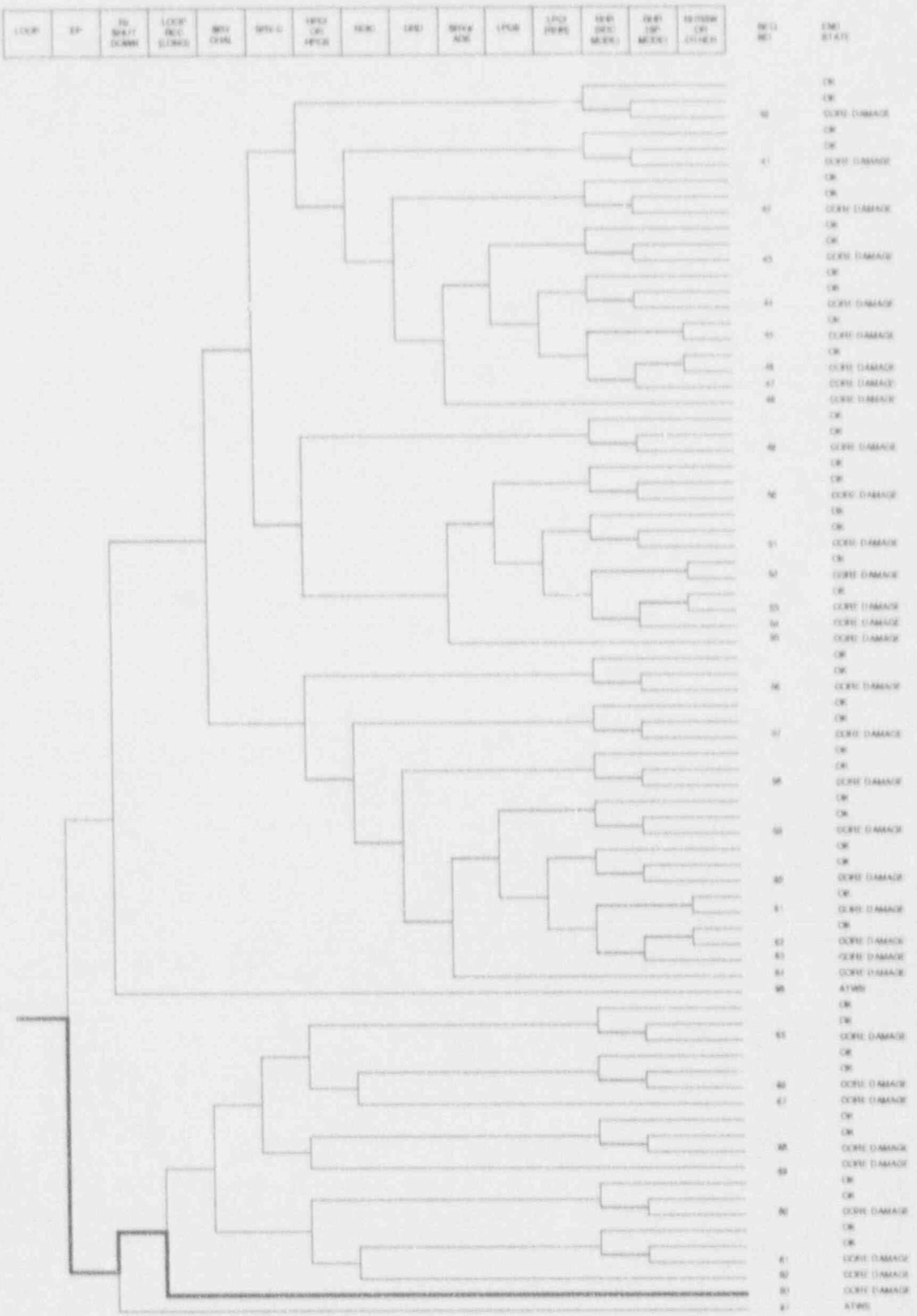


Figure 1. Vermont Yankee AC power system



Dominant core damage sequence for LER 271/91-009

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 271/91-008
Event Description: Extended loss of offsite power
Event Date: 04/23/91
Plant: Vermont Yankee

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.9E-04
Total	2.9E-04
ATWS	
LOOP	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
83	LOOP EMERG.POWER -rx.shutdown/ep EP.REC	CD	2.8E-04	1.0E-01
98	LOOP -EMERG.POWER rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
98	LOOP -EMERG.POWER rx.shutdown	ATWS	3.0E-05	1.0E+00
83	LOOP EMERG.POWER -rx.shutdown/ep EP.REC	CD	2.8E-04	1.0E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\vermont.sll
PROBABILITY FILE: c:\asp\1989\bwr_csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.5E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	3.6E-01 > 1.0E+00	
Branch Model: INITOR			

Event Identifier: 271/91-008

Initiator Freq:	1.6E-05		
loca	5.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	1.0E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 2.9E-.	8.0E-01 > 1.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02		
EP.REC	1.4E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.6E-01 > 1.0E+00		
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
hpci	2.9E-02	7.0E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Micarick
08-06-1992
10:01:45

Event Identifier: 271/91-009

NRC Form 366 U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER)	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NO. (2)	PAGE (3)
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TITLE (4)
Reactor Scram Due to Loss of Normal Off-site Power (LNP) Caused By Inadequate Procedure Guideline

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ #	REV#	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NO.(S)
0 4	2 3	9 1	9 1	- 0 0 9 -	0 1	0 8	3 0	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10 CFR §: CHECK ONE OR MORE (11)							
POWER LEVEL (10)	1 0 0		20.402(b)		20.405(c)	XX	50.73(a)(2)(iv)		73.71(b)
			20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER)
			20.405(a)(1)(iii)	XX	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO. AREA CODE
DONALD A. REID, PLANT MANAGER	8 0 2 2 5 7 - 7 7 1 1

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

CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS	CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS
X	F K	B Y C	B 3 5 3	N	N/A				
X	F K	2 4	W 3 5 1	N	N/A				

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MO	DAY	YR
YES (If yes, complete EXPECTED SUBMISSION DATE)	XX NO				

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

On 04/23/91 at 1448 hours, during normal operation with Reactor power at 100%, a Reactor Scram occurred as a result of a Generator/Turbine trip on Generator Load Reject due to the receipt of a 345KV Breaker Failure Signal. The Failure Signal was the result of Breaker Failure Interlock (BFI) signals that occurred simultaneously in the 345KV and 115KV Breaker control circuitry during the restoration of a battery bank to Switchyard Bus DC 4A. The cumulative effects of both (BFI) signals resulted in a total loss of 345KV and 115KV off-site power. An Unusual Event was declared at 1507 hours. Both Emergency Diesel Generators provided power for essential safety related systems during the LNP until approximately 0430 hours on 04/24/91 at which point off-site 345KV power was restored and backfed through the Station Auxiliary Transformer. During the event, Torus Water volume exceeded the Technical Specification limit of 70,000 cubic ft. The Unusual Event was terminated at 1950 hours on 04/24/91. The reactor reached Cold Shutdown at 0357 hours on 04/25/91 and was returned to critical at 0300 hours on 04/30/91.

The Root Cause of this event is failure of the repair department personnel to recognize the consequences of operating a DC bus without a connected battery bank.

Corrective actions to prevent reoccurrence are outlined within this report.

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

DESCRIPTION OF EVENT

On 04/23/91 at 1448 hours, during normal operation with Reactor power at 100%, a Reactor scram occurred as a result of a Generator/Turbine trip on Generator Load Reject due to the receipt of a 345KV Breaker Failure Signal. The 345KV Breaker Failure Signal was received as a result of Breaker Failure Interlock (BFI) signals that occurred simultaneously in the 345KV Breaker 81-1T and 115 KV Breaker K-1 control circuitry.

The (BFI) signal from 115KV Breaker K-1 initiated the following automatic system responses:

- Opening of 115KV Breaker K-186
- Opening of 345KV Breakers 379 and 381

The loss of 381 and 379 breakers removed all power sources to the Auto Transformer which in conjunction with the K186 trip resulted in a total loss of 115KV power.

The (BFI) signal from 345KV Breaker 81-1T initiated the following automatic system responses:

- Generation of 345KV Breaker Failure Signal
- Opening of 345KV Breakers 381 and 1T
- Lockout of Main Generator 86GP and 86GB relays, causing the Main Generator and Exciter Field breakers to open

The Generator Primary and Backup Lockout relays initiated the following automatic system responses:

- Main Turbine Trip
- Opening of 345KV Breaker 81-1T and Northfield Line trip at Northfield
- Attempted Fast Transfer of 4KV Buses 1 and 2 to the Startup Transformers but 115KV power was unavailable

The cumulative effects of both (BFI) signals resulted in a total loss of 345KV and 115KV off-site power. However, an additional off-site power source was available through the Vernon Hydro Station Tie line. The 4KV Hydro Station output, which is designated as a delayed access off-site power source, was available throughout the event.

Prior to the event, the plant was in the process of completing the replacement of Switchyard Battery Bank 4A in accordance with a Maintenance Department guideline. All work, with the exception of restoring the connection of the battery bank to the DC 4A bus, was completed without incident. While performing the final sequence of actions necessary to reconnect the battery bank to DC Bus 4A, a DC voltage transient occurred on the bus which initiated the event.

During the first second of the event (1448:29 hours), as a result of the inability to reenergize 4KV buses 1 and 2 from Fast Transfer to the Startup transformers, all station loads fed from these buses were lost. Major system responses to the loss of the power included the

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

DESCRIPTION OF EVENT (Cont.)

trip of Reactor Protection System (RPS)(*JC) "A" and "B" MG sets and receipt of Primary Containment Isolation Signals (PCIS)(*JM) Groups 1, 2, 3 and 5 resulting in the required closure of PCIS Groups 1, 2, and 3 isolation valves. (Motor operated valve closures within these Groups occurred after Emergency Diesel Generator power was supplied to the respective buses).

The loss of all power on 4KV Buses 1 thru 4 initiated the opening of Tie breakers 3T1 and 4T2 to provide isolation of Safety Buses 3 and 4 which, in the event of normal power loss, are aligned with the station Emergency Diesel Generators. An autostart of both diesels followed which reenergized Bus 3 and Bus 4 at 1448:45 hours. Both diesels remained in operation without incident until approximately 0430 hours on 04/24/91 at which time off-site 345KV power was restored and backfed through the Station Auxiliary Transformer.

In response to the Scram, Operation personnel entered Emergency Operating Procedure OE 3100, "Scram Procedure" which governs reactor operation in a post-scram environment. Immediate actions initiated at 1450 hours by Operations personnel to stabilize Reactor pressure and level included the manual lifting of Safety Relief Valve (SRV)-A, the manual initiation of High Pressure Coolant Injection System (HPCI)(*BJ), and startup of both RHR loops in the Torus Cooling mode. Both RPS MG sets were successfully restarted and RPS buses reenergized at 1515 hours. The initial scram was reset at 1533 hours.

During the period from 1450 hours on 04/23/91 to 1346 hours on 04/24/91, the combination of HPCI and Reactor Core Isolation Cooling (RCIC) (*BN) systems and SRV's were manually employed in accordance with procedure OE 3100 to control Reactor pressure and level. The first use of RCIC system began at 1645 hours on 04/23/91. During the above 23 hour period, several additional events transpired. The following is a summary and discussion of those events:

A. Reactor Scrams on "Lo" Reactor Water Level were experienced at 1534 hours and 2112 hours on 04/23/91.

   The first Scram occurred due to low Reactor water level during the process of securing HPCI and transferring to RCIC. Prior to the scram, reactor pressure and level had been steadily decreasing during the first 30 minutes of HPCI operation which prompted a change in cooling systems by Operations personnel. During the process of securing HPCI, Reactor Water level continued to decline to the 132 inch "Lo" level setpoint which initiated the Reactor scram. PCIS - Groups 2, 3, and 5 isolations which would normally initiate on "Lo" Reactor water level were already present from the initial Scram at 1448 hours. After receiving the Scram, Operations personnel completed the transfer to RCIC for level and pressure control. Reactor pressure and level recovered after RCIC initiation. The Scram and PCIS Groups 2, 3, and 5 isolations were subsequently reset at 1548 hours.

   The second Scram resulted as a momentary drop in water level was experienced due to level shrink resulting from an increase in Reactor pressure experienced after cycling SRV-D. Water level dropped to approximately 112 inches during the pressure surge. The initiation of PCIS

*Energy Information Identification System (EIIS) Component Identifier

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

DESCRIPTION OF EVENT (Cont.)

Groups 2, 3, and 5 logic occurred coincident with the level drop as required. The scram was subsequently reset at 2127 hours. PCIS Groups 2 and 5 logic were reset at 2128 hours and Group 3 logic later reset at 2154 hours.

B. Emergency Operating Procedure OE 3104, "Torus Temperature and Level Control Procedure", was entered at 1533 hours and 2112 hours on 04/23/91 due to Torus water volume exceeding the Technical Specification limit of 70,000 cubic ft.

In both occurrences, actions were taken in accordance with OE 3104 to reduce Torus water volume. Water reduction actions undertaken after the first entry into OE 3104 were successful and Torus water volume was reduced and maintained below 70,000 cubic ft. Later in the event, at 2112 hours, Torus water volume was not able to be maintained below 70,000 cubic ft. This resulted in the entry into the Technical Specification, "required cold shutdown in 24 hours" requirement. Due to the volume limitations of Torus water being processed through Radwaste, the Torus water volume remained above 70,000 cubic ft. until 1925 hours on 04/24/91. The Technical Specification cold shutdown requirement and OE 3104 were excited at this time.

C. RCIC tripped on overspeed at 1904 hours on 04/23/91. The overspeed trip was reset at 1912 hours and operation of the system resumed.

The trip is attributed to an operator error in the adjustment of the RCIC Flow Controller prior to switching from the MANUAL to AUTO mode.

D. The "A" Station Air Compressor tripped at 1542 hours on 04/23/91 due to inadequate Service Water cooling flow. A reserve diesel air compressor was subsequently connected to the outlet of the "D" Station air compressor and became operable at 1759 hours. The remaining "B" Station Air Compressor also tripped at 1731 hours on Thermal Overload due to inadequate Service Water cooling flow and was subsequently restarted at 1736 hours. The "C" and "D" station Air Compressors were unavailable due to the LNP.

The 5 minute interval in which all Station Air compressors were out of service resulted in a 15 psig. Instrument Air header pressure drop. In response to the "B" Station Air Compressor trip, Operations personnel entered procedure ON 3146, "Low Instrument/Scram Air Header Pressure", and initiated immediate efforts to restart the "B" Station Air Compressor. No air supplied equipment malfunctions were experienced during this interval. The reduced Service Water flow to the Station Air Compressors and other plant equipment is being reported separately as Licensee Event Report (LER) 91-12.

At 1925 hours on 04/23/91, 115KV Breaker K186 was manually closed which restored power to the Startup transformers via the Keene (K186) line. 4KV bus breakers 13 and 23 were subsequently closed to reenergize Buses 1 and 2 which power the normal station loads. Because of the fact that testing was continuing in the Switchyard with only one breaker closed, the decision was made to leave the Emergency Diesels connected to 4KV Buses 3 and 4. This would ensure that power to 4KV Buses 3 and 4 would not be interrupted if another LNP occurred.

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

DESCRIPTION OF EVENT (Cont.)

At 1950 hours on 04/24/91, based on normal off-site power having been restored and Torus water volume having been reduced below 70,000 cubic ft., the Unusual Event was terminated. At 0207 hours on 04/25/91, Shutdown Cooling using the "D" RHR pump on the "B" loop was initiated. The reactor reached cold shutdown at 0357 hours. The reactor was eturned to critical at 0300 hours on 04/30/91.

Investigations into the cause of the event, along with troubleshooting, testing, and repair efforts were initiated immediately after the start of the event. A Switchyard response team was formed with specific directives to:

- recover off-site power
- stabilize the switchyard
- gather technical information related to the event
- begin root cause analysis research

The recovery of off-site power began with the attempt to restore 115KV power from the Switchyard via 115KV Breaker K186 and the Startup transformers. This was determined to be the easiest path in obtaining an off-site power source due to the need to close only one breaker. However, the K1 Breaker BFI signal remained locked in due to a failed zener diode on the associated trip card and prevented the closure of K186. At 1925 hours, the BFI signal from the K1 to the K186 Breaker was blocked allowing reclosure of K186 and subsequent restoration of power to 4KV buses 1 and 2. The K1 BFI trip card was subsequently replaced with an identical card from a spare breaker. The 4 hour effort to close the K186 breaker was a direct result of the length of time required for New England Power Service Co. (NEPSCO) relay technicians to travel to Vermont Yankee from Providence, Rhode Island.

After 115 KV power was established through the Keene K186 line, efforts to close Breaker K1 continued in order to establish a more reliable source of 115KV power through the Auto Transformer. However, due to communication problems between VY and the New England Switching Authority (REMVEC) concerning priorities over breaker testing, a three hour delay occurred before 115KV power was made available through the Auto Transformer. While Vermont Yankee was attempting to close the K1 breaker, REMVEC was pursuing efforts to establish connections between the ring bus and the Northfield line by reclosing the 81-1T breaker.

In a parallel effort, at 1900 hours, Operation orders were given to complete backfeeding of the plant from the 345 yard through the Main Transformer. The effort to backfeed was possible due to the availability of the Coolidge and Scobie lines. The Northfield line was unavailable due to the 81-1T BFI signal. Again, the backfeed effort was hampered by communication problems with REMVEC, personnel delays, and equipment malfunctions. Backfeeding was completed at 0410 hours on 04/24/91. Vermont Yankee Technical Specification requirements for Off-Site Power were met during the Backfeeding effort by the availability of one off-site transmission line (Keene K186 line in service) and a delayed access power source (Vernon Hydro Station).

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DESCRIPTION OF EVENT (Cont.)

In conjunction with the above efforts, Maintenance department personnel with the help of technicians supplied by NEPSCO and the battery charger vendor, performed preventative and corrective maintenance on the four battery chargers related to DC Bus 4A and 5A. Significant repairs and testing were performed on the affected units. Additional testing and repairs were initiated to the Stuck Breaker Failure Unit (SBFU) logic trip cards for the 81-1T, 381 and K1 breakers. The cards for 381 and K1 breakers were found to have failed zener diodes. The 81-1T (SBFU) relay was found to be functioning properly.

Discussions with the manufacturer indicated that the zener diodes are no longer employed on newer revision trip cards and have recommended the removal of the zener diodes based on their vulnerability to voltage transients. Based on this recommendation, the Maintenance Dept. has removed the zener diodes from these units in accordance with written direction from the vendor.

After response team efforts were completed, a Root Cause/Corrective Action Report (CAR) was drafted on the event from a Switchyard perspective. In the draft report, the following conclusions were reached:

- The voltage transient on the DC 4A bus occurred when battery charger 4A-5A was disconnected from the DC-5A bus which rendered bus DC 4A susceptible to voltage spikes due to the absence of a battery bank.

- The specific cause of the zener diode failures which resulted in the 81-1T and K1 breaker (BFI) signals is attributed to the voltage transient which occurred on Bus DC 4A.

- A portion of the additional problems found with DC Bus 4A and 5A battery chargers which ranged from shorted diodes/SCRs and blown surge suppressor fuses, were concluded to be pre-existing and were responsible for the voltage transient.

CAUSE OF EVENT

The Root Cause of this event is the failure of the repair department personnel to recognize the consequences of operating a DC bus without a connected battery bank. The Maintenance Guideline, an internal Maintenance Department document prepared by the department Electrical Engineering staff, was inadequate in that it did not take into consideration all battery charger failure modes when floating a DC bus without a battery bank. The consequences of losing battery charger power while the bus is energized without a battery connected were considered during the revision of the Guideline but not the potential of the battery chargers to fail high or induce a high voltage spike on the bus, both which have the potential to damage electronic circuitry.

The previous revision of the Guideline called for the two DC buses (4A & 5A) to be cross-connected and fed jointly by the 4A/5A battery charger during the maintenance on the batteries. Following cross-connection, the Guideline required opening of the battery breakers. This

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CAUSE OF EVENT (Cont.)

evolution was successfully accomplished and the required work on the batteries was completed without incident. Recovery of the battery required the closure of the battery output breaker first, essentially paralleling the two battery banks until the 4A/5A charger output breaker was opened. In June 1990, the guideline was revised due to Operations Department concern with paralleling batteries. The new revision required that the cross connection between bus 4A and 5A provided by battery charger 4A/5A be opened prior to the reclosure of the bus 4A battery breaker. This configuration rendered bus 4A without a battery and susceptible to voltage excursions from either the 4A or 4A/5A battery chargers.

CONTRIBUTING CAUSES

1. 345KV and 115KV breaker failure relays were susceptible to false initiation due to control voltage transients. Both the 345KV and 115KV breaker BFR's are fed from one bus (DC-4A) rendering them susceptible to a single system transient.

2. The switchyard battery chargers were in a degraded mode such that they created DC bus control voltage disturbance when the chargers were disconnected from associated batteries. This included the installation of incorrect capacitor fuses and other degraded components.

3. Lack of Switchyard battery charger and overall Switchyard preventative Maintenance.

ANALYSIS OF EVENT

The events had minimal adverse safety implications.

1. The plant responded to the reactor trip and LNP as designed. The Emergency Diesel Generators operated as designed and supplied power to Emergency plant buses until off-site power was restored.

2. The Reactor Protective System operated as designed and scrammed the reactor on Generator Load Reject resulting from the 345KV Breaker Failure Signal.

3. An evaluation was performed by the Operations Department relevant to the loss of both "A" and "B" Station Air Compressors. The analysis concluded that the 5 minute interval in which the "B" Station Air Compressor was out of service which resulted in a 15 psig. drop in the station air supply system did not significantly challenge any plant equipment.

4. All other safety systems responded as expected.

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CORRECTIVE ACTIONS

SHORT TERM CORRECTIVE ACTIONS

1. Immediate corrective actions included recovering from the reactor scram, restoration of off-site power, and Switchyard and reactor stabilization utilizing appropriate plant procedures.

2. The current revision of the Maintenance Dept. Guideline has been cancelled and the previous revision reinstated with an additional requirement that a review be performed prior to its use for dealing with any evolution requiring switchyard battery removal.

3. Review all other plant guidelines and Procedures pertaining to battery switching operations.

LONG TERM CORRECTIVE ACTIONS

N The following Long Term Corrective Action plans have been developed in accordance with our Root Cause/Corrective Action Program and in response to the NRC Augmented Inspection Team (AIT) review conducted at our facility during the period of April 25 - 29, 1991 as detailed in NRC Report No. 50-271/91-13. Except where specifically noted, our corrective actions are scheduled for completion by December 31, 1991.

1. Representatives of Vermont Yankee and REMVEC met on June 10, 1991 and discussed the communication problems which occurred during the April 23, 1991 LOOP event. At this meeting, several communication improvements were discussed, including the identification of a single point of contact for switching operations at Vermont Yankee, the establishment of clear priorities for switching, a more thorough understanding of organizational responsibilities and restoration of offsite power. Both parties agreed to continue to meet periodically to ensure that effective communications are maintained.

2. Vermont Yankee has developed an additional source of offsite relay technician assistance to improve availability and response time. Switchyard relay technicians are now available from two utility affiliates (NEPSCO and VELCO) in the event of switchyard emergencies.

3. Vermont Yankee will establish the resources and conduct the training necessary to optimize the time required for backfeeding the normal station service busses through the auxiliary transformer. These corrective actions will be completed by December 31, 1991.

4. Procurement of new switchyard breaker failure relays (BFR) has been initiated. Installation is scheduled to be completed during the March 1992 Refueling Outage.

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FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6)					PAGE (3)	
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TEXT (If more space is required, use additional NRC Form 366A) (17)

LONG TERM CORRECTIVE ACTIONS (Cont.)

5. Administrative controls for switchyard activities, which are important to safety or plant reliability, will require additional management review, including PORC review, as determined by the Maintenance Supervisor. This enhancement is effective immediately and ongoing.

6. Vermont Yankee will evaluate the potential for voltage transients when any station DC bus is operated without its battery and will implement the changes necessary to preclude such transients. This corrective action will be completed by December 31, 1991.

7. Breaker failure relay (BFR) power supply assignments and assignments for common mode failure mechanisms will be reviewed to determine if other improvements to reliability can be made. Additionally, other static protective relays installed at Vermont Yankee will be similarly reviewed to determine if the original manufacturer has recommended design enhancements to increase surge withstand capabilities. These corrective actions will be completed by April 30, 1992.

8. All switchyard PM programs will be reviewed to develop an effective battery charger PM and surveillance test procedure. This corrective action will be completed by December 31, 1991.

9. Removal of Zener diodes from the BFRs and use of incorrect fuses is being evaluated for potential reportability. This review will be completed by December 31, 1991.

10. A review of the FSAR statements regarding availability of offsite power has been completed and has identified the need for revisions to Appendix F, "Conformance to AEC General Design Criteria." The FSAR will be revised during the next scheduled update in June, 1992.

11. An evaluation of the adequacy of maintenance and surveillance programs for non-nuclear safety (NNS) technical specification equipment will be performed to ensure that other switchyard and plant components similar to the battery chargers meet the appropriate reliability requirements. This evaluation will be completed by December 31, 1991.

12. A review of the inventory requirements for the switchyard will be conducted by December 31, 1991.

ADDITIONAL INFORMATION

There have been no similar events of this type reported to the commission in the past five years.

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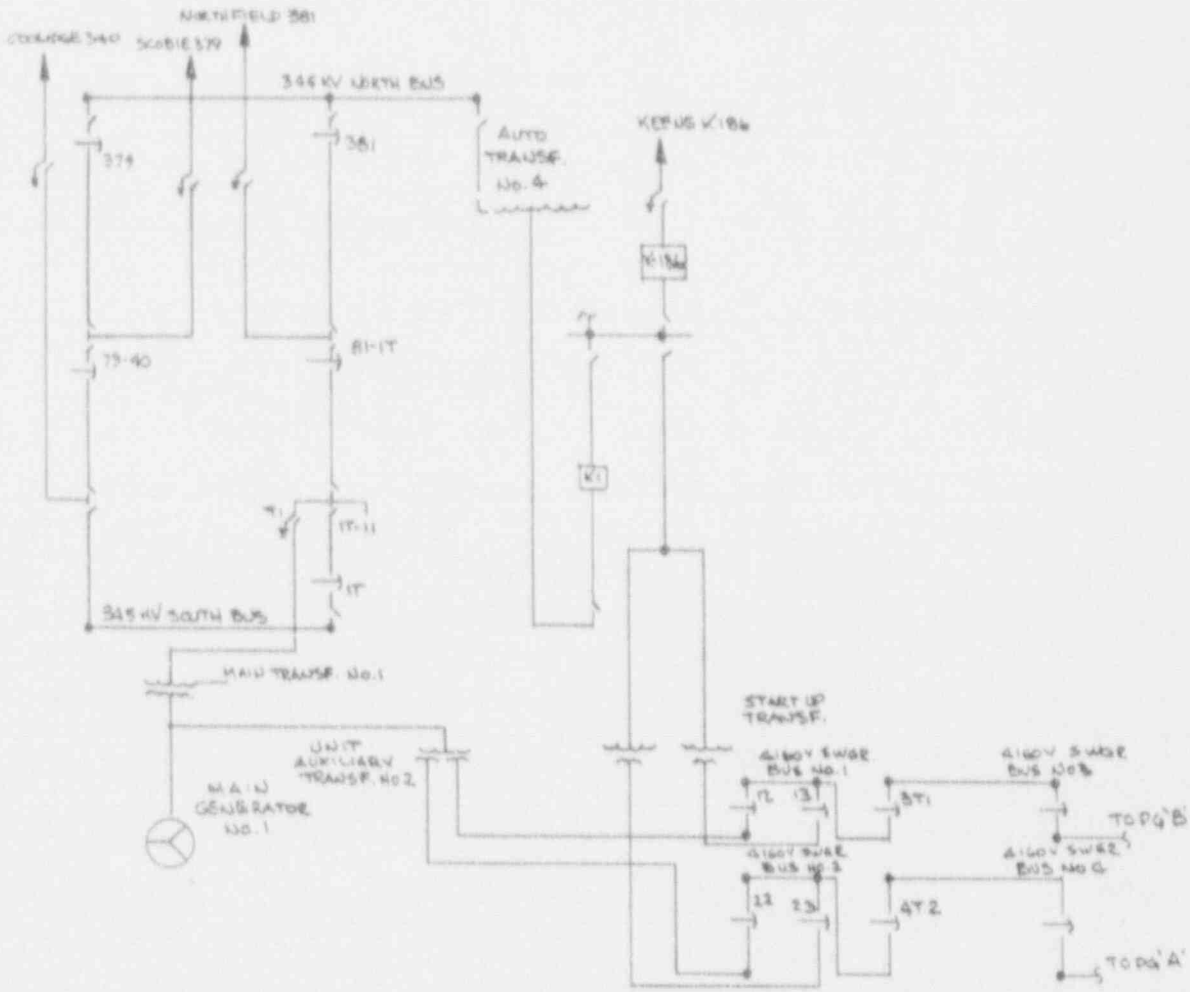
TEXT (If more space is required, use additional NRC Form 366A) (17)



SWITCHYARD DISTRIBUTION

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.
FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6)	PAGE (3)
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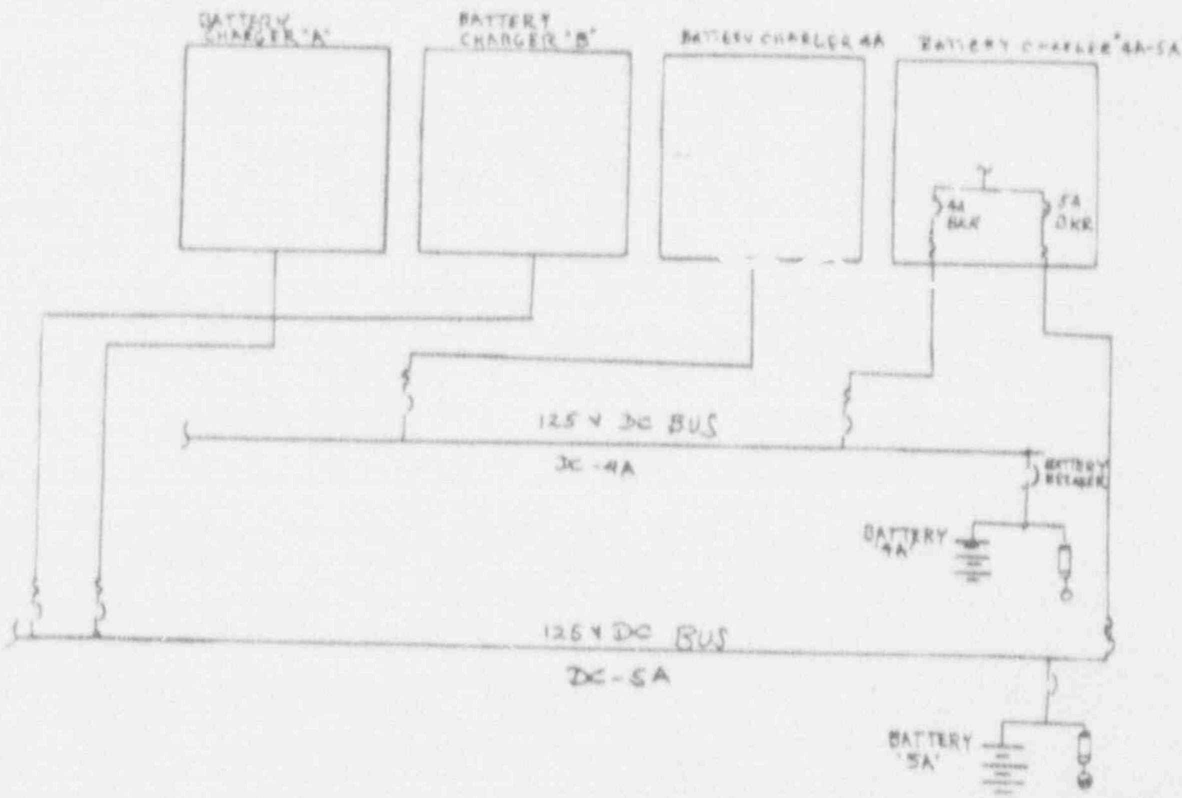
TEXT (If more space is required, use additional NRC Form 366A) (17)



SWITCHYARD DC BUS SYSTEM

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92
LICENSEE EVENT REPORT (LER) DEC 06 1991	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANA EMT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NO. (2)	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	0 1 OF 0 6

TITLE (4)
Reduced Cooling Water Flow to Diesel Generator Heat Exchangers and Station Service Air Compressors Due to High Service Water System Backpressure Caused by Weak Design

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ #	REV#	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NO.(S)
										0 5 0 0 0
0 4	2 3	9 1	9 1	- 0 1 2 -	0 1	1 1	0 7	9 1		0 5 0 0 0

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO REQ'MTS OF 10 CFR §: CHECK ONE OR MORE (11)			
		20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)		20.405(a)(1)(i)	50.36(c)(1)	X 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)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	/ 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO. AREA CODE
DONALD A. REID, PLANT MANAGER	8 0 2 2 5 7 - 7 7 1 1

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

CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS	CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS
N/A					N/A				
N/A					N/A				

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MO	DAY	YR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On April 23, 1991, at 1448 hours, and at 100% power, a Loss of Normal Power (LNP) was experienced. Following the expected start of both Emergency Diesel Generators (EDG), it was observed that the EDG heat exchangers were operating at reduced flow and that the station air compressor coolers were operating with reduced/reverse flow.

The root cause of the event was a weak design modification resulting in an incorrect procedure. The incorrect procedure established an alternate cooling discharge path to the cooling towers and produced a high service water system backpressure of approximately 40 psid. System backpressure was further increased due to various system design and operating characteristics present during the LNP.

A task force was convened to analyze and test the response of the service water system. The service water system was reconfigured to eliminate the primary contributor of backpressure.

A Corrective Action Report was generated to further identify and confirm the root cause of the event and provide detailed long term corrective actions.

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NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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

DESCRIPTION OF EVENT

On April 23, 1991, at 1448 hours a loss of normal power (LNP) was experienced (see Ler 91-09) at 100% power. The two Emergency Diesel Generators (EDGs) auto-started and loaded normally and two of four Service Water pumps cycled on line as designed. The two additional service water pumps and two Residual Heat Removal (RHR) Service Water pumps were manually started. During the scram recovery it was observed by Operations personnel that the EDG heat exchangers (EDG-Hx)(EIIS=HX) were operating at reduced (but adequate) cooling water flow and that the station service air compressors coolers (EIIS=CLR) were operating under reduced/reverse flow due to high discharge pressure conditions.

This event is being reported under the reporting criteria of 50.73(a)(2)(ii) and 50.73(a)(2)(v). The degraded cooling water condition for the Emergency Diesel Generator Heat Exchangers could have been severe enough alone to have prevented the operation of these vital power sources and thereby prevented the fulfillment of their safety function. Subsequent analysis demonstrated that adequate cooling margin for the Emergency Diesel Generators was available during and following the LNP event. The loss of the service air compressors is a significant loss of systems important to the operation of the plant and is outside the design basis of the plant. The service air compressors are not required to support any accident function or accident response and are classified as non nuclear safety.

CAUSE OF EVENT

The root cause of the event was a weak cooling tower basin deicing design coupled with isolated FSAR statements. The potential for creating significant additional hydraulic line resistance during an LNP event from this alternate system configuration was not identified in the original design or by the authors of the FSAR. No operational limitations or restrictions were placed upon this alternate valve lineup and as a result an inadequate valve lineup procedure was developed.

The Vermont Yankee Service Water system is designed with normal discharge to the main discharge structure via valve SB-1. An alternate cooling scheme is provided for the facility in the event of a loss of the main cooling water supply (Vernon Pond). One of two cooling towers contains a deep basin and has the capacity to receive, cool, and provide water to the station for one week without makeup after such an event. The interface between the service water system and the cooling tower is provided via valve V70-11.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

CAUSE OF EVENT (Cont.)

FSAR Section 10.8.3. reflects the need to deice the deep basin during winter months and states that warm service water will be discharged via V70-11 to the deep basin. The overflow is then spilled/discharged to the Circulating Water system ..charge structure. This alternate Service Water system lineup became a standard mode of operation in 1987.

The alternate system lineup provides a flow path of higher resistance and develops significant backpressure at the discharge of the EDG heat exchangers. This condition reduced flow to the heat exchangers, but was not sufficient to render the EDGs inoperable. This same high backpressure also closed the pressure control valves on the station air compressor coolers, opened the "B" air compressor relief valve and created a reduced/reverse flow condition to the drain on that unit.

Additional backpressure within the service water system was also developed by several other less significant sources. See Analysis of Event below)

ANALYSIS OF EVENT

The FSAR permits opening and the V70-11 valve for cold weather operation and does not prohibit opening the V70-11 summer operations. An alternate (SB-1 closed, V70-11 open) valve lineup was determine.. be acceptable and became the "normal" year round system lineup. This configuration creates . gnificant backpressure conditions to the Service Water system due to the higher resistance of this flow path and the cooling tower deep basin head of water. The resultant backpressure is preferred during normal operations for control of heat exchanger discharge flows and provides very favorable conditions for certain Service Water radiation monitors. This configuration also obviates the need for procedure revisions and valve lineup changes on a seasonal frequency. However, the alternate valve lineup also creates increased backpressure for the Emergency Diesel Generator heat exchangers and the air compressor coolers. The net contribution in backpressure caused by this valve lineup is estimated at approximately 40 psid.

The two EDG heat exchangers discharge into a common 8" discharge line which is also shared by the station air compressor coolers. During the LNP both EDGs auto started and were discharging to the single 8" line. The EDGS have independent 8" supplies. During surveillance testing, only one diesel is normally operating at any one time.

The net contribution in backpressure from the common discharge line design is estimated at approximately 9 psid.

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FACILITY NAME (1)	DOCKET NO (2)	LER NUMBER (6)	PAGE (3)
		YEAR - SEQ # - REV #	
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1 - 0 1 2 - 0 1	0 4 OF 0 6

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

ANALYSIS OF EVENT (Cont.)

The Service Water system is identified to be subject to attack by aerobic microbes (MIC) which has reduced the effective diameter of the subject 8" discharge line to a nominal 7" pipe. The net contribution in backpressure due to MIC is estimated at 10 psid.

During the LNP, the Service Water System flow was higher than normal due to the operation of two EDGs, four Service Water Pumps and two RHR Service Water Pumps. This additional flow to the system also increased system backpressure. The net contribution in backpressure resulting from this additional flow is estimated at approximately 8 psid.

During the LNP, the above developed backpressures, and principally the 40 psid developed by operating with V70-11 open and SB-1 closed, resulted in reduced flow to the EDG heat exchangers and reverse flow to the station air compressor coolers. The other sources of backpressure compounded this hydraulic effect.

While flow to the heat exchangers was significantly reduced during the LNP, the EDGs remained fully operable. In addition, it was verified by calculation that if the service water inlet temperature had been at a maximum design temperature of 95°F, the EDG heat exchangers would have had sufficient flow and cooling capacity to maintain the EDGs operable while under the load experienced during the event.

Reverse air compressor cooling water flow was observed. The air compressor pressure control valves are set at 65 psi and they closed when matched against the greater backpressure of the system. The high backpressure then lifted the "B" air compressor relief valve and created a flow path in the reverse direction through the cooler to drain. The station air compressors are non-safety class equipment and are not relied upon to operate during any transient or accident condition.

During the LNP, the total system backpressure due to all conditions was approximately 65 psid at the EDG heat exchangers. During surveillance testing this backpressure, in the alternate valve lineup, is considerably less (approx. 45 psid) and provided acceptable operating hydraulic conditions. The additional backpressure developed during an LNP due to "other" sources drives the hydraulic conditions to an unacceptable level for the air compressor coolers.

With the Service Water system configured with the SB-1 valve open and the V70-11 closed there is no plant transient which will provide a backpressure condition sufficient to inhibit EDG heat exchanger flow or induce reverse flow in the air compressor coolers.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BUR)EN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUC ON PROJECT (3160-0104), OFFICE OF MANAGEMENT A.. BUDGET, WASHINGTON, DC 20603.		
FACILITY NAME (1)	DOCKE (2)	LER NUMBER (6) YEAR - SEQ # - REV #	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	9 1 - 0 1 2 - 0 1	5 OF 6

TEXT (If more sp.. is required, use additional NRC Form 366A) (17)

IMMEDIATE CORRECTIVE ACTIONS

1. Both Emergency diesel Gener. . remained operable and were closely monitored throughout the event.

2. During the LNP event, a , .able auxiliary diesel driven air compressor was crossconnected t the Service Air system at 1759 hours to provide service air.

LONG TERM CORRECTIVE ACTIONS

Immediately following the LNP, a task force was convened to investigate the root cause of the event, to provide immediate corrective actions to address short term operational needs, and to undertake a detailed assessment of the Service water system relative to design basis and operating performance.

A focused analysis was completed and substantiated by a complex testing program. The testing included operating the Service Water system in various configurations and taking flow and pressure measurements.

The results of the analysis and testing provided a clear understanding of precisely how the service Water system responds to SB-1 and V70-11 lineup changes and how increased or high flow backpressures are developed.

The results of the task force efforts were presented to the Plant Operations Review Committee and plant management and were accepted prior to plant startup.

An in-depth Corrective Action Report with a detailed Root Cause Analysis was also completed and reviewed and accepted by management.

Based on the results of the analysis and testing and the completed Corrective Action Report the following long term corrective actions are/will be completed.

1. The Service Water System was reconfigured to position SB-1 open and V70-11 closed. This lineup assures that the excessive backpressures developed during this event cannot recur.

2. A review of Service Water System loads was performed to verify optimum system performance.

3. The basis and assumptions made during the design of the deep basin de-icing system will be further reviewed by 12/31/91.

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TEXT (If more space is requ/ /d, use additional NRC Form 366A) (17)

LONG TERM CJRRECTIVE ACTIONS (Cont.)

4. New Service Water System analysis/test data, .ncluding the identified corrosion and tuberculation effects, will be incorporated into Vermont Yankee's Service Water (computer) flow model by June 30, 1992.

5. Alternate methods for cooling tower deicing and normal cooling tower makeup are identified. A method will be selected and implemented by November 30, 1991. This will modify item 5.

6. Vermont Yankee design change and procedure change programs will be revised by December 31, 1991 to emphasize the need to review the FSAR when making operational and design changes to plant equipment.

7. Training was provided to Operations, Engineering and other appropriate personnel on the April 23, 1991 event to emphasize that the "minimum" equipment response is not necessarily the "worst case" scenario. Enhancements were made to the applicable surveillance and operating procedures and additional guidance was incorporated into the Procedure Writer's guide.

8. The Calibration/Preventative Maintenance (PM) frequencies of Safety Class 3 Service Water flow and pressure control valves will be reviewed and necessary changes made by December 31, 1991.

9. The SW surveillance tests have been reviewed and alternative requirements have been identified which confirm the operability of vital plant equipment during a LOOP and other design basis conditions. The alternative requirements are currently being evaluated to determine the most appropriate parameters and equipment configuration for incorporation in our ongoing SW surveillance testing program. Specific SW surveillance test procedures will be revised by December 31, 1991.

ADDITIONAL INFORMATION

No similar events have been reported to the Commission in the last five years.

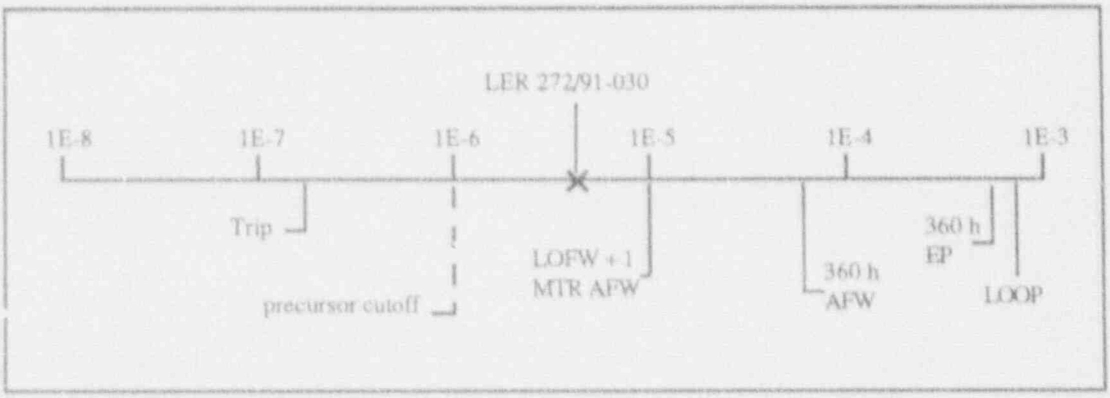
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No: 272/91-030
Event Description: Both PORVs failed due to leaking actuators
Date of Event: September 20, 1991
Plant: Salem 1

Summary

The power-operated relief valves (PORVs) at Salem 1 were inoperable because of leakage from the flange bolting area on the air-operated PORV actuators. It is assumed that both PORVs were inoperable for one half of their surveillance period (81 d).

The conditional probability of core damage estimated for this event is 4.4×10^{-6}. The relative significance of the event compared to other postulated events at Salem 1 is shown below.



Event Description

The plant was in Mode 4 (200°F < T_{avg} < 350°F) with a plant shutdown to Mode 5 (T_{avg} ≤ 200°F) in progress to support a maintenance outage. Technical Specifications require that the pressurizer PORVs be used to provide pressurizer overpressure protection when one or more of the reactor cooling system (RCS) cold legs is less than or equal to 312°F (except with the reactor head removed). The PORVs were functionally checked and failed to open upon demand. At the time of these functional tests, the control room alarm for PORV accumulator low air pressure actuated. Investigations showed that both the 1PR1 and 1PR2 valve actuators leaked. The valve actuator diaphragm bolts were observed to be loose, which allowed air leakage from the flange bolting area. The valves successfully stroked after the actuator bolts were tightened.

Investigations indicated that the 1PR1 and 1PR2 actuator diaphragms appeared to be in a functional condition. Further assessment showed that the diaphragm material (Buna–N rubber) is subject to "creep," where the diaphragm may change from its original geometry under load and over time. This phenomena can be exacerbated by uneven torquing of the actuator joint. Leak paths may develop that were not present at the time of original installation. The 1PR1 and 1PR2 actuator diaphragms had been replaced on March 21, 1991, and April 12, 1991, respectively.

Additional Event-Related Information

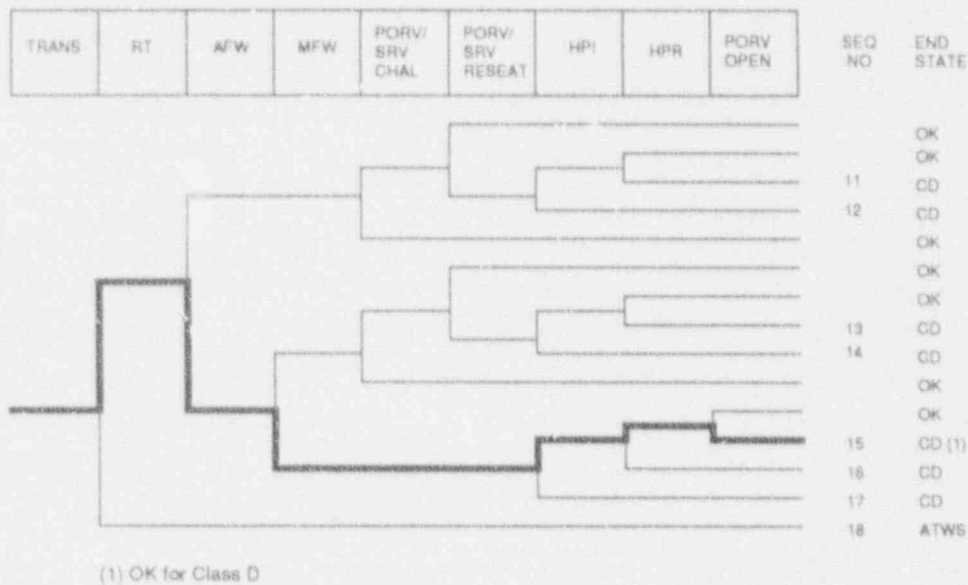
At Salem, the PORVs and pressurizer spray valves are used to help mitigate the consequences of a steam generator (SG) tube rupture. Additionally, the PORVs are used for a total loss of feedwater (LOFW) accident. During a LOFW with failure of auxiliary feedwater, decay heat removal would be provided by utilizing the PORVs and the safety injection (SI) pumps in a "feed and bleed" mode. This is addressed in the station emergency operating procedures (EOPs) in FRHS-1, "Functional Restoration of Heat Sink."

ASP Modeling Assumptions and Approach

It was assumed that both PORVs were inoperable for half the period from April 12, 1991, to September 20, 1991 (81 d). Unavailability of either PORV results in failure of feed and bleed capability. One of the PORVs (1PR2) was assumed to be still capable of performing its pressure relief function (since it apparently lifted partially during testing).

Analysis Results

The conditional probability of subsequent core damage estimated for this event is 4.4×10^{-6}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated transient with unavailable secondary-side cooling and unavailability of feed and bleed.



Dominant core damage sequence for LER 272/91-030

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 272/91-030
Event Description: Both PORVs failed due to leaking actuators
Event Date: 09/20/91
Plant: Salem 1

UNAVAILABILITY, DURATION= 1944

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	5.2E-01
LOOP	1.7E-02
LOCA	2.0E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	2.8E-06
LOOP	1.6E-06
LOCA	1.4E-08
Total	4.4E-06
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt afw mfw -hpi(f/b) -hpr/-hpi PORV.OPEN	CD	2.8E-06	1.8E-02
43	loop -rt/loop -emerg.power afw -hpi(f/b) -hpr/-hpi PORV.OPEN	CD	1.6E-06	1.4E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt afw mfw -hpi(f/b) -hpr/-hpi PORV.OPEN	CD	2.8E-06	1.8E-02
43	loop -rt/loop -emerg.power afw -hpi(f/b) -hpr/-hpi PORV.OPEN	CD	1.6E-06	1.4E-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:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\salem1.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

Event Identifier: 272/91-030

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.7E-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	7.5E-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	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	1.0E+00	1.0E-03
PORV.OPEN	1.0E-02 > 1.0E+00	1.0E+00	4.0E-04
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		

* branch model file
** forced

Minarick
06-07-1992
20:19:22

Event Identifier: 272/91-030

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Salem Generating Station - Unit 1	0 5 0 0 0 2 7 2	1 OF 0 6

TITLE (4): Both Pressurizer Pressure Operated Relief Valves Failed An Operability Check

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 NAMES	DOCKET NUMBER(S)
0 9	2 0	9 1	9 1	— 0 3 0 —	0 0	1 0	1 8	9 1	Salem Unit 2	0 5 0 0 0 3 1 1
										0 5 0 0 0

OPERATING MODE (9): 4

POWER LEVEL (10): 0 0 0

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

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
M. J. Pollack - LER Coordinator	6 0 9	3 3 9 - 2 0 2 2

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
B	A B	P C V	0 6 3 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 2	2 8	9 2

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

On 9/20/91, a plant shutdown was in progress. The Pressurizer Pressure Operated Relief Valves (PORVs) are used to provide overpressure protection at low Reactor Coolant System temperatures. In accordance with Surveillance 4.4.9.3.1.1 the PORVs were functionally checked. Both valves failed to open. The 1PR1 valve did not lose its closed limit indication and though the 1PR2 valve indicated movement, it apparently did not reach its full open limit. Investigation showed that both the 1PR1 and 1PR2 valve actuators leaked. The valve actuator diaphragm bolts were observed to be loose allowing air leakage from the flange bolting area. The root cause of the valves failing to open is continuing. The 1PR1 and 1PR2 valves are Copes-Vulcan reverse acting air actuated globe valves. Investigation indicated that the diaphragms appeared to be in a functional condition. Further assessment had shown that the diaphragm material (Buna-N rubber) is subject to "creep". This phenomena can be exacerbated by uneven torquing. When the diaphragms were installed (April 1991), the specific installation procedure was not used. The administrative controls for implementing new maintenance procedures will be modified. A review of new procedures will be conducted to ensure they have been incorporated into existing planned work. The diaphragms were replaced in all Copes-Vulcan actuators located inside the Unit 1 Pressurizer. The Salem Unit 2 PORVs were successfully tested. The actuator diaphragm material is under investigation for elevated temperature environments.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
Unit 1	5000272	91-030-00	2 of 6

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as {xx}

IDENTIFICATION OF OCCURRENCE:

Both Pressurizer Pressure Operated Relief Valves failed an operability check

Event Date: 9/20/91

Report Date: 10/18/91

This report was initiated by Incident Report No. 91-659.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 4 (Hot Shutdown); Unit preparing to go to Mode 5 (Cold Shutdown)

DESCRIPTION OF OCCURRENCE:

On September 20, 1991, a plant shutdown, to Mode 5, was in progress to support a maintenance outage. Per Technical Specification 3.4.9.3, when the temperature of one or more of the RCS cold legs is less than or equal to 312°F (except with the reactor head removed), the Pressurizer Pressure Operated Relief Valves (PORVs) {AB} are used to provide Pressurizer overpressure protection. Therefore, in accordance with Technical Specification Surveillance 4.4.9.3.1.1 the PORVs were functionally checked (at 0115 hours) using Operations procedure II-2.3.4, "Pressurizer Overpressure Protection - Operability". Both valves failed to open upon demand. The 1PR1 valve did not lose its closed limit indication and though the 1PR2 valve indicated movement, the Control Room indication did not show it reaching its full open limit. At the time of the valves' functional check, the Control Room overhead alarm for PORV accumulator low air pressure actuated.

Investigation showed that both the 1PR1 and 1PR2 valve actuators leaked. The valve actuator diaphragm bolts were observed to be loose allowing air leakage from the flange bolting area. The valves successfully stroked in accordance with procedure SP(O)1.0.5-V-MISC-1 after actuator bolts were tightened.

APPARENT CAUSE OF OCCURRENCE:

Investigation of this event's root cause is continuing. The initiating cause of both PORV valves failing to open is equipment failure.

The 1PR1 and 1PR2 valves are Copes-Vulcan reverse acting air actuated

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
Unit 1	5000272	91-030-00	3 of 6

APPARENT CAUSE OF OCCURRENCE: (cont'd)

globe valves. They require air pressure of at least 6? psig to move the valve off its seat and 85 psig to fully open under system pressure. The air actuator opens the valve by providing an upward net force sufficient to overcome actuator spring compression force.

Investigation by System Engineering indicates that the 1PR1 and 1PR2 actuator diaphragms (which had been subsequently replaced) appeared to be in a functional condition. Further assessment has shown that the diaphragm material (Buna-N rubber) is subject to "creep" where the diaphragm may change from its original geometry under load and over time. This phenomena can be exacerbated by uneven torquing of the actuator joint. Leak paths may develop that were not present at the time of original installation.

Buna-N rubber, per available industry standards, can be used in a temperature range of between -40°F to 250°F. The PORV manufacturer, Copes-Vulcan, was contacted to confirm System Engineering's conclusion that the actuator diaphragm material is acceptable for the pressurizer environment of elevated temperatures to approximately 170°F. Copes-Vulcan responded in a letter, dated October 2, 1991, which concluded:

> "Our review indicates the supplied equipment is suitable for use at the design conditions stated in the original equipment purchase specification. This purchase specification required that the equipment be suitable for use at a maximum temperature of 120°F.
>
> Our review indicates that deterioration of the Buna-N diaphragm should not occur due to exposure to 170°F for a period of 18 months. Unfortunately, Copes-Vulcan has no documented field usage under service conditions similar to your service conditions and no certified testing has been performed which would allow us to guarantee that acceptable performance can be maintained for a period of 18 months at 170°F."

Based upon Copes-Vulcan's response, Copes-Vulcan has been requested to certify the diaphragm material to elevated temperatures, above the original Westinghouse specification.

The 1PR1 and 1PR2 actuator diaphragms were replaced on March 21, 1991 and on April 12, 1991, respectively. After replacement both valves were successfully stroked. These diaphragms were installed using a general procedure (1IC-1.4.003, "General Instrument Calibration Procedure For Field Devices"). Procedure SC.IC-PM.RC-0001, "Pressurizer PORV Operator Maintenance Procedure", contained specific instructions for installation of these diaphragms. Although available, it was not used. This procedure details torque requirements for actuator diaphragm bolting and torquing sequence.

Procedure SC.IC-PM.RC-0001 was not used due to inadequate

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER	LER NUMBER	PAGE
	5000272	91-030-00	4 of 6

APPARENT CAUSE OF OCCURRENCE: (cont'd)

administrative controls. The Maintenance planner was not aware of the approval and issuance of this procedure. As a result, when the diaphragm replacement work order was issued it did not reference the subject procedure.

When a procedure is revised, Station Planning is notified. However, this is not done, in all cases, when new procedures are issued. When procedure SC.IC-PM.RC-0001 was issued, Station Planning was not notified to update applicable planned work. In addition to notification, when a procedure is revised or created, the master procedure index and the procedure summary index are revised. The master procedure index was revised when procedure SC.IC-PM.RC-0001 was issued; however, the procedure summary index was not revised.

ANALYSIS OF OCCURRENCE:

In Modes 1, 2, and 3, the PORV's function to relieve Reactor Coolant System (RCS) (AB) pressure during all design transients up to and including the design step load decrease with steam dump. Operation of the PORVs minimizes the undesirable opening of the spring loaded pressurizer code safety valves.

The PORV's also provide Pressurizer overpressure protection, per Technical Specification 3.4.9.3, when the temperature of one or more of the RCS cold legs is less than or equal to 312°F (except with the reactor head removed). When used for this purpose, they are required to be set to actuate at Pressurizer pressure of ≤ 375 psig.

As addressed by an NRC Generic Letter dated June 25, 1990, the role of PORVs has changed such that they are now relied upon to perform one, or more, of the following safety related functions:

"1. Mitigation of a design-basis steam generator tube rupture accident,
2. Low-temperature overpressure protection of the reactor vessel during startup and shutdown, or
3. Plant cooldown in compliance with Branch Technical Position RSB 5-1 to SRP 5.4.7, "Residual Heat Removal (RHR) System.""

At Salem Station, the PORVs, pressurizer spray and the pressurizer safety valves are used to help mitigate the consequences of a "steam generator tube rupture" accident. Additionally, the PORVs are specifically taken credit for a "loss of all feedwater" accident. This accident is not addressed by the Updated Final Safety Analysis Report (UFSAR) since it is considered beyond the plants design basis. However, it is addressed by the Westinghouse Emergency Response Guidelines (ERGs). During a loss of all feedwater accident, reactor pressure control would be maintained by utilizing the PORVs and the safety injection pumps (i.e., bleed and feed). This is addressed in the station Emergency Operating Procedures (EOPs) in FRHS-1, "Functional Restoration of Heat Sink".

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 91-030-00	PAGE 5 of 6

ANALYSIS OF OCCURRENCE: (cont'd)

With both PORVs inoperable, the plant was in a condition that alone could have prevented the fulfillment of a safety function to mitigate the consequences of an accident. The Nuclear Regulatory Commission (NRC) was notified of this event on September 20, 1991, at 0752 hours, in accordance with Code of Federal Regulations 10CFR 50.72(b)(2)(iii)(D). This event is also reportable to the NRC in accordance with 10CFR 50.73(a)(2)(v)(D) and 50.73(a)(2)(vii)(D).

Salem Unit 2 is currently operating at 100% power. Its PORVs were stroke tested as a result of the Unit 1 PORV failures. Both Unit 2 valves were successfully tested.

CORRECTIVE ACTION:

The diaphragms were replaced in all Copes-Vulcan actuators located inside the Unit 1 Pressurizer. These included the PORVs (1PR1 and 1PR2) and the Pressurizer Spray valves (1PS1 and 1PS3). The latest revision to procedure SC.IC-PM.RC-0001 was used for completing the diaphragm replacement.

As indicated in the Analysis of Occurrence section, the Salem Unit 2 PORVs were successfully tested after discovery of the failed Unit 1 valves.

System Engineering has assessed the material qualification of the actuator diaphragm. The diaphragm is Buna-N rubber and is qualified (per available industry standards) for elevated temperatures. The valves were supplied to a Westinghouse specification of 120°F. The valve manufacturer has been requested to certify the diaphragm material to elevated temperatures, above the original Westinghouse specification.

The manufacturer has changed the actuator bolt pattern to reduce uneven diaphragm loading by increasing the number of bolts used. System Engineering is assessing the need to replace the current 12 bolt pattern actuators with the new 24 inch bolt pattern actuators.

The administrative controls for new/revised procedure implementation will be reviewed and revised as appropriate. As an interim measure to ensure planners are advised when new procedures are issued, the Procedure Upgrade Project will provide the Maintenance Planning Engineer with the new procedure cover page and applicability page (2nd page).

A review of new procedures (issued by the Procedure Upgrade Project) will be conducted to ensure that Maintenance planners have incorporated them into their planning effort.

A review of prior similar events is continuing.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER	LER NUMBER	PAGE
	5000272	91-030-00	6 of 6

CORRECTIVE ACTION: (cont'd)

The root cause investigation of this event is continuing. Upon completion, a supplemental report will be issued.

General Manager -
Salem Operations

MJP:pc

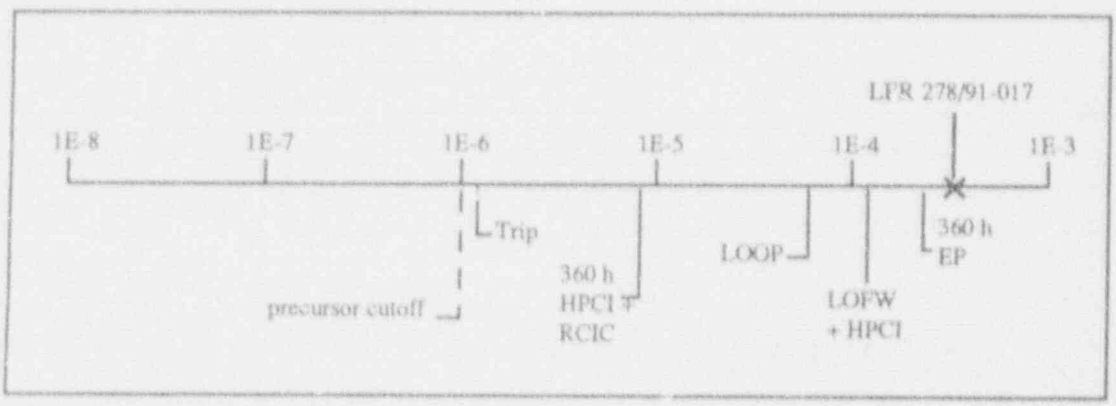
SORC Mtg. 91-107

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	278/91-017
Event Description:	Control wiring for ADS/relief valves found damaged
Date of Event:	September 24, 1991
Plant:	Peach Bottom 3

Summary

Improperly installed insulation on the automatic depressurization system (ADS) / safety relief valves (SRVs) resulted in damage to SRV control wiring. This condition existed throughout the refueling cycle. The high-pressure coolant injection (HPCI) system was also unavailable for periods of time during that interval. The conditional core damage probability estimated for this event is 3.3×10^{-4}. The relative significance of this event compared to other postulated events at Peach Bottom 3 is shown below.



Event Description

Following shutdown for refueling in September 1991, three SRVs were removed for preventive maintenance. On examination, the control solenoid valve wiring insulation was found to be degraded on each SRV. The electrical cable insulation between the solenoid coil and its junction box was cracked and hardened on all three valves. A termination splice between the solenoid and the junction box was melted on two of the valves.

An investigation determined that the damage occurred because SRV insulation was improperly installed during the previous refueling outage, which was completed in December 1989. The installed configuration left a significant portion of the piping around the valve and adjacent to the solenoid uncovered. This allowed the solenoid and its wiring to experience temperatures in excess of 400°F. These high temperatures resulted in accelerated thermal aging — qualified lifetimes were exceeded within 3 d after startup.

The solenoids for the eight remaining SRVs were operated and verified to function as expected under shutdown conditions. The valves were then removed and sent to a test facility to determine how well they could perform under accident conditions. Initial results of that testing indicated that some failures occurred, but final results were unavailable at the time that the LER and an associated Nuclear Regulatory Commission (NRC) inspection report were written.

The SRVs associated with the ADS system, in conjunction with low-pressure makeup sources, are intended to back up the HPCI system in maintaining vessel inventory during small-break loss-of-coolant accidents (LOCAs). The HPCI system was unavailable for an estimated total of ~510 h during the 21-month period that the SRV control circuits were compromised (NRC Inspection Reports 50-277/91-33 and 50-278/91-33, dated December 23, 1991).

Additional Event-Related Information

The SRVs at Peach Bottom are Target Rock two-stage, pilot-operated valves. As installed, high main steamline pressure will operate a pilot valve that will, in turn, operate the main valve in the unit to relieve steam to the suppression pool. An electrically operated solenoid valve can also be used to align compressed gas to open the main valve. This allows remote operation of the valve either by the operator or by the ADS.

ASP Modeling Assumptions and Approach

Wiring for 8 of the 11 SRVs (including 4 of 5 dedicated to ADS) was shown to be still functional under normal conditions; the concern is that the valves might not have functioned under small-break LOCA conditions. As reactor core isolation cooling (RCIC) is assumed unable to provide sufficient makeup during a small-break LOCA in the Accident Sequence Precursor (ASP) models, HPCI provides the only reliable high-pressure source of makeup. Should HPCI be unavailable in this circumstance, the ADS system is required to rapidly depressurize the reactor vessel to permit makeup by low-pressure sources.

Small-break LOCAs may be classified into two categories: those involving relief valves that operate and fail to reseat correctly and those involving other reactor pressure boundary failures. Failures of the first type could be expected not to result in significant changes to the containment atmosphere. In accidents of this type, the information available indicates that the ADS system would have worked.

Failures of the second type could result in release of steam to the containment atmosphere, and it is unclear whether the control circuits for the SRVs could have continued to function. For the purposes of this analysis, it was assumed that the SRVs would have failed in the event of a small-break LOCA other than those involving relief valve leakage.

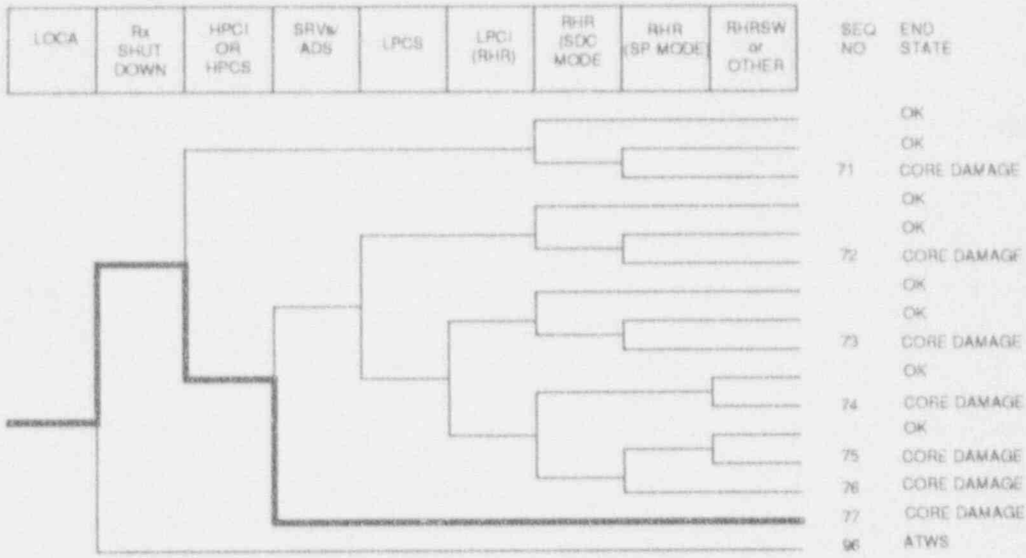
The ASP Program estimates the small-break LOCA frequency at 3.3×10^{-6}/h, with a nonrecovery probability of 0.5, and these values were used in this analysis. The ASP Program normally estimates a HPCI failure-on-demand probability of 0.029. In this case, however, data regarding HPCI unavailability during the event were available, which suggested that a higher value should be employed. As noted earlier, the HPCI system was unavailable for ~510 h during the 21 months of operation with degraded SRVs. Assuming the plant was at power or in hot shutdown for 70% of the 21-month period results in an estimated HPCI unavailability of 0.047. (LER 278/91-017 reports an HPCI unavailability of ~0.036 for the entire 21-month period.) The nonrecovery probability of 0.7 normally employed was used in this case.

This event was modeled as an unavailability of SRVs for the ADS function during a LOCA. HPCI was modeled as having a higher than usual failure probability. To estimate the relative significance of the event within a 1-yr observation period (the interval between precursor reports), a 1-yr unavailability period was utilized in the analysis (6132 h, assuming the plant was critical or at hot shutdown for 70% of the time).

Analysis Results

The estimated core damage probability associated with this event is 3.3×10^{-4}. The dominant core-damage sequence, highlighted on the following event tree, involves a postulated LOCA with HPCI and ADS failures.

Additional information concerning this event is included in combined inspection reports 50-277/91-33 and 50-278/91-33 dated December 23, 1991.



Dominant core damage sequence for LER 278/91-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 278/91-017
Event Description: Control wiring for SRVs found damaged (T1 LOCAs)
Event Date: 09/24/91
Plant: Peach Bottom 3

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.4E+00
LOOP	2.3E-02

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.5E-07
LOOP	1.5E-07
Total	3.0E-07
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
28	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close fw/pcs.trans HPCI srv.ads	CD	1.5E-07	1.7E-01
55	loop -emerg.power -rx.shutdown srv.chall/loop.-scram srv.close HPCI srv.ads	CD	1.3E-07	1.2E-01
67	loop emerg.power -rx.shutdown/ep -ep.rec srv.chall/loop.-scram -srv.close HPCI rcic	CD	9.7E-09	9.4E-02
69	loop emerg.power -rx.shutdown/ep -ep.rec srv.chall/loop.-scram srv.close HPCI	CD	8.7E-09	1.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
28	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close fw/pcs.trans HPCI srv.ads	CD	1.5E-07	1.7E-01
55	loop -emerg.power -rx.shutdown srv.chall/loop.-scram srv.close HPCI srv.ads	CD	1.3E-07	1.2E-01
67	loop emerg.power -rx.shutdown/ep -ep.rec srv.chall/loop.-scram -srv.close HPCI rcic	CD	9.7E-09	9.4E-02
69	loop emerg.power -rx.shutdown/ep -ep.rec srv.chall/loop.-scram srv.close HPCI	CD	8.7E-09	1.3E-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:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\peach.all
PROBABILITY FILE: c:\asp\1989\bwr_csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	5.5E-04	1.0E+00	
loop	1.6E-05	2.4E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-01	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	1.4E-03	8.0E-01	
ep.rec	2.1E-01	1.0E+00	
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
HPCI	2.9E-02 > 4.7E-02	7.0E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-02 > 4.7E-02		
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Minarick
06-09-1992
09:38:45

Event Identifier: 278/91-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 278/91-017
Event Description: Control wiring for SRVs found damaged (non-RV LOCAs)
Event Date: 09/24/91
Plant: Peach Bo tom 3

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E-02

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	3.3E-04
Total	3.3E-04
ATWS	
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
77	loca -rx.shutdown HPCI SRV.ADS	CD	3.3E-04	3.5E-01

** non-recovery credit fo: edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
77	loca -rx.shutdown HPCI SRV.ADS	CD	3.3E-04	3.5E-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:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\peach.sll
PROBABILITY FILE: c:\asp\1989\bwr_call.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	5.5E-04	1.0E+00	

Event Identifier: 278/91-017

loop	1.6E-05	2.4E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	1.4E-03	8.0E-01	
ep.rec	2.1E-01	1.0E+00	
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
HPCI	7.9E-02 > 4.7E-02	7.0E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-02 > 4.7E-02		
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
SRV.ADS	3.7E-03 > 1.0E+00	7.1E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	3.7E-03 > Failed		
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Minarick
06-09-1992
09:40:09

Event Identifier: 278/91-017

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Peach Bottom Atomic Power Station - Unit 3	0 5 0 0 0 2 7 8	1 OF 0 5

TITLE (4): Automatic Depressurization System Inoperability Due to Components Being Unqualified as a Result of Insulation not being Installed Properly

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 NAMES	DOCKET NUMBER(S)
0 9	2 4	9 1	9 1	0 1 7	0 0	1 2	0 6	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

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

[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[X] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[X] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Albert A. Fulvio, Regulatory Engineer	7 1 7 4 5 6 - 7 0 1 4

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		0 2	2 8	9 2

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

On 9/24/91 at 1300 hours, the Main Steam Relief Valve (MSRV) solenoid valves (SV) wiring insulation was discovered to be degraded. An investigation revealed that the MSRV thermal insulation was improperly installed. This caused an unusually high temperature environment in the immediate vicinity of the SVs and associated wiring. On 11/9/91, it was determined by engineering analysis that there was no longer a reasonable assurance that the Automatic Depressurization System relief valves were operable. The temperature increase from the insulation installation error caused the expiration of the Environmental Qualification life of the components. The cause of this event has been determined to be that the MSRV insulation was improperly installed. The maintenance procedure did not provide the necessary level of detail. The insulation was properly reinstalled and the SVs were replaced. The maintenance procedure will be revised. Insulation on Unit 2 was verified to be properly installed. Eight of the Unit 3 MSRV SVs and associated wiring were sent to a test facility to undergo testing in an accident environment. A formal root cause investigation is currently underway. The safety consequences is currently under review. No previous similar LERs identified.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Peach Bottom Atomic Power Station Unit 3	0 5 0 0 0 2 7 8	9 1	— 0 1 7 —	0 0	0 2 OF 0 5

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

Requirements for the Report

This report is being submitted to satisfy the requirements of 10 CFR 50.73 (a)(2)(ii)(B) describing conditions which were potentially outside the design bases of the plant and 10 CFR 50.73(a)(2)(v) due to a potential loss of a safety system function.

Unit Conditions at Time of Discovery

Unit 3 was in the REFUEL mode.

Description of the Events

On 9/24/91 at 1300 hours, during the performance of routine preventive maintenance on the Main Steam Relief Valve (MSRV) solenoid valves (SV) associated with the present Refueling Outage, the MSRV SV wiring insulation was discovered to be degraded. An investigation revealed that the MSRV thermal insulation was improperly installed (see attached drawing) during the previous Refueling Outage in 1989. This caused an unusually high temperature environment in the immediate vicinity of the SVs and associated wiring. This high temperature condition caused the MSRV SV wiring insulation to degrade.

On 11/8/91, it was determined by engineering analysis that there was no longer a reasonable assurance that the Automatic Depressurization System (ADS) (EIIS:RV) relief valves were operable. The purpose of the insulation is to ensure that the Drywell environment is maintained at design conditions. It was determined by engineering analysis that the temperature increase from the insulation installation error caused the expiration of the Environmental Qualification (EQ) life of the components after approximately three days of operation. The ADS MSRVs comprise 5 of the 11 MSRVs. This condition had existed since the last Refueling Outage in November of 1989 when the MSRV thermal insulation was improperly installed after it had been removed to support the piping replacement modification. The NRC was notified via ENS on 11/8/91 at 1220 hours.

Cause of the Events

The cause of this event has been determined to be that the MSRV insulation was improperly installed. The maintenance procedure used to remove and reinstall the MSRV thermal insulation did not provide the necessary level of detail to ensure that the insulation was properly installed.

A formal root cause investigation is currently underway to identify significant causes, failed barriers, generic implications, and associated corrective actions that may be warranted. Findings will be submitted in a revision to this report as necessary.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPO (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Peach Bottom Atomic Power Station Unit 3	0 5 0 0 0 2 7 8	9 1	— 0 1 7	— 0 0	0 3 OF 0 5

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

Analysis of Event

The MSRV SVs and associated wiring were functionally tested in a cold condition which provides some basis to expect the MSRV's to be functional prior to and possibly during a design basis event.

If a design basis event had occurred and the ADS did not perform properly, the HPCI system was available approximately 96.4% of the time during the last operating cycle. HPCI is used to provide core cooling and to reduce reactor (EIIS:RPV) pressure to allow the Low Pressure Coolant Injection (EIIS:BO) and the Core Spray (EIIS:BM) Systems to inject.

During the time that the HPCI system was unavailable, the Reactor Core Isolation Cooling (RCIC) System (EIIS:BN) was available for high pressure core cooling but its capacity may have been inadequate for all design basis events.

The safety consequences of this condition for design basis events is currently under review. The SVs will be tested under simulated accident conditions. The test findings will be used to determine the actual ADS operability and safety consequences of this event. When these results have been received, fully analyzed, and the root cause investigation has been completed, a revision to this report will be submitted.

Corrective Actions

After discovery of the event, the Unit 3 MSRV thermal insulation was properly reinstalled and the SVs were replaced.

The maintenance procedure will be revised to include the appropriate details to ensure that MSRV thermal insulation removal and installation is properly controlled.

The same insulation on Unit 2 was verified to be properly installed per configuration prints during a recent plant shutdown. Therefore, the same concern does not exist on Unit 2.

Eight of the Unit 3 MSRV SVs and associated wiring were sent to a test facility to undergo testing in an accident environment. The test result findings will be used to determine the actual operability condition and safety consequences of this event.

A formal root cause investigation is currently underway to identify significant causes, failed barriers, generic implications, and associated corrective actions that may be warranted. Findings will be submitted in a revision to this report as necessary.

The pertinent information from this event will be provided to the appropriate Maintenance personnel and members of the plant staff.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Peach Bottom Atomic Power Station Unit 3	0 5 0 0 0 2 7 8	9 1	— 0 1 7 —	0 0	0 4 OF 0 5

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

Previous Similar Events

There have been no previous similar LERs identified involving unqualified components due to insulation installation.

NRC FORM 366A
(6-89)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

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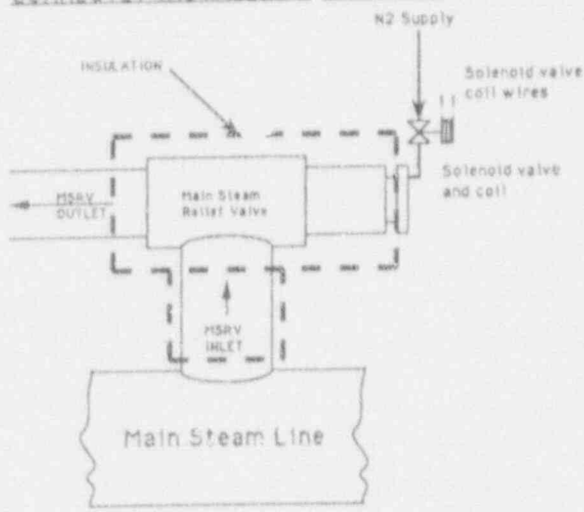
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

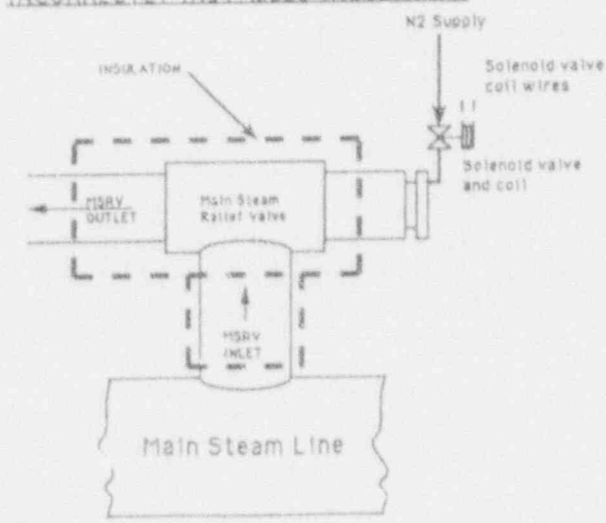
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Peach Bottom Atomic Power Station Unit 3	0 5 0 0 0 2 7 8	9 1	— 0 1 7	— 0 0	0 5 OF 0 5

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

CORRECTLY INSTALLED INSULATION



INCORRECTLY INSTALLED INSULATION



NRC Form 366A (6-89)

U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/91-33 50-278/91-33	License Nos. DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	November 5 - December 13, 1991	
Inspectors:	J. J. Lyash, Senior Resident Inspector L. E. Myers, Resident Inspector M. G. Evans, Resident Inspector J. G. Schoppy, Reactor Engineer D. J. Mannai, Reactor Engineer	

Approved By: L. T. Doerflein, Chief, Reactor Projects Section 2B, Division of Reactor Projects — 12/23/91 Date

Areas Inspected:

The inspection included routine, on-site regular, backshift and deep backshift review of accessible portions of Units 2 and 3. The inspectors reviewed operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, engineering and technical support activities, maintenance, and outage activities.

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 91-33

Plant Operations

The management oversight and staff performance related to the Unit 3 refueling outage continued to be strong. The licensee effectively identified and resolved emerging problems, and there was evidence of excellent coordination among the working groups (Section 1.0).

The inspectors observed that the physical condition and housekeeping in the Unit 2 and Unit 3 drywells was very good (Section 1.0).

An isolation of the Unit 2 reactor core isolation cooling system occurred during surveillance testing. The control room operator did not respond promptly to investigate the isolation, because he assumed that it was spurious and caused by the ongoing surveillance testing. Operations management is providing guidance to operators concerning the proper response to unanticipated alarms and isolations (Section 2.3).

Maintenance and Surveillance

The licensee discovered and initiated analysis of degraded Unit 3 safety relief valve (SRV) solenoid valves, cables and splices. Improper installation of the thermal insulation on all 11 SRVs during the last refueling outage resulted in component heat stress, and significant degradation. This exceeded the environmental qualification of the components, and resulted in the automatic depressurization system (ADS) being inoperable for about 21 months. Based on preliminary investigation, it appears that contributing factors included weaknesses in post-modification and maintenance inspection, maintenance procedure quality and oversight of contractor activities. This issue will be discussed in detail during a future Enforcement Conference (Violation 91-33-01, Section 2.1).

Engineering and Technical Support

During follow-up inspection of several Unit 3 fuel failures experienced during the last operating cycle, the licensee identified the presence of metal shavings in the fuel assemblies. The licensee concluded that this debris had caused the failures, and initiated comprehensive actions to locate and remove all similar material. The inspectors monitored the licensee's fuel, bottom head and bottom head drain line cleaning efforts. The licensee performed the activities in a well planned, controlled and professional manner. One personnel safety issue identified by the inspectors related to the operation was promptly resolved (Section 3.0).

The licensee's technical staff evaluation and trending of leakage past a Unit 2 residual heat removal system injection valve was very good. In response to an increasing leakage trend the licensee took action to isolate the penetration, and later completed a plant shutdown for repairs (Section 2.2).

Assurance of Quality

In response to identification of debris in the Unit 3 reactor vessel, licensee management directed performance of a 100 % inspection and cleaning of all the fuel bundles being returned to the core. In addition, the licensee inspected and cleaned the bottom vessel head region. This decision demonstrated a clear safety conscious approach to assessment and resolution of the issue (Section 3.0).

Licensee actions to evaluate Unit 2 in response to identification of the degraded SRV components on Unit 3 were inadequate. Despite component walkdowns, the licensee did not identify that an installation error existed on one of the Unit 2 ADS valves. After the inspector informed the licensee of the deficiency, the insulation was repaired and the potentially degraded components were replaced (Violation 91-33-02, Section 2.1).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)[1]

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing safety significant activities and equipment, touring the facility, and interviewing and discussing items with licensee personnel. The inspector independently verified safety system status and Technical Specification (TS) Limiting Conditions for Operation (LCO), reviewed corrective actions, and examined facility records and logs. The inspectors performed 16 hours of deep backshift and weekend tours of the facility.

The eighth refueling outage for Unit 3 continued throughout this inspection period. The licensee identified that debris induced fuel failures had occurred during Cycle 8 operation. As a result, licensee management decided to inspect for debris and clean all irradiated fuel bundles which had been returned to the core (see discussion in Section 3.0). This work extended the outage about two to three weeks. The inspector continued to attend licensee outage planning, status and management briefings during the inspection period. Staff and management appeared well informed, emerging problems w promptly raised and addressed, and cooperation among working groups was observed to be excellent.

During the period, the inspector toured the Unit 2 and 3 drywells and general plant work areas. The inspector noted that housekeeping in the drywells was very good.

2.0 FOLLOW-UP OF PLANT EVENTS (93702, 71707, 73756)

During the report period, the inspector evaluated licensee staff and management response to plant events to verify that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications. Events occurring during the period and reviewed by the inspector, are discussed individually below.

2.1 Unit 3 Automatic Depressurization System Inoperable During Cycle Seven

2.1.1 Event Summary

On November 8, 1991, the licensee determined that the automatic depressurization system (ADS) had been inoperable from shortly after the plant startup in December 1989 to shutdown for the refueling outage on September 14, 1991. The licensee concluded that the environmental qualification (EQ) of the solenoid operated valves (SOV), electrical cables and splices, to the five ADS safety relief valves (SRV) had expired shortly after startup. The thermal insulation over all 11 SRVs, including the 5 SRVs dedicated to ADS, had been installed backwards during the last refueling outage. This created a high temperature environment, in excess of 400 Fahrenheit (F), in the area of the SOVs, the electrical cables and the splices. The EQ Branch of the licensee's Nuclear Engineering Division (NED) determined that accelerated thermal aging due to the high temperature environment resulted in expiration of the component qualified lives

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1 The inspection procedure from the NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section.

within three days after the startup. The licensee made a four hour report via the Emergency Notification System (ENS) on the inoperable ADS valves.

2.1.2 Background

Unit 3 utilizes 11 SRVs, RV-3-16-71A to 'L' (I is an e[illegible] designation). Five of the SRVs are dedicated to ADS, RV-3-16-71A, 'B', 'C', 'G' an[illegible]. The SRVs are Target Rock Model 67F two stage pilot operated safety relief valves. The second stage disc and piston are displaced by either a pressure-sensing pilot, or a pneumatically operated mechanical push rod. The push rod is operated when the single SOV actuates and ports plant instrument nitrogen into the pneumatic operator. All SRVs may be manually opened from the control room. The SOVs are manufactured by Airmatic - Allied, Model 6910-020, and are energized to actuate from a safety-related DC power supply.

The SRV assembly is "T" shaped with the exhaust line on one side, and the air operator and SOV on the other. The thermal insulation supplied with the valve is designed to protect the air operator and the associated SOV and cables from the high temperatures generated by the main steam line and the valve body. The insulation is asymmetric. The long end of the "T" covers the valve, with about a 3 inch diameter opening for the air operator and SOV. The short end of "T" extends only to the flange of the exhaust tail pipe, and is provided with a cover which has a ten inch opening.

Three of the eleven SRV valves, RV-3-16-71B, 'J', and 'L', were removed for preventive maintenance (PM) during the current refueling outage on September 24, 1991. The licensee discovered that the electrical cable insulation between the solenoid coil and the junction box for these valves was hardened and cracked due to heat stress. The Raychem termination splice between the solenoid and the junction box was melted on the 'J' and 'K' valves. The licensee inadvertently discarded these three SOVs and the cable. The cause of the heat stress was confirmed by inspection to have been backw[illegible] installation of the thermal insulation of all 'SRVs'. It appeared that the insulation had be[illegible] [illegible]dified to allow the backwards installation. The licensee initiated Reportability Evaluatio[illegible] Eve[illegible] Investigation Form (RE/EIF) 3-91-104 and a Nonconformance Report (NCR) P-91754.

Technical Specification (TS) 3.5.E.1 requires that the ADS subsystem shall be operable whenever there is irradiated fuel in the reactor vessel and the reactor steam pressure is greater than 105 psig. TS 3.5.E.2 allows that one valve in ADS may be inoperable for 7 days provided that the high pressure coolant injection (HPCI) subsystem is operable. HPCI was also inoperable for a total of about 510 hours during the last operating cycle. Between December 1989 and September 1991 Unit 3 was operated with the ADS, and in some instances HPCI, inoperable. This is an apparent violation of TS 3.5.E (Violation 91-33-01).

2.1.3 Immediate Licensee Corrective Actions

The eight remaining SRVs were tested by actuating the SOVs from the switch in the control room. All eight SR[illegible] [illegible]OVs were verified to operate in the shutdown environment by audible click. All of the [illegible]trical cables and splices had visible heat stress effects, browning and cracking. After consultation with NED, the licensee replaced all the SOVs and cables on each of the SRVs. The Unit 3 SRV thermal insulation was re-installed properly after the component repairs were completed. As a result of follow-up investigation, the licensee confirmed that the thermal insulation had been installed backwards by an insulation contractor before the plant restart in December 1989.

Unit 2 SRV thermal insulation had been installed by the plant maintenance group during the last unit outage. The licensee interviewed the maintenance foreman involved, who stated that the Unit 2 insulation had been correctly installed. The licensee informed the inspector that they had verified this assertion by visual inspection during the unplanned outage of Unit 2 on October 17, 1991. This verification was also documented in Licensee Event Report (LER) 3-91-017.

2.1.4 Licensee Investigation Results

Before the end of the inspection period the licensee had completed portions of the event investigation. Preliminary results are described below.

2.1.4.1 Insulation Installation

During the last refueling outage the SRVs were removed to support the recirculation piping replacement modification. Near the end of the outage Brand Mid-Atlantic, Incorporated, was contracted to repair and replace the SRV insulation.

Several Maintenance Requests Forms (MRF) (87-07688, 88-09258, and 88-09474) were generated to complete the removal and storage, the fabrication or repair, and the replacement and installation of SRV insulation. However work planning was poor, and none of the MRFs provided clear instructions to complete the inspection of the installed insulation. Consequently, the licensee did not complete the post-maintenance testing of the insulation installation. The MRFs did not specify the use of drawings, procedures, or other instructions regarding how the insulation was to be installed and inspected. This is a failure to implement Maintenance Procedure A-26, "Corrective and Preventive Maintenance Using CHAMPS," Revision 26, which states that planning shall ensure the completed post-maintenance testing adequately proves component reliability for the work performed. The licensee is investigating what oversight was provided for the activities of the contractor, however, there is no documentation of licensee oversight and inspection.

2.1.4.2 Modification Acceptance Tests

The modification acceptance test (MAT) for Modification (MOD) 1536, "Recirculation Pipe Replacement," included the use of a Special Procedure (SP) 1142J, "MOD 1536 Pipe Replacement Component Reinstallation Verification - Insulation Inside the Drywell Part J." The SP purpose was to ensure that all piping insulation inside the drywell was repaired, replaced, and properly secured before plant restart. The acceptance criteria contained in SP 1142J was that the insulation should be installed such that the system will perform as designed. The licensee performed a walkdown and visual verification using drawing 6240-M38B-140, Revision 4. The drawing clearly indicated the configuration of the SRV insulation. The walkdown found that the '[illegible]' SRV insulation was taped together with duct tape. The licensee issued NCR 890942 to document the condition. The NCR was resolved by completion of MRF 8909603, which removed the tape and banded together the mirror insulation with metal straps. The inspector reviewed the NCR and noted that the NCR referenced an incorrect drawing, 6280-M38B-170, which provided no detail of the SRV insulation.

Neither conduct of the SP or disposition of NCR 89-0942 resulted in identification of the incorrectly installed insulation. The SP results were approved by Plant Operations Review Committee (PORC) meeting 89-266 on November 16, 1989.

2.1.4.3 Testing of the SOVs, Cables, and Splices Under Accident Conditions

[illegible] an independent laboratory test eight of the SRVs to determine if ADS would [illegible]der loss of coolant accident (LOCA) conditions. The components associated [illegible] SRVs, 'B', 'J', and 'L', were lost after removal. The components were subjected to either a test simulating the envoronment that would exist following a break inside or outside containment, followed by a seismic test. For the test the components were configured as in the plant.

Only preliminary results were available near the end of the inspection period. The results indicated at least several failures. The licensee is evaluating the results and the final report will be available at a later time.

2.1.5 Inspector Follow-up

The inspector monitored the licensee's investigation and independently reviewed drawings, procedures and records related to the event. The licensee's effort was well focused, and appropriate management attention and oversight were applied. However, the inspector identified two additional areas of concern.

2.1.5.1 Maintenance Procedure Weakness

During the Unit 3 mid-cycle outage in October, 1990, the licensee removed and replaced the 'E' SRV under MRF 9004065 because the valve had been leaking through the main seat. The craftsman did not identify that the insulation was on backwards, and the insulation was reinstalled to the as-found condition. Maintenance Procedure M-001-006, "Main Steam 6" X 10" RV-71 A-L Relief Valve Replacement," Revision 1, did not contain precautions, limitations, references to drawings, or instructions to guide the craft in installing the insulation properly. The MRF package contained no additional guidance for the installation of the insulation.

2.1.5.2 Ineffective Corrective Action

On December 12, the inspector toured both the Unit 2 and 3 drywells to verify independently that the SRV insulation configuration. The inspector reviewed photographs of the Unit 2 configuration and design drawings. The inspector found that the insulation of the 'C' SRV of

Unit 2, an ADS valve, was improperly installed; in that, the end of the SRV facing the solenoid valve and cabling was not completely covered. All other insulation on the SRVs of both units was installed properly.

In response to the inspector's finding, the licensee inspected the 'C' SRV and concluded that the insulation was improperly installed. The licensee replaced the SOV and cable, and properly insulated the SRV. The licensee plans to subject the SOV, cable and splice to testing similar to that described above. In LER 91-17, issued on December 6, the licensee stated that before startup of Unit 2 from a forced outage in October, the insulation had been verified to be properly installed per configuration prints. This verification was by visual inspection of the SRVs by personnel from the maintenance and outage departments, but neither individual had ever been involved in the installation of the insulation. This immediate corrective action taken by the licensee was ineffective in that it did not identify that the 'C' SRV insulation was improperly installed. As a result, Unit 2 was returned to power with an inoperable SRV. This is an apparent Violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action, which requires that conditions adverse to quality such as defective equipment and nonconformances be promptly identified and corrected (Violation 91-33-02).

2.1.6 Safety Significance

The high pressure coolant injection (HPCI) system and ADS comprise the diverse engineered safety features designed to mitigate the consequences of a small break LOCA. If HPCI is unavailable ADS is designed to automatically depressurize the reactor, allowing the low pressure emergency core cooling systems to inject. Failure of ADS, combined with the unavailability of HPCI, would result the loss of a safety function and the potential inability to cope with a small break LOCA. It appears that Unit 3 operated for about 21 months with the ADS in an indeterminate or inoperable state. During this time there were periods of HPCI unavailability totaling about 510 hours, that placed the plant in an unanalyzed condition. No plant transients which would have challenged this function occurred. In addition, it must be noted that the test program being applied by the licensee to these degraded components will provide additional insight into whether they would likely have functioned under accident conditions.

2.1.7 Conclusions

In summary, the licensee or the inspector identified concerns in the following areas:

- The adequacy of post-modification and post-maintenance inspection of the SRV insulation during 1989,
- The adequacy of licensee oversight of contractor activities during the installation of the SRV insulation,
- Failure to identify the incorrectly installed insulation before closure of the NCR,
- The adequacy of the maintenance procedure and planning related to installation of the SRV insulation, and

- Ineffective immediate corrective actions with respect to verification of proper insulation installation on Unit 2

At the close of the inspection period, the licensee's review of these issues and development of corrective actions were continuing. The inspector informed the licensee that the Violations of NRC requirements characterized above will be discussed further during an Enforcement Conference to be scheduled during January, 1992.

2.2 Unit 2 Forced Shutdown due to Excessive Leakage Past the Residual Heat Removal System Injection Check Valve

At 6:00 p.m. on December 5, 1991, the licensee began an orderly Unit 2 shutdown from about 100% power. The shutdown was required by Technical Specifications (TS) because the 'B' loop of the residual heat removal (RHR) system was inoperable and could not be returned to operable status without a unit shutdown. On December 3, the licensee had confirmed excessive leakage past the RHR testable injection check valve (AO-2-10-46B) and the bypass valve (AO-2-10-163B) around the injection check valve. At that time, the licensee electrically disarmed the motor operated injection valve (MO-2-10-25B) to maintain primary containment isolation capability. With MO-2-10-25B shut, the 'B' loop of RHR is inoperable. The licensee reported the initiation of the required shutdown to the NRC via the emergency notification system (ENS).

During the hydrostatic pressure test conducted on April 3, 1991, the licensee identified leakage of 0.016 gpm past MO-2-10-25B and 0.105 gpm past AO-2-10-163B and AO-2-10-46B. These results were within the licensee's established requirement of less than 1 gpm of leakage past each valve. After returning the unit to operation the licensee identified an increase in the leakage past MO-2-10-25B on June 23. At that time, leakage had increased enough to pressurize the RHR discharge header and to cause an alarm to be received in the control room. Upon investigation, the 'B' RHR discharge header was found to be at 400 psig. Operations personnel reduced pressure in the header to 160 psig. The licensee monitored the pressure increase in the header and licensee engineering calculation determined that leakage past MO-2-10-25B had increased to 0.024 gpm. The licensee developed an abnormal procedure (AO)-10.9-2, "Depressurization of the RHR System Discharge Piping," to provide direction to operations personnel in depressurizing the RHR discharge piping. The licensee routinely monitored the average leak rate past MO-2-10-25B. On July 12 and October 28, the licensee calculated the leak rate to be 0.035 gpm and 0.13 gpm, respectively. In late November, the frequency of depressurizing the discharge piping had increased from about once per 12 hours to once every two hours. Testing and calculations performed on December 2, showed that the leakage past MO-2-10-25B was 0.2 gpm. At that time, the licensee took additional action to determine the leakage past AO-2-10-163B and AO-2-10-46B. Testing was performed on December 3, and the licensee determined the leakage to be about 4.5 gpm. At that time, the licensee electrically disarmed MO-2-10-25B to maintain primary containment isolation capability and declared the 'B' RHR loop inoperable.

Following shutdown of the unit, the licensee found that the excessive leakage was past AO-2-10-163B. The licensee disassembled AO-2-10-25B and AO-2-10-4-163B and found that the leakage was the result of normal wear on the valves. The licensee repaired and reinstalled the valves and performed the appropriate diagnostic testing. Local leak rate test (LLRT) ST/LLRT 20.10.13, "LLRT 'B' RHR Pump Discharge," and inservice inspection (ISI) test ST/ISI-6, "Appendix CC - Leakage Test of the RHR Containment Isolation Valves ('B' Loop)," were performed on December 12.

The inspector held discussions with licensee personnel and reviewed and evaluated the licensee's actions regarding the leakage past MO-2-10-25B several times during the period June 23 through December 3. The inspector reviewed the results of the tests performed on December 12 and found them to be acceptable. The inspector determined that the licensee's monitoring of the condition during operation, decision to isolate the system after confirming the leakage rates, and follow-up to this event were appropriate. The inspector had no further questions.

During this shutdown, equipment failures were identified with contactors in the reactor protection system and leaking feedwater heater tubes. Therefore, at the end of the inspection period, the unit remained shutdown pending resolution of these issues.

2.3 Spurious Unit 2 Reactor Core Isolation Cooling System Isolation

On December 5, 1991, at 3:10 p.m., a reactor core isolation cooling (RCIC) system isolation occurred during the performance of surveillance test SI2T-13-4936-C1CQ, "Calibration Check of RCIC Turbine Compartment Temperature Instruments TE/TS 4936C." The reactor operator (RO) reset the RCIC isolation at 4:30 p.m. The cause of the isolation was not apparent, so the licensee declared RCIC inoperable pending further investigation. The licensee reported the RCIC isolation, an emergency safeguards feature (ESF) actuation, to the NRC via the ENS.

On December 5 at noon, Instrumentation and Control (I&C) technicians replaced the temperature switch (TS) card for TS 4936C and TS 4937C (one card is a dual switch unit). At 2:25 p.m. the technicians began surveillance test SI2T-13-4936-C1CQ. During the test a RCIC isolation signal (results in half RCIC isolation) is initiated in the primary containment isolation system (PCIS) Channel C, Group 5. If a PCIS Channel A Group 5 or Channel B Group 5 signal occurs concurrently, either inadvertently or due to other testing, a full RCIC isolation will result. Therefore at the beginning of the test, the I&C technicians verified that no RCIC isolation signals were initiated. Between 2:25 and 3:30 p.m. the I&C technicians performed the test. The technicians stated that during that time, they inserted a RCIC isolation signal and the appropriate test light connector box light (D-E) came on. Since this light would not come on with a full RCIC isolation in, it appears the trip which produced a full isolation must have come in after the I&C technicians inserted their isolation signal. At 3:10 p.m. during shift turnover, the RO in the control room received the RCIC full isolation and alarm. The RO did not expect the isolation, but he assumed that the I&C technicians had caused it and that they would call him. Therefore, the RO did not contact the I&C technicians. At 3:30 p.m. the I&C technicians came out from behind a panel in the control room to inform the RO that the test was completed. At that time, the technicians noticed that the RCIC isolation alarm had been received.

The licensee began troubleshooting in an attempt to determine the cause of the isolation. The shift technical advisor and the I&C technicians went to the cable spreading room to check relays, but only determined that the RCIC isolation had resulted from either high temperature, low pressure, or steam line high flow signals. Other troubleshooting included a test of the test light connector box and a visual inspection of the associated socket and wiring. The licensee did not find any discrepancies. On the following shift, I&C technicians re-performed SI2T-13-4936-C1CQ and a RCIC isolation did not occur. I&C technicians also performed SI2T-13-4936-ADFM, "Functional Test of RCIC Turbine Compartment and Steam Line Area Temperature Instruments TS 4936A-D, TS 4937A-D, TS 4938A-D and TS 4939A-D," to determine if any of the other temperature switches were defective. The licensee did not identify any discrepancies. The licensee also interviewed other personnel who were working in the cable spreading room at the time of the RCIC isolation, but could not determine the cause. Based on the testing performed, operations declared RCIC operable on December 10. The licensee concluded that the cause of the RCIC isolation could not be determined.

The inspector discussed this issue with several licensee personnel and reviewed the results of surveillance tests SI2T-13-4936-C1CQ and -ADFM. The inspector found the test results to be acceptable. The inspector questioned the licensee regarding the possibility that a personnel error occurred which caused the RCIC isolation. The licensee stated that no one involved had indicated that they had done anything incorrectly which could have caused the isolation. The licensee stated that if the RO had informed the I&C technicians of the RCIC isolation when it occurred, identification of the cause would have been more likely. The inspector further discussed this issue with operations management who stated that management expectations are that the ROs respond to and determine the cause of all alarms received. Operations management stated that during the event investigation for the RCIC isolation, the extent of the ROs failure to respond to alarms would be explored and long-term corrective actions would be taken, as necessary. After discussion with the inspector, operations management decided that their expectations for proper RO response to alarms should be reiterated in the Shift Night Orders as a short term corrective action. The inspector concluded that the licensee conducted a thorough investigation into the cause of the RCIC isolation. The inspector did not have any additional questions.

2.4 Unusual Event Due To Transport Of A Potentially Contaminated Injured Worker Offsite

On December 11, 1991, about 11:40 p.m., a contract employee while closing a watertight door injured his hand in the door, lost consciousness, and struck his head on the floor. Due to the head injury, the individual was placed on a back board by the first aid group. The individual was wearing work clothes and had not been in any contaminated areas. Since the individual's back could not be surveyed for contamination, he was determined to be potentially contaminated. An Unusual Event was declared at 1:07 a.m. per Emergency Response Procedure 101, because the individual was transported offsite potentially contaminated. The individual was accompanied by a Health Physics Technician to York Hospital. At the hospital, the individual was determined not to be contaminated. At 3:00 a.m. the Unusual Event was terminated. The individual was treated and released from the hospital.

3.0 UNIT 3 DEBRIS INDUCED FUEL FAILURES (37700, 60710)

Before the shutdown on September 14, 1991, to begin the Reload 8 Refuel Outage, the Unit 3 offgas activity was about 26,000 microcuries per second. This offgas activity was indicative of potential fuel failure. Therefore, during core reload, the licensee tested (sipped) all irradiated fuel bundles which were to be returned to the core for Cycle 9. Through sipping, the licensee identified six leaking fuel bundles. Three of the bundles had been first loaded into the reactor during Reload 7 and three during Reload 6. The licensee visually inspected the six bundles and identified that one of the bundles had experienced failure caused by a manufacturing defect, while the other five bundles had experienced debris induced failure. The debris appeared to be small metal chips. The licensee replaced the six leaking bundles with six Reload 5 bundles which had been discharged from the core during this reload.

Based on the identification of debris in the failed fuel bundles, licensee management decided that the 508 irradiated bundles which had been returned to the core for Cycle 9, would be removed from the core and inspected for debris, and the debris would be removed. During the period November 21 through December 8, the licensee cleaned the 508 bundles. The licensee identified 330 bundles without debris and 178 bundles with some amount of debris. The bundles which contained debris did not show any signs of failure. The licensee cleaned these bundles and all the fuel was returned to the reactor. The licensee conducted the final core verification on December 8 and verified that all bundles were in their proper location.

In addition to the fuel cleaning, the licensee developed and implemented a plan to clean the reactor bottom head drain piping and to vacuum accessible parts of the vessel bottom head. Early during Cycle 8 operation, the licensee suspected that the drain was plugged, because whenever the second recirculation pump was taken out of service, reactor water temperature readings taken at a point on the drain line showed significant cool down. On September 15, 1991, after the unit was shutdown for the outage, the reactor engineers performed Special Procedure (SP) 1319, "Unit 3 Reactor Bottom Head Drain Piping," Revision 1, and verified that the line was plugged. Licensee survey of the drain line identified a 500 Rem/hour hot spot about 18 inches from the bottom of the reactor vessel at the first elbow in the drain line. The licensee removed the four fuel assemblies, the control rod and guide tube, the control rod housing thermal sleeve, and the fuel support piece for each of two fuel cells to allow access through the core plate to the bottom head above the bottom drain. On November 27, the licensee lowered a camera to the bottom of the vessel and verified that objects were plugging the bottom drain. On November 29, the licensee implemented SP 1319, Revision 3, and cleaned the bottom head drain piping. Debris removed from the drain line included several tools, unidentified rusty pieces of metal, and metal chips similar to those found in the fuel. The licensee vacuumed a minimal amount of metal chips off of the vessel bottom head. In addition, the licensee performed the required inservice inspection (ISI) of the bottom head including visual weld inspections. The licensee did not identify any discrepancies.

The licensee accumulated the metal chips found in the fuel, on the bottom of the vessel and in the drain line, and is currently conducting an analysis for identification. In addition, the tools and larger metal objects found in the drain line are being traced to Loose Parts Analyses for objects which were known to be lost in the vessel or attached piping. The licensee began an investigation to determine the source of the debris, and a root cause analysis. The licensee's preliminary conclusion is that the debris resulted from the recirculation, core spray and jet pump instrument line piping replacement which took place in 1988. The contractor performing the work made three cuts on each N2 nozzle safe-end to the vessel. Following the second cut, the N2 nozzle safe-end thermal sleeve cut, the contractor's procedure required putting into place a metal catcher. However, for the first two cuts no metal catcher was used. During this time, a HEPA filter unit was being used to draw a negative pressure on the reactor vessel to control radiological conditions. It appears that the use of the HEPA filter unit caused the metal chips from the first two cuts to be drawn into the vessel. This work was conducted by the same contractor for Unit 2 in 1985. The same practices were followed, however, a HEPA filter unit was not used to control radiological conditions. The licensee has not identified debris in the Unit 2 fuel during subsequent refueling outages.

The inspector followed the licensee's activities and attended several licensee planning meetings regarding the fuel, bottom head and bottom head drain line cleaning. The inspector reviewed the documents listed in Attachment A associated with these activities. The inspector attended the Plant Operations Review Committee (PORC) meeting on November 26, at which SP 1319, Revision 3, was approved. The inspector attended Nuclear Maintenance Division (NMD) turnover meetings on the refuel floor and noted that NMD management did a very good job of ensuring that all personnel understood the evolutions that would take place on their shift and their responsibilities. The inspector toured the refuel floor and witnessed several bundles being inspected and cleaned. In addition, the inspector reviewed several video tapes of the fuel inspections and of the bottom head drain line. The inspector reviewed completed procedure SP 1319, and discussed the conduct of the procedure with applicable licensee personnel. The inspector also discussed the investigation and root cause analysis being conducted with applicable licensee personnel.

During a tour of the refuel floor, the inspector noted that the refuel bridge operator was standing on the railing of the refuel bridge and leaning over the reactor cavity to reach the controls to operate the bridge. NMD personnel were verifying that the moisture separator was appropriately latched. It appeared to the inspector that since the bridge operator was not secured in any way to the bridge that he could slip on the railing and fall into the reactor cavity. The inspector discussed this issue with NMD management, who took appropriate corrective action to ensure that, in the future, the bridge operator would wear a safety harness when performing this evolution. Other appropriate personnel were also retrained in the requirements for wearing safety harnesses.

The inspector did not identify any additional unacceptable conditions. The inspector found that all activities observed were performed in a well planned, controlled and professional manner. The inspector concluded that the licensee had made a conservative and safety conscious decision to proceed with the inspection and cleaning of all of the fuel bundles. The licensee's decision to inspect and clear the bottom head drain demonstrated their desire to fully evaluate and resolve this issue.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspector verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks, and jet pump and control rod operability. The inspector did not identify any unacceptable conditions.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspector reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspector verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspector did not identify any concerns.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspector examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspector monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspector verified compliance with RWP requirements. The inspector reviewed RWP line entries and verified that personnel had provided the required information. The inspector observed personnel working in the RWP areas to be meeting the applicable requirements and individuals frisking in accordance with HP procedures. During routine tours of the units, the inspector verified a sampling of high radiation area doors to be locked as required. The inspector did not identify any unacceptable conditions.

7.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspector observed security staffing, operation of the Central and Secondary Access Systems, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspector observed protected area access control and badging procedures. In addition the inspector routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspector did not identify any concerns.

8.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Unresolved Item 90-80-02, Evaluate the Licensee's Corrective Actions to Resolve Weaknesses in Implementation of the Equipment Trouble Tag Program

A weakness was noted in the licensee's issuance, control, and disposition of equipment trouble tags (ETT). Instances were identified where ETTs remained in place on equipment after maintenance had corrected the deficiency, tags were placed on equipment but the licensee did not initiate a maintenance request form (MRF) or nonconformance report (NCR), and the ability to track ETT status to ensure corrective action had been implemented could not be demonstrated. Failure to initiate a MRF or NCR after placement of an ETT, or failure to remove the ETT following completion or cancellation of the MRF has the potential to mask material deficiencies in the plant.

Since this weakness was identified, the licensee has replaced the Computer History and Maintenance Planning System (CHAMPS), which was used to track maintenance functions, with the computer management system called Plant Information Management System (PIMS). In conjunction with necessary changes in documentation and nomenclature associated with the implementation of PIMS, the licensee initiated a complete rewrite of the procedure which administratively controls the maintenance work process, A-26, "Plant Maintenance Work Process." A-26 specifies the process for the resolution of the deficiency identified by an ETT and removal of the ETT when resolved. Administrative Guideline AG-26.1 details the initiation and processing of ETTs, and specifies the position of ETT coordinator in the maintenance planning staff responsible for the tracking of ETTs. After an ETT is issued, an Action Request (AR) is generated which results in a Work Order (WO), NCR, or cancellation. When the WO or NCR is generated, the ETT is updated with the appropriate documentation. Resolution of the deficiency by the responsible group results in the removal of the ETT. PIMS has been configured so that ARs, WOs, NCRs, or ETTs can be effectively tracked. This system appears to resolve the previously identified tracking weakness. The inspector reviewed a representative sample of ETTs hung in the plant to determine if the revised ETT program was effective in the initiation of ARs and the subsequent removal of the ETTs. No deficiencies were noted. This item is closed.

9.0 MANAGEMENT MEETINGS (71707)

The resident inspectors provided a verbal summary of preliminary findings to the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the resident inspectors verbally notified licensee management concerning preliminary findings. The inspectors did not provide any written inspection material to the licensee during the inspection. This report does not contain proprietary information. The inspectors also maintained the progress of the following inspection during the report period:

Date	Subject	Report No.	Inspector
11/4 to 11/22	Emergency Service Water	91-31	Prividy, Shea, Jones, Mannai, Evans

ATTACHMENT A

Documents Reviewed During Inspector Follow-up of Unit 3 Fuel Failure

SP 1319	Unit 3 Reactor Bottom Head Drain Line, Revision 1 and 3
10CFR50.59	Review for SP 1319
FH 6C	Core Component Movement-Core Transfers
M-018-016	Control Rod Blade Latching and Double Blade Guide Seating Verification
M-018-104	Control Rod Guide Tube Removal and Installation
WO C0076886	Remove Guide Tube at Core Location 30-27
WO C0076884	Remove Guide Tube at Core Location 26-31
WO C0076842	Disassemble Cell 26-31, Reassemble After Vacuuming
WO C0076747	Disassemble Cell 30-27, Reassemble After Vacuuming

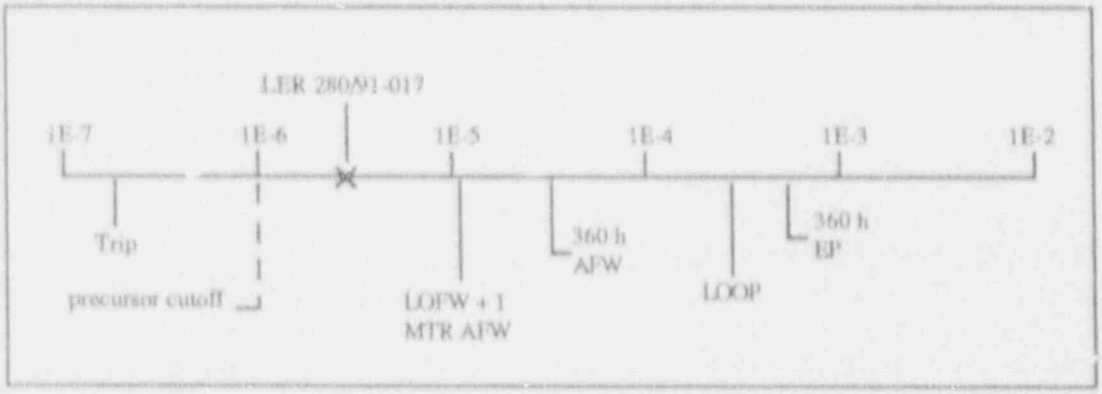
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No:	280/91-017
Event Description:	Both emergency diesel generators for Unit 2 inoperable for 13 h
Date of Event:	July 15, 1991
Plant:	Surry 2

Summary

Both emergency diesel generators (EDGs) were inadvertently out of service at Surry 2 for 13 h. EDG 3, the dual-unit swing diesel, had been unavailable since May 7, 1991, because of inadequate post-maintenance testing. EDG 2 was removed from service for 13 h on July 15, 1991.

The conditional probability of core damage estimated for this event is 2.9×10^{-6}. The relative significance of the event compared to other postulated events at Surry 2 is shown below.



Event Description

On August 9, 1991, with Unit 1 and Unit 2 at 100% power, it was discovered that EDG 3 had been inoperable since May 9, 1991. The discovery was made while investigating the cause for EDG 3 failing to achieve rated speed during a Unit 2 engineered safeguards features actuation on August 2, 1991. This safety injection/reactor trip occurred as a result of vital bus power oscillations on one channel and a failed steam generator (SG) pressure transmitter on another channel. During this event, EDG 3 achieved a speed of approximately 835 rpm, which is below the 870 rpm permissive needed to allow the output breaker to close. Therefore, operator action would have been required to bring EDG 3 up to speed should it have been necessary for the EDG to supply power to its emergency bus.

The failure of EDG 3 was due to previous maintenance that began on May 7, 1991, during which a replacement governor was installed. Adjustments were made to the governor to correct observed problems, but these adjustments rendered EDG 3 incapable of achieving rated speed when called upon to respond to a fast start signal. The required post-maintenance testing had not been performed on May 9, 1991, to verify proper response of EDG 3 to a fast start. Such testing would have detected the failure.

EDG 2 was inoperable (reason unknown) for approximately 13 h on July 15, 1991. Therefore, no EDGs were available for Unit 2 for 13 h on July 15, 1991. Since it was not known that EDG 3 was inoperable from May 9, 1991, EDGs 1 and 2 (the dedicated diesels for Units 1 and 2, respectively) were not tested daily, nor were the units placed in cold shutdown within the Technical Specification-required 7-d period.

Additional Event-Related Information

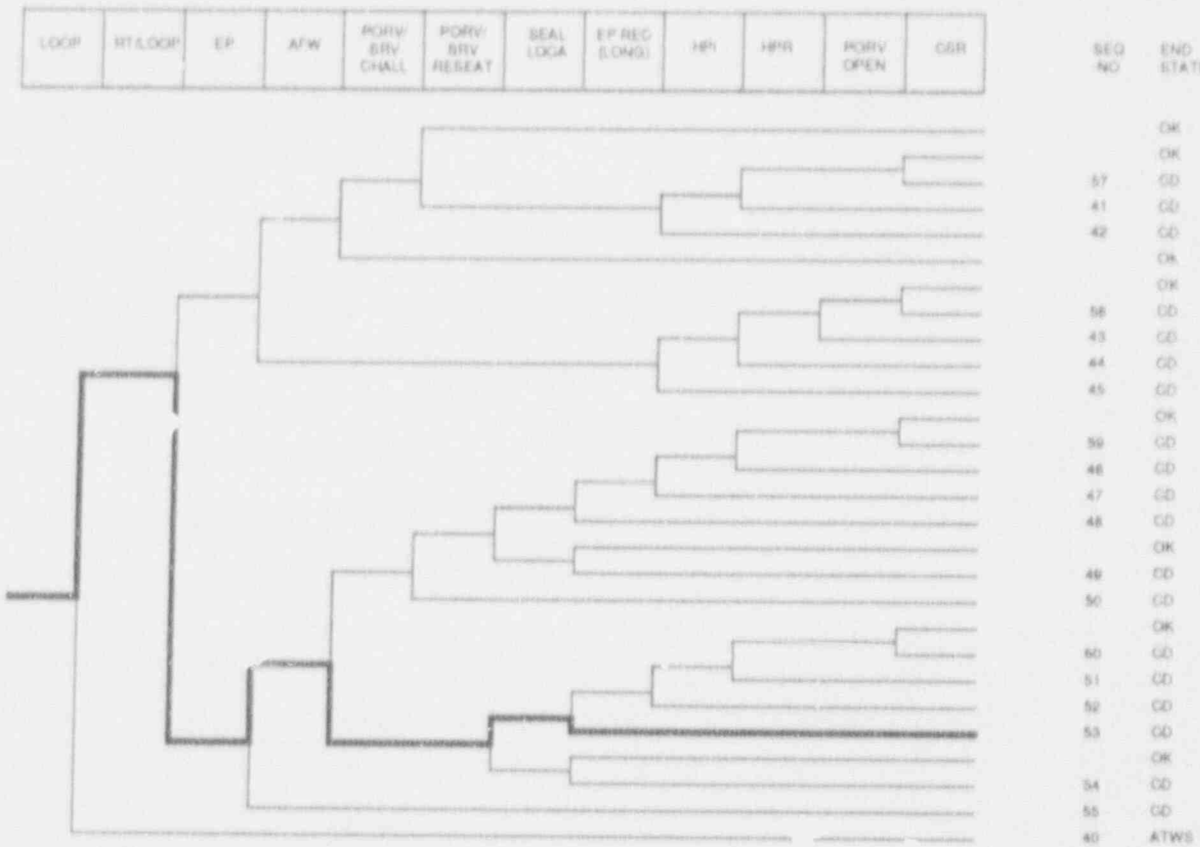
The emergency power system for Surry consists of three EDGs for the two units. EDG 1 is dedicated to Unit 1, EDG 2 is dedicated to Unit 2, and EDG 3 is a "swing" diesel that serves as a backup for either Unit 1 or Unit 2. Each EDG has 100% capacity and is connected to independent 4.16-kV emergency buses. Each unit has two emergency buses, "H" and "J", and the "H" bus for each unit is connected to its exclusive EDG. The "J" bus of the affected unit would be supplied by EDG 3.

ASP Modeling Assumptions and Approach

The event has been modeled as a potentially recoverable unavailability of emergency power for 13 h. A nonrecovery probability of 0.12 was utilized. This reflects the potential for recovery from the control room under burdened conditions following a blackout (LER 280/91-018 reports a similar incorrectly set governor for Unit 2, which was adjusted from the control room).

Analysis Results

The conditional probability of subsequent core damage estimated for this event is 2.9×10^{-6}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated loss of offsite power (LOOP) with failure of emergency power, successful auxiliary feedwater (AFW) initiation, a reactor coolant pump seal loss-of-coolant accident (LOCA), and failure to recover AC power before core uncovery.



Dominant core damage sequence for LER 280/91-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 280/91-017
Event Description: Both EDGs for Unit 2 inoperable for 13 h
Event Date: 05/08/91
Plant: Surry 2

UNAVAILABILITY, DURATION= 13

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.1E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.9E-06
Total	2.9E-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	1.9E-06	6.3E-02
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	6.4E-07	6.3E-02
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	2.2E-07	2.2E-02
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	7.8E-08	6.3E-02

** 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	7.8E-08	6.3E-02
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	1.9E-06	6.3E-02
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	6.4E-07	6.3E-02
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	2.2E-07	2.2E-02

** 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.

Event Identifier: 280/91-017

SEQUENCE MODEL: c:\asp\1989\pwraseal.cmp
BRANCH MODEL: c:\asp\1989\surry2.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	8.6E-05	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 > 1.0E+00	8.0E-01 > 1.2E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.9E-01	3.4E-01	
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-[illegible]	1.0E+00	
ep.rec(sl)	5.[illegible]	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
hpi	1.5E-03	8.4E-01	
hpi(f/b)	1.5E-03	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.0E-04
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
csr	9.3E-05	1.0E+00	

* branch model file
** forced

Minarick
06-08-1992
16:15:17

NRC FORM 366 (9-83) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	1 OF 0 5

TITLE (4): Emergency Diesel Generator Rendered Inoperable Due to Personnel Error in That Specified Testing Was Not Performed

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 NAMES	DOCKET NUMBER(S)
									Surry, Unit 2	0 5 0 0 0 2 8 1
0 5	0 9	9 1	9 1	— 0 1 7 —	0 1	1 1	1 3	9 1		0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

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

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)	X	50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
M. R. Kansler, Station Manager	8 0 4	3 5 7 - 3 1 8 4

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On August 9, 1991, with Unit 1 and Unit 2 at 100% power, it was determined that Emergency Diesel Generator (EDG) #3 had been inoperable since May 9, 1991. This determination was made while performing a root cause evaluation of the observed performance of EDG #3 during an August 2, 1991, Engineered Safeguards Feature (ESF) actuation on Unit 2. This safety injection/reactor trip, which occurred as a result of vital bus power oscillations on one channel and a failed steam generator pressure transmitter on another channel, is being reported separately by Licensee Event Report 52-91-007-00. A root cause investigation team appointed to determine the cause of the failure of EDG #3 to achieve rated speed found that inadequate Post Maintenance Testing (PMT) was performed following replacement of the governor on May 7, 1991. This was due to a cognitive error on the part of utility personnel in that an approved work order step which specified a fast start test of the EDG was not performed. During the period EDG #3 was inoperable, the Unit's other source of emergency power, EDG #2, was inoperable for approximately thirteen hours on July 15, 1991. This event is being reported pursuant to 10CFR50.73(a)(2)(i)(B) and (ii)(B).

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	9 1	— 0 1 7	— 0 1	0 2 OF 0 5

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

1.0 DESCRIPTION OF THE EVENT

On August 9, 1991, with Unit 1 and Unit 2 at 100% power, it was determined that Emergency Diesel Generator (EDG) #3 (EIIS-EK-DG) had been inoperable since May 9, 1991. This determination was made while performing a root cause evaluation of the observed performance of EDG #3 during the August 2, 1991, Unit 2 Engineered Safeguards Feature (ESF) actuation. During this event EDG #3 failed to achieve rated speed of 900 rpm ± 2%. A speed of approximately 835 rpm was attained, which is equivalent to a frequency of 55.67 Hz. This speed is below the 870 rpm speed permissive needed to allow the EDG output breaker to close. Operator action would have been required to bring the EDG up to speed to allow the output breaker to close should it have been necessary for the EDG to supply electrical power to the emergency bus. Station procedures were in place to provide guidance to operating personnel to take appropriate action to adjust speed and energize the emergency bus if required. However, because manual operator action would have been required, EDG #3 was declared inoperable on August 2, 1991, since it could not automatically fulfill its design function.

Surry's EDGs utilize Woodward UG-8D governors for engine speed and load control. This governor is of a mechanical-hydraulic design and is driven by a spur gear on the accessory gear train of the EDGs. A new replacement governor was installed on EDG #3, adjusted, and tested satisfactorily for fast start operation on May 7, 1991 by a team consisting of a vendor representative and utility personnel. On May 8, 1991, full load post maintenance testing of EDG #3 was begun. During initial full load testing, EDG #3 would not achieve full load. The EDG was secured, a hot fuel rack adjustment was performed, and testing was resumed. During this subsequent full load testing, the engine exhibited slight load drift and additional adjustments were made to the governor. The cumulative affects of these adjustments was that EDG #3 would not achieve its rated speed when called upon to respond to a fast start. Because PMT was not performed to verify proper response of EDG #3 to a fast start following these adjustments, the root cause evaluation team determined that EDG #3 had been inoperable since May 9, 1991.

Since EDG #3 was previously believed to be operable from May 9, 1991 through August 2, 1991, the dedicated EDGs for Units 1 and 2 were not tested daily, nor were the units placed in cold shutdown within the required seven day period in accordance with Technical Specification 3.16.B.1. During the time period EDG #3 was inoperable, the redundant emergency power

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	9 1	0 1 7	0 1	0 3 OF 0 5

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

supply (EDG #2) had been inoperable for approximately thirteen hours on July 15, 1991. This event is being reported pursuant to 10CFR50.73(a)(2)(i)(B) and (ii)(B).

2.0 SIGNIFICANT SAFETY CONSEQUENCES AND IMPLICATIONS

Surry's emergency electric power system is designed to provide reliable power to engineered safety functions and other essential loads in the event of loss of off-site power (LOOP). The system consists of three 100% capacity diesel generator sets for the two Units. One generator is used exclusively for Unit 1 (EDG #1), the second exclusively for Unit 2 (EDG #2), and the third (EDG #3) functions as a backup for either Unit. Each Unit has two emergency buses normally fed from an independent off-site power source, with the EDGs functioning as on-site backup power sources.

A safety injection signal, whether automatic or manually initiated, starts an EDG (EDG #1 or #2, depending upon the Unit affected) and the redundant EDG (EDG #3). By design, during a safety injection, the EDGs start and accelerate to 900 rpm, but their output breakers do not close unless there is an undervoltage condition sensed on the associated 4160 volt emergency bus.

During the event, EDGs #2 and #3 started as required and EDG #2 accelerated to 900 rpm. However, EDG #3 only accelerated to approximately 835 rpm which does not satisfy the 870 rpm speed permissive requirement for closure of the output breaker. This speed is also below the GDC-17 and EDG load-sequencing scheme acceptable minimum of 882 rpm. The EDGs by design are required to automatically supply electrical power to the 4160 volt emergency buses on a loss of power to those buses. Had it been required, existing procedures directed operations personnel to manually place EDG #3 on its respective emergency bus.

Although EDG #3 failed to achieve rated speed, during this event, EDG #2 functioned as designed and could have carried its emergency bus had the need arisen. Both during this event and on July 15, 1991 when EDG #2 was inoperable, no actual demands were made on the emergency power system. Therefore, the health and safety of the public were not affected.

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	9 1	— 0 1 7 —	0 1	0 4 OF 0 5

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

3.0 CAUSE OF THE EVENT

The reason for the EDG #3 not reaching its required speed and frequency range was attributed to a cognitive error on the part of utility personnel in that an approved work order step which specified a fast start test of EDG #3 was not performed. A contributing cause was that the post-maintenance testing follower associated with the work package did not specify an EDG fast start test be performed.

4.0 IMMEDIATE CORRECTIVE ACTION(S)

EDG #3 was declared inoperable August 2, 1991, and an investigation into its failure to achieve rated speed was initiated.

5.0 ADDITIONAL CORRECTIVE ACTION(S)

The governor for EDG #3 was readjusted and two consecutive fast start tests were performed satisfactorily. EDG #3 was declared operable at 1000 hours on August 3, 1991, approximately seventeen hours after it had failed to achieve rated speed.

EDG #1 and EDG #2 were also tested to verify operability. EDG #1 "as found" speed and frequency were within the allowable target band. EDG #2 "as found" speed and frequency were slightly above the target band, but the engine was determined to be operable. Both governors were adjusted and two more fast starts of each engine confirmed speed and frequency to be well within specification.

The governor gearing and speed knobs for the EDG #1 and EDG #2 governors were scribed at the 900 rpm setting. Because of previous testing activities for speed control of EDG #3, these scribe marks were already in place on that governor. Station operating procedures were changed to direct the speed knobs to be reset to the scribe marks as part of aligning the EDGs for automatic operation. The resetting of the speed knobs for the 900 rpm scribe marks eliminates the need for the servo motor to adjust the governor during the starting sequence. This resetting also makes up the high speed limit switch and prevents the servo motor from energizing.

"See through" cover plates plates have been installed on each engines governor limit switch enclosure so that the scribed match marks can be easily observed without disassembly. The match mark alignments are checked each shift to verify the governors are properly set.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	9 1	— 0 1 7	— 0 1	0 5 OF 5

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

The procedures for EDG governor maintenance and fast start operation have been upgraded, and the PMT testing matrix for the EDGs has been revised to provide specific fast start testing requirements following governor maintenance.

This event was reviewed with station employees by corporate management at recent Employee Update Meetings, and the Station Manager issued a memorandum emphasizing procedural compliance and attention to detail.

6.0 ACTIONS TO PREVENT RECURRENCE

Training for station personnel involved in governor maintenance will be improved.

In order to ensure the effectiveness of the corrective actions taken to date, monthly EDG fast start testing will be conducted through December 1991. In addition, Event Review and Failure Analysis Evaluation Teams are reviewing testing data and overall EDG performance to ensure continued EDG reliability and availability.

7.0 SIMILAR EVENTS

None.

8.0 ADDITIONAL INFORMATION

None.

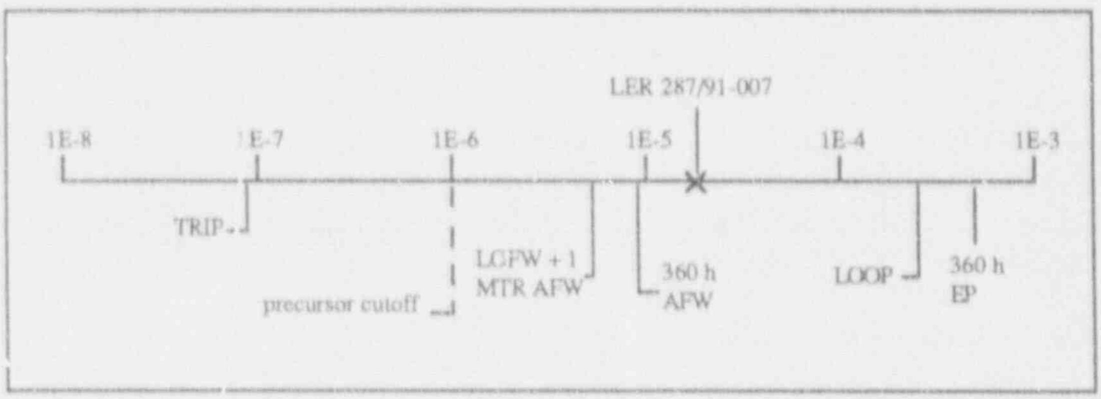
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No:	287/91-007, 269/91-009
Event Description:	Reactor trip due to LOFW plus degraded EFW
Date of Event:	July 3, 1991
Plant:	Oconee 3

Summary

A loss of condensate flow caused a loss of main feedwater (LOFW) and a reactor scram. All three emergency feedwater (EFW) pumps started as required. The EFW flow control valve for one steam generator (SG) did not automatically respond, and manual control was taken 4 min into the event. Operator errors while restarting the main feedwater (MFW) pumps further degraded the EFW system. Two main steam relief valves (MSRVs) did not reseat until pressure was reduced to 90% of their actuation setpoints.

The conditional probability of core damage associated with this event is 1.8×10^{-5}. The relative significance of the event compared to other postulated events at Oconee 3 is shown below.



Event Description

On July 3, 1991, at 1118 hours, while operating at 100% full power, Oconee 3 scrammed as a result of an LOFW. The LOFW was initiated when particles from a degraded seal clogged an instrument air flow path in the master valve controller for the condensate demineralizer system. This caused five parallel valves to fail closed, blocking all condensate flow. Demineralizer bypass valves did not open to compensate because an operator had failed to return them to automatic control The loss of condensate flow resulted in the trip of condensate booster pumps due to low suction pressure, which then caused a trip of the main feedwater pumps, followed by the reactor scram.

All three EFW pumps started on a low main feedwater pump turbine control oil pressure signal. At 1119 hours, operators shut down the turbine-driven EFW pump, after confirming that both motor-driven EFW pumps were operating. As SG level dropped toward the post trip setpoint, it was observed that FDW-315, EFW throttle valve to SG A, was not controlling properly in automatic, so manual control was initiated at 1122 hours. SG level reached a minimum of 21 in. prior to operators taking action to compensate for the failed valve. The valve failed to control in automatic because a normally energized solenoid valve failed to move to its deenergized position. This solenoid valve model had caused earlier problems at Oconee, and a decision was made after this event to replace this and similar valves.

Two MSRVs did not reseat until main steam pressure was reduced to approximately 88% to 90% of their actuation setpoints, which is slightly lower than desired. Also, the low-flow alarm for cooling water flow to EFW pump B did not clear as expected. An operator was dispatched to check local instrumentation and verified that cooling flow to the pump was acceptable.

After the unit was stabilized at hot shutdown, the operators initiated actions to restart the MFW pumps so that they could be used for SG makeup. This required starting a condensate booster pump in the recirculation mode, which fills the upper storage tank (UST) with water from the hotwell. Water in the UST is then used to makeup to the hotwell as its inventory is used by the MFW pumps. Refilling the UST with water from the hotwell increased its temperature to 170°F. This exceeded a 130°F procedural limit for maximum EFW pump source water temperature. At the time of the event, the operators believed that the 130°F limit only applied while at power, and that a 190°F limit applied while shut down. A subsequent review of the Reactor Trip Recovery Procedure indicated that the 130°F limit also applied for up to 5 h after a trip. With the UST temperature greater than 130°F within the 5-h post-trip period, decay heat removal required two of three EFW pumps instead of one of three.

When the operators added water to the UST from the hotwell, they overfilled the tank, which resulted in water flowing into the normally dry reference leg of the UST level instrumentation and generating a false low-level signal. For ~30 min during post-trip recovery, UST level instrumentation indicated that the tank level was less than minimum requirements. During this event the condensate storage tank, which receives overflow from the UST, itself overflowed onto the turbine building floor, and operators were able to confirm that the UST was full. The UST serves as the primary source of water for the EFW pumps. If the UST is determined to be unavailable, procedures require the operators to break condenser vacuum and provide EFW from the hotwell, which can consume substantial personnel resources and time.

Analysis of post-trip data indicated that one of the two EFW pump actuation signals following loss of the MFW pumps, low pump discharge pressure, was not generated during the LOFW. (The EFW pumps actuated on a low MFW pump turbine control oil pressure signal.) Continued operation of the D heater drain pumps maintained MFW pump discharge piping pressure above the low discharge pressure setpoint. This was subsequently determined to be a potential problem on all three Oconee units for all trips in which the heater drain pumps continue to operate.

ASP Modeling Assumptions and Approach

The event has been modeled as a potentially recoverable LOFW with one EFW flow control valve unavailable. Because of the high UST temperature, two of three EFW pumps were assumed to be required for success. A revised EFW failure probability given these conditions was calculated as follows:

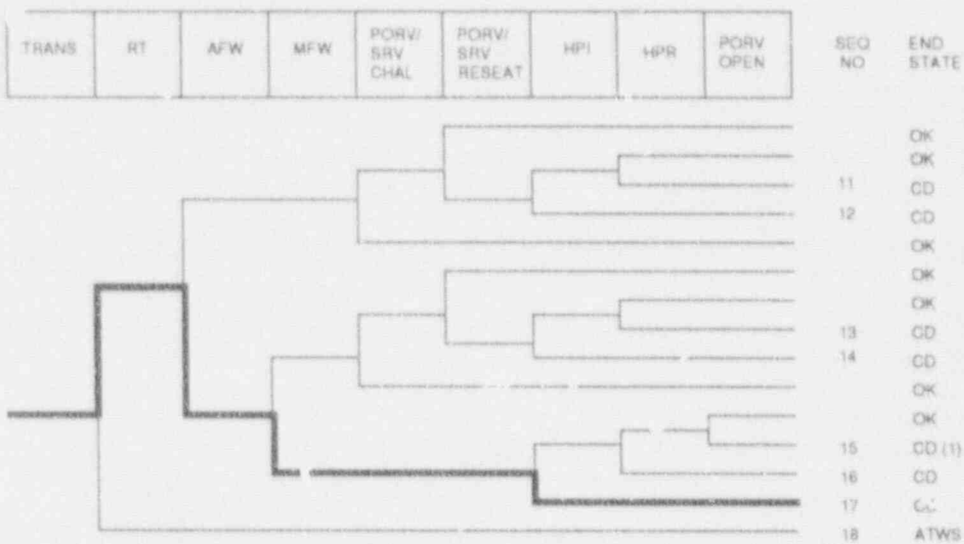
p(EFW) = [p(MTR PMP 3A) × p(MTR PMP 3B | MTR PMP 3A fails) + p(MTR PMP 3A) × p(TURB PMP) + p(MTR PMP 3B) × p(TURB PMP) + p(common cause)] × p(NON REC) + p(second EFW flow control valve fails) × p(fail to manually control flow from control room)

$$p(EFW) = [0.01 \times 0.1 + 0.01 \times 0.05 + 0.01 \times 0.05 + 0.00028] \times 0.26 + 0.1 \times 0.04$$

$$p(EFW) = 4.6 \times 10^{-3}$$

Analysis Results

The conditional probability of subsequent core damage estimated for this event is 1.8×10^{-5}. The dominant core damage sequence, highlighted on the following event tree, involves a failure to recover from the LOFW, a subsequent failure of EFW, and failure of feed and bleed.



(1) OK for Class D

Dominant core damage sequence for LER 287/91-007

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 287/91-007
Event Description: Reactor trip due to LOFW plus degraded EFW
Event Date: 07/03/91
Plant: Oconee 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.8E-05
Total	1.8E-05
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
17	trans -rt AFW MFW hpi(f/b)	CD	1.6E-05	2.9E-01
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	1.8E-06	3.4E-01
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	1.8E-06	3.4E-01
17	trans -rt AFW MFW hpi(f/b)	CD	1.6E-05	2.9E-01
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrdseal.cmp
BRANCH MODEL: c:\asp\1989\oconee3.all
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.5E-04	1.0E+00	

Event Identifier: 287/91-007

loop	1.6E-05	2.4E-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	8.0E-01	
AFW	3.8E-04 > 4.6E-03 **	2.6E-01 > 1.0E+00	
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		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Failed		
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
ep.rec	4.5E-01	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Minarick
06-08-1992
15:21:25

Event Identifier: 287/91-007

NRC FORM 366 (6-89) — U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 3	0 5 0 0 0 2 8 7	1 OF 1 0

TITLE (4) Equipment Failure Closes Pneumatic Valve In Condensate Demineralizer System Causing Loss of Feedwater and Reactor Trip

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 NAMES	DOCKET NUMBER(S)
0 7	0 3	9 1	9 1	— 0 0 7 —	0 0	0 8	0 2	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

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

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	50.72(b)(2)(11)
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Henry R. Lowery, Chairman, Oconee Safety Review Group	8 0 3 8 8 5 - 3 0 3 4

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
F	S F	6 5	F 1 8 0	YES	F	S D	X I S	M 2 2 5	YES
F	B A	V	V 0 3 0	YES					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR

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

On July 3, 1991, at 1118 hours, while operating at 100 % Full Power, Oconee Unit 3 tripped as a result of a loss of feedwater. The loss was initiated when particles from a degraded seal clogged an Instrument Air flow path in the master valve controller for the condensate demineralizer system. This caused five parallel valves to fail closed, blocking all condensate flow. Demineralizer bypass valves could not open to compensate because an Operator had failed to return them to Automatic control. The loss of condensate flow resulted in the trip of condensate booster pumps due to low suction pressure, which then caused a trip of the main feedwater pumps, followed by the reactor trip. Emergency feedwater pumps started, but a solenoid valve failed, requiring manual operator action to control flow to one steam generator. The operators stabilized the unit at hot shutdown. Corrective actions included replacement of the defective parts and counselling of the Operator. The root cause was Equipment Failure with a contributing cause of Inappropriate Action.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 3	0 5 0 0 0 2 8 7	9 1	— 0 0 7	— 0 0	0 2 OF 1 1

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

BACKGROUND

The Condensate System [EIIS:SD] has three main system functions: 1) to deliver condensate from the condenser hotwell to the suction of the main feedwater [EIIS:SJ] pumps at adequate pressure, 2) to purify the condensate for chemistry control, and 3) to increase the temperature of the condensate to improve thermal efficiency. Chemistry control is largely provided by the Demineralizer System (Powdex) [EIIS:SF], which consists of five parallel resin bed filter cells [EIIS:DM]. Each cell can be individually valved out of service for resin replenishment (precoating). Precoating is performed as needed on a staggered schedule to avoid having several cells out of service simultaneously. A master controller [EIIS:65] provides a pneumatic control signal to valves on each cell to balance flow equally across the cells in service. Individual controllers receive this signal and compensate for differences in pressure drop over the individual cells.

Additionally, two valves, C-14 and C-15, act as Powdex bypass valves. They open sequentially in response to a single controller which can be operated either by the control room operator when in manual or in response to overall Powdex system pressure drop when in automatic.

EVENT DESCRIPTION

In March, 1991, during the last Unit 3 refueling outage, Nuclear Station Modification 32522 was implemented. This modification revised controls for several valves which formerly had reverse-acting pneumatic controllers. The old controllers showed 100 % demand for zero flow. The new controllers showed 100 % demand for full flow. As part of this modification, the controllers for several valves, including the condensate demineralizer system (Powdex) Bypass Valves (C-14 and C-15), were replaced with controllers which have programmable logic for automatic control functions. The old controller for the Powdex Bypass responded to a high pressure drop across the Powdex by opening the Bypass valves even if the controller was manually set to an intermediate valve position. The new controller was programmed so that the high pressure drop signal would only open the Bypass valves if the controller was in AUTO. An operator training package containing a description of this change was distributed prior to the end of the outage. Additionally, a label was installed immediately under the controller, stating that it should be placed in AUTO whenever the Bypass Valves were closed.

On July 3, 1991, Unit 3 was operating at 100 % full power when Operations and Chemistry personnel began the routine operation of precoating a cell in the Powdex. At 0950 hours, Control Room Operator (CRO) A placed the control for Powdex bypass valves in manual and opened them to maintain adequate Condensate flow and Condensate Booster Pump (CBP) suction pressure. At approximately 0952 hours, Chemistry Technician A (CT A) placed the Powdex master controller into manual and took one of five cells out of service to precoat the cell by closing its inlet and outlet valves.

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After the cell was isolated, the master controller was returned to AUTO. CRO A used the bypass valve controller to throttle C-14 and C-15 until the other four cells carried 85 % of total condensate flow and the remaining 15 % flow was routed through the bypass. The bypass controller was left in Manual during the precoat cycle.

At 0952 hours CRO A started Low Pressure Injection (LPI) [EIIS:BP] pump A for a scheduled Performance Test. After data acquisition was complete, pump A was stopped, the system was re-aligned and CRO A started LPI pump B at 1047 hours. He set the flow rate as required by the test procedure, and left the control room to perform other duties after giving verbal turnover concerning the tasks in progress to CROs B and C.

After the Powdex cell was precoated, CRO B increased Powdex Bypass flow by opening C-14 and C-15 again at 1048. CT A valved the Powdex cell back into service and placed the Powdex master controller back into AUTO. At approximately 1056 hours, CT A telephoned the control room to have C-14 and C-15 returned to normal. CRO B states that he operated the control to close the valves, but was interrupted by a second telephone call prior to returning the control to AUTO mode. The valves finished closing at 1057 hours. CT A confirmed from local indications of individual cell flows that full condensate flow was going through the Powdex cells, concluded that the bypass valves had closed and considered the procedure step satisfied. CT A had no local indication of AUTO/MANUAL mode for the Powdex Bypass valves, and the Chemistry procedure did not specifically address having the Bypass control placed in AUTO.

CRO B states that, in response to the second telephone call, he became involved in supporting the LPI pump test which was already in progress. His involvement continued for several minutes after which he forgot to finish returning the control for C-14 and C-15 to AUTO. At 1109 hours he secured LPI pump B and subsequently aligned and started LPI pump C at 1117 hours.

At 1117:33, alarms were received in the control room to indicate high differential pressure across the Powdex, high Hotwell Pump discharge pressure, and low CBP suction pressure. Alarms also indicated low hotwell flow and an automatic start of the standby CBP. At 1117:36 the Integrated Control System [EIIS:JA] reached a feedwater (FDW)/Reactor power mismatch limit. This caused reactor power to be decreased to match a decrease in actual FDW flow. The operators investigated the alarms, but, before they could take any corrective actions, the unit tripped from 95% full power at 1118:02. A review of post trip data shows that the CBP suction pressure indicated low, which caused a trip of all three CBPs, followed rapidly by trip of both Main FDW Pumps, which, in turn, caused an anticipatory trip of the reactor.

Several immediate automatic actions occurred. All three Emergency FDW [EIIS:BA] Pumps started. The Control Rod Drive [EIIS:AA] breakers [EIIS:BRK] opened, and all control rods were inserted into the core.

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shutting down the reactor. The turbine/generator tripped, station auxiliary power [EIIS:EA] switched from normal to start-up (Emergency) power, and the Main Steam Relief Valves (MSRVs) and Turbine Bypass Valves opened.

The operators also took manual action. They confirmed that the reactor and turbine had tripped, verified that the Emergency FDW Pumps had started, and monitored for proper operation of other automatic equipment. They started a second High Pressure Injection (HPI) [EIIS: BG] pump at 1118:36 and opened HP-26, HPI Loop A Emergency Make up Valve to increase HPI flow to maintain Pressurizer level.

At 1118:47 CBP suction pressure increased from approximately 85 psi to 163 psi (Hotwell Pump discharge pressure). Pressure between the CBP discharge and the Main FDW Pump suction increased to 750 psi. Main FDW Pump discharge pressure momentarily increased to 1145 psi then decayed to approximately 250 psig. At 1119 both "D" heater drain pumps were manually stopped, and Main FDW pump discharge pressure dropped to approximately 165 psig.

Also at 1119, the operators shut down the Turbine Driven Emergency FDW Pump, after confirming that both Motor Driven Emergency FDW pumps were operating.

At 1120 the operators closed HP-26 and stopped the second HPI pump.

As Steam generator level dropped toward the post trip setpoint, it was observed that FDW-315, Emergency FDW throttle valve to Steam Generator A, was not controlling properly in AUTO, so CRO A took manual control at approximately 1122.

One of the Turbine Bypass Valves, MS-19, had been observed to operate erratically in Automatic following a previous Unit 3 trip on 6-9-91, so the operators took Turbine Bypass Valve control into manual at 1129.

The operators observed that the low flow alarm for cooling water flow to Motor Driven Emergency FDW Pump B did not reset as expected. A Non-Licensed Operator was dispatched to check the local indication and verified that flow was indicating higher than the low flow alarm setpoint.

Two Main Steam Relief Valves did not reseat until after main steam pressure was reduced to approximately 88 to 90 % of their actuation setpoints.

Specific post-trip parameters remained in acceptable limits. Reactor Coolant System (RCS) [EIIS:AB] pressure ranged between 1855 and 2202 psig. Momentary operation of the second HPI pump enabled the Operators to maintain Pressurizer inventory on scale between a high of 230 inches at the time of trip and a low of 89.5 inches. RCS temperatures converged smoothly to approximately 555 F. Steam Generator pressure reached a post-trip high of 1111 psig and was controlled at approximately 1010 psig except when

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pressure was reduced to approximately 940 psig to reseat two main steam relief valves. Steam generator inventory reached a minimum of 21 inches prior to the operators taking action to compensate for the failed FDW-315.

An investigation was started to determine the exact cause of the trip. The CBP emergency low suction pressure switch, PS-228 [EIIS:XIS], was found to be leaking. It was isolated and found to have a split diaphragm. It was observed that one of four housing bolts which hold the diaphragm assembly in place was missing. The technician left the pressure switch electrical circuit open, clearing the trip signal to the CBPs, and permitting subsequent restart of a CBP. The entire switch assembly, including diaphragm, was replaced prior to unit restart. This failure was initially thought to have been the cause of the trip, because an emergency low suction pressure signal, sustained for 30 seconds, will trip all three CBPs, cause the Main FDW Pumps to trip, and result in a reactor trip. However, Transient Monitor [EIIS:IQ] and control room indications show that a real flow reduction occurred prior to the trip. Also, the Hotwell Pump discharge pressure increased, indicating a flow blockage in the Powdex system.

Therefore, the Powdex was checked and the master flow controller was found to have failed, which caused the outlet valves on the individual demineralizer cells to close when they should have been open. The controller was further investigated. A pneumatic AUTO/MANUAL transfer switch was found to have the AUTO position air port clogged by particles from a worn rubber seal. The seal was replaced.

After the unit was stabilized at hot shutdown, Operations personnel desired to restart the main FDW pumps. One of the first steps to do so required starting a CBP in condensate recirculation mode, in which condensate is routed from the Hotwell through Powdex to the Upper Surge Tank (UST). Water in the UST is then used to makeup to the Hotwell as Hotwell level drops. However, no procedure specifically covered restart of a CBP under the existing conditions. Specifically, a concern was raised that starting a CBP would cause hot water from feedwater heaters to be pumped into the UST, raising the UST temperature above 130 F. The UST also serves as the primary source of water for the Emergency FDW pumps and 130 F is the maximum supply temperature assumed in Design Engineering calculations of the required Emergency Feedwater flow rates following a trip from full power. Several procedures, including the Reactor Trip Recovery Procedure, contained caution statements that the UST temperature must be less than 130 F with the Reactor critical, but it could be up to 190 F with the Reactor subcritical. Operations Staff personnel were consulted and concurred with the decision that the 190 F limit applied because the Reactor was subcritical.

At 1530, the operators restarted a CBP and established condensate recirculation. As expected, UST temperature rose to approximately 170 F within ten minutes. Shortly after entering this line-up, the operators observed that the UST level was indicating less than the 6 foot minimum

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level required by Technical Specifications, despite the fact that make-up flow from several sources should have been causing the level to increase. Make-up flow was increased further and the Condensate Storage Tank, which receives overflow from the UST, began to overflow onto the turbine building basement floor. This indicated that the UST was actually full, so make-up flow was then isolated. A work request was initiated to investigate the level instrumentation. Subsequent review of the Reactor Trip Recovery Procedure revealed another caution, on a later page than the first caution, which stated that the UST could not exceed 130 F unless it had been greater than five hours after the reactor trip.

The operators started a main FDW pump, and stopped the motor driven Emergency FDW pumps at 1427, terminating the loss of feedwater event. The reactor went critical at 2310 hours and the turbine was placed back on-line at 0230 hours, 7-4-91.

Analysis of Post-Trip data also showed that, although the Emergency Feedwater Pumps were started by one actuation path, i.e. due to low control oil pressure on the Main FDW Pump turbines, they did not receive a timely start signal from the other actuation path. The second path is actuated by low Main FDW Pump discharge pressure. It was observed that pressure in the condensate/feedwater system stayed higher than the low discharge pressure setpoint due to continued operation of both "D" heater drain pumps. Analysis showed this phenomenon to be a potential occurrence on loss of feedwater events for all three Oconee units, therefore one path of Emergency FDW actuation logic has been technically inoperable for some time. This situation will be reported separately as LER 269/91-09.

CONCLUSIONS

The root cause of this event is Equipment Failure. The Powdex master controller, a Foxboro model 52A "Consotrol" failed due to normal wear and age degradation of a rubber seal which is a component of a part number C123MT Switch Assembly. This failure is NPRDS reportable. This seal is internal to the controller and is not specifically inspected during calibration or routine maintenance. It has apparently been in service for a long time, possibly since initial installation prior to Unit 3 start-up.

A contributing cause for this event is Inappropriate Action, Improper Action where the proper action was chosen but execution failed because a required action was omitted. Had CRO B placed the Powdex Bypass Valve control in AUTO, the unit trip could have been avoided because the bypass valves would have been able to respond to the increased pressure drop across the demineralizer system as the Powdex cell flow control valves failed shut on loss of air. The Powdex Bypass Valve control has a label which states that the control should be placed in AUTO whenever the valves are closed. This is accomplished simply by pressing a button on the control. CRO B was knowledgeable of this requirement, but was distracted

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by an interruption related to another task, and did not think about the need to return and complete this task.

Although other unit trips have occurred recently due to equipment failures, none involved the Powdex system controls and none of the corrective actions could have addressed this failure. Therefore, this event is not considered recurring.

Several additional equipment failures/problems occurred during this event, but were not causal factors of the event. Subsequent investigation by Maintenance revealed several apparent causes of some of the post-trip discrepancies.

1. A solenoid valve (SV) failure disabled the automatic control of FDW-315, the Emergency Feedwater Loop A throttle valve. The solenoid valve is normally energized but is required to operate to the de-energized position upon Emergency FDW actuation to permit automatic control. This failure is NPRDS reportable. The SV was a Valcor V-70900-21-3. This model SV is used in several other applications at the plant and has failed to operate properly in the past. Because it is normally energized and operates at an elevated temperature (approximately 250 F), Maintenance Engineering suspects that the temperature causes degradation leading to the valve sticking open when de-energized. This specific SV had been installed in the cooling water system for a Motor Driven Emergency Feedwater Pump on Dec 31, 1990. However, it was cannibalized to replace the previous SV on FDW-315, which failed during a Periodic Test of FDW-315 during the last Unit 3 refueling outage. Following that outage, plans were initiated to replace this model as the service intervals expire.

2. The Motor Driven Emergency FDW pump cooling water low flow alarm is normally received when the pump start signal is received, but normally clears as soon as the cooling water valve opens to establish flow. In this case, the instrument was found out of calibration enough that the indicated flow would not reset the alarm.

3. The reseating of two Main Steam Relief Valves at slightly lower than desired system pressure is not considered a component failure. However, additional data evaluation will be performed following future trips to better identify the exact pressure at which the valves reseat and look for adverse trends.

4. The diaphragm on PS-228 (CBP suction pressure switch) ruptured post trip. Although CBP suction pressure went from a pre-trip value of approximately 80 psig to 160 psig after the trip, these switches were rated for 320 psig. Markings on the component indicate a date of manufacture of 1973. Maintenance records indicate that the switch has not been replaced since initial installation prior to Unit 3 startup in 1974. The mode of failure was a crack on the outer edge of the metal switch diaphragm. The presence of some rust on the

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inside surface of the crack indicates that it had degraded over a period of time, then failed under higher than normal pressures. The failure of PS-228 was primarily due to age but may have been influenced by the missing bolt on the unit housing. The housing holds the switch diaphragm securely, and restrains the diaphragm from flexing at its periphery. The absence of the housing bolt could allow the diaphragm to flex at its outer edge, subjecting the area at the point of failure to stress fatigue. The bolt was apparently left out after a gasket was poorly installed such that it blocked the bolt hole. It was not possible to identify when this occurred, who did it, or why the person(s) involved failed to realign the gasket so that the bolt could be properly installed. It was noted that the housing is not disassembled during routine calibration of the switch and the degradation would not have been visible without disassembly. This failure is NPRDS reportable. The switch is a Meletron model 2221-32.

5. For approximately thirty minutes during trip recovery, the Upper Surge Tank (UST) level instrumentation indicated less than the minimum level required by Technical Specifications. This was due to the UST being overfilled when the Condensate recirculation line-up was established. The overfilled condition allowed water to enter the level instrument reference leg, which should be dry. This reduced the differential pressure seen by the instrument, resulting in an erroneous low reading. Because the actual UST level was full, rather than as indicated, the Technical Specification was not violated. The resulting overflow of uncontaminated water to the Turbine basement floor did not impact safety. However, the procedural limit on UST temperature was exceeded. This temperature limit is based on Design Engineering calculations of the minimum Emergency FDW flow rates at assumed FDW supply temperatures for removal of RCS Decay Heat. The Emergency FDW system did adequately remove decay heat while the UST temperature was higher than the procedure limit. The cause of the procedure limit being exceeded is Defective Procedure, Ambiguous Information and Poor Format in that limits were presented differently on different pages.

There were no personnel injuries, radiation exposures, or releases of radioactive materials associated with this event.

CORRECTIVE ACTIONS

Immediate

1. Operations personnel took appropriate actions per the Emergency Operating Procedure and Abnormal Procedure for Loss of Main Feedwater to bring the unit to a safe conditions.

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Subsequent

1. The solenoid valve on FDW-315 was replaced.

2. The Motor Driven Emergency Feedwater (FDW) pump B low flow alarm was calibrated.

3. The operation of the Main Steam Relief Valves (MSRV) was evaluated and determined to be acceptable. The Post-Trip Review process has been revised to better define the MSRV performance expectations and to improve Post-trip determination of actual reseat pressures.

4. PS-228 pressure switch, including the diaphragm assembly, was replaced. Equivalent switches on Units 1 and 2 were inspected.

5. The seal on the Powdex master controller was replaced.

6. The Upper Surge Tank (UST) level instruments were checked and the reference legs dried.

7. Control Operator B has been counselled concerning his Inappropriate Action in this event.

8. A problem was discovered with the system function and setpoints for actuation of Emergency Feedwater pumps in response to loss of main feedwater as detected by low discharge pressure. That problem and the corrective actions are being reported separately as LER 269/91-09.

Planned

1. The solenoid valve model used on FDW-315 will be replaced with an improved model in all safety related applications at Oconee.

2. Instrument and Electrical (I&E) Section management will communicate to I&E technicians the potential failure mode of pressure switches with missing/loose assembly bolts.

3. The equivalent seals on Unit 1 and 2 Powdex master controllers will be inspected and replaced if necessary.

4. Operating Procedures will be revised as necessary to eliminate conflicting guidance on UST temperature limits.

5. A Station Problem Report will be initiated to revise the control logic of Powdex Bypass valves to allow them to respond to high Powdex pressure drop while in Manual.

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SAFETY ANALYSIS

Failure of the Condensate Demineralizer (Powdex) master controller due to a clogged control air path resulted in a loss of control signal to the controllers for five parallel demineralizer resin tank flow control valves. These valves all went closed, as designed, resulting in the isolation of the condensate flow path. The Powdex system Bypass valves were effectively removed from service due to the inappropriate action of an operator. Had the Bypass valves been in service, they should have opened to provide an alternate flow path and to avoid a system transient. The loss of condensate flow path constituted a loss of feedwater (FDW).

Loss of FDW is an anticipated transient and is described in Section 10.4 of the Final Safety Analysis Report (FSAR). Loss of FDW initiates a reactor trip and starts the Emergency FDW System to provide decay heat and reactor coolant pump heat removal. In this event, most of the equipment and systems operated as designed to mitigate the consequences of the Loss of FDW. As expected, low Condensate Booster Pump suction pressure was detected and instrumentation tripped the Condensate Booster Pumps. The Main FDW pumps tripped as expected. Instrumentation detected the low hydraulic oil pressure in the Main FDW pump turbine control systems and initiated the Loss of FDW trips of the Main Turbine and the Reactor and provided the start signal to the Emergency FDW System. All three Emergency FDW pumps started and the unit was stabilized at hot shutdown.

The failure of the redundant train of Loss of FDW detection logic, i.e. failure of the system to reach the actuation setpoint for Main FDW pump low discharge pressure, is described in a separate Licensee Event Report, but had no safety significance in this event.

The failure of the solenoid in the controls for FDW-315 resulted in that valve being unable to respond to control signals while in automatic. This was a single failure within the design basis of the Emergency FDW System. The operators took appropriate action to take manual control of the valve and maintained proper level in the affected steam generator throughout this event. Had the operator failed to take proper action, the affected steam generator would have boiled dry and the entire RCS heat load would have been carried by the other steam generator and eme[illegible]y FDW train.

The failure of the diaphragm on PS-228 had no safety consequence. If it had occurred at some other time, independent of the condensate system transient associated with this trip, the result would have been another loss of feedwater trip. This devi e is one of many which can cause a unit trip due to single failure.

The overflow of the Upper Surge Tank (UST) is slightly more significant in that it demonstrates that both trains of post-accident level monitoring instrumentation can be made inoperable by over filling the tank. The level instruments are intended to be used to verify the adequacy of the UST as a source of water for the Emergency FDW system. In some scenarios the UST

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inventory is expected to be depleted over time and the Emergency FDW pump suctions must be realigned to the Hotwell. This realignment requires that condenser vacuum be broken. If a similar loss of level indication occurred due to overfilling the UST during such an event, considerable operator time and resources could be diverted to performing unnecessary actions in order to assure an adequate source of water. However, if the erroneous indication is properly diagnosed, as occurred in this event, no adverse consequence would occur.

The operation with UST temperatures in excess of procedural limits also demonstrates the possibility of exceeding design basis assumptions that potentially could lead to technical or physical inoperability of systems or components. The temperature limit of 130 F is based on a design calculation assuring decay heat removal capability in the worst case conditions of operation with a single Emergency FDW pump immediately after a trip from full power. The limit of 190 F is intended to reflect the reduced decay heat removal requirements for the scenario where a loss of FDW occurs during startup several hours after a trip. In this case, only two hours, rather than the procedurally required five hours, had elapsed following the trip. The system was able to provide adequate flow to remove the existing decay heat load. However, two Emergency Feedwater pumps were in operation, with a third available if needed, rather than the one operating pump assumed in the design calculation. If one of the two operating Emergency Feedwater pumps was assumed to fail, the potential exists that the remaining pump might not have been able to provide the additional flow needed to maintain decay heat removal due to the higher supply temperature. In the unlikely event that a failure of one of the pumps had occurred during this time, the Turbine Driven Emergency FDW pump could have been restarted. Another option would have been alignment of Emergency FDW pumps on one of the other two Oconee units to supply cooler water from that unit's UST. Other options include use of the Standby Shutdown Facility Auxilliary Service Water System or forced cooling of the Reactor Coolant System by using the High Pressure Injection System to establish flow through the Power Operated Relief Valve. All of these options are included in appropriate procedures.

There were no releases of radioactive materials, radiation exposures, or personnel injuries associated with this event. The health and safety of the public was not affected by this event.

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TITLE (4): One of Two Diverse Actuation Systems for Loss of Main Feedwater Mitigation Systems Was Found Inoperable Due to a Design Deficiency

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 NAMES	DOCKET NUMBER(S)
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0 7	0 3	9 1	9 1	0 0 9	0 1	0 8	0 2	9 1	Oconee, Unit 3	0 5 0 0 0 2 8 7

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

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

- [X] 50.73(a)(2)(i)(B)
- [X] OTHER (Specify in Abstract below and in Text, NRC Form 366A): 50.72(b)(1)(A)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Henry R. Lowery, Chairman, Oconee Safety Review Group

TELEPHONE NUMBER: AREA CODE 8 0 3 8 8 5 - 3 0 3 4

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)

- [ ] YES (If yes, complete EXPECTED SUBMISSION DATE)
- [X] NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

On July 3, 1991, all Oconee units were operating at 100 percent full power (FP) when Unit 3 tripped due to a loss of feedwater at 1118 hours. A post-trip review showed that feedwater pump discharge pressure remained slightly above the 750 psig setpoint required to actuate the Emergency Feedwater (EFDW) system, the loss of feedwater Reactor Protective System anticipatory trip, and the ATWS Mitigation Safety Actuation Circuit. This prevented the Technical Specification required systems from receiving one of the two initiation signals when Main Feedwater pumps tripped. EFDW did actuate from the independent signal. The problem was caused by the D heater drain pumps (HDP) charging the closed feedwater system. The other two Oconee units were subject to the same potential problem. The root cause of this event was a design deficiency, failure to anticipate the interaction of systems, during the original design of the these systems. Units 1 and 2 reduced power to 72 percent FP to remove the D HDPs from service. Unit 3 increased power to 71 percent FP, but did not place D HDPs in service. Feedwater pump low discharge pressure setpoints were changed to 800 psig on all units prior to allowing HDP operation and a return to 100 percent FP on July 7, 1991.

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NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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BACKGROUND

There are three systems at Oconee which are designed to automatically actuate when main feedwater (MFDW) [EIIS:SJ] flow is lost: the Emergency Feedwater (EFDW) [EIIS:BA] system, the Reactor Protective System (RPS) [EIIS:JC], and the ATWS (Anticipated Transient Without Scram) Mitigation Safety Actuation Circuit (AMSAC). The AMSAC system has been installed on Units 2 and 3 and is scheduled to be installed on Unit 1 during the next refueling outage. Each of these systems use diverse means to determine when main feedwater has been lost. System actuations occur when signals are received that both main feedwater pumps can no longer provide feedwater to the steam generators. This condition is sensed by both turbine hydraulic oil [EIIS:JK] pressures dropping below 75 psig or both main feedwater pump discharge pressures dropping below 750 psig.

The EFDW system actuation signal will start the three EFDW pumps and enable a circuit which controls steam generator level [EIIS:JB] at predetermined setpoints. The purpose of this system is to remove decay heat and Reactor Coolant Pump [EIIS:AB] heat following a loss of main feedwater. The RPS system uses the loss of main feedwater signal as an anticipatory trip; the reactor trip occurs prior to Reactor Coolant System (RCS) [EIIS:AB] parameters reaching their own RPS trip setpoints. The AMSAC signal will initiate EFDW in the same way as the normal EFDW system and trip the main turbine [EIIS:TA]. The AMSAC system is intended to mitigate the consequences of an anticipated transient without scram event.

Technical Specifications 3.4 and 3.5 address the EFDW and RPS system respectively. Technical Specification 3.4 requires operable EFDW initiation circuitry. The basis of this specification states that the EFDW system is "...designed to start automatically in the event of loss of both main feedwater pumps or low main feedwater header pressure." Table 3.5.1-1 of Technical Specification 3.5 requires a minimum of three operable RPS loss of MFDW anticipatory trip channels. AMSAC requirements are outlined in the Selected Licensee Commitment manual, Section 16.7.2, and state that both AMSAC channels will be operable when the reactor is critical.

The secondary system at Oconee uses two pairs of heater drain pumps (HDP) [EIIS:SM] to pump condensed extraction steam to the condensate [EIIS:SD] and feedwater systems. The D1 and D2 HDPs combined flow at 100 percent full power is approximately 9,000 gpm. The E1 and E2 HDPs have a combined flow of approximately 900 gpm. Attachments 1 and 2 show the general arrangement of these pumps in the condensate system. Because of the significant amount of flow of the D Heater Drain pumps, they cannot be stopped during power operation unless load is reduced to approximately 72 percent full power. The HDPs will automatically trip when both MFDW pump discharge pressures reach a pre-determined low pressure setpoint.

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EVENT DESCRIPTION

On July 3, 1991, all three Oconee units were at 100 percent full power. At 1118 hours, Unit 3 tripped due to a loss of all main feedwater. This event is reported in LER ~~269~~ 287/91-09. During the post-trip review, it was discovered from transient monitor data that main feedwater pump discharge pressure remained slightly above the low discharge pressure setpoint of 750 psig despite the trip of both main feedwater (MFDW) pumps. This condition continued until after the D HDPs were manually secured, at which time pressure dropped. Emergency feedwater (EFDW) actuated as required when the diverse initiation signal was received from low hydraulic oil pressure on the MFDWP turbines. The unit was stabilized at hot shutdown conditions.

An investigating team was formed consisting of the Superintendent of Operations, the Superintendent of Technical Services, the Design Engineering Site Manager, and Engineering Support personnel from Technical Services, Operations, and Maintenance departments. Investigation of the failure to reach the low discharge pressure setpoint continued during the afternoon and evening of July 3, 1991. Several possible causes were considered including back pressure from the Main Steam [EIIS:SB] system through leaking check valves, leakage from the EFDW to the MFDW system, and the possibility that the heater drain pumps (HDP) were maintaining pressure in the feedwater system. A review of the trip data suggested that the HDP hypothesis was the most likely. When the D HDPs were secured, MFDW pressure dropped immediately. A review of the data from a Unit 1 trip on August 28, 1990 (LER 269/90-13), which involved a single MFDW pump trip, showed a similar condensate-feedwater pressure response. In this event, the D HDPs did not trip since only one MFDW pump tripped. The discharge check valve on the tripped MFDW pump prevented the upstream components in the condensate system from being pressurized by the operating MFDW pump. This situation presented another opportunity to determine the role of D HDPs in maintaining an elevated feedwater pump discharge pressure. The transient monitor data from that trip showed that the discharge pressure of the tripped MFDW pump stayed at approximately 730 to 760 psig until the D HDPs were secured.

At 2120 hours, station management decided to reduce power on Units 1 and 2 to a point which would allow securing the D heater drain pumps. Unit 1 had reduced power to 72 percent full power by 2215 and stopped both D heater drain pumps at 2226 hours. Unit 2 reduced power to 72 percent full power and secured both D heater drain pumps at 2350 hours. Unit 3 was allowed to return to power operation, but without the use of the D heater drain pumps. Unit 3 achieved criticality on July 3, 1991 at 2310 hours and reached 71 percent full power at 1301 hours on July 4, 1991.

A question arose that perhaps the E heater drain pumps could also maintain an elevated feedwater pressure. An operability evaluation showed that the E HDPs maximum shutoff head pressure was 730 psig while the maximum discharge pressure during shutoff conditions for the D HDPs was 773 psig.

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The investigating team decided that the best short term solution to restore the feedwater pump low discharge actuation signals was to change the actuation setpoint from 750 psig to 800 psig on pressure switches which sense feedwater pump low discharge pressure. Duke Design Engineering was asked to perform an operability determination for the Reactor Protective System (RPS) anticipatory trip, the EFDW system, and the ATWS Mitigation Safety Actuation Circuit (AMSAC) system based on the new 800 psig setpoints. On July 5, 1991 Design Engineering determined that all three systems would be operable with the new setpoints. The calculations justifying this determination were based on manufacturer's original pump data at shutoff conditions and the relief valve setting serving the D Flash tank. The pump manufacturer has stated that pump casing wear and degradation would tend to decrease the HDP performance over time, especially since they are multistage pumps. The maximum D HDP discharge pressure at shutoff conditions was found to be 773 psig. This is 27 psig less than the new 800 psig setpoint, which provides a margin for instrument drift and calibration tolerance. A condition of operability was that the AMSAC calibration procedure be changed to require a 10 psig as-left tolerance. This is less tolerance than what was previously allowed.

The investigating team discussed the possibility that, if the D HDP recirculation valves were opened, the D heater drain pumps would not be able to develop sufficient pressure to stay above the feedwater pump low discharge pressure setpoint. This alignment would allow a certain amount of flow to be recirculated back to the D Flash Tanks. Both D heater drain pumps on Unit 1 were operated in this manner on July 4, 1991 for approximately 30 minutes each. Their discharge pressures were 710 psig for 1D1 HDP and 720 psig for 1D2 HDP. Since these tests were not done at shutoff head conditions, these values did not provide adequate margin between the pump discharge pressure and the low MFDW discharge pressure setpoints to ensure loss of feedwater system actuation. Nevertheless, it was decided to operate with a recirculation pathway to the D Flash Tanks throttled open on all three units, since this mode of operation increases the margin between D HDP discharge shutoff pressure and the feedwater pump low discharge pressure setpoint. Operation procedures were changed accordingly.

The setpoint changes and procedure revisions were performed for the EFDW system, the AMSAC system, and the RPS system on all three units by July 6, 1991. As these changes were completed on each unit, the HDPs were returned to service and power increased at the electrical power dispatcher's request. All three units were at 100 percent full power by 0100 on July 7, 1991.

There are a total of eight pressure switches per MFDW pump per unit which sense feedwater pump low discharge pressure. Four of these switches feed the four loss of feedwater anticipatory RPS trip channels. The two pressure switches associated with RPS Channel D also serve as inputs to the start circuitry of the Turbine Driven Emergency Feedwater Pump (TDEFDWP).

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Two pressure switches per MFDW pump are used for actuation of the two Motor Driven Emergency Feedwater Pumps. All of these switches have been set at 750 psig since their installation.

One pressure switch per pump is used for alarm indication, Integrated Control System [EIIS:JA] runback signal, feedwater pump recirculation control and, on Units 2 and 3, AMSAC Channel 2. The remaining pressure switch on each pump is an input to Hotwell pump and Condensate Booster pump trip circuitry, main turbine trip, D and E Heater Drain pump feedwater pump low discharge pressure trip and, on Units 2 and 3, AMSAC Channel 1. This last AMSAC-related pressure switch, which also serves to trip the Heater drain pumps, was changed from a setpoint of 800 psig to 750 psig during the installation of the AMSAC modification. This setpoint change was approved on October 10, 1990 on Unit 2 and April 2, 1991 on Unit 3. The modification has not been made on Unit 1 and the setpoint for the AMSAC related pressure switches is still 800 psig.

Design Engineering was asked to perform a past operability evaluation of the loss of feedwater mitigation systems. This evaluation showed that the feedwater pump low discharge pressure portion of the actuation circuitry for the Emergency Feedwater system, the loss of feedwater anticipatory RPS trip, and the AMSAC system on Units 2 and 3, had been technically inoperable while the D HDPs were operating since the systems' original design. This determination was based on the following considerations:

Though the redundant hydraulic oil pressure switches would have actuated the loss of feedwater mitigation systems, each system was designed to include two separate and diverse actuation signals.

Pressure switches which would have tripped the D HDPs upon loss of MFDW pumps were not safety grade. These pressure switches would have been required for operation of the MFDW pump low discharge pressure portion of the EFDW and RPS anticipatory trip systems.

After the AMSAC system was installed on Units 2 and 3, the MFDW pump discharge pressure switches which trip the D HDPs were set below the pressure developed by the HDPs against a closed system.

CONCLUSIONS

The safety systems which respond to a loss of main feedwater receive automatic actuation from the presence of a low Main Feedwater (MFDW) pump discharge pressure or low main feedwater pump hydraulic oil pressure. These systems, though they actuated on the low hydraulic pressure signal, did not immediately receive the low discharge pressure signal when Unit 3 tripped following the loss of both Main Feedwater (MFDW) pumps. The D heater drain pumps (HDPs) remained on following the trip. Their shutoff discharge pressure, when added to the static pressure of the D Flash Tanks

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on the pump suction, maintained pressure in the feedwater lines above the 750 psig setpoint until the D heater drain pumps were secured.

The result of an operability evaluation performed for this problem was that the feedwater pump low discharge pressure portion of the actuation circuitry of all channels of the Reactor Protective System (RPS) anticipatory loss of feedwater pumps trip, the Emergency Feedwater (EFDW) system, and the ATWS Mitigation Safety Actuation Circuit (AMSAC) were technically inoperable while the D HDPs were operating. RPS, EFDW, and AMSAC systems were declared technically inoperable since their original installation.

The technical inoperability of the systems was not apparent until the operability evaluation was performed. While the evaluation was being performed, conservative actions were taken to reduce power on the operating units and remove the D HDPs from service. These actions were completed within the required times of Technical Specifications 3.5.1, 3.4, and Selected Licensee Commitment 16.7.2. Unit 3 was allowed to start up and increase power but was prohibited from using its HDPs. The operability evaluation showed that securing D HDPs made the loss of feedwater mitigation systems operable when the low main feedwater discharge pressure setpoints were at 750 psig. The corrective actions of resetting low main feedwater discharge pressure setpoints to 800 psig was performed prior to restarting the D HDPs and increasing power.

The root cause of this event is Design Deficiency, unanticipated interaction of systems, design oversight. The design of a major EFDW modification in 1979 which added the motor driven pumps and upgraded the instrumentation and controls did not consider the role of HDPs. Similarly, the installation of the loss of feedwater anticipatory RPS trip in 1981 also did not consider the role of the HDPs. At that time, the non-safety related HDP pressure switch trip setpoint was 800 psig for all units, as it still is on Unit 1. This setpoint should be sufficient to trip the HDPs during a loss of main feedwater transient. However, if excessive calibration drift or even complete switch failure occurs, then the D HDPs could have prevented the main feedwater pump discharge pressure from reaching its low setpoint.

The AMSAC system utilizes the same pressure switches that trip the D and E HDPs on feedwater pump low discharge pressure. The AMSAC design changed the setpoint to 750 psig for these switches to minimize the possibility of inadvertent AMSAC operation prior to EFDW system actuation. The AMSAC system was installed on Unit 2 in October, 1990 and on Unit 3 in April, 1991. Again, when the setpoints were changed, the effects of the lower setpoint on HDP operation and subsequent post-trip feedwater pressure were not considered. By lowering the setpoints, the HDPs would not automatically trip since their shutoff discharge pressure prevented feedwater pressure from reaching the new setpoint.

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It is noted that the identification of this problem in the design process requires knowledge of several areas of expertise. The design of the AMSAC system, which changed the D HDP trip setpoint to 750 psig, was performed by the Electrical Section of Design Engineering. A knowledge of the electrical circuitry, the operating parameters of the D HDPs, and the post-trip operation of the condensate-feedwater system would be required to foresee the problem. Integrated Design Reviews, which take a multi-disciplinary approach to Nuclear Station Modification design, are performed for some NSMs where such an approach is deemed appropriate. An Integrated Design Review was performed for the AMSAC modification. Design Engineering personnel will review the criteria used when performing these multi-disciplinary reviews with respect to system interactions.

A review of Oconee Problem Investigation Reports over the last two years indicates that two separate events occurred which involve the EFDW, [illegible] or AMSAC systems which have either a root or contributing cause of design deficiency, failure to anticipate the interaction of systems. One event, described in PIR-090-0042, involved the Emergency Feedwater system. In that event, the discharge pressure of the Motor Driven Emergency Feedwater Pumps exceeded the design pressure of the recirculation piping when the pump was run in the recirculation mode. Another event, described in PIR-3-091-0035 and LER 287/91-05 involved the AMSAC system design. A failure to anticipate certain electrical circuit phenomenon of the associated Diverse Scram System led to control rod insertion and subsequent manual reactor trip. None of the loss of main feedwater actuation circuits were involved in these events. This problem is therefore considered non-recurring.

This event did not involve radiation overexposure or release of radioactive material. No personnel injuries were involved. There was no equipment failure which would require reporting to NPRDS.

CORRECTIVE ACTIONS

Immediate

1. Automatic initiation of the Emergency Feedwater (EFDW) system occurred due to the diverse initiation logic from feedwater pump low hydraulic oil pressure.

Subsequent

1. An investigation team was formed to determine the cause of the low Main Feedwater (MFDW) pump discharge pressure initiation channel failure.

2. Units 1 and 2 reduced power and their heater drain pumps (HDP)s were secured.

3. Unit 3 was allowed to restart but was not permitted to use its HDPs.

4. Pressure switches which detect low main feedwater pump discharge pressure and actuate EFDW, Reactor Protective System, and ATWS Mitigation Safety Actuation Circuits were reset to 800 psig following an operability evaluation which justified these setpoints. These setpoints will be maintained until a permanent solution to the problem has been resolved. Instrument and Electrical procedures as well as Operations procedures were revised to reflect the new setpoints.

5. The recirculation flow paths of the D heater drain pumps were aligned such that a larger difference occurs between the D HDP shutoff discharge pressure and the 800 psig setpoint. These alignments are not required to maintain EFDW, RPS, or AMSAC operability, but further increase the margin between the actual pump discharge pressure against shutoff conditions and the revised setpoints.

Planned

1. A Station Problem Report will be initiated which will consider permanent solutions to this problem.

2. Oconee operator training will be enhanced by changing training material to reflect the new MFDW pump discharge pressure setpoints and by making the required setpoint changes to the plant simulator.

3. The Safety Parameter Display System, used by the control room, will be changed to reflect the new MFDW pump discharge pressure setpoints.

4. The EFDW Design Basis Document will be revised to reflect problems discovered in this event.

5. Design Engineering will review the criteria used to perform interdisciplinary reviews of design packages.

SAFETY ANALYSIS

In this event, the low Main Feedwater (MFDW) pump discharge pressure signal, used to detect and mitigate a loss of feedwater, was found to be unable to independently actuate the required systems. The systems affected by this degradation are: the Emergency Feedwater System (EFDW), the Loss of Feedwater Anticipatory Trip of the Reactor Protective System (RPS), and the ATWS Mitigation Safety Actuation Circuit (AMSAC). Each of these systems can be actuated from a separate signal which monitors low hydraulic oil pressure, indicating a tripped condition, on the MFDW pumps. Manual actuation is also possible. The degradation of the MFDW pump discharge pressure portion of the actuation circuitry depends on the discharge pressure of the D heater drain pumps (HDP). When the D heater drain pumps were operating against a shutoff head, the feedwater pressure exceeded the 750 psig setpoint.

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There is no safety significance to the inoperability of the low MFDWP discharge pressure signal if the hydraulic low oil pressure signal actuates as designed. The loss of MFDW would be sensed and the appropriate system actuations would take place. There would also be no safety significance if the D heater drain pumps were not operating, as in the case of a loss of power. In this situation, not only would the hydraulic oil pressure signal continue to be available, but the MFDW pump low discharge pressure signal would also function.

During most of the time of technical inoperability, the HDPs had a trip setpoint of 800 psig which should have prevented the problem from occurring. However, wide calibration tolerances and instrument drift may have compromised the switch reliability. When AMSAC modifications were performed in October, 1990 on Unit 2 and April, 1991 on Unit 3, the probability of D HDPs remaining in service following a trip of feedwater pumps was significantly increased.

Each EFDW pump has its own associated hydraulic oil pressure switch so that a failure of one pressure switch will affect only one EFDW pump. If a single failure occurred to a hydraulic oil pressure switch on either MFDW pump turbine during a loss of MFDW while the MFDW pump low discharge pressure signal was inoperable, then the EFDW pump corresponding to that signal would not start. If the EFDW system was degraded in this manner, an automatic start would only occur on two of the three EFDW pumps. The design of the EFDW system is such that only one of the three EFDW pumps is necessary to successfully perform an orderly cooldown of the Reactor Coolant System (see Final Safety Analysis Report Section 10.4.7.1). Either multiple switch failures or a common cause failure of three switches would have to occur to totally prevent feedwater from automatically actuating in these circumstances.

Reactor operators are required by the Subsequent Actions section of the Emergency Operating Procedure (EOP) to check for main feedwater flow. If EFDW has not automatically actuated, they are instructed to follow the Loss of Feedwater procedure, AP/1,2,3/A/1700/19, which has the operator manually start the EFDWPs and verify proper flow. This is done from the control room.

The effect of a failure of a single hydraulic oil pressure switch, while operating with a degraded MFDWP discharge pressure alignment, on the Reactor Protective System is that the associated RPS channel will not trip on loss of main feedwater. The anticipatory reactor trip due to a loss of MFDW will only fail to occur if three of the eight hydraulic oil pressure switches fail in such a manner that three RPS channels do not trip. If the anticipatory FDW trip fails to occur, Reactor Coolant System (RCS) pressure and temperature will increase until the reactor trips at either of these parameters' high setpoint. Furthermore, Operations Management Procedure 2-1, "Duties and Responsibilities of Reactor Operators, Non Licensed Operators, and the Senior Reactor Operator in the Control Room", requires all licensed reactor operators to know from memory that the reactor must be

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manually tripped if both MFDWPs trip. The result is that the reactor will be tripped, but not as quickly as when the anticipatory trip is operational. The longer delay may result in a higher RCS pressure transient. If pressure reaches 2450 psig (150 psig above the RCS trip setpoint of 2300 psig) then the Pilot Operated Relief Valve (PORV) [EIIS:AB] will open to relieve RCS pressure.

The AMSAC system is designed to ensure that the main turbine trips and emergency feedwater actuates if there is a loss of main feedwater associated with an ATWS event. In this event, the reactor fails to trip when required. Tripping the turbine ensures that power will not increase due to moderator temperature effects. Because of a negative moderator temperature reactivity coefficient, overcooling of the RCS will result in a power increase. Emergency feedwater is actuated as a backup to the normal EFDW system actuation. The AMSAC system uses a two out of two channel initiation logic. A single failure of a hydraulic oil pressure switch while the low discharge pressure signals are inoperable will therefore prevent actuation of the system. The Unanticipated Nuclear Power Production section of the EOP requires that the reactor operator manually trip both the reactor and the main turbine. As previously stated, the Loss of Feedwater procedure has the operator initiate EFDW manually if not already automatically initiated.

Although the AMSAC system is designed specifically for EFDW actuation during an ATWS event, the AMSAC and normal EFDW actuation circuits serve as independent systems to start the EFDW pumps. Both AMSAC and normal EFDW actuation will start the EFDW pumps whether or not an ATWS has occurred. This design aspect is not credited in the basis of Technical Specifications but is present nevertheless.

Modifications are also scheduled to be performed on the EFDW actuation circuits as a result of NRC Generic Letter 89-19. These modifications will start the EFDW system on low steam generator level.

In conclusion, the safety significance of the feedwater pump low discharge pressure setting is minimal. All automatic actions have separate and diverse feedwater pump turbine hydraulic oil pressure signals. More than one hydraulic oil switch must fail to actuate to prevent the normal EFDW or RPS anticipatory trip from occurring. The Emergency Operating procedure and Loss of Feedwater procedures give adequate procedural guidance to initiate manual actuation if automatic actuations do not occur. The RPS feedwater anticipatory trip is backed up by automatic trips on high pressure or temperature. The EFDW start circuitry and AMSAC EFDW start circuitry are redundant.

The health and safety of the public were not endangered by this event. It did not involve the release of radioactive material, overexposure to radiation, or personnel injuries.

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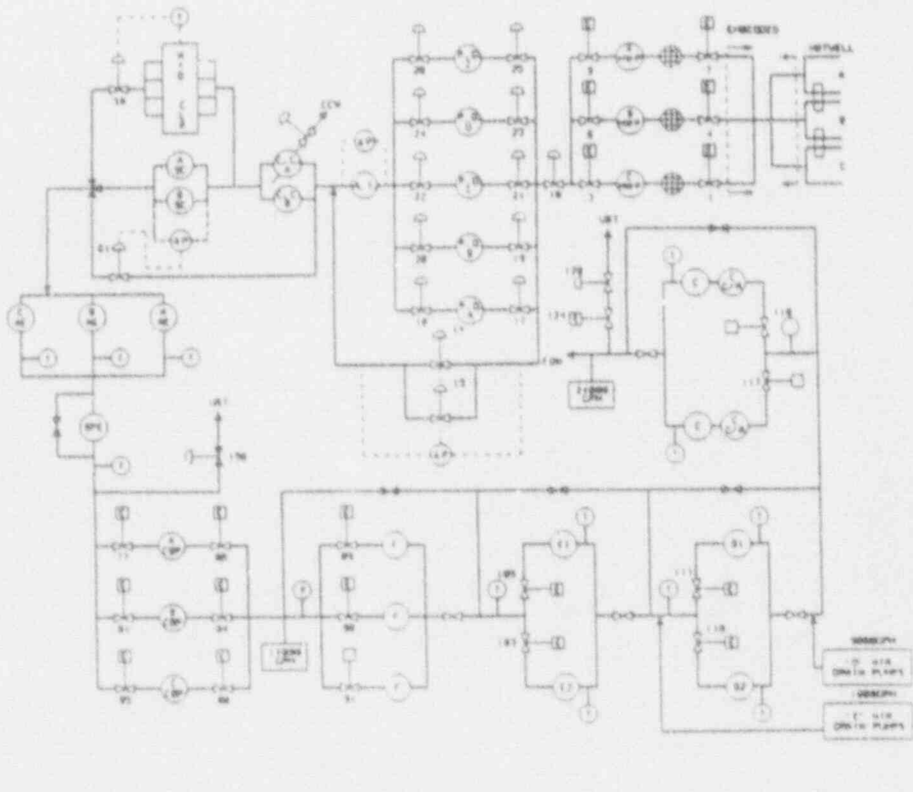
DUKE POWER COMPANY

ATTACHMENT 1

CONDENSATE SYSTEM ARRANGEMENT



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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

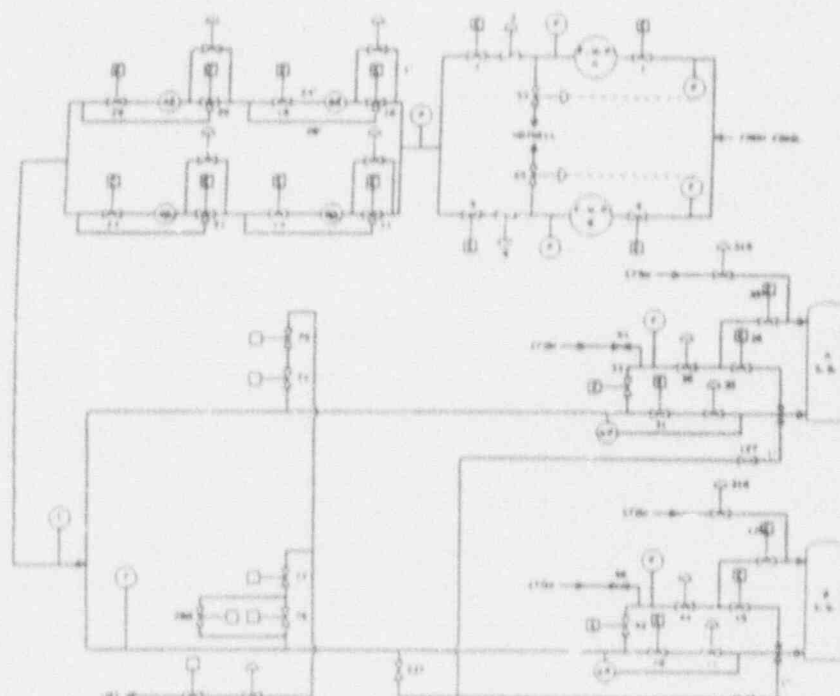
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6): YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 1	— 0 0 9	— 0 1	1 2 OF 1 2

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

DUKE POWER COMPANY

ATTACHMENT 2

FEEDWATER SYSTEM ARRANGEMENT



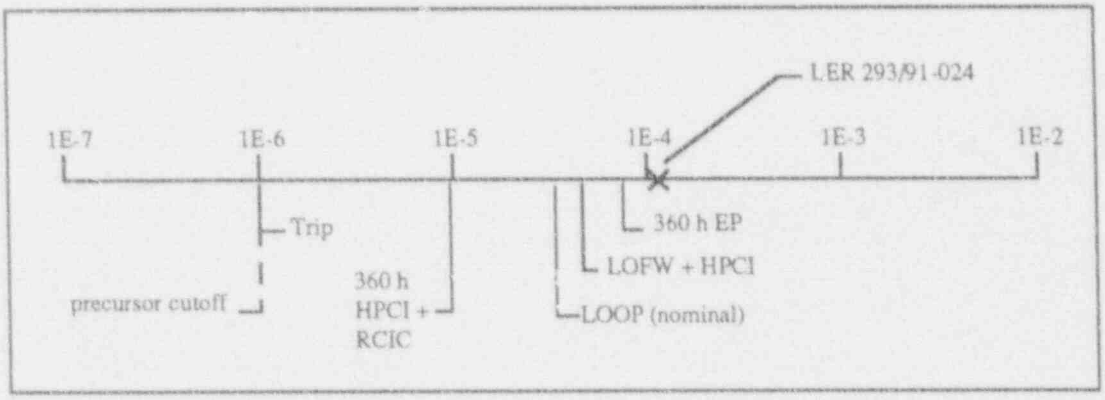
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	293/91-024, 293/91-006, 293/91-021, 293/91-025
Event Description:	Loss of offsite power and RCIC trip
Date of Event:	October 30, 1991
Plant:	Pilgrim

Summary

A loss of offsite power (LOOP) occurred at Pilgrim 2-1/2 h after the plant was shut down during a storm. Both emergency diesel generators (EDGs) started and powered the safety-related buses. Reactor core isolation cooling (RCIC) was manually started but tripped on overspeed when opening of the discharge isolation valve was delayed. Four min later, the RCIC inverter tripped because of a voltage transient caused by the start of a residual heat removal (RHR) pump. The inverter was reset in the control room, and RCIC operability was restored.

The conditional core damage probability estimated for this event is 1.2×10^{-4}. The relative significance of this event compared to other postulated events at Pilgrim is shown below.



Event Description

The reactor was shut down in response to severe storm conditions at 1710 hours on October 30, 1991. The main condenser vacuum had become degraded due to the storm wind and tide conditions in which seaweed was carried over from the intake structure onto the main condenser tubesheets. Reactor power was reduced to backwash the main condenser.

At 1942 hours, preferred offsite 345-kV power was lost, resulting in loss of the station startup transformer. A flashover had occurred on an insulator column on air circuit breaker (ACB) 104 due to salt deposit buildup on the insulator (see Fig.1). This caused ACBs 103, 104, and 105 to trip open, thereby deenergizing one of the two lines providing preferred offsite power. The second line was deenergized when ACB 102 tripped open in response to operation of relay 62/5, which is a time delay relay designed to respond to a stuck ACB 105. The operation of relay 62/5 was false since ACB 105 had opened as required by design. The cause of the ACB 105 stuck-breaker relay operation is unknown but is speculated to be either a random signal or self-excitation of the breaker through electrical noise coupling.

EDGs A and B started automatically following the loss of preferred power and successfully reenergized emergency buses and related AC-powered load center buses, motor control centers, and distribution panels. Eleven minutes after the loss of preferred offsite power, the secondary source of offsite power was lost when a storm-damaged tree fell onto the 23-kV line serving the shutdown transformer.

Following the loss of preferred offsite power, the RCIC turbine pump tripped due to mechanical overspeed. This resulted when the operator failed to open the RCIC injection valve promptly following the opening of the turbine steam inlet valve. Without a coolant flowpath for the RCIC, the turbine tripped within 4 s of actuation. The operator initially started to open the full flow test valve, realized this mistake, and closed the valve. This delayed the manual opening of the injection valve. In addition, the simulator allows ~15 s to open the valve before RCIC trip compared to 4 s on the plant.

The operator reset the turbine trip and manually restarted the RCIC. Four minutes after the initial RCIC trip, start of an RHR pump resulted in an overvoltage trip of the RCIC system inverter. The RHR pump start caused an AC voltage transient, which caused a DC voltage transient of 152.5-VDC on the 125-VDC system. This exceeded the inverter overvoltage setpoint of 150-VDC and tripped the inverter. Inability of the 125-VDC battery chargers to adequately regulate DC output under AC transient conditions resulted in the output overvoltage. The inverter trip prevented RCIC from attaining rated flow. The operators responded by manually shutting down the RCIC, resetting the inverter, and successfully restarting the system. The duration from the initial overspeed trip to successful resumption of the RCIC function was 5 min.

Two hours after the loss of preferred offsite power, the startup transformer was returned to service when ACB 102 was manually closed following a switchyard inspection and re-energization of a 345-kV line. The shutdown transformer was restored about 2.25 h after initial loss of secondary offsite power.

Additional Event-Related Information

Pilgrim 1 is a BWR with a Mark I pressure suppression containment. The unit has two dedicated diesel generators, two 125-V and one 250-V batteries. Fig. 1 shows the preferred offsite 345-kV power distribution system at Pilgrim.

The RCIC mission is to provide reactor coolant makeup during vessel isolation. The RCIC inverter converts 125-VDC to 120 VAC to power the RCIC flow control circuit and the test circuit power supply. With the inverter tripped, the RCIC can both start and continue to operate, but at minimum speed. The RCIC inverter can be reset and RCIC restored from the cont[illegible] room.

The source 125-VDC bus for the inverter is energized by a 125-VDC battery in parallel with a backup battery charger. The main battery charger, at the time of the event, was inoperable. The backup charger, by design, is required only to maintain the charging voltage within 0.5% from no load to full load with an AC supply voltage variation of 10%. The transient conditions encountered in the event were not addressed in the design specifications.

LER 293/91-006 reports a combined RCIC and HPCI trip due to inverter trips during a recirculation pump start. The pump was being started after an earlier lockout of one of the 4160-VAC emergency buses (see LER 293/91-005). Both inverters were reset in 9 min from the control room.

LER 293/91-021 described a change to an alarm response procedure, which specified required operator actions if the RCIC inverter trips. An extension of the 7-d RCIC system Limiting Condition for Operation (LCO) to 97 d had been requested by the utility on October 24, 1991, to allow testing to be conducted and modifications to be implemented to address the inverter problem. However, as a result of the October 30, 1991, event, RCIC inverter problems were to be resolved prior to startup.

Experience of multiple RCIC overspeed trips in transient conditions exists also at Pilgrim (see LER 293/90-013).

ASP Modeling Assumptions and Approach

The event has been modeled as a severe weather-related LOOP with RCIC unavailable but recoverable from the control room. A nonrecovery probability of 0.08 was assigned to RCIC. This addressed the potential for in-control-room recovery [p(nonrecovery ≈ 0.04)] from the two separate and unrelated RCIC unavailabilities that occurred during the event. The probabilities used for LOOP nonrecovery in the short-term and LOOP nonrecovery prior to battery depletion were also revised to reflect values associated with a severe weather-related LOOP (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989).

Analysis Results

The conditional core damage probability estimated for the event is 1.2×10^{-4}. The dominant sequence, highlighted on the following event tree, involves a LOOP with failure of emergency power and failure to recover AC power prior to battery depletion. The recoverable unavailability of RCIC did not significantly contribute to the core damage probability associated with the event.

Additional information concerning an associated event is included in LER 293/90-013 (see NUREG/CR-4674, Vol. 13).

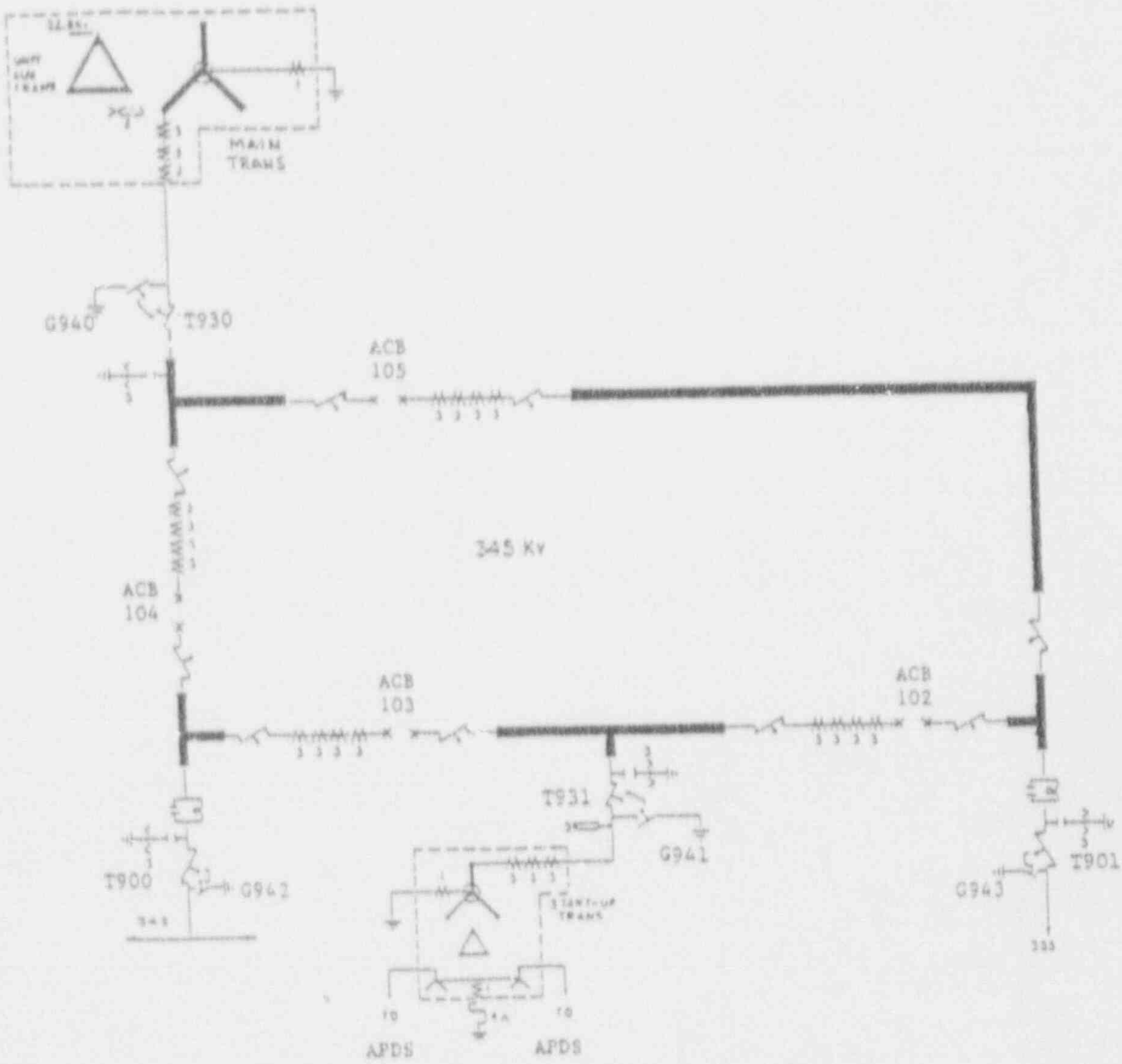
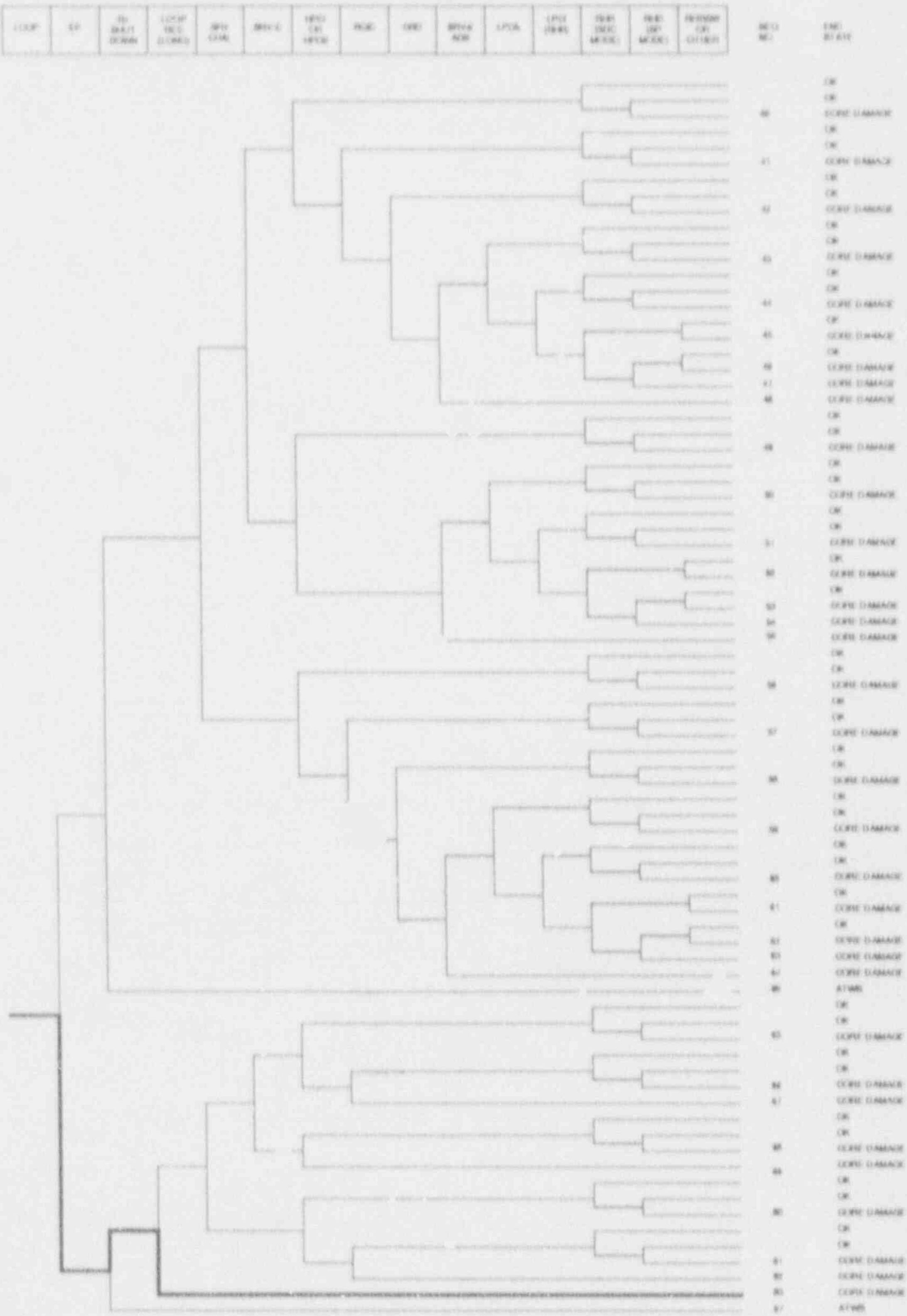


Fig. 1. Pilgrim 345-kV di tribution system



Dominant core damage sequence for LER 293/91-024

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 293/91-024
Event Description: Loss of Offsite Power and RCIC trip
Event Date: 10/30/91
Plant: Pilgrim 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	9.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	1.2E-04
Total	1.2E-04
ATWS	
LOOP	2.7E-05
Total	2.7E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
83	LOOP emerg.power -rx.shutdown/ep EP.REC	CD	1.1E-04	7.2E-01
40	LOOP -emerg.power -rx.shutdown srv.chall/loop.-scram -srv.close -hpci rhr(sdc) rhr(spcool)/rhr(sdc)	CD	4.8E-06	1.0E-01
98	LOOP -emerg.power rx.shutdown	ATWS	2.7E-05	9.0E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
40	LOOP -emerg.power -rx.shutdown srv.chall/loop.-scram -srv.close -hpci rhr(sdc) rhr(spcool)/rhr(sdc)	CD	4.8E-06	1.0E-01
98	LOOP -emerg.power rx.shutdown	ATWS	2.7E-05	9.0E-01
83	LOOP emerg.power -rx.shutdown/ep EP.REC	CD	1.1E-04	7.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\pilgrim.sll
PROBABILITY FILE: c:\asp\1989\bwr_csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail

Event Identifier: 293/91-024

trans	5.5E-04	1.0E+00	
LOOP	2.0E-05 > 2.0E-05	4.3E-01 > 9.0E-01	
Branch Model: 1OF/OR			
Initiator Freq:	2.0E-05		
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.''-01	1.0E+00	
srv.chall/trs.e,-scram	1.L 00	1.0E+00	
srv.chall/loop,-scram	1.0E+00	1.0E+00	
srv.close	1.3E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
EP.REC	3.1E-02 > 5.5E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	3.1E-02 > 5.5E-02		
fw/pcs.trans	2.9E-01	3.4E-01	
fw/pcs.loca	4.0E-02	3.4E-01	
hpci	2.9E-02	7.0E-01	
RCIC	6.0E-02 > 1.0E+00	7.0E-01 > 8.0E-02	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > Failed		
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci,rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci,rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Minarick
06-01-1992
08:52:49

Event Identifier: 293/91-024

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	1 OF 1 2

TITLE (4)

Loss of Preferred and Secondary Offsite Power Due to Severe Coastal Storm While Shutdown

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 NAMES	DOCKET NUMBER(S)
1 0	3 0	9 1	9 1	— 0 2 4 —	0 0	1 1	2 9	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

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

[ ]	20.402(b)	[ ]	20.405(c)	[X]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[ ]	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ]	20.405(a)(1)(iii)	[X]	50.73(a)(2)(i) (B)	[ ]	50.73(a)(2)(viii)(A)		
[ ]	20.405(a)(1)(iv)	[ ]	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Douglas W. Ellis - Senior Compliance Engineer	AREA CODE 5 0 8 — 7 4 7 - 8 1 6 0

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)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

On October 30, 1991 at 1942 hours a loss of preferred offsite 345 KV power occurred while shut down during a severe coastal storm. The loss of preferred offsite power resulted in designed responses including automatic actuations of the Reactor Protection System, Primary and Secondary Containment Isolation Control Systems, and Emergency Diesel Generators.

The cause of the loss of preferred offsite power was the flashover of a 345 KV switchyard insulator, and separate operation of a stuck breaker circuit. The flashover caused three switchyard air circuit breakers (ACBs) to open as designed. A fourth ACB opened about 1.4 seconds later (stuck breaker circuit) even though the r lated ACB opened as designed. The most probable cause of the stuck breaker circuit operation was 345 KV electrical noise coupled into the stuck breaker circuit. Corrective actions planned include the installation of a high speed recorder to monitor switchyard circuitry. A loss of the secondary source of offsite power occurred at 1953 hours and an Unusual Event was declared at 2003 hours. The cause of the loss of secondary offsite power (23 KV) was also storm related, when a tree fell onto a 23 KV line. Preferred offsite power was restored at 2142 hours and the Unusual Event was terminated at 2230 hours. The loss of preferred offsite power occurred about two and one-half hours after a shutdown with the reactor mode selector switch in the REFUEL position. The Reactor Vessel (RV) pressure was approximately 920 psig with the RV water temperature at 530 degrees Fahrenheit. This report is submitted in accordance with 10 CFR 50.73 subparts (a)(2)(i)(B) and (a)(2)(iv). These events posed no threat to the public health and safety.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 2 4 —	0 0	0 2 OF 1 2

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

BACKGROUND

A period of sustained dry northeasterly onshore winds (25-40 mph) began early on October 28, 1991 and continued until early October 30, 1991 when increased onshore winds (5 minute average speed of 51 - 56 mph) were experienced due to the combined effects of the northeasterly winds and the remnants of an offshore hurricane (Grace). The winds resulted in salt deposits on the 345 KV switchyard and insulators. The storm that produced the dry winds and resulting salt deposits on the switchyard insulators was rare. The rareness of the storm is important but more noteworthy is the period of the sustained dry northeastern onshore winds.

Seaweed was transported to the Intake Structure as a result of the winds and tides. Continuous operation of the traveling screens that are part of the Circulating Water System was necessary because of the seaweed. The Main Condenser vacuum gradually degraded as a result of the carryover of some of the seaweed onto the Main Condenser inlet tubesheets, and increased Circulating Water pump motor amperages were also noted. Reactor power was reduced to backwash the Main Condenser.

At 0521 hours, while lowering reactor power to backwash the Main Condenser, the Control Room received a Recirculation Pump Motor 'B' lower bearing low oil level alarm. After initial investigation of the oil level alarm, it was decided to shut down the recirculation pump. The Recirculation System 'B' motor-generator set/pump was shut down at 1154 hours while at approximately 47 percent reactor power. The shutdown was conducted in accordance with procedure 2.1.5 (Rev. 39) Attachment 1 Section G, "Controlled Shutdown With One Recirc Pump Out of Service". Drywell de-inerting began at 1210 hours in preparation of a Drywell entry to further investigate the oil level alarm. After the shutdown, the oil level was found to be slightly low, i.e. approximately 0.25 inch below the level existing near the end of the recent refueling outage (RFO 8). The oil consumption was not excessive when compared to the level of the Recirculation System Loop 'A' pump motor. Control rod drive scram timing began at 1355 hours.

At 1631 hours, 345 KV switchyard air circuit breakers (ACBs) 103 and 104 tripped open. ACBs 103 and 104 opened as designed (due to a line 342 disturbance) and were reclosed by 1640 hours with line 342 still in service. Located at the end of this report is a figure depicting a simplified single-line diagram of the 345 KV switchyard including the ACBs and Startup Transformer (SUT).

At 1645 hours the Main Condenser low vacuum alarm cleared. However, the Circulating Water System pumps 'A' and 'B' motor amperage remained high and the Main Condenser vacuum was still poor. Therefore, preparations for an earlier shutdown were initiated. The Feedwater System pump 'A' and Condensate System pump 'A' were shut down and the Feedwater Control System was put into single element control (reactor water level) by 1701 hours, and the Intermediate Range Monitors were inserted. At 1705 hours, the 4160 VAC Auxiliary Power Distribution System (APDS) buses including emergency Buses A5 and A6 were transferred from the Unit Auxiliary Transformer (UAT) to the SUT in accordance with Procedure 2.1.5.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 2 4 —	0 0	0 3 OF 1 2

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At 1710 hours, ACB 104 was manually opened via control switch in the Control Room and the reactor mode selector switch was moved to the SHUTDOWN position while at approximately 30 percent reactor power. These actions were taken in accordance with procedure 2.1.5 Attachment 1 section G. The movement of the mode switch to the SHUTDOWN position resulted in the expected Reactor Protection System (RPS) scram signal and scram. The scram resulted in expected designed responses that included a decrease in the Reactor Vessel (RV) water level, an automatic opening of ACB 105 and trip of the Turbine-Generator. The RV water level decrease was the normal response to the scram. The decrease, to approximately -14 inches, resulted in expected designed responses that included an actuation of the Primary Containment Isolation Control System (PCIS) and Reactor Building Isolation Control System (RBIS). At 1711 hours, Emergency Operating Procedure EOP-02 was entered because of the indicated position of some control rods and was exited at 1714 hours after verifying the inserted position of all control rods.

The PCIS actuation included the following designed responses:

- The inboard and outboard Primary Containment System (PCS) Group 2 (two)/Sampling System isolation valves that were open closed automatically.

- The inboard and outboard PCS Group 3 (three)/Residual Heat Removal (RHR) System isolation valves remained in the closed position.

- The inboard and outboard PCS Group 6 (six)/Reactor Water Cleanup (RWCU) System isolation valves closed automatically.

The RBIS actuation included the following designed responses:

- The inboard and outboard Secondary Containment System (SCS)/Reactor Building ventilation supply and exhaust dampers closed automatically.

- The SCS/Standby Gas Treatment System (SGTS) Trains 'A' and 'B' started automatically.

At 1716 hours ACB 103 tripped open automatically as designed (due to a line 342 disturbance) and ACB 104 (in the open position) remained open as designed. ACB 103 was manually closed via control switch in the Control Room at 1720 hours. At 1729 hours, the RPS was reset and the PCIS/RBIS was reset at 1800 hours. The RWCU System was returned to service, the Reactor Building dampers were reopened and the SGTS was returned to normal standby service. The Main transformer/345 KV switchyard mechanical disconnects (T930) were opened and ACBs 104 and 105 were closed via control switches in the Control Room at 1740 hours. By 1849 hours, scram recovery and RPS reset were complete. Main Condenser backwashing activities resumed at 1850 hours.

At approximately 1730 hours, the last of several pre-evolutionary briefings was conducted regarding the manual initiation of the High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System in the event of a loss of offsite power.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	0 2 4	0 0	0 6 OF 1 2

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

EVENT DESCRIPTION

On October 30, 1991 at 1942 hours, a loss of preferred offsite power (345 KV) occurred. The loss of preferred offsite power occurred when ACBs 103, 104 and 105 tripped open and ACB 102 tripped open approximately 1.4 seconds later. The SUT became de-energized because ACB 102 (line 355) and ACB 103 (line 342) were open. The loss of preferred offsite power resulted in the following:

- The APDS, energized by preferred offsite power via the SUT, became de-energized and resulted in the following:.
    - De-energizing/actuation of the RPS, PCIS, and RBIS that included:
        - Multiple concurrent RPS scram signals. The control rod drives remained in the inserted position.
        - PCIS (Groups 1,2,3, and 6) actuations that resulted in the automatic closing of PCS isolation valves that were open including the inboard and outboard Main Steam Isolation Valves (MSIVs) and Main Steam drain isolation valves. The closing of the MSIVs and drain isolation valves eliminated the Main Steam piping as a pathway for removing steam heat from the RV to the Main Condenser. The RV pressure was approximately 920 psig when the MSIVs and drain isolation valves closed.
        - RBIS actuation that resulted in the automatic closing of the inboard and outboard Reactor Building/SCS ventilation supply and exhaust dampers and automatic start of the SGTS Trains 'A' and 'B'.
- Emergency Diesel Generators (EDGs) 'A' and 'B' started automatically and re-energized emergency Buses A5 and A6, and related AC powered load center buses, motor control centers, and distribution panels.

At 1942 hours, the RCIC System was manually started for RV level control purposes. During the start of the RCIC System, an overspeed trip occurred and is separately reported via LER 91-025-00. While the overspeed trip was being manually reset, the HPCI System was manually started for RV pressure control purposes and the RHR System was started in the Suppression Pool Cooling (SPC) mode. After the RCIC turbine overspeed trip was manually reset, the RCIC inverter was found to be tripped and is separately reported via LER 91-025-00. The RCIC inverter was reset and the RCIC System was manually started in the injection mode for RV level control at 1947 hours.

At 1953 hours, the Shutdown Transformer (SDT), that is the secondary source of offsite (23 KV) power to emergency Bus A5 and A6, became de-energized. This, in conjunction with the earlier loss of preferred offsite power, resulted in a total loss of all offsite power and an Unusual Event was declared at 2003 hours.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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

At 2028 hours, Emergency Operating Procedure EOP-03 was entered due to the Suppression Pool bulk water temperature exceeding 80 degrees Fahrenheit (due to HPCI and RCIC turbine operation). A maximum Suppression Pool bulk water temperature of approximately 107 degrees Fahrenheit occurred at 2033 hours.

At 2030 hours, the HPCI and RCIC turbine-pumps tripped automatically as designed when the RV water level reached the high water level setpoint (calibrated at approximately +46 inches). At 2031 hours, the Main Steam/Target Rock two-stage relief valve RV-203-3B (pilot serial number 1040) was manually opened for pressure control in accordance with EOP-01 because the RV pressure was approximately 800 psig and increasing. The valve was manually closed at 2032 hours when the RV pressure was approximately 600 psig and decreasing. At 2033 hours, the HPCI and RCIC high water level isolations were reset and the HPCI System was manually started in the full flow test mode for RV pressure control and the RCIC System was manually started in the injection mode for RV water level control.

At 2142 hours, the SUT was returned to service when ACB 102 was manually closed via control switch in the Control Room. This action was taken after line 355 was re-energized by the regional power authority following a switchyard inspection and reset of protective relaying. This restored one source of preferred offsite power (345 KV line 355) to the SUT and APDS. The SDT was restored to service at 2210 hours. This restored the secondary source of offsite power (23 KV) to emergency Bus A5 and Bus A6.

At 2216 hours, safety-related 480 VAC Bus B6 was manually transferred from Bus B1 (powered by EDG 'A' via Bus A5) to Bus B2 (powered by EDG 'B' via Bus A6). Emergency Bus A5 was then transferred from EDG 'A' to the SUT. At 2225 hours, B6 was manually transferred from Bus B2 to Bus B1 (powered by the SUT via Bus A5). Bus A6 was then transferred from EDG 'B' to the SUT, and EDGs 'A' and 'B' were shut down. At 2230 hours, the Unusual Event was terminated and the RHR System loops 'A' and 'B' were put into service in the Suppression Pool Cooling (SPC) mode.

At 2335 hours, a PCIS Group 6/RWCU isolation signal occurred when the RWCU System was being returned to service. The event is separately reported via LER 91-026-00. The PCIS was reset and the RWCU System was returned to service by 2339 hours. At 2336 hours, the Suppression Pool water level was noted as exceeding -3 inches and a Limiting Condition for Operation (LCO A91-277) was entered. The LCO was terminated on October 31, 1991 at 0549 hours when the level was less than -3 inches (LR-5038).

On October 31, 1991 at 0026 hours, the PCIS Group 1 (one) circuitry was reset and the MSIVs were re-opened. This restored the Main Steam piping as a steam pathway from the RV to the Main Condenser. The HPCI System was removed from RV pressure control and shut down at 0029 hours. The RCIC System was removed from RV level control and shut down at 0035 hours. The Main Condenser mechanical vacuum pump was placed into service at 0041 hours.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
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At 0248 hours, a PCIS Group 6/RWCU isolation signal occurred when the position of the RWCU System valve MO-1201-85 was being adjusted. The event is separately reported via LER 91-026-00. The PCIS was reset and the RWCU System was returned to service by 0254 hours.

By 0257 hours, the RV pressure was reduced to less than 150 psig (146 psig) and the RHR System/Shutdown Cooling (SDC) suction piping high pressure isolation signal (calibrated at approximately 122 psig) cleared at 0340 hours.

By 0421 hours, the Suppression Pool water level had decreased to -4.5 inches (LR-5038) and EOP-03 (Suppression Pool water temperature) was exited at 0423 hours. At 0433 hours, the RHR System pump 'B' was shut down from the SPC mode of operation.

By 0927 hours, the RV pressure had decreased to approximately zerr psig. At 1000 hours, the Main Steam drain line isolation valves were opened.

At 1632 hours, an RHR Loop 'B' pump was started for the SDC mode of operation, and by 1643 hours the RWCU System inlet water temperature (i.e. RV water temperature) was less than 212 degrees Fahrenheit and cold shutdown was achieved at that time. The other RHR Loop 'B' pump was also started for the SDC mode at 1700 hours.

The RV head vent valves were opened at 2500 hours.

Failure and Malfunction Report (F&MR) 91-446 was written to document the loss of secondary offsite power and F&MR 91-447 was written to document the loss of preferred offsite power and Unusual Event. The NRC Operations Center was notified of the Unusual Event in accordance with 10 CFR 50.72 on October 30, 1991 at 2007 hours. A followup telephone call to the NRC Operations Center was made on October 31, 1991 at 1915 hours to ensure the communications on October 30, 1991 at 2007 had been recorded correctly. F&MR 91-466 was written to document the Suppress:on Pool water level exceeding -3 inches. Other F&MRs were written to document related events that occurred.

CAUSE

The causes and related corrective actions for the loss of preferred and secondary offsite power are separately described as follows:

1. Loss of Preferred Offsite Power (345 KV)

The 345 KV tranmission system (lines 342 and 355), 345 KV switchyard, Main Transformer, and SUT are equipped with protective primary, secondary, and backup (local and remote) relaying. This relaying consists of distance, high speed, fault detection (phase, phase to phase, phase to ground), stuck breaker (ACBs 102, 103, 104, 105), transfer trip, 345 KV bus differential, SUT differential (ACBs 102 and 103), Main Transformer differential (ACBs 104 and 105), and Turbine/Generator lock out (ACBs 104 and 105).

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

ACBs 103, 104, and 105 tripped open and line 342 became de-energized (via a transfer trip signal to remote switching devices) because of a flashover that occurred on a 345 KV insulator column on ACB 104. The flashover was the result of environmental conditions, i.e. salt deposits on the insulator, and the equipment functioned as designed in response to the flashover. The opening of ACB 103 and de-energizing of line 342 removed line 342 as one source of preferred offsite power to the SUT and left line 355 as the only source of preferred offsite power to the SUT via ACB 102.

Approximately 1.4 seconds after ACBs 103, 104, and 105 tripped open, time delay relay 62/5 (ACB 105 stuck breaker time delay relay) operated. The ACB 105 stuck breaker scheme is designed to generate a trip signal to ACBs 102 and 104 and to devices at the offsite (remote) end of line 355. Relay 62/5 is a Westinghouse type TD-50 time delay relay (set at 100 milli-seconds). The operation of relay 62/5 satisfied the protective circuit logic that generated a trip signal for ACBs 102 and 104 (already open) and devices at the remote (offsite) end of line 355. ACB 102 opened as designed, and line 355 became de-energized as designed as a result of remote switching.

Because ACB 105 opened as designed and was not slow in opening, the reason for operation of the ACB 105 stuck breaker circuitry was investigated. Remote, offsite fault analysis equipment indicated only one fault (flashover on the ACB 104 insulator column) occurred. The root cause investigation on the ACB 105 stuck breaker circuit operation consisted of circuit analysis, component testing, individual relay testing, ACB 105 timing tests, overall relay and ACB system functional timing tests, and special tests of relays 62/5 and 50/5 (Westinghouse type SI) in the ACB 105 stuck breaker circuit. Except for a filter capacitor, all of the tests confirmed the components functioned as designed. The filter capacitor was found to have a loose connection that was subsequently tightened. The capacitor is designed to protect relays 62/5 and 50/5 from voltage transients or interference on the switchyard 125 VDC control power supply.

The loose connection cou d have allowed the relays to be susceptible to interference with a potential for false operation of relay 62/5. The root cause for the ACB 105 stuck breaker circuit operation is believed to be either a random signal of unknown origin or the infrequent development of some sequence of 345 KV transmission system electrical events which results in self excitation of the stuck breaker circuit through noise coupling. Typically, these conditions require special monitoring to identify and remedy the cause of the condition. A high speed recorder will be purchased and installed to monitor applicable switchyard circuitry. The installation of the recorder is expected to be completed in January 1992. To preclude the potential for future improper operations of relay 62/5, the relay will be replaced. The replacement is expected to be completed in December 1991. Also, a possible modification of the stuck breaker circuitry is being explored to reduce the susceptibility of false stuck breaker circuit operation.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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

The ACB 104 insulator flashover (which initiated the opening of ACBs 103, 104, and 105) was the first switchyard flashover since the insulators were treated with a covering (Sylgard) in the summer of 1987. Since that treatment, a significant reduction in insulator corona during adverse weather conditions has been noted. After the storm, the switchyard was inspected for evidence of flashover damage and no damage was found. The switchyard insulators were washed to remove salt deposits before Pilgrim Station was returned to commercial service.

2. Loss of Secondary Offsite Power (23 KV)

The SDT became de-energized as a result of electrical protection devices that actuated the SDT lockout relay. The lockout relay actuated because of a sensed fault on the offsite 23 KV distribution system. The direct cause was the environmental effects of the storm, i.e. winds that damaged trees, including one tree that fell onto the 23 KV line that powers the SDT. The tree was located on Pilgrim Station property between the 23 KV distribution system and the SDT. Corrective action taken included the removal of the fallen tree. Long term corrective action planned includes periodic inspection of trees along the 23 KV lines on Pilgrim Station property for pruning or removal.

SAFETY CONSEQUENCES

These events posed no threat to the public health and safety.

The Standby AC Power (4160 VAC) System consists of EDGs 'A' and 'B' that are self-contained and independent of the offsite power sources. The safety objective of the Standby AC Power System is to provide a single failure proof source of onsite AC power adequate for the safe shutdown of the reactor following abnormal operational transients and postulated accidents. A loss of all offsite power is described in the UFSAR Chapter 14. The Chapter 14 analysis bounds the analyses in the UFSAR Appendix R that includes a loss of all offsite power to station auxiliaries. The EDGs started and provided power to Buses A5 and A6, and the related electrical system in response to the loss of power to Bus A5 and Bus A6.

The Core Standby Cooling Systems (CSCS) consist of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and the RHR/LPCI mode. The HPCI System provides water to the RV for high pressure core cooling. Although not part of the CSCS, the RCIC System is capable of providing water to the RV for high pressure core cooling, similar to the HPCI System. The ADS is a backup to the HPCI System and functions to reduce RV pressure to enable low pressure core cooling provided independently by the Core Spray System and the RHR/LPCI mode. The CSCS were operable.

The highest RV water level that occurred was approximately +55 inches. The level was less than the level (+112 inches) corresponding to the bottom of the Main Steam piping. The lowest RV water level that occurred was approximately -14 inches. The level was greater than the level corresponding to the CSCS low-low water level setpoint (calibrated at approximately -45 inches) and the level (-127.5 inches) corresponding to the top of the active fuel zone.

The highest Suppression Pool bulk water temperature that occurred was approximately 107 degrees Fahrenheit which occurred after the shutdown. The temperature was less than the maximum water temperature (120 degrees Fahrenheit) specified by Technical Specification 3.7.A.1.h during RV isolation conditions.

The highest Suppression Pool water level that occurred was approximately -1 inch (LR-5038). The level was less than the level corresponding to the maximum Suppression Pool volume of 94,000 cubic feet specified by Technical Specification 3.7.A.1.b. A Suppression Pool volume of 94,200 cubic feet corresponds to a level of +6 inches (LR-5038/5049) or 139 inches (LI-1001-604A/B). The level was also less than the settings of the level switches (LS-2351A/B) that control the Suppression Pool/HPCI pump suction valves.

Technical Specification 3.7.A.1.m specifies the Suppression Pool/Chamber be maintained between -6 to -3 inches which corresponds to a downcomer submergence of 3.00 and 3.25 feet, respectively. A Suppression Pool level of -1 inches corresponds to a downcomer submergence of 3.42 feet. The specified downcomer submergence values were based, in part, on reactor operation at full pressure conditions (i.e., approximately 1035 psig). The maximum RV pressure during the period when the Suppression Pool level was greater than -3 inches was approximately 600 psig (decreasing). The water level was decreased to less than -3 inches in approximately six hours. The Suppression Pool water level is logged daily in accordance with Procedure 2.1.15 (currently Rev. 87), "Daily Surveillance Log", Attachment 1 (daily log test #15). As part of this test, the Suppression Pool water level is verified to be greater than -6 inches and less than -3 inches (LR-5038/LR-5049).

This report is submitted in accordance with 10 CFR 50.73(a)(2)(iv) because of the automatic actuations of the RPS, PCIS, RBIS, and EDGs after the shut down.

This report is also submitted in accordance with 10 CFR 50.73(a)(2)(i)(B) because the Suppression Pool level of -1 inch, although less than the level corresponding to the maximum Suppression Pool volume of 94,000 cubic feet, was greater than the level corresponding to a maximum downcomer submergence of 3.25 feet.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) submitted since January 1984. The review focused on LERs involving a loss of preferred offsite power, or stuck breaker circuit operation. The reviewed identified LERs 89-010-00, 87-014-01, 87-005-00, 86-029-00, and 86-027-01 that involved a loss of preferred offsite power. LER 87-014-01 also involved operation of the ACB 104 stuck breaker circuit.

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

For LER 89-010-00, a loss of preferred offsite power (345 KV) occurred while shut down on February 21, 1989 at 0450 hours. At the time of the event, lines 342 and 355 were in service and powering the SUT via ACBs 102 and 103, and secondary offsite power (23KV) was available via the SDT. The loss of preferred offsite power occurred when ACBs 102 and 103 tripped open because of a cable fault in the underground portion of one of the SUT phase 'C' power cables between the secondary side ('X' winding) of the SUT and nonsafety-related 4160 VAC Bus A4. The fault actuated the differential ground current relay that tripped lockout relay 186-4 and caused ACBs 102 and 103 to open. The EDGs started automatically and supplied power to the emergency buses and related electrical system. The cause of the cable failure was cable jacket damage during original cable installation. Corrective action taken included replacement of the failed section of cable.

For LER 87-014-01, a loss of preferred offsite power (345 KV) occurred while shut down during a severe storm on November 12, 1987 at 0206 hours. Just prior to the event, ACBs 102, 103, 104, and 105 were in the closed position, and transmission lines 342 and 355 were in service and powering the SUT. The SDT was not in service because of modification activities related to the blackout diesel generator. The event occurred as a result of a line 342 ground fault at 0205 hours and a line 355 fault approximately one minute later. The line 342 fault resulted in the opening of ACBs 103 and 104. ACB 104 opened slowly and caused the ACB 104 stuck breaker circuitry to operate and caused ACB 105 to open and a transfer trip signal to the remote (offsite) end of line 342. ACB 102 remained closed during that sequence (0205 hours) but tripped open approximately one minute later. The EDGs started automatically and supplied power to the emergency buses and related electrical system. ACB 102 opened as a result of the SUT differential protection circuitry. The circuitry operated because of an increasing voltz-per-hertz condition that tripped the differential protection relay. The relay functioned properly to lock out ACB 103 (already open) and to trip open ACB 102. The cause of the loss of preferred offsite power was a series of storm related faults in the 345 transmission system (lines 342 and 355) remote from the switchyard.

For LER 87-005-00 a loss of preferred offsite power (345 KV) occurred while shut down during a storm on March 31, 1987 at 0845 hours. Just prior to the event, ACBs 103, 104, and 105 were in service. ACB 102 was tagged open for maintenance and was not in service. The 345 KV transmission lines 342 and 355 were in service and the SUT was in service providing power to the APDS except for Bus A6 that was tagged out of service for maintenance. EDG 'A' was in standby service and EDG 'B' was tagged out of service for maintenance. The EDG 'A' started automatically and supplied power to emergency Bus 'A' and the related electrical system. The loss of preferred offsite power occurred when ACBs 103 and 104 tripped open as a result of an offsite line 342 fault due to a broken static line. The location where the static line fell onto the 345 KV line 342 conductors was several miles from the switchyard. The broken static line was attributed to high winds and rain from the storm.

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

For LER 86-029-00, a loss of preferred offsite power (345 KV) occurred while shut down on December 23, 1986 at 1120 hours. At the time of the event, a de-energized switchyard phase 'C' insulator located between ACB 104 and disconnect 104B was being washed. The insulator washing was being conducted with ACBs 103 and 104 open, and the SUT was being powered from line 355 via ACB 102. During the washing of the insulator, overspray onto an energized switchyard insulator caused a loss of line 355 and the SUT became de-energized. EDG 'A' started and powered Bus A5 and the related electrical system. EDG 'B' had been removed from service and did not start, and the SDT re-energized Bus A6 and related electrical system. The root cause was a wind change causing overspray from the insulator washing to be carried over to energized insulators.

For LER 86-027-01, a loss of preferred offsite power (345 KV) occurred during a severe storm while shut down on November 19, 1986. Prior to the event the SUT was powered from lines 342 and 355 that were in service, and the SDT was in service. At 0819 hours, ACBs 103, 104, and 105 tripped open. At 0840 hours, ACB 102 tripped open and the SUT became de-energized at that time. The EDGs started and supplied power to the emergency buses and related electrical system. Subsequent investigation and inspections determined the most probable cause of the loss of preferred offsite power to have been arcing of the high voltage (345 KV transmission) lines due to ice and snow.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Breaker (ACBs)	BKR
Capacitor	CAP
Insulator	INS
Relay, Instantaneous Overcurrent (50/5)	50
Relay, Time-Delay Stopping or Opening (62/5)	62
Transformer	XFMR

SYSTEMS	
Condenser System	SG
Containment Isolation Control System (PCIS/RBIS)	JM
Engineered Safety Features Actuation System (PCIS, RBIS, RPS)	JE
Emergency Onsite Power System (EDGs)	EK
Heat Rejection System (Circulating Water System)	KE
Main Steam System	TA
Medium Voltage Power System (4.16 KV)	EA
Plant Protection System (RPS)	JC
RWCU System	CE
Standby Gas Treatment System (SGTS)	BH
Switchyard System (345 KV)	FK

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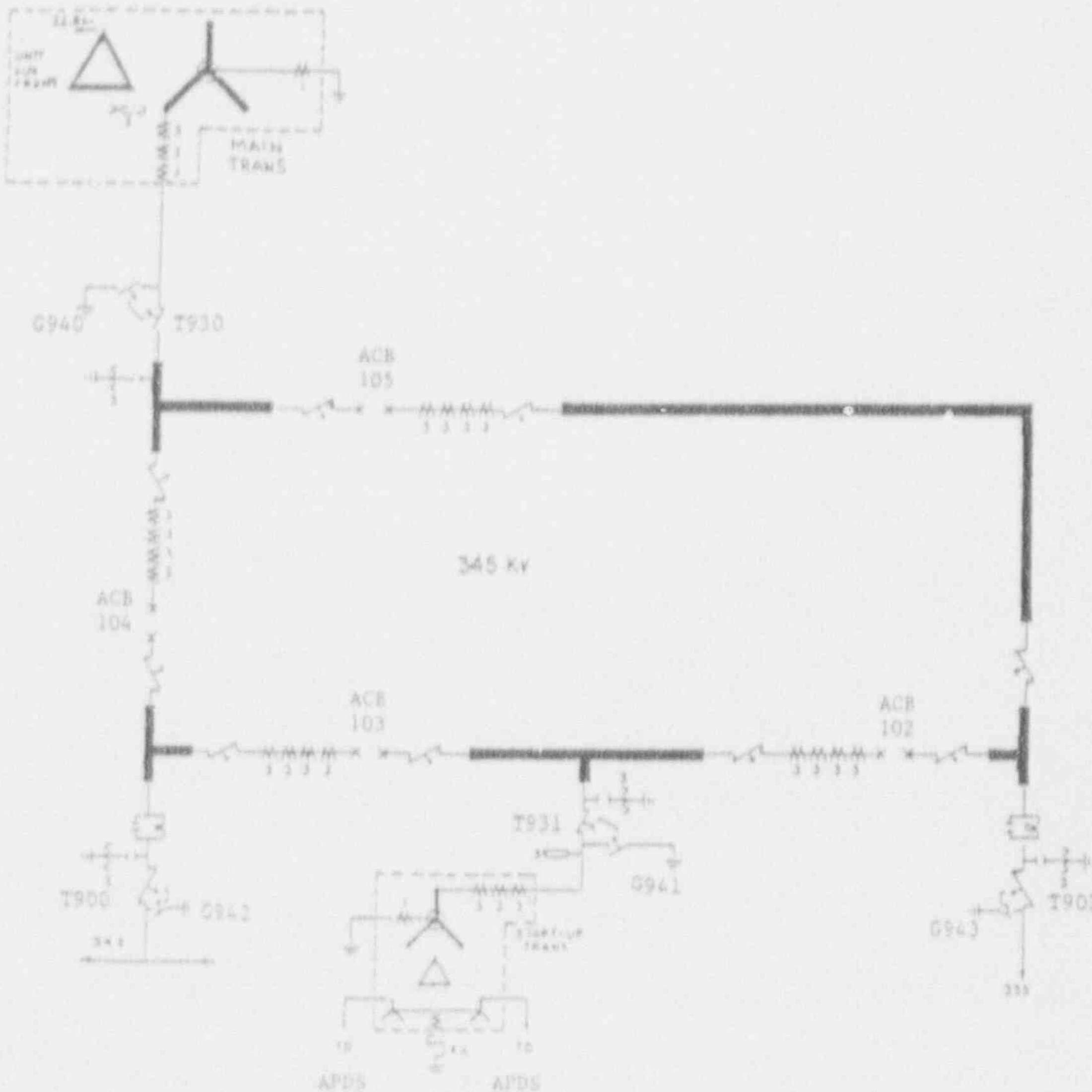
TEXT (If more space is required, use additional NRC Form 366A's) (17)



MAY 13 1991

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FACILITY NAME (1): Pilgrim Nuclear Power Station

DOCKET NUMBER (2): 0 5 0 0 0 2 9 3 | PAGE (3): 1 OF 0 4

TITLE (4): High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Became Inoperable Due to Tripped Inverters

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 NAMES	DOCKET NUMBER(S)
0 3	2 6	9 1	9 1	0 0 6	0 0	0 4	2 4	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 3 0

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

X 50.73(a)(2)(v) (D)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Gary J. Basilesco - Senior Compliance Engineer

TELEPHONE NUMBER: AREA CODE 5 0 8 | 7 4 7 - 8 5 3 4

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): YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

JUN 18 1991

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

On March 26, 1991 when starting the 'B' Reactor Recirculation Pump, the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) System inverters tripped on high voltage. The HPCI and RCIC Systems were inoperable for nine minutes. The cause of the inverter trips was a voltage fluctuation that occurred during pump start. The load required by the pump start caused the battery charger that supplies DC voltage to the inverters to overcompensate resulting in a voltage surge. The trip setpoint of the inverters was exceeded during this surge.

Corrective action was taken to reset the inverters. An engineering evaluation has been initiated to investigate enhancements to preclude the inverters from tripping as a result of large pump starts. Interim measures will include an administrative change to caution operations personnel that the potential for inverter trips exists. The inverters were manufactured by Topaz Electronics, Model No. 125-GH-125 (60).

The event occurred at power operation with the reactor mode selector switch in the RUN position. The Reactor Vessel (RV) pressure was approximately 956 psig and the RV water temperature was 542 degrees Fahrenheit. The reactor power level was 30 percent. This report is submitted in accordance with 10 CFR 50.73(a)(2)(v)(D) and the event posed no threat to the public health and safety.

9104290246

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

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

EVENT DESCRIPTION

On March 26, 1991 at 0043 hours when starting the 'B' Reactor Recirculation Pump, the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) System inverters tripped on high voltage. This made the HPCI and RCIC Systems inoperable. The Recirculation Pump was being started because of a prior event that resulted in a lockout of the emergency 4160 volt bus A-6 and subsequent trip of the 'B' Recirculation Pump (see LER 91-005-00 for details). The pump was started in accordance with Procedure 2.2.84 (Rev. 33), "Reactor Recirculation System". The inverters tripped when the pump was started and the inverter failure alarms were received at control room panels 903C and 904L for HPCI and RCIC, respectively.

Corrective action was taken to reset the inverters at 0052 hours at the associated panels in the Control Room. Failure and Malfunction Report 91-103 was written to document the event. The NRC Operations Center was notified as required by 10CFR 50.72 on April 10, 1991 at 0927 hours. The late call was made because at the time the inverters tripped, the HPCI and RCIC Systems were not considered inoperable. A Limiting Condition of Operation was not entered as the inverters were promptly reset, nine minutes after tripping.

The event occurred at power operation with the reactor mode selector switch in the RUN position. The Reactor Vessel (RV) pressure was approximately 956 psig and the RV water temperature was 542 degrees Fahrenheit. The reactor power level was approximately 30 percent.

CAUSE

The cause of the inverter trips was a fluctuation of the input DC voltage that resulted when the 'B' Recirculation Pump was started. A reduction in voltage occurred on the 4160V AC bus A-6 due to the load demand caused by the pump start. This also caused a voltage reduction on the 480V AC buses that feed the battery chargers. The battery chargers supply DC power to the HPCI and RCIC inverters. The battery charger maintains a constant DC output provided the AC input does not vary by more than ± 10 percent. When the Recirculation Pump was started, the input voltage to the chargers went below its 10 percent input voltage margin. With the input voltage reduced the battery charger output voltage was also reduced. The battery charger responded by overcompensating for the low output voltage. This resulted in a voltage surge thereby causing the inverters to trip.

The trip range of the inverters was not sufficient to endure the transient. The inverters are calibrated to trip at approximately 140V DC. Values obtained from plant recorders at the time of the trips were 145V and 149V DC for the HPCI and RCIC inverters, respectively. The inverters convert 125V DC power to AC power for the HPCI and RCIC flow controllers and square root converters. With the inverters tripped, the systems would not automatically reach rated speed nor full flow conditions. The inverters were manufactured by Topaz Electronics, Model No. 125-GH-125 (60).

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 0 6	— 0 0	0 3 OF 0 4

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

CORRECTIVE ACTION

Immediate corrective action was to follow the Alarm Response Procedures (ARPs) 903C and 904L for the trip of the HPCI and RCIC inverters. The applicable breakers in distribution panels D4 and D5 were checked to verify 125V DC power was available to the inverters, and the inverters were reset at 0052 hours.

An Engineering Service Request (91-249) was generated to investigate adjusting the trip setpoints on the inverters or installing an inverter that can accommodate such voltage fluctuations. In addition, the battery charger response with respect to AC supply voltage fluctuations is being evaluated. An update to this report will be submitted if significant new information becomes available.

Interim measures to be taken include a change to Procedure 2.2.84 to caution operations personnel of the potential for inverter trips when placing the Recirculation Pumps in service. The procedure will require the operators to promptly reset the inverters as required by the ARP. With regards to the late notification to the NRC Operations Center, a night order was issued to instruct the operators that when the HPCI and RCIC inverters trip the systems are to be considered inoperable until the circuitry is reset. The appropriate notifications will be made.

SAFETY CONSEQUENCES

The event posed no threat to the public health and safety.

The trip of the HPCI and RCIC inverters was the designed response. The inverters were reset nine minutes after tripping. If the systems were required to function during the nine minutes, the circuitry could have been reset immediately and the systems would have been available.

During the time HPCI and RCIC were inoperable due to the tripped inverters, the automatic actuation of the Automatic Depressurization System was capable of reducing the Reactor Vessel pressure for low pressure cooling provided independently by the Core Spray System and Residual Heat Removal System/Low Pressure Coolant Injection mode.

The report is submitted in accordance with 10 CFR 50.73(a)(2)(v)(D) because the HPCI and RCIC Systems became inoperable.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	0 0 6	0 0	0 4 OF 0 4

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

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) issued since January of 1984. The review focused on LERs where HPCI and/or RCIC became inoperable due to tripped inverters. The review revealed one similar event. LER 85-029-00 involved receipt of the HPCI inverter circuitry failure alarms and an ATWS trouble alarm in the Control Room. It was determined that the HPCI inverter and the breaker feeding the ATWS inverter had tripped. Immediate corrective action was to reset the HPCI inverter and ATWS breaker. The cause of the trips was determined to be a fluctuation of the input DC voltage.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Inverter	INVT
Charger, battery	BYC

SYSTEMS

High Pressure Coolant Injection (HPCI) System	BJ
Reactor Core Isolation Cooling (RCIC) System	BN
Low Voltage Power System (480V AC)	EC
DC Power System	EI

NRC FORM 366 — U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104

[illegible]

FACILITY NAME (1)	Pilgrim Nuclear Power Station
DOCKET NUMBER (2)	0 5 0 0 0 2 9 3
PAGE (3)	1 OF 0 5
TITLE (4)	Reactor Core Isolation Cooling System Declared Inoperable Due to Insufficient Battery Charger Test

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
1 0	0 9	9 1	9 1	0 2 1	0 0	1 1	0 8	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9)	N
POWER LEVEL (10)	1 0 0
THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (11)	X 50.73(a)(2)(v) (D)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Douglas W. Ellis - Senior Compliance Engineer	5 0 8 747-8160

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
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On October 9, 1991 at 1802 hours, the Reactor Core Isolation Cooling (RCIC) System was declared inoperable and a seven day Limiting Condition for Operation (LCO) began at that time. The system was declared inoperable because sufficient test data was not available to demonstrate that sufficient margin to the RCIC inverter trip setpoint existed if a 125 VDC Bus 'A' voltage transient were to occur. The DC voltage transient is possible if an AC voltage transient of sufficient magnitude occurs at the input of the 125 VDC battery charger. The 125 VDC Battery 'A' and backup battery charger were in service supplying power to the RCIC inverter via 125 VDC Bus 'A' when this condition was identified.

The RCIC System was maintained in the normal standby mode and was not removed from service as a result of declaring the system inoperable. A written request for relief from the requirement to shut down on October 16, 1991 because of this condition was granted by the NRC on October 16, 1991. Compensatory measures were implemented as a result of this condition. The plant was shut down on October 30, 1991 for reasons unrelated to the RCIC System LCO. Corrective action planned consists of testing and/or the implementation of modifications to preclude unacceptable voltage transients from occurring on the 125 VDC Bus 'A'.

This condition was identified during power operation with the reactor mode selector switch in the RUN position. The reactor power level was 100 percent. The Reactor Vessel (RV) pressure was 1028 psig with the RV water temperature at 548 degrees Fahrenheit. This report is submitted in accordance with 10 CFR 50.73(a)(2)(v)(D) and this condition posed no threat to the public health and safety.

NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST. SEE HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH, U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	0 2 1	0 0	0 2 OF 0 5

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

BACKGROUND

The Reactor Core Isolation Cooling (RCIC) System safety objective is to provide makeup water to the reactor vessel following reactor vessel isolation in order to prevent the release of radioactive materials to the environs as a result of insufficient core cooling. The system is required to operate automatically to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised. The RCIC System is designed to cope with a control rod drop accident, a loss of feedwater flow transient, and a loss of offsite power transient. Each of the events results in an isolated reactor vessel with no breach of the primary pressure boundary. Reactor water level will drop as a result of the initiating events followed by a "boil down" as the Safety Relief Valves (SRVs) relieve on high pressure. The RCIC System is designed to automatically restore level by providing flow in excess of the boiling rate. Technical Specification 3.5.D requires that the RCIC System be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig, and reactor coolant temperature is greater than 365 degrees Fahrenheit.

The RCIC inverter converts 125 VDC (nominal) to 120 VAC to power a square root converter and flow controller in the RCIC flow control circuit and the test circuit power supply. With the inverter tripped, the RCIC System could start and operate at minimum speed. An inverter trip would not prevent system initiation or cause a trip during RCIC System operation. The capability for subsequent restoration of RCIC System flow control is available to the operator in the Control Room. The RCIC inverter is powered from the 125 volt DC Bus 'A'. The 125 VDC Bus normally receives power from 125 VDC Battery 'A' in parallel with a battery charger. AC voltage transients of sufficient magnitude at the input of the 125 VDC battery charger can cause DC voltage transients at the output of the battery charger. DC voltage transients in excess of the setpoint can cause the RCIC inverter to trip.

EVENT DESCRIPTION

On October 9, 1991 at 1802 hours, the RCIC System was declared inoperable and a seven day Technical Specification 3.5.D.2 Limiting Condition for Operation (LCO) began at that time. The RCIC System was declared inoperable because sufficient test data for the backup 125 VDC battery charger was not available to ensure the RCIC inverter would not trip if a normal AC voltage transient were to occur. At the time the RCIC System was declared inoperable, the 125 VDC Battery 'A' in parallel with the backup battery charger were supplying power to the RCIC inverter via 125 VDC Bus 'A'.

This action was taken as a result of Nuclear Engineering Department evaluation regarding additional test data needed to supplement 125 VDC battery charger test data collected while shut down during the recent refueling outage (RFO 8). The data was collected as part of corrective actions resulting from a trip of the High Pressure Coolant Injection (HPCI) and RCIC inverters that was reported via LER 91-006-00.

Failure and Malfunction Report 91-423 was written to document this condition. The NRC Operations Center was notified in accordance with 10 CFR 50.72 on October 9, 1991 at 1811 hours. The RCIC System was maintained in its normal standby mode and was not removed from service as a result of declaring the system inoperable.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: ... HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

This condition was identified during power operation with the reactor mode selector switch in the RUN position. The Reactor Vessel (RV) pressure was 1028 psig with the RV water temperature at 548 degrees Fahrenheit. The 125 VDC Battery 'A' and 125 VDC backup battery charger were in service powering 125 VDC Bus 'A'. The 125 VDC battery charger 'A' was not in service.

A request for relief from a shut down specified by Technical Specification 3.5.D.2 was submitted to the NRC on October 15, 1991 (BECo Letter 91-300). The relief was requested prior to 1800 hours on October 16, 1991 to preclude an unnecessary shut down of Pilgrim Station due to the seven day LCO that began on October 9, 1991 at 1802 hours. Discretionary enforcement was granted by the NRC for an additional 24 hours on October 16, 1991 at 1620 hours. The request was granted by the NRC on October 17, 1991 at 1102 hours until such time the NRC could act upon an exigent Technical Specification change request to extend the RCIC System LCO for the RCIC inverter.

CAUSE

The 125 VDC Battery 'A' and backup 125 VDC battery charger were supplying power to the RCIC inverter via the 125 VDC Bus 'A' when this condition was identified. Extrapolated test data from the 125 VDC battery charger 'A' and backup 125 VDC battery charger indicated the RCIC inverter trip setpoint would not be reached. However, because sufficient test data for the backup battery charger was not available to demonstrate that sufficient margin to the inverter trip setpoint existed, the RCIC System was declared inoperable.

When this report was prepared, the root cause and related corrective actions were to be identified in an update of LER 91-006-00. However, on October 30, 1991 at approximately 1946 hours, after a shut down for reasons unrelated to the RCIC System LCO, a RCIC inverter trip occurred. The inverter trip will be separately reported via LER 91-025-00. The root cause, therefore, will be included in LER 91-025-00 instead of an update of LER 91-006-00.

COMPENSATORY MEASURES

The following compensatory measure has been implemented. Whenever the RCIC inverter trips, as indicated by Control Room Panel C-904L annunciator I4, "RCIC Inverter Failure", the licensed operator will immediately perform section 3 (three) of the alarm response procedure ARP-904L alarm window I4. The operator actions include transferring the RCIC controller to manual, adjusting the flow controller to minimum, resetting the RCIC inverter, and transferring the flow controller to the desired mode.

CORRECTIVE ACTION

The alarm response procedure ARP-904L for alarm window I4 was changed (SRO 91-196). The change identifies specific operator actions to take if the RCIC inverter trips when the RCIC System is operating or is in the standby mode.

NRC FORM 366A (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR / SEQUENTIAL NUMBER / REVISION NUMBER		PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1 — 0 2 1 — 0 0		0 4 OF 0 5

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

A proposed change to Technical Specification 3.5.D.2 under exigent circumstances was submitted to temporarily extend the seven day RCIC System LCO to 97 days for the RCIC inverter trip concern. The proposed change was submitted on October 24, 1991 (BECo Letter 91-136). The extension would have permitted testing to be conducted or modifications to be implemented. However, the plant was shut down on October 30, 1991. Therefore, the proposed change is no longer valid and will be withdrawn.

When this report was prepared, corrective action planned consisted of modifications and/or testing. The purpose of the modifications was to preclude normal AC voltage transients from causing unaceptable DC voltage transients, i.e. affecting the capability of the RCIC System to perform its intended function. The purpose of the testing was to ensure normal AC voltage transients would not cause unacceptable DC voltage transients. The modifications and/or testing were expected to be completed by January 14, 1992.

As a result of the shut down that occurred on October 30, 1991, the previously mentioned modifications and/or testing will be completed prior to startup.

SAFETY CONSEQUENCES

This condition posed no threat to the public health and safety.

The Core Standby Cooling Systems (CSCS) consist of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and Residual Heat Removal (RHR) System/Low Pressure Coolant Injection (LPCI) mode. The design of the CSCS includes provision for high and low pressure core cooling. The HPCI System is tested for operability at least monthly and was operable. In the unlikely event a HPCI System failure had occurred when its operation was necessary, an automatic (or manual) actuation of the ADS would reduce the Reactor Vessel pressure for low pressure core cooling provided independently by the Core Spray System and RHR System/LPCI mode.

This report is submitted in accordance with 10 CFR 50.73(a)(2)(v)(D) because the RCIC System was declared inoperable.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) issued since January 1984. The review focused on LERs involving the RCIC System being declared inoperable or becoming inoperable due to a RCIC inverter trip. The review identified a previous event reported via LER 50-293/91-006-00.

For LER 91-006-00, the RCIC inverter and HPCI inverter tripped during power operation on March 26, 1991 at 0043 hours. The inverters tripped when the Recirculation System Loop 'B' motor-generator set/pump was restarted. At the time of the event, the 125 VDC Battery 'A' and Battery Charger 'A' were supplying power to the RCIC inverter via 125 VDC Bus 'A'. The 125 VDC Battery 'B' and the 125 VDC backup battery charger were supplying power to the HPCI inverter via 125 VDC Bus 'B'. The 125 VDC battery charger 'A' and backup battery charger were being powered from Bus A5 via Bus B1 and Bus B6, respectively.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Charger, Battery	BYC
Inverter	INVT

SYSTEMS	
DC Power System (125 VDC)	EI
Low Voltage Power System (480 VAC) - Class 1E	ED
Medium Voltage Power System (4160 VAC) - Class 1E	EB
RCIC System	BN

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	1 OF 0 7

TITLE (4) Reactor Core Isolation Cooling System Became Inoperable Due to Overspeed Trip and Inverter Trip

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 NAMES	DOCKET NUMBER(S)
1 0	3 0	9 1	9 1	0 2 5	0 0	1 1	2 9	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v) (D)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Thomas F. McElhinney - Senior Compliance Engineer	508 747-8465

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)

YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR

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

On October 30, 1991 at 1942 hours, the Reactor Core Isolation Cooling (RCIC) System turbine tripped as operators manually started the system for Reactor Vessel (RV) water level control. The trip was reset and the RCIC System was manually started. However, the RCIC inverter had tripped when the "A" Residual Heat Removal (RHR) pump was started at 1946 hours resulting in the RCIC System not reaching rated flow. The operators manually shut down the RCIC System, reset the inverter and restarted the system successfully.

The RCIC turbine tripped due to mechanical overspeed. The licensed operator did not open the injection valve within four (4) seconds after opening the turbine steam inlet valve. During system restoration the RCIC inverter (Topaz Electronics, Model 125-GH-125 [60]) tripped due to a DC voltage transient caused when the "A" RHR pump was started. The battery charger was not originally designed to maintain DC output during AC voltage transients caused by starting large AC motors. Corrective actions for the overspeed trip include changing the procedure to require valves to be opened simultaneously. A modification was completed that installed new RCIC and High Pressure Coolant Injection inverters having a higher trip setpoint and an automatic reset function. Extensive testing was performed to ensure the inverters will not trip due to DC voltage transients. The RCIC turbine trip and inverter trip occurred with the reactor mode selector switch in the REFUEL position. The RV pressure was 920 psig and the RV water temperature was 530 degrees Fahrenheit. This report is submitted in accordance with 10 CFR 50.73(a)(2)(v)(D). The event posed no threat to the public health and safety.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 2 5 —	0 0	0 2 OF 0 7

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

BACKGROUND

The Reactor Core Isolation Cooling (RCIC) System safety objective is to provide makeup water to the reactor vessel following reactor vessel isolation in order to prevent the release of radioactive materials to the environs as a result of insufficient core cooling. The system is required to operate automatically to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised. The RCIC System is designed to cope with a control rod drop accident, a loss of feedwater flow transient, and a loss of offsite power transient. Each of the events results in an isolated reactor vessel with no breach of the primary pressure boundary. Reactor water level will drop as a result of the initiating events followed by a "boil down" as the Safety Relief Valves (SRVs) relieve on high pressure. The RCIC System is designed to automatically restore level by providing flow in excess of the boiling rate. Technical Specification 3.5.D requires that the RCIC System be operable whenever there is irradiated fuel in the reactor vessel, reactor pressure is greater than 150 psig, and reactor coolant temperature is greater than 365 degrees Fahrenheit.

The RCIC inverter converts 125 VDC (nominal) to 120 VAC to power a square root converter and flow controller in the RCIC flow control circuit and the test circuit power supply. With the inverter tripped, the RCIC System could start and operate at minimum speed. An inverter trip would not prevent system initiation or cause a trip during RCIC System operation. The capability for subsequent restoration of RCIC System flow control is available to the operator in the Control Room. The RCIC inverter is powered from the 125 volt DC Bus "A". The 125 VDC Bus normally receives power from 125 VDC Battery "A" in parallel with a battery charger. However, the backup charger was aligned to the "A" Bus due to the "A" charger being inoperable. AC voltage transients of sufficient magnitude at the input of the 125 VDC battery charger can cause DC voltage transients at the output of the battery charger. DC voltage transients in excess of the overvoltage trip setpoint can cause the RCIC inverter to trip.

As discussed in the Similar Events section, previous RCIC and High Pressure Coolant Injection (HPCI) inverter trips have occurred. In response to the March 26, 1991 event, Plant Design Change (PDC) 91-34 was implemented in July 1991 during Refueling Outage No. 8 (RFO 8). This PDC raised the inverter overvoltage trip setpoint from 140 VDC to 150 VDC. This setpoint change was made to prevent an inverter trip when a recirculation pump is started. Testing performed prior to startup from RFO 8 identified that the inverters may trip when a large motor is started with the Emergency Diesel Generators (EDGs) supplying the safety related 4160 VAC Buses A5 and A6. Failure and Malfunction Reports 91-363 and 91-368 were written to document the peak transient DC voltage obtained during this testing. The battery chargers' float voltage was reduced from 134 VDC to 132 VDC to prevent an inverter trip under this scenario. The lower float voltage has the effect of lowering the peak DC voltage during an AC voltage transient caused by start of a large motor. The plant was restarted since it was believed the lower float voltage would preclude an inverter trip. However, as reported in LER 91-021-00, the RCIC System was declared inoperable on October 9, 1991 because sufficient test data was not available to demonstrate adequate margin to the RCIC inverter overvoltage trip setpoint existed if a 125 VDC Bus "A" transient was to occur. Compensatory measures were implemented and a relief request was granted on October 16, 1991 to allow an additional 90 days of plant operation until testing and/or modifications could be completed.

NRC Form 366A (6-89)

NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 2 5 —	0 0	0 3 OF 0 7

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

EVENT DESCRIPTION

On October 30, 1991 at 1942 hours , the RCIC System turbine tripped as operators manually started the system for Reactor Vessel (RV) water level control. The RCIC System was being started following a Loss of Offsite Power (LOOP) event which is reported in LER 50-293/91-024-00. The operators reset the turbine trip and manually restarted the RCIC System. However, the RCIC System inverter (Topaz Electronics, Model 125-GH-125 [60]) had tripped when the "A" Residual Heat Removal (RHR) pump was started at 1946 hours for suppression pool cooling. The RHR pump start caused an AC voltage transient that resulted in a DC voltage transient of 152.5 VDC that was above the 150 VDC inverter overvoltage trip setpoint. This resulted in the RCIC System being unable to attain rated flow. The operators manually shut down the RCIC System, reset the inverter and restarted the system successfully for RV water level control.

Failure and Malfunction Reports 91-445 and 91-448 were written to document the inverter trip and turbine trip, respectively. The NRC Operations Center was notified during the LOOP event and was informed of the plant conditions. On October 31, 1991 a followup notification was made to ensure all of the reportable events identified during the LOOP were recorded during the previous notification.

A Multidiscipled Analysis Team (MDAT) was formed to review the events associated with the LOOP, including the RCIC System turbine trip and inverter trip.

These events occurred with the reactor mode selector switch in the REFUEL position. The RV pressure was 920 psig and the RV water temperature was 530 degrees Fahrenheit.

CAUSE

The direct cause of the RCIC turbine trip was a mechanical overspeed trip. The overspeed trip setpoint (5512 rpm to 5737 rpm) is approximately 125 percent ± 2 percent of rated speed (4500 rpm). Plant information computer traces showed the turbine speed reaching 5607 rpm. The turbine oversped because the licensed operator manually starting the RCIC System did not open the RCIC injection valve in sufficient time to provide a flowpath. Procedure 2.2.22, "Reactor Core Isolation Cooling System", Rev. 36 Attachment 8 provided instructions for manual RCIC System operation for Reactor Vessel injection. Step 5 required the turbine steam inlet valve (MO-1301-61) be opened first with the injection valve (MO-1301-49) opened when the RCIC turbine increased speed. These steps were to be performed in close sequence. The computer traces showed the turbine steam inlet valve was opened and the turbine reached overspeed within four (4) seconds before the injection valve was opened. When the steam inlet valve was opened all the pump flow was directed to the Suppression Pool via the minimum flow bypass line. The flow element (FE 1360-3) for the flow transmitter (FT 1360-4) that provides input to the RCIC turbine control logic is located downstream of the minimum flow bypass line. Since no flow was sensed by the flow transmitter, the turbine governor valve received input to open in an attempt to achieve rated flow.

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

A Human Performance Evaluation System (HPES) investigation revealed there were three areas that contributed to this event:

1. The Operator initially started to open the MO-1301-53 Valve (Full Flow Test).

   - The Operator realized this mistake and attempted to recover from it by closing the valve; however, the turbine reached overspeed in four (4) seconds.

2. The turbine reached the overspeed trip four (4) seconds after the Mo-1301-61 Valve started off its open seat.

   - The normal response time based on plant simulator performance is approximately 15 seconds. This would indicate to the operators this is not a time sensitive operation.

3. The procedure was written to minimize the challenges to the RCIC injection check valve 1301-50 and associated stored energy that develops in the discharge line.

   - Under the plant condition at the time of this event, four (4) seconds was not enough time for the operator to perform the required valve manipulations (i.e., close MO-1301-53 and open MO-1301-49).

The direct cause of the inverter trip was a fluctuation of the 125 VDC battery charger output voltage in excess of the 150 VDC overvoltage setpoint. The fluctuation resulted from an AC voltage transient caused by the start of the "A" RHR pump with the "A" EDG supplying power to 4160 VAC Bus A5.

The root cause of the inverter trips was due to the 125 VDC battery chargers which did not regulate DC output when subjected to an AC input transient that exceeded its design. Specifically, battery charger DC output is not adequately regulated during the start of large AC motors. AC voltage input transients and the resulting DC output transients were not specified as design criteria for the 125 VDC battery chargers in the original purchase specification. The 125 VDC battery chargers are only capable of maintaining the charging voltage within $\pm$ 0.5 percent from no load to full load with an AC supply voltage variation of $\pm$ 10 percent and a frequency variation of $\pm$ 5 percent, as designed.

The MDAT performed a detailed review of the battery chargers including review of the design and licensing basis and an as-built verification to ensure the chargers were configured in accordance with the design.

During the as-built verification of the three 125 VDC battery chargers, differences were noted between the control modules in the "A" and the "Backup" battery chargers and those in the "B" battery charger. The original design control modules were installed in the "B" charger. These modules are "fast response" control circuits that have consistently produced voltage transients of much less magnitude when compared to the "A" and "Backup" battery chargers.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

The maximum AC voltage transient occurs during battery charger power-up after a shutdown >/= 10 seconds, as would be experienced during a Loss of Coolant Accident with a Loss of Offsite Power (LOCA/LOOP) event. The "B" battery chargers peak transient voltage in this scenario is 146 VDC at a float voltage of 132 VDC. The control modules installed in the "A" and "Backup" battery chargers were "slow response" control circuits that were provided by the original equipment manufacturer as equivalent to the original modules. These modules produce a voltage transient different in magnitude and profile when compared to the "B" battery charger. The "slow response", control modules installed in the "A" and "Backup" chargers eliminate the startup DC voltag transients by delaying the power-up following the LOCA/LOOP event. The limi ng transient for these chargers is when the EDGs are supplying the safety buses and a large motor is started (RHR or Core Spray pump). The peak DC voltage observed at a float voltage of 132 VDC was 152.5 VDC for the "Backup" charger and 159.5 VDC for the "A" charger.

CORRECTIVE ACTION

The operator was counseled regarding the importance of following the proper sequence of valve operation when manually starting the RCIC System. Procedure 2.2.22 was revised (to Rev. 37) to provide instructions for opening the injection valve at the same time the steam admission valve is opened. This sequence mimics the automatic start sequence. The operators have been trained on this procedure change. A Request for Investigation (RFI) 91-596 was written to evaluate installing a pushbutton in the control room for RCIC System manual initiation. The pushbutton will actuate the automatic start valve sequencing thereby reducing the probability of a turbine overspeed trip. Additionally, RFI 91-597 was written to evaluate revising the plant simulator to react like the plant during the manual RCIC start sequence.

Plant Design Change (PDC 91-63) was implemented to replace the RCIC System and High Pressure Coolant Injection (HPCI) System inverters. The new inverters have a higher trip setpoint of 160 VDC and an automatic reset function. Additionally, a 125 VDC end device review was conducted to verify other safety related 125 VDC equipment will not be damaged by DC System voltage fluctuations. Extensive battery charger and 125 VDC System response testing was performed to satisfactorily demonstrate the HPCI/RCIC inverters will not trip during a start of a large AC motor. The "A" 125 VDC battery charger was not returned to service since sufficient margin to the inverter overvoltage trip setpoint did not exist. Troubleshooting will continue in order to re-establish the "A" battery charger operability.

SAFETY CONSEQUENCES

The RCIC overspeed trip and inverter trip posed no threat to the public health and safety.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

The Core Standby Cooling Systems (CSCS) consist of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and RHR System/Low Pressure Coolant Injection (LPCI) mode. During the time the RCIC System was inoperable all of the CSCS were operable and capable of providing sufficient core cooling if required.

The overspeed trip of the RCIC turbine was the expected system response when the steam inlet valve is opened and the injection valve maintained closed. The operators promptly reset the overspeed trip and followed the proper valve sequence to operate the RCIC System.

The trip of the RCIC inverter was the designed response to an overvoltage condition. The inverter was reset approximately 90 seconds after tripping and the RCIC System operated satisfactorily to maintain Reactor Vessel water level.

This report is submitted in accordance with 10 CFR 50.73(a)(2)(V)(D) because the RCIC System became inoperable.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) issued since January 1984. The review focused on LERs involving RCIC or HPCI System turbine overspeed and/or inverter trips due to the similar causes. The review identified previous events reported via LERs 50-293/85-029-00, 90-013-00, 91-006-00 and 91-021-00.

For LER 85-029-00, the HPCI inverter tripped during power operation on October 18, 1985 at 1545 hours. The most probable cause of the HPCI inverter trip was fluctuation of the inverter input DC voltage. The inverter was reset within approximately 60 seconds restoring the HPCI System operability.

For LER 90-013-00, the RCIC turbine tripped due to mechanical overspeed on September 2, 1990. The overspeed occurred as a result of the manual injection step sequence specified in Procedure 2.2.22 "Reactor Core Isolation Cooling System" Rev. 33. Section 7.4 specified that the turbine steam inlet valve be opened and the injection valve opened after the pump discharge pressure equals reactor pressure. Plant computer traces showed that the turbine oversped before the injection valve could be opened. Corrective action taken included revising 2.2.22 to direct the operators to open the injection valve after opening the turbine steam supply valve and the turbine increases speed.

For LER 91-006-00, the RCIC inverter and HPCI inverter tripped during power operation on March 26, 1991 at 0043 hours. The inverters tripped when the Recirculation System Loop 'B' motor-generator set/pump was restarted. At the time of the event, the 125 VDC Battery "A" and Battery Charger "A" were supplying power to the RCIC inverter via 125 VDC Bus "A". The 125 VDC Battery "B" and the 125 VDC backup battery charger were supplying power to the HPCI inverter via 125 VDC Bus "B". The 125 VDC battery charger "A" and backup battery charger were being powered from Bus A5 via Bus B1 and Bus B6, respectively.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

For LER 91-021-00, the RCIC System was declared inoperable on October 9, 1991 at 1802 hours and a seven day Technical Specification Limiting Condition for Operation (LCO) was entered. The RCIC System was declared inoperable because sufficient test data for the backup 125 VDC battery charger was not available to assure that the RCIC inverter would not trip if a 125 VDC Bus "A" voltage transient were to occur. At the time the RCIC System was declared inoperable, the 125 VDC backup battery charger was supplying the RCIC inverter via the "A" 125 VDC bus. A request for relief from a shutdown specified by Technical Specification 3.5.D.2 was submitted to the NRC in October 15, 1991. The request was granted by the NRC on October 17, 1991 until the NRC could act upon an exigent Technical Specification change request. The exigent Technical Specification change request was subsequently withdrawn due to the October 30, 1991 RCIC inverter trip.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Charger, Battery	BYC
Inverter	INVT

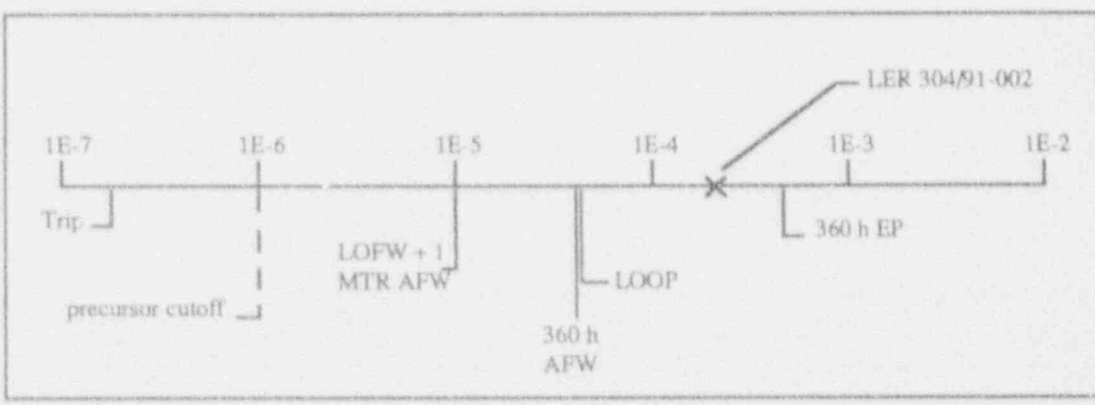
SYSTEMS	
DC Power System (125 VDC)	EI
Low Voltage Power System (480 VAC) - Class 1E	ED
Medium Voltage Power System (4160 VAC) - Class 1E	EB
RCIC System	BN
HPCI System	BJ

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	304/91-002
Event Description:	Loss of offsite power with one diesel generator out of service
Date of Event:	Ma[illegible] 21, 1991
Plant:	Z[illegible]

Summary

Multiple inadvertent deluge system actuations sprayed the station auxiliary transformer (SAT) at Zion 2 and resulted in a loss of offsite power (LOOP). One emergency diesel generator (EDG) was out of service for maintenance at the time of the event. Equipment rendered unavailable by the LOOP complicated recovery from the event. The conditional core damage probability for this event, based on the current Accident Sequence Precursor (ASP) models, is estimated to be 2.1×10^{-4}. The relative significance of this event as compared to other postulated events at Zion 2 is shown below.



Event Description

On March 21, 1991, Zion 2 was operating at full power. EDG 0, the common swing diesel for the two Zion units, was out of service to repair a jacket water leak. Surveillance testing of the Unit 2 EDGs was in progress, as was Performance Test (PT)-211, "Wet Pipe Sprinkler Test."

During the morning, three inadvertent deluges occurred on the main power transformer (MPT)/unit auxiliary transformer (UAT) and SAT. In each case, the operators confirmed that no fire had occurred. After the second deluge, the deluge isolation valve for the MPT/UAT was closed. A third deluge occurred while the operators were trying to reset the deluge valve and reopen the isolation valve.

At 1307 hours in the afternoon, another inadvertent deluge of the Unit 2 SAT occurred. While the deluge flow was being isolated, the SAT tripped because of a phase-to-ground fault. Buses 243 and 244 supplied by the SAT were automatically transferred to the UAT, which is powered by the main generator. An arc strike was subsequently found on the C phase transformer bushing, and the deluge system spray nozzles were found to have been incorrectly aligned and tested.

Feedwater for Unit 2 was being supplied by one turbine-driven pump and the motor-driven main feedwater (MFW) pump; the second turbine-driven pump was out of service for maintenance. When the SAT tripped, the motor-driven feedwater pump lost power. Unavailability of the motor-driven feedwater pump caused a reduction in feedwater flow to the steam generators (SGs) and a consequent reduction in SG level, since steam flow had not changed. A lo-lo SG level reactor trip occurred at 1310 hours. Following the reactor trip, the UAT tripped as expected, resulting in a LOOP.

At the time of the SAT trip, surveillance testing was in progress on EDG 2A. The generator was running, paralleled to bus 248, and loaded to 1 MW. At the time of the UAT trip, EDG 2A output breaker tripped on reverse power but closed again on the LOOP undervoltage signal and repowered bus 248. EDG 2B automatically started and reenergized bus 249 essential loads. Since EDG 0 was out of service for maintenance, bus 247 was not repowered until the operators manually transferred it at 1405 hours (approximately 1 h after the LOOP) to Unit 1 vital bus 141, which is the backup emergency power source for the Unit 2 vital buses.

A number of other problems occurred during and following the LOOP that affected plant and operator response to the event.

1. The sequence of events recorder was powered from a nonvital bus that was lost following the LOOP. Because of this, events that occurred immediately following the reactor trip were not recorded. This lack of information complicated diagnosis of the event.

2. Prior to Unit 2 entering cold shutdown, both power-operated relief valves (PORVs) were stroke-tested to confirm operability for low-temperature overpressure protection. PORV 455C failed to open because of a failed air line. Inoperability of this valve impacted the unit's ability to remove decay heat using bleed and feed, if that had been required.

3. Component cooling water (CCW) pump 0A was tripped by an operator after it was observed that there was no oil in the pump. The CCW system is a shared system between the two units, and four CCW pumps remained operable.

4. Following a loss of nonvital AC power at Zion, the SG relief valve controls fail as is. The valves were nearly full-open at the time of the LOOP because the operators were attempting to match feed and steam flow following loss of the motor-driven MFW pump. The valves had to be closed locally by bleeding control air. One of the relief valves failed open and the associated isolation valve had to be closed to terminate flow.

5. Some doors between the power block and the service buildings failed closed when power was apparently lost from the security inverter (reason unspecified). This delayed personnel outside the power block in responding to the event. Personnel inside the power block were not affected. Security personnel responded to the failure in an uncoordinated manner, and station personnel were unaware of which doors would be manned by security personnel in such a situation.

Additional Event-Related Information

The Zion 2 emergency power system consists of three buses (247, 248, and 249), which provide essential AC power to safety-related equipment. EDGs 2A and 2B provide emergency power to buses 248 and 249, and swing EDG 0 provides power to bus 247 or Unit 1 bus 147. In addition, power from the Unit 1 SAT can be manually aligned to supply power to Unit 2. In a similar manner, three batteries provide backup DC power for Unit 2. The two batteries that only provide power to Unit 2 are capable of supplying loads for at least 3 h.

If secondary-side cooling is unavailable, feed and bleed can provide decay heat removal at Zion. Based on the information provided in the NUREG-1150 analysis for Zion (NUREG/CR-4550, Vol. 7, Rev. 1), feed and bleed success requires one-of-two safety injection (SI) pumps and two PORVs or one-of-two charging pumps and one PORV.

ASP Modeling Assumptions and Approach

The event has been modeled as a plant-centered LOOP with one EDG unavailable. Unavailability of EDG 0 resulted in unavailability of one charging, service water, SI, and containment spray pump. Manual connection of the emergency buses to the Unit 1 feeder bus was not addressed, and therefore the analysis is somewhat conservative. Nonrecovery probabilities for LOOP (short-term), electric power prior to battery depletion or core uncovery following a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA), and the probability of an RCP seal LOCA, were revised to reflect the observed plant-centered LOOP (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989).

The current ASP models do not address the use of the charging pumps as an alternate to the SI pumps for high-pressure injection (HPI) and feed and bleed. The branch probabilities for HPI and feed and bleed were modified to reflect the potential use of the charging pumps, and these probabilities were used in a sensitivity analysis.

Because of the unavailability of EDG 0 and PORV 455C, only one charging pump, one SI pump, and one PORV were available for HPI and feed and bleed. Using the train-level screening probabilities typically employed in ASP calculations results in the following branch estimates for these functions:

Branch	Current ASP models	SI or charging pumps provide success
HPI	$\sim 8.4 \times 10^{-3}$*	$\sim 8.4 \times 10^{-5}$*
Feed and bleed	1.0*	$\sim 2.8 \times 10^{-2}$*

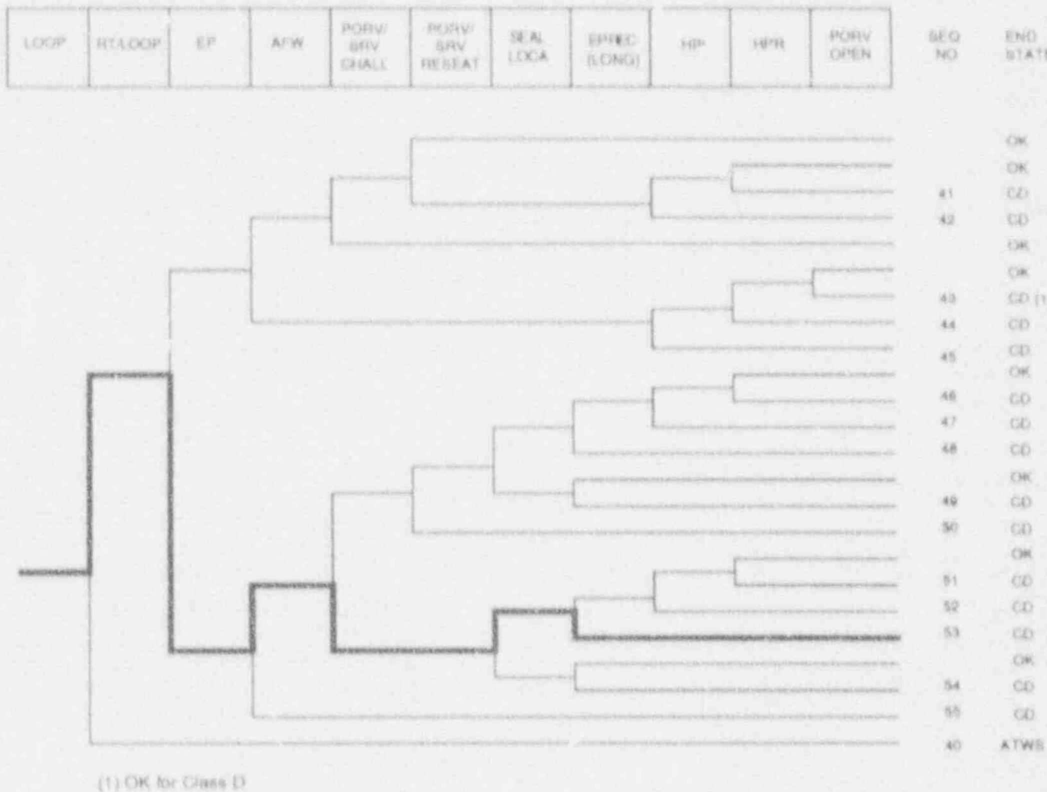
*conditional on unavailability of EDG 0 and PORV 455C

Analysis Results

The conditional core damage probability for this event, based on the current ASP models, is estimated to be 2.1×10^{-4}. The dominant core damage sequence, highlighted on the following event tree, involves a LOOP with emergency power failure, a resulting RCP seal LOCA, and failure to recover AC power prior to core uncovery.

The second most dominant sequence involves a postulated failure of auxiliary feedwater (AFW) and feed and bleed following emergency power success. The probability of this sequence is affected by assumptions concerning those systems that can provide HPI and feed and bleed, as discussed earlier. Considering the charging pumps as an alternate high-pressure source reduces the core damage frequency estimate for this event to 1.6×10^{-4}.

Additional information concerning this event is included in Region III AIT inspection team report 50-304/91006 (DRP), dated April 17, 1991.



Dominant core damage sequence for LER 304/91-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 304/91-002
Event Description: LOOP with one EDG out of service (only SI for HPI)
Event Date: 03/21/91
Plant: Zion 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.1E-04
Total	2.1E-04
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-04	4.0E-01
43	LOOP -rt/loop -EMERG.POWER afw -HPI(F/B) -HPR/-HPI PORV.OPEN	CD	4.8E-05	1.3E-01
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	1.9E-05	1.4E-01
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	7.9E-06	4.0E-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	5.1E-06	4.0E 1

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
43	LOOP -rt/loop -EMERG.POWER afw -HPI(F/B) -HPR/-HPI PORV.OPEN	CD	4.8E-05	1.3E-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	5.1E-06	4.0E-01
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.2E-04	4.0E-01
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	7.9E-06	4.0E-01
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	1.9E-05	1.4E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp

Event Identifier: 304/91-002

BRANCH MODEL: c:\asp\1989\zion.all
PROBABILITY FILE: c:\asp\1989\pwr_ball.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.5E-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		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	5.4E-04 > 2.9E-03	8.0E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02		
Train 3 Cond Prob:	1.9E-01 > Unavailable		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
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 > 2.4E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.7E-01 > 2.4E-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	3.1E-02 > 9.7E-03	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	3.1E-02 > 9.7E-03		
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 > Unavailable		
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 > Unavailable		
HPR/-HPI	1.5E-04 > 1.0E-02	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
PORV.OPEN	1.0E-02 > 1.0E+00	1.0E+00	4.0E-04
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		

* branch model file
** forced

Minarick
05-22-1992
17:50:06

Event Identifier: 304/91-002

LICENSEE EVENT REPORT (LER)

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Facility Name (1)	Docket Number (2)	Page (3)
Zion Unit 2	0 5 0 0 0 3 0 4	1 of 0 7

Title (4)
System Auxiliary Transformer Deluge and Reactor Trip

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Facility Names	Docket Number(s)
0 3	2 1	9 1	9 1	— 0 0 2 —	0 0	0 4	2 0	9 1	Zion Unit 1	0 5 0 0 0 2 9 5

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 9

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

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

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
Suzanne L. Mika, Regulatory Assurance ext. 2323	AREA CODE 7 0 8 7 4 6 - 2 0 8 4

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

CAUSE	SYSTEM	COMPONENT	MANUFAC- TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC- TURER	REPORTABLE TO NPRDS
B	K P	V	A 6 0 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

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

Expected Submission Date (15): Month 1 0 Day 3 1 Year 9 1

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

At 0930, during the performance of Operating Periodic Test (PT)-211, Wet Pipe Sprinkler System Test, the Unit 2 Unit Auxiliary Transformer (UAT) and the Main Power Transformer (MPT) were inadvertently deluged. At 1309, another deluge occurred on the System Auxiliary Transformer (SAT) causing the SAT to trip. The buses fed from the SAT automatically transferred to the UAT. The 2A feedwater pump tripped when the SAT tripped causing a Reactor Trip on Lo-Lo Steam Generator Level. When the main generator tripped, one diesel generator (D/G) was Out of Service (OOS) for maintenance so an essential bus was not automatically re-energized. A Generating Station Emergency Plan (GSEP) Unusual Event (EAL 3D) was declared at 1335 and both units were started toward Cold Shutdown. The event was caused by spurious actuation of the Unit 2 transformer's fire protection deluge system and the improper positioning of the fire protection deluge nozzles. During this event all failures and actions taken were within the bounds of the Technical Specification limiting conditions for operation. Various corrective actions have been developed to address the concerns that were raised as a result of this event.

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

A. CONDITION PRIOR TO EVENT

Unit 1
MODE 3 - Hot Shutdown RX Power 0% RCS [AB] Temperature/ Pressure 510.8°F /2235 psig

Unit 2
MODE 1 - Power Operations RX Power 99.5% RCS [AB] Temperature/ Pressure 557.7°F/ 2235 psig

B. DESCRIPTION OF EVENT

At 0930, during the performance of Operating Periodic Test (PT)-211, Wet Pipe Sprinkler System Test, the Unit 2 Unit Auxiliary Transformer (UAT) and the Main Power Transformers (MPT) were inadvertently deluged. Verification was made that no fire was present and the deluge isolation valve for both the UAT and the MPT's was subsequently closed. At 1030, after resetting the deluge valve, the Equipment Attendant (EA) began to open the manual isolation valve, but heard the deluge valve actuate again on the MPT's and the UAT, so he immediately reclosed the manual isolation valve. The Shift Supervisor (SS) verified that there was no fire and no water actually sprayed on the MPT/UAT.

At 1245, PT-211 was resumed on the Diesel Generator Oil Storage Tank room fire protection system without incident. At 1303, PT-11, Diesel Generator Loading Test, was started on 2A DG to satisfy the surveillance requirements with "0" D/G Out of Service (OOS) for maintenance. After the DG was run for approximately 5 minutes the Nuclear Station Operator (NSO) closed the output breaker of the DG and loaded it to 1 MW. While holding at 1 MW, the System Auxiliary Transformer (SAT) Trouble annunciator alarmed, the SAT, MPT, and UAT alarms on the Fire Alarm Panel then came in, and a deluge began on the Unit 2 MPT's, SAT, and UAT. The SS and an EA were dispatched from the Control Room to investigate the alarms. The SAT tripped at 1309 followed by the reserve feed breakers to Buses 243 and 244 (Breakers 2432 and 2442). Service Buses 243 and 244 automatically transferred to the UAT.

Feedwater for Unit 2, at the time of this event, was being supplied by one turbine-driven (2C) and one motor-driven (2A) feedwater pump because the second turbine-driven feedwater pump (2B) was OOS for miscellaneous maintenance. 2A feedwater pump was being fed from the SAT, and subsequently tripped when the SAT tripped. When the 2A feedwater pump tripped, insufficient feedwater to the Steam Generator caused a Reactor Trip due to Steam Generator Lo-Lo Level at 1310. At 1311, the main generator tripped, de-energizing all Unit 2 4KV service buses. Since 2A D/G was already running when the SAT tripped, the load was transferred to 2A D/G after the UAT tripped, 2A D/G output breaker tripped on reverse power but it immediately closed in again on the Loss of Offsite Power signal to energize essential service bus 248. 2B Emergency Diesel Generator (EDG) automatically started, re-energizing essential service bus 249. The 0 EDG, which provides power to bus 247 was OOS for maintenance, so bus 247 was manually transferred to bus 141 which is the reserve feed for the Unit 2 essential buses.

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

B. DESCRIPTION OF EVENT (con't)

At 1335, a Generating Station Emergency Plan (GSEP) Unusual Event (EAL [illegible]) was declared. The proper notifications were made and the Technical Support Center (TSC) was [illegible] 1410. At 1426, boration to Cold Shutdown began for Unit 2, and at 2045 cooldown was initiate[illegible] 1.

After the action plan for SAT repairs had been determined and the necessary paperwork assembled, the SAT was taken OOS for repairs at 2000. Evidence showed that a phase to ground fault occurred on the Phase C bushing of the SAT. Repairs were made to the SAT, the OOS was cleared, and the SAT was re-energized at 0112.

Once the SAT was returned to service, the Unsual Event classification was changed from EAL 3D to EAL 3A, Equipment in Technical Specifications degraded such that the Limiting Condition for Operation (LCO) requires a shutdown, because 0 D/G was OOS for maintenance. A Temporary Waiver of Compliance had allowed maintenance to be perform[illegible] on 0 D/G while Unit 1 was left in Hot Shutdown. This Temporary Waiver of Compliance was cancelled as a result of the Unit 2 SAT trip. A second Temporary Waiver of Compliance was initiated following the SAT trip and Compensatory Actions for this Waiver required that both Units be brought to Cold Shutdown. The second Waiver was the reason that EAL 3A was implemented.

At 1830 on 3/22/91, when 0 D/G was returned to service, the GSEP Unusual Event was terminated and the TSC was de-activated.

C. APPARENT CAUSE OF EVENT

The cause of the phase to ground fault on Phase C of the SAT has been determined to be the spurious actuation of the Unit 2 transformer's Fire Protection deluge system and the improper positioning of the Fire Protection deluge nozzles. The cause of the spurious actuation of the deluge system was due to a mechanical/hydraulic perturbation of the Fire Protection System deluge valve. These valves are automatic deluge valves and they have been determined to be overly sensitive to system pressure spikes and vibration. The deluge valves for the MPT/UAT and the SAT are connected to a common fire protection system header. When the EA opened the 2" drain valve for the Turbine Building Wall and D/G Air Intake prior to the first deluge to verify that water pressure was being maintained up to the Turbine Building wall deluge valve, the water pressure was sufficient to go back up through the common 2" drain valve header into the MPT/UAT deluge valve clapper protective cover and dislodge the dead weight that causes the deluge valve to open. The water was able to flow back through the common 2" drain valve header because the check valves that were supposed to prevent this flow path were never installed. A check valve was not installed on the SAT flowpath either, but the SAT was not deluged at this time. The fire protection deluge equipment was originally designed and supplied from the manufacturer and although pre-service testing was performed, it did not identify that these check valves were missing. Validation of the root cause of the actuation of the SAT deluge valve will occur after testing is performed during the scheduled SAT outage.

The cause of the fire protection deluge nozzles being mispositioned was attributed to the fact that no guidelines had been established for the position of these nozzles prior to this event. This mispositioning caused water to be sprayed in close proximity to Phase C of the transformer which provided a conduction path to ground, and is believed to have caused the SAT to trip.

The cause of the Unit 2 reactor trip has been attributed to Low Steam Generator Level. This low level resulted after one of the two feedwater pumps supplying the Steam Generator tripped when the SAT tripped.

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

D. SAFETY ANALYSIS OF EVENT

During this event all failures and actions taken were within the bounds of the Technical Specification Limiting Conditions for Operation. There was therefore no safety significance to this event.

Following the loss of the SAT and the subsequent Reactor Trip/Generator Trip, the 2A and 2B D/G's assumed their safe shutdown loads per design and all the associated safe shutdown loads actuated per design. Since the 0 D/G was OOS for maintenance, essential bus 247, which is fed from 0 D/G during blackout conditions, had to be manually re-energized from it's Unit 1 cross-tie. All three essential buses were available from this point. Two essential buses are required per the Updated Final Safety Analysis Report (UFSAR) Chapter 8.4.2, so the requirements for safe shutdown were satisfied.

The Steam Generator (S/G) heat removal following the Reactor Trip was controlled by the atmospheric relief valves. Adequate S/G feedwater was supplied by the three auxiliary feedwater (AFW) pumps.

The Reactor Coolant System (RCS) pressure war controlled by the pressurizer heaters and the pressurizer auxiliary spray. The Reactor Coolant Pumps were not available because they are fed from the non-essential buses which were de-energized due to the SAT trip and the subsequent Reactor Trip. The maximum RCS pressure attained during this event was 2347.7 psig. The Technical Specification Safety Limit for RCS pressure is 2735, so the RCS pressure was well within it's limits. The maximum average RCS temperature attained was 561.8 F which was below the Safety Limits outlined on Technical Specification Safety Limit Table (Figure 1.1-1 Reactor Core Thermal and Hydraulic Safety Limits for Four Loop Operation Units 1 and 2). Reactor Power response was normal for a Reactor Trip/Generator Trip. All control rods inserted correctly, and the Reactor Trip was completed in a normal manner.

E. CORRECTIVE ACTIONS

A. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to develop and validate the Sequence of Events.

1. The Management Information System (MIS) department will review the Sequence of Events recording priority with the Operating department and revise if appropriate. (304-180-91-022-01)

2. The MIS department will review the Sequence of Events buffer capabilities for upgrade to recapture all pertinent information. (304-180-91-022-02)

B. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine why the deluge system activated.

1. Technical Staff (Tech Staff), Electrical Maintenance (EM), and Engineering will review for adequacy and consider replacing the deluge valves with either new valves or with a different type of valve. Unit 2 deluge valves will be replaced prior to entering Mode 1. The Unit 1 deluge valves will be replaced, however, replacement may not be completed prior to entry into Mode 1. (304-180-91-022-06)

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

E. CORRECTIVE ACTIONS (cont.)

2. The Operating and Training departments will review the procedure and training needs for the operators on resetting the deluge valves for possible enhancement. If the deluge valves are replaced with a different type of valve, procedure changes and training on new valves will be completed per the modification process. (304-180-91-022-04 and 05)

3. Tech Staff, Engineering and EM's will inspect, repair or replace the SAT fire protection detector system as required. (304-180-91-022-07)

4. Tech Staff, Engineering and Electrical Maintenance departments will inspect, repair, or replace, as necessary, UAT and MPT fire protection detector systems. (304-180-91-022-08)

5. Tech Staff, Engineering, and Operating will perform testing during the Unit 2 SAT outage to validate root cause of the deluge actuation. (304-180-91-022-09)

6. Operating Department will review the current fi   ide response methodology. This should include response to alarms that are real, inadvert   , or expected. The Operating department will also determine the Station Laborers' role in the fire company. (304-180-91-022-11)

7. Tech Staff and Engineering will determine the proper position of all transformer fire protection deluge nozzles and correct as n sary. (304-180-91-022-13)

8. Regulatory Assurance will review the root cause methodology to investigate the previous event documented under DVR 2-90-138. (304-180-91-022-14)

9. Tech Staff and Engineering will review the impact of missing check valves on the Unit 2 fire protection system. The missing check valve issue will be resolved prior to running PT-211.(304-180-91-022-28)

10. Operating will review PT-211 for human factoring and technical adequacy. (304-180-91-022-28.1)

C. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine the reason for the Reactor Trip.

1. Tech Staff, Engineering and Operating will review and determine a method to preclude inadvertent resetting of the First Out Annunciator, if possible. (304-180-91-022-15)

2. Onsite Nuclear Safety will issue a letter to the Operating department explaining the Main generator reverse power trip. (304-180-91-022-16)

3. Emergency Planning will perform a GSEP lessons learned review. (304-180-91-022-17)

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

E. CORRECTIVE ACTIONS (cont.)

D. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine the cause of the SAT failure.

1. Operating will establish a breaker and relay target logging system. This is a short term item until the Log Keeping Committee identifies a permanent solution. (304-180-91-022-01B)

2. Tech Staff and Engineering will perform testing during Unit 2 SAT outage to validate root cause of the SAT trip. (304-180-91-022-19)

3. Operating and Regulatory Assurance will review the communications between the Control Room and field personnel during testing activities. A Management Action Plan will be developed to address this concern. (304-180-91-022-20)

E. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine if actions of the personnel involved were appropriate and the extent of management involvement in decisions made concerning the test.

1. Emergency Preparedness will review different options of keeping unnecessary people out of the control room during GSEP activities. (304-180-91-022-21)

F. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine whether adequate controls were imposed on testing of the fire main or deluge system prior to the trip.

1. Security Department will review compensatory measures for security doors based on this event. (304-180-91-022-22)

2. Security and Operating departments will review the need for vital area keys for operators outside the vital area. (304-180-91-022-29)

G. Items that need to be completed on both units prior to Unit 1 Power Operations (Mode 1) to determine whether there were design deficiencies with the deluge system which contributed to the event.

1. Engineering will review the design features that cause a deluge actuation to trip oil pumps and cooling fans but allow the SAT to remain energized. (304-180-91-022-23)

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

E. CORRECTIVE ACTIONS (cont.)

H. Items that need to completed on both units prior to Unit 1 Power Operations (Mode 1) to determine whether the station properly implemented the terms of the Temporary Waiver of Compliance.

1. Regulatory Assurance will ensure that future Temporary Waivers of Compliance specifically address applicability in the event of plant events. (304-180-91-022-24)

2. Operating and Administration will review and revise, if necessary, the Standing Order distribution list. (304-180-91-022-25)

3. Operating and Administration will review the method of delivering Standing Orders and revise this method if necessary. (304-180-91-022-26)

4. Regulatory Assurance will use a formal hand out at morning meetings that relay compensatory actions for future Temporary Waivers of Compliance. (304-180-91-022-27)

In addition to the above actions, Zion Station has embarked upon a program to enhance the safety culture of Station personnel through the development of a critical thinking process and a questioning attitude. This has been discussed by the Plant Manager with plant personnel at the April 1991 State of the Station presentation and was factored into Crew Interaction Training which has just finished being presented to all Operating personnel. The concepts of this Crew Interaction Training are also being shared with the rest of the station through various other training programs during 1991.

F. PREVIOUS EVENTS

DVR 22-2-90-138 documents a similar event when the Unit 2 SAT was deluged and a D/G (1A) was OOS for maintenance. The investigation did not determine the cause of the deluge, but it was noted that the automatic deluge valve was functioning properly. It is now evident that the previous event was caused by the same mechanical/hydraulic perturbations that caused this event. The investigation for the previous event focused on DC grounds on the DC power supply to the deluge system, but were inconclusive. The corrective actions for the previous event would not have prevented this event.

G. COMPONENT FAILURE DATA

Manufacturer	Nomenclature
Automatic Sprinkler Corporation	Automatic Deluge Valve

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-304/91006(DRP)

Docket No. 50-304 License No. DPR-48

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: Zion Nuclear Generating Station, Unit 2

Inspection At: Zion, IL

Inspection Conducted: March 22 - 25, 1991

Inspectors: M. J. Farber
D. S. Butler
R. A. Westberg
R. J. Leemon
C. P. Patel
J. N. Stang
G. B. Kelly

Approved By: W. D. Shafer, Chief
Reactor Projects Branch 1

W.D. Shafer 4/17/91
Date

Inspection Summary

Inspection on March 22 - 25, 1991 (Report No. 50-304/91004(DRP))

Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the partial loss of off-site power and reactor trip event at Zion Station, Unit 2, on March 21, 1991. The review included validation of the sequence of events, determination of the root cause for the deluge system actuation and reactor trip, determination of the root cause of any transformer failures, evaluation of adequacy and appropriateness of operator actions during and after the event, evaluation of the adequacy of controls imposed on fire main and deluge system testing prior to the event, evaluation of whether design deficiencies in the deluge system contributed to the event, and a determination of what actions the licensee implemented to meet the terms of the temporary Waiver of Compliance.

Results: The team concluded that the System Auxiliary Transformer (SAT) fault and subsequent reactor trip were the result of an inadvertent transformer deluge, that the plant responded properly, and that the licensee responded appropriately to the event.

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The team identfied causes for the individual actuations which occurred during this event. The inadvertent deluge valve actuation was apparently caused by hydraulic perturbations induced by the fire header testing. The SAT tripped on a 245Kv to ground fault across the "C" phase bushing. Improper nozzle configuration resulted in a spray around the bushing sufficiently dense to be conductive with a 345Kv potential. The reactor tripped on Low-Low Steam Generator Level due to the loss of the motor-driven feedwater pump.

The team identified two fundamental causes for the event: a flawed root cause analysis for the November 27, 1990 transformer trip and failure of the station staff to terminate fire header testing activities following the initial deluge system actuation. The flawed root cause analysis led to the failure to identify either the mechanical actuation of the deluge valve or the mispositioned spray nozzles on the SAT. The failure of the station staff to terminate the fire header testing led to continued pressure perturbations which eventually tripped the deluge valve.

Augmented Inspection Team Report

50-304/91006

VII. EXIT

VIII. ATTACHMENTS

Attachment Number	Description
1	Confirmatory Action Letter
2	AIT Charter
3	Shift Engineers Log - March 21, 1991
4	Unit 2 Operators Log - March 21, 1991
5	Sequence of Events Report
6	Unit 2 Pre-Reactor Trip Report
7	Unit 2 Post-Reactor Trip Report
8	Prime Computer Point Plots
9	Strip Charts
10	Zion AC Electrical Distribution Drawings
11	Request for Temporary Waiver of Compliance
12	Standing Order 91-07
13	Unit 2 Supervisor Turnover Sheets
14	PT-211, "Wet Pipe Sprinkler Test"

I. INTRODUCTION

A. AIT Formation

On Thursday, March 21, 1991, at approximately 1:10 p.m. (CST), Zion Station, Unit 2, experienced a partial loss of off-site power and reactor trip, which was initiated by the loss of the System Auxilary Transformer (SAT). As a result of the transformer trip and the reactor trip, the unit was left without normal AC power and forced to rely on natural circulation to remove decay heat with electrical power supplied to the safeguards buses by the unit's emergency diesel generators (EDGs). Following notification of the event by the Senior Resident Inspector, communication lines with the station and the Office of Nuclear Reactor Regulation were opened by members of the Region III staff in the Incident Response Center. Subsequently, the Deputy Director, Division of Reactor Projects, and an electrical specialist from the Division of Reactor Safety were dispatched to the site to monitor the licensee's response to the event. Based on lack of a clear understanding of the event, the potential generic implications of the event, the occurrence of a previous similar event at Zion, and questions with regard to management involvement in decisions relating to testing preceding the event, senior NRC managers determined that an Augmented Inspection Team was warranted. On Friday, March 22, 1991, an Augmented Inspection Team (AIT) was formed consisting of:

Team Leader:	M. J. Farber, Chief, Reactor Projects Section 1A
Team Members:	R. J. Leemon, Resident Inspector Zion Station D. S. Butler, Reactor Inspector, Electrical, Region III R. A. Westberg, Reactor Inspector, Electrical, Region III C. P. Patel, Project Manager, NRR J. F. Stang, Project Manager, NRR G. B. Kelly, Senior Reliability Risk, Analyst, NRR
Additional Personnel:	R. B. Landsman, Project Engineer, Section 1A, RIII

The team leader and three members of the team were on-site early on March 22 and began gathering and evaluating available data. The remaining members of the team arrived later that afternoon and met with the licensee's root cause investigation committee. In parallel, with the AIT formation, RIII issued a Confirmatory Action Letter (CAL) (Attachment 1) which confirmed certain actions in support of the AIT and established conditions required to be met prior to the restart of unit 2.

B. Charter

A charter was formulated for the AIT and transmitted from Hubert J. Miller to Martin J. Farber on March 22, 1991 (Attachment 2) with copies to appropriate EDO, NRR, AEOD, and RIII personnel.

The AIT was terminated on Monday, March 25, 1991 by the Deputy Regional Administrator.

C. Persons Contacted

Commonwealth Edison

*T. Joyce, Station Manager
K. Graesser, General Manager, PWR Operations
*A. Amoroso, Nuclear Engineering
*A. Broccolo, Services Superintendent
*R. Budowle, Nuclear Safety Director
*G. Burris, Electrical Maintenance
*P. Cantwell, Technical Staff Assistant Supervisor
*R. Cascarano, Operating Engineer
*R. Chrzanowski, Regulatory Assurance Supervisor
*C. Diaz, Fire Protection Engineer
*K. Dickerson, Regulatory Assurance
*P. Fay, Maintenance Supervisor
*E. Fuerst, Nuclear Operations
*K. Hansing, Daily Planning Supervisor
*P. Holland, Corporate HPES Coordinator
*D. Hubeler, Chief Steward
*R. Johnson, Assistant Superintendent, Maintenance
*D. Johnson, Stores Supervisor
*D. Kaley, Procedures Group Coordinator
*D. Karjala, Performance Improvement Director
*B. Knepper, Nuclear Station Operator
*W. Kurth, Production Superintendent
*J. LaFontaine, Assistant Superintendent, Work Planning
*R. Landrum, Training
*P. LeBlond, Assistant Superintendent, Operations
*L. Lespisa, Zion Project Engineering Support Group
*K. Mahoney, Office Supervisor
*R. Mason, Nuclear Engineering
*R. Mika, Health Physics Supervisor
*R. Milne, Station Security Administrator
*A. Miosi, On-site Engineering Supervisor
*I. Netzel, Licensed Shift Supervisor
C. Prymula, Technical Staff
*T. Rieck, Technical Superintendent

*B. Schramer, Chemistry Supervisor
*C. Schultz, Q.C. Supervisor
*T. Schuster, Nuclear Licensing Administrator
*R. Smith, Assistant Performance Improvement Director
*R. Squires, Off-site Nuclear Safety
*W. Stone, Assistant to Technical Superintendent
*N. Valos, Zion Project Engineering Support Group
*T. VanderVoort, Maintenance Staff
*R. Whittier, Nuclear Quality Programs
*D. Wozniak, Zion Project Engineering Support Group

Sargent and Lundy (S&L)

*J. Windiate, Fire Protection Engineer

*Denotes those attending the exit interview conducted on March 26, 1991.

In addition, other members of the Zion staff were contacted by AIT members.

II. DESCRIPTION - EVENTS OF MARCH 21, 1991

A. Overview of Event

On March 21, 1991, Zion Station, Unit 1, was in Hot Shutdown (Mode 3), at normal operating temperature and pressure, preparing for plant restart; Unit 2 was operating at full power. The station was in the 18th hour of a 72 hour Temporary Waiver of Compliance to allow time to complete repairs to a jacket water leak on the Common-unit Emergency Diesel Generator (0 EDG). Major evolutions in progress included the repairs to the 0 EDG, routine surveillance testing of unit 2 EDGs, 1B EDG 24-hour endurance test, and conducting Performance Test (PT)-211, "Wet Pipe Sprinkler Test."

At approximately 1:07 p.m. (CST), an inadvertent deluge of the Unit 2 (SAT) occurred. The SAT is a 345Kv/4Kv transformer that supplies all normal offsite power to the unit while the unit is shutdown and a portion of the unit's AC power when the unit is operating. Station personnel responded to the deluge station and, after confirming that no fire had occured, began to isolate the SAT deluge. While the deluge was being stopped, the SAT tripped. The electrical buses supplied by the SAT were automatically transferred to the Unit Auxiliary Transformer (UAT) which is powered by the output of the main generator.

Because of maintenance being performed on the 2B (turbine-driven) Main Feedwater pump, unit 2 feedwater was being supplied by one turbine-driven (2C) and the motor-driven (2A) Main Feedwater pump, which receives power direct from the SAT. The 2A feedwater pump lost power when the SAT tripped. The operators recognized the loss of the main feed pump and immediately attempted to reduce power; the reactor subsequently tripped for reasons which were not clearly understood at the time due to the loss of sequence of events data.

During the period of time between the SAT trip and the reactor trip, all five non-vital 4Kv buses and all three vital 4Kv buses were being supplied by the UAT. Following the reactor trip, the UAT tripped, causing a loss of off-site power to the eight 4Kv buses. Loss of the UAT is expected with a reactor trip, however, in this event it was not immediately clear whether the UAT tripped routinely subsequent to the reactor trip or for other reasons. The loss of power to the non-vital buses caused all four Reactor Coolant Pumps to trip, forcing the plant to rely on natural circulation for decay heat removal.

At the time of the SAT trip, routine surveillance testing of the 2A EDG had just commenced, the generator having been paralleled to vital bus 248 and loaded to 1 Megawatt electrical (MWe). The 2B EDG was in normal standby. 2A EDG's output breaker opened, and immediately reclosed to supply its associated bus. 2B EDG automatically started and the output breaker closed to supply vital bus 249. Vital bus 247 was not immediately reenergized because the 0 EDG was out of service for maintenance. Bus 247 was manually transferred to non-vital bus 141 (Unit 1), which is the back-up emergency power for the Unit 2 vital buses.

The licensee declared an Unusual Event at 1:35 p.m and manned the Technical Support Center at 2:10 p.m. Shortly afterward, the Reactor Coolant System was borated to cold shutdown concentration and at 4:14 p.m. Unit 2 began a natural circulation cooldown to Cold Shutdown (Mode 5).

Relay targets, oscillograph traces, and visual inspections provided initial indications that the SAT was undamaged. Further inspections revealed signs of arcing and ceramic blistering on the phase C bushing. Repairs to the bushing and corona ring were completed, gas and oil samples were taken and analyzed, testing satisfactorily completed, and the SAT was reenergized at 1:13 a.m. March 22, 1991. A reactor coolant pump was started and forced circulation re-established at 7:33 a.m. Repairs to the 0 EDG were completed, surveillance testing satisfactorily completed, the diesel was declared operable, and the Unusual Event terminated at 6:30 p.m. on March 22, 1991.

To evaluate the event, identify root causes for the deluge actuation, SAT trip, reactor trip, and any anomalous equipment behavior, the licensee formed a root cause investigation committee. The committee was not only tasked with identifying root causes but to also provide recommendations for corrective actions and improvements.

B. Sequence of Events

The AIT and the licensee compiled sequence of events listings using control room logs, operator interviews, computer and alarm printouts, and control room strip charts. Copies of logs, computer and alarm printouts, and the strip charts are included as attachments 3 through 9.

Initial conditions: Unit 1 - Hot Shutdown (Mode 3), Normal Operating Temperature and Pressure

Unit 2 - 100% power, Normal Operating Temperature and Pressure

March 21, 1991

0630 PT-211, "Wet Pipe Sprinkler Test" is identified at the regular planning meeting between Shift Engineers (SE), Operating Engineers (OE) and Planning as a Technical Specification quarterly surveillance.

0930 While performing the 2" drain line portion of PT-211 for the Unit-2 wall, Unit-2 Main Power Transformer (MPT)/UAT and SAT deluge actuated. Operators believe they receive a fire alarm on performance of first area, however, no subsequent alarms were received.

0940 Control room operators receive fire alarms indicating deluge actuation for MPT/UAT. The Shift Foreman and an Equipment Operator (EO) go to the deluge station and verify that no fire has occurred. Another EO closes the deluge isolation valve for Unit 2 MPT/UAT.

1025 MPT/UAT deluge actuated again while trying to reset the deluge valve and open isolation valve to the deluge system.

1030 MPT/UAT deluge reset and isolation valve reopened.

1303 2A EDG is started by a secondary reactor operator for performance of routine surveillance PT-11. The diesel is run for five minutes and then loaded to 1 MWe.

1307	Shift engineer and operators receive audible alarm indicating "Computer SAT 42 trouble" and observe SAT and MPT/UAT alarms. PT-211 is in progress in other areas of the plant, the operators performing PT-211 are between the 2A and 2B EDG oil storage tank rooms, and no valve manipulations have taken place at the deluge station.
1309.32	Computer "2A D/G output BKR closed". At this point the EDG is being loaded to 1MWe as part of PT-11.

The following sequence was extracted from pre and post-trip review and is a precise accounting of the events between the trip of the SAT and the and main generator trip, which deenergized the UAT and placed the unit in the loss of off-site power situation.

1309:45.447	Computer "2A D/G trouble"
1309:45.536	SAT 242 BKRS 34 & 23 Trip. Bus 244 reserve feed BKR 2422 TRIPS Auto bus transfer verified by NSO's and Unit supervisor
1309:45.586	Alarms S/G. FWP trip
1309:45.604	Computer Bus 243 Reserve feed BKR 2432 trips
1309:45.656	Bus 44 main BKR 441 auto close. Bus 43 main BKR 431 auto close During this period of time, operators are following indications and matching targets. The SE observed the loss of the Main Feed Pump and the decrease in steam generator levels. The reactor operator is directed to reduce load immediately by using "governor valve fast down". Steam generator levels are at approximately 40% and decreasing; there is a steam flow/feed flow mismatch and steam generator level alarm.
1309:45.694	EHC OPC monitor on (overspeed protection control)
1309:45.738	EDG 2A output BKR open. Perturbation during auto transfer During this period of time the SE observes 2A EDG output BKR open and reclose and observes 2B EDG starting and loading
1309:45.876	EHC OPC monitor off
1310:26	Bank D rods drive in. This is the Rod Control System in automatic responding the rapid load reduction. All reactor coolant pumps are running and reactor coolant system flow is normal.

1310:49	RX trip 85%. This is based on "nixie tube" indication by the Unit Supervisor. Reactor trip breakers are verified open.
1310:56	Rods falling
1311.14	Gen Watts low alert (20MW)
	Unit SUP saw 2 loop loss of flow after performance of immediate action in EOP-0. This was back lit indicating "First" out. This is in response to the generator trip and loss of power to the non-vital buses. Flow is coasting down and Loop D shows less than 92% flow. The operators transition from E-0 to Es 0.1 (Natural circulation cooldown).
1325	Declared an Unusual Event
1350	Notified NARS, NRC, Resident Inspe... and Station duty officer.
1400	TSC activated
1405	Bus 247 crosstied to Unit 1
1426	Starting 1000 gal boration
1429	TSC has taken command and control. Tom Joyce (Station Manager) is in charge and there is sufficient staffing available.
1600	Established RCS cooldown rate of 25 degree F/Hr per ES0.2 on Unit 2.
1617	Using AUX spray to depressurize to 1850 - 1900 PSIG
1735	Process computer is returned to service
1900	Entered GOP-4 on U1, commencing RCS cooldown
2010	Report from SAT: Arc marks in one spot C Phase coronia ring & 2 blister marks on porcelain
2115	2A SWP still has autostart signal, TSC investigating, leaving in PTL, continuing the cooldown on both units
2300	Unit 1 Mode 3 cooling to Mode 5 Unit 2 Mode 3 cooling down to Mode 5, 390 degree F starting to very slowly depressurize RCS while maintain ¶225 degree F subcooling (per ES 0.2) & 15 §320 Delta T PZR to charging.
2330	Opened 2AOV-VC8146 & closed 2AOV-VC8169 to depressurize RCS.

March 22, 1991

0015	Opened OCB 23 & 24 in preparation for closing disconnects and energizing the SAT.
0113	SAT energized
0145	U2 service busses all energi..d. 4kV service busses energized from system Aux. Trans. 242, erergized 4kV service busses from SAT.
0150	Energized 480V Buses 232, 233, 234 on Unit 2 Crosstie breaker 2332 to Bus 235 will not close, 480V service Busses 232, 233, 234 energized, energized 480V service busses 232, 233, 234.
0212	Energized Bus 248 & 249 from service busses, Bus 248 & 249 energized from off-site power, energized Busses 248 and 249 from main feed.
0219	Secured 2A & 2B EDGs
0223	Bus 247 energized by off-site power
0705	Secured AFW PPS due to suction pressure spiking - investigation found, spikes due to auto start of condensate makeup pump
0733	Started 2D RCP, established forced circulation and transitioned to GOP-4 from from the EOPs.
0857	Started depressurization of RCS to 900 PSIG using Aux. spray because normal spray is ineffective (normal spray being investigated).
1220	2 PCV-RC 455C (PORV) failed PT-2T and IM calibration. Work request initiated and valve declared inoperable. PORV 456 operates satisfactorily.
1338	Depressurizing RCS to approximately 400 PSIG on auxiliary spray. Continuing the cooldown and depressurization of both units.
1358	U1 entered Mode 4, RCS §350 degrees F.
1830	Unusual event after completing repairs and testing of common diesel generator
1837	NARS, ENS notificat s made on termination of U/E GSEP, NARS notification of GSEP termination secured cooldown U2, maintaining Mode 4.

C. Equipment Problems/Failures

The following equipment problems or failures that occurred during or immediately after the station blackout event are considered to have safety significance.

1. Security Invertor - Some security doors between the service buildings and the power block failed locked, due to equipment inoperability. This caused a delay to some NRC and licensee personnel responding to the power block from the service buildings. However, essential plant personnel responding from within the power block were not delayed by the failure. The AIT noted that the initial response by security personnel to the door failures appeared disjointed and did not adequately address the safety/safeguards significance of the event. The failure of security equipment, security personnel to properly respond, and the lack of awareness by station personnel of which doors would be manned by security could have been safety significant if a more serious event had occurred. The licensee has taken immediate steps to remedy the short term needs of providing better access should such an event recur. A special security inspection, conducted by a Region III Security Specialist, began on March 25, 1991. The purpose of the inspection was to review all security related aspects of this event. The results of the inspection will be transmitted to the licensee in a separate inspection report.

2. Sequence of Events Printer - The failure of the non-vital busses on loss of offsite power resulted in failure to record the events that occurred immediately following the reactor trip. The licensee's selection of non-vital power supplies for many chart recorders resulted in an incomplete record of plant response to the event. The plant computer does not record all of the parameters that are needed to diagnose an event.

3. PORV Will Not Open - Because Unit 2 was going to cold shutdown, PORV 455C had to be stroke tested to verify the operability of the valve for low temperature overpressure protection. The valve failed to open during the test because of a failed air line. The licensee believes that the valve would have opened at its high pressure setpoint to provide normal overpressure protection because there is an air bottle attached to the system. It is not clear that this conclusion is correct. There are two PORVs at Zion 2; PORV 456A operated properly when tested. The success criterion for feed and bleed at Zion requires operation of one charging pump (both were operable) and one PORV. Inability of PORV 455C to open is significant in that it would have forced reliance on the redundant PORV for successful feed and bleed.

The following equipment failures occurred during the loss of offsite power event, but are not considered to be safety significant.

1. Component Cooling Water Pump OA - The Component Cooling Water System (CCW) is a shared system between Units 1 and 2. It consists of five CCW pumps (only four of which are needed to meet FSAR requirements. CCW pump OA was operating when the loss of offsite power occurred. The CCW pumps are powered off of Class 1E busses. Pump OA was tripped by the operators who observed through a sight glass that there was no oil in the pump. Since the CCW pumps have significant redundancy and since the CCW system is shared among the two units (three pumps receiving power from Unit 1 ESF buses and two from Unit 2 ESF busses), this was not a safety significant failure.

2. Radiation Monitors - Some of the radiation monitors failed to power up (PR 40).

3. Temperature Indication in Source Range Wells - The temperature indicator from the source range wells was unavailable and the operators had to use the power range detectors.

4. Condensate Storage Tank Drained - On loss of normal AC, the condenser overflow valve from the condensate storage tank to the condenser hotwell went full open. This drained the condensate storage tank (a non-safety grade water supply) into the hotwell.

5. Residual Heat Removal Heat Exchanger Bypass Valves - The RHR flow control valves that control the bypass flow (and therefore the rate of temperature decrease in the primary system when on RHR) around the RHR heat exchangers failed and resulted in a high cooldown rate at the beginning of the event. Since pressurized thermal shock is not a concern at these units, a cooldown event is not particularly safety significant and is bounded by more severe events such as steam line breaks.

6. Service Water System Pump Automatic Starts - During the event, the operators attempted to manually trip service water system pump 2A. The pump immediately would automatically restart once the operator returned the breaker handle to the "after trip" position. This was later determined to be the proper behavior for the pump.

7. Auxiliary Feedwater Level Control - Following the loss of AC power, the motor-driven Auxiliary Feedwater pumps automatically started and fed the Unit 2 steam generators. The AFW system does not have automatic steam generator level control. A leaking valve in the header normally used by the motor-driven AFW pumps in combination with the failure of a steam generator atmospheric valve resulted in increasing level in one steam

generator. The normal header was isolated and the motor-driven pumps were aligned to the steam-driven AFW pump header. The steam generator level was successfully controlled.

8. Steam Generator Atmospheric Relief Valve Fails Open - Following a loss of non-vital AC power, the steam generator relief valve controls fail-as-is. The valves were nearly full open at the time of loss of non-vital AC due to the operators attempting to match feed/steam flow following loss of the motor driven feedwater pump. An operator had to go to the atmospheric relief valves and bleed off the control air to close them. One of the atmospheric steam generator relief valves failed open. The in-series isolation valve had to be controlled manually by an operator.

9. Diesel Generator Trip - After it auto started on the loss of offsite power, EDG 2A output breaker tripped on reverse power, but the diesel engine continued to operate. This was not expected by the operator. When the main generator tripped and the UAT deenergized, the diesel generator output breaker closed and picked up its ESF bus. After review, it was determined that the diesel generator and its controls operated properly.

D. Plant Staff Response

The AIT evaluated three aspects of plant staff response to this event: appropriateness of operator actions during and after the SAT and reactor trips, appropriateness of the station's response in the near-term following the event, and the station's investigation into the event. Appropriateness of operator actions and the station's response in the near term are discussed in this section. An assessment of the licensee's investigation is discussed in Section IV. A.

The operators' immediate responses to the event were generally appropriate with the exception of resetting of the "first out" annunciator after the reactor trip. This action cleared the true cause of the reactor trip and caused difficulties in identifying the actual protection system signal. During interviews, the operators only remembered seeing loss of RCS flow on the "first out" panel; this led to concerns that the generator had tripped before the reactor with resultant loss of power to the reactor coolant pumps. Later examination of the protective relay schemes revealed that the generator tripped on reverse power resulting from the turbine trip/reactor trip on low-low steam generator level.

The operators immediately recognized the loss of the SAT, and understanding the implications, verified proper transfer of electrical buses to the UAT, that RCPs were still running, and that power to one of the two operating main feed pumps had been lost. Both the Shift Engineer and the Unit Supervisor directed the primary reactor operator to reduce load by starting "governor fast down" on the main turbine.

Consequently, steam flow and feed flow mismatch was cleared before the reactor tripped, however, there was not enough time to stabilize and recover steam generator level.

Throughout the event, the operators used the appropriate operating, abnormal, emergency, and fault tree procedures. They maintained good lines of communication within the control room and brought the plant to a stable condition as expected.

The station's response to the event was generally good although some difficulties were noted. The AIT was informed that the resident inspector staff was concerned that there were too many people in the control room early in the event. The resident staff was also concerned that early in the event, operators had to deal with unnecessary phone calls from people wanting information on plant status.

Shortly after the event, the Station Manager activated the Technical Support Center (TSC) to reduce impact on the operators from additional personnel in the control room, direct resources, and provide expanded communications capabilities. The TSC activation was completed in a timely manner, a clear command and control was established, and all communications were channeled through the TSC to minimize impacts on the operators. Activating the TSC also provided additional engineering expertise and management oversight to assist the Shift Engineer in dealing with plant conditions and transfer decision-making to a higher level of management.

Although communications involving the TSC were generally good, some difficulties were noted. The operators were locally controlling "C" SG pressure and steaming rate using the atmospheric dump valve isolation valve due to failure of the associated atmospheric dump valve. Either this information was not communicated to the TSC or the TSC staff lost track of it; it is not clear which occurred. This caused confusion in responding to an NRC question regarding possible tube leakage in the "C" SG because its level was higher than the other three. The higher level in "C" SG was due to the local adjustment of steam demand; had the TSC been aware of this, they could have explained it to the NRC.

A Temporary Waiver of Compliance (TWOC) was in effect at the time of the event to allow maintenance on the 0 EDG Following the event the licensee did not clearly understand the time required to take the plant to cold shutdown. There was confusion due to the licensee's misunderstanding of the requirements of the TWOC and what time clocks were in effect. The TSC staff did not recognize that on the reactor trip they exited the TWOC, that the unit was immediately considered to be in Hot Shutdown, and that the Technical Specifications and the 1980 Confirmatory Order were the controlling documents for plant conditions. The was identified by the NRC and acknowledged by the licensee.

III. INSPECTION EFFORTS

A. System Auxiliary Transformer Deluge System Actuation

The most probable cause of a system activation was a pressure transient and/or water hammer in the fire protection supply piping. This transient would have caused the clapper valve in the "Automatic" Sprinkler Suprotex-Deluge Valve to lift allowing system water pressure to open the valve fully, resulting in the advertent actuation of the spray system on to the SAT. This event occurred at approximately 1:10 p.m. This is confirmed by the sequence of events which occurred prior to the 1:07 p.m. deluge actuation. On March 21, 1991 the licensee chose to perform system testing of the automatic sprinkler systems in the plant (PT-211). While performing a 2 inch drain flow test, to determine if there was degradation in the system piping, the deluge valve controlling the water to the main and UAT inadvertently actuated causing the system to operate. This occurred at approximately 9:30 a.m. While resetting and restoring the same system to service at approximately 10:30 a.m. the deluge valve activated again (i.e. upon opening the isolation valve the clapper valve on the deluge valve operated due to the pressure perturbation induced while reintroducing the system water pressure to the bottom of the clapper valve). These two actuations indicate that the deluge valves were very sensitive to pressure perturbations.

The licensee is also investigating the possibility of the system being initiated electrically by either a fault in the detection circuit or the deluge system control panel. Upon inspection of the SAT no damage due to fire or transformer failure could be found. In addition once the fault was removed from the SAT the transformer reset without incident. This further indicates that the first event was not electrically initiated, but most likely a pressure perturbation which activated the deluge valves.

B. Transformer Failures/System Interactions

The 4kV bus alignments prior to the event were the following (See Attachment 10):

* Non-essential bus 242 was being fed through circuit breaker (ACB) No 2421 to the UAT with ACB No. 2422 open from the SAT.

  Ess Bus 247 was being fed through ACB No. 2471 and No. 2424 (tie Breaker) to the Bus 242 with ACB No. 2472 open from the reserve feed.

* Non-essential bus 243 was being fed through circuit breaker (ACB) No 2432 to the SAT with ACB No. 2431 open from the UAT.

  Ess Bus 248 was being fed through ACB No. 2481 (ESS) and No. 2434 (tie Breaker) to the Bus 243 with ACB No. 2482 open from the reserve feed.

* Non-essential bus 244 was being fed through ACB No. 2442 to the SAT with ACB No. 2441 open from the UAT.

  Ess Bus 249 was being fed through ACB no. 2491 (ESS) and No. 2444 (tie Breaker) to the Bus 244 with ACB No. 2492 open from the reserve feed.

* Non-essential Bus No. 245 was being fed through ACB No. 2451 to the UAT with ACB No. 2452 open from the SAT.

PT-11 testing of the 2A EDG started at approximately 1:02 p.m. The EDG was manually started and loaded (approximately 1MW) through ACB No. 2483 to Bus No. 248 after running for approximately five minutes.

At approximately 1:07 p.m., control room personnel observed the fire alarm annunciator and two red lights (indicating the fire area) on fire panel No. 2CB51. The lights indicated that the deluge system had actuated on the main, UAT and SAT's. As a result of the deluge, a flash over occurred on the SAT's C phase at approximately 1:09 p.m.

The SAT's lockout relay (86T242) actuated on a C phase to ground fault. This isolated the SAT from the switchyard and opened secondary feeder ACB Nos. 2432 and 2442. This initiated an automatic bus transfer (ABT) of non-essential bus Nos 243 (along with the 2A EDG) and 244 to the UAT. The ABT took approximately 52 msec to complete the transfer (break before make transfer). During this time, the lightly loaded EDG was powering Bus No. 243 loads, including a reactor coolant pump (RCP). As the voltage was collapsing, Bus No. 243 was increasingly going out-of-phase with the UAT. The 2A EDG output breaker (2483) tripped in approximately 150 msec following the ABT on reverse power (67 relay). The EDG remained operating at rated voltage and frequency following the breaker trip.

During the power ramp down, a steam generator shrink occurred and actuated the reactor trip system. A subsequent turbine trip occurred at approximately 1:10p.m. and 49 seconds. The turbine slowly coasted down and continued to supply power to the grid and RCP buses. At approximately 1:10 p.m. and 52 seconds, the main generator reverse relay (32G2) actuated and at approximately 1:11 p.m. and 14 seconds tripped the main generator. The main generator lockout relay (86G2B) initiated the isolation of the main and unit auxiliary transformers. The lockout relays tripped the non-essential bus feeder ACBs. The loss of voltage relays on Bus No. 243 tripped the 243 tie breaker (2434) to ESS Bus No. 248. Subsequent tripping of ACB No. 2434 or the combination of EDG 2A at voltage and frequency plus Bus No. 248 undervoltage tripped ACB No. 2481. The Bus No. 248 undervoltage relays (427 device) initiated a two second time delay (427TD) which reclosed the EDG output breaker (2483) into a then dead bus. The 2A EDG satisfactorily picked up loads.

In parallel with the reloading of the 2A EDG, the 2B EDG also satisfactorily picked up loads on bus No. 249 in less than 10 seconds after the main generator trip.

Essential bus 247 lost all power as a result of the swing EDG being out-of-service. Power was restored by manually closing reserve ACB No. 2472 to the Unit 1 SAT.

During the event, the protective relaying operated as expected. Commonwealth Edisons's Operational Analysis Department (OAD) determined that all of the relays that actuated in the switchyard were the result of an initiating event that involved a phase to ground fault on C phase of the SAT. The team concurred with this assumption of the initiating event based on the following:

1. The physical evidence indicated an arc strike on the C phase transformer bushing.

2. The recording oscillograph from the switchyard clearly shows that the fault occurred on C phase.

3. The operation of the overcurrent relays actuated both of the redundant "486" relays, which indicates that this was an actual event and not a relay malfunction.

The licensee's post trip review of the event and interviews with personnel indicated that the main generator reverse power relay tripped the generator on reverse power after the reactor/turbine trip which was per the design. The 2A EDG reverse power relay also operated during the event. When the event started, the 2A EDG was connected to ESF Bus No. 248 and was paralleled to the grid through the SAT. The relay actuated when the bus voltage decreased and the loads on Bus No. 248 auto transferred to the UAT. When this occurred, there was a slight difference in the bus voltages and power factors, which caused the reverse power relay to actuate. However, when the main generator tripped, the EDG reclosed and sequenced the blackout equipment onto the bus which was per the design.

The team reviewed the sequence of events, the logic diagrams, and the systems electrical diagrams and concurred with the licensee assumption that all electrical devices and control logic performed as designed. The impact on plant safety was minimized and redundant equipment was available to further assure a safe plant shutdown.

C. Reactor trip

Identification of the cause of the reactor trip was complicated by the loss of sequence of events (SOE) data, loss of strip charts, reset of "first out" annunciator, loss of Point History data from the Prime computer, and the large number of alarms received in the control room in the immediate aftermath of the SAT and reactor trips.

A number of factors contributed to the loss of SOE data. The typers for SOE data are powered from vital bus 248. When bus 248 was deenergized all of the data loaded into a single buffer which was rapidly overloaded. In the Zion Station computer system, data sets are prioritized for output to the typers, SOE data has third priority behind control rod position Pre/post trip reactor trip reports. As a result SOE data was not outputed until approximately 90 seconds after the alarm typers were repowered.

Vital data which would normally be obtained from control room strip chart recorders and other instuments was lost because many of these instruments are powered from non-vital buses and so were lost when off-site power was lost. Collection of point history data was prevented because the prime computer failed due to voltage transients during the event.

During the event, the operators were faced with a large number of alarms in an extremely short period of time. After the event was over, the operators were unable to recall the exact sequence in which alarms were received. Also during the response, the "first out" annunciator panel was reset, clearing the cause of the reactor trip. The operators did not recall what alarm was lighted at the time or exactly who reset the alarms.

The team interviewed operators and examined available computer data and strip charts. The team also examined logic and wiring diagrams to test the validity of several event sequences. The team concluded that the rector tripped from approximately 85% power on Low-Low SG level. The 85% power level is a best estimate from the Shift Engineer from his observations of the megawatt meter and the "nixie tube" indication. Two factors led to this condition. The first was the loss of the motor-driven feed pump which was powered directly from the SAT. With the loss of this pump, SG level dropped rapidly due to severe underfeeding. The second factor was a shrink caused by the rapid closing of the main turbine governor valves as the operators attempted to reduce steam flow and power. Although their action was timely and they were able to match steam flow and feed flow, they were not able to avoid the reactor trip. As discussed in Section III. B. above, the main generator tripped on reverse power approximately 18 seconds after the reactor trip/turbine trip. When the main generator tripped, power to the UAT was lost as expected. To this point, the trip is routine with the significant exception of the faulted SAT.

D. <u>Deluge system design deficiencies</u>

The improper alignment of the water spray nozzles on the SAT resulted in a ground fault occurring when the SAT deluge valve was inadvertently operated on March 21, 1991. In the licensee's response to Branch Technical Position APCSB 9.5-1 they indicated that water spray systems at Zion Station were in accordance with NFPA 15. NFPA requires water spray systems be full flow tested annually to determine if spray nozzle impingement is adequate for the hazard being protected. The last time the licensee performed a full flow test of the water spray system for the SAT was in November 1988 which is in excess of NFPA 15 recommendations. As indicated above, the incorrect position of the spray nozzles most probably caused C Phase to arc to ground causing the SAT to trip following the inadvertent operation of the SAT deluge system. If annual inspections of the nozzle spray patterns had been performed by the licensee the incorrect spray pattern could have been discovered and the SAT trip following the inadvertent operation of the deluge valve may not have occurred.

E. Management involvement and administrative controls

When the SAT tripped, the station was in the 18th hour of a 72 hour TWOC to allow time to complete repairs to a jacket water leak on the 0 EDG. In the request for the TWOC (Attachment 11), the licensee included compensatory measures which were intended to protect electrical power supplies. Because the event involved the loss of electrical power, concerns were raised regarding administrative controls on fire protection and deluge system testing, management involvement in the decisions made related to this testing, and what actions licensee management took to ensure that station personnel were aware of the terms of the TWOC. The fundamental issue was the linking of fire protection testing to a hazard to electrical power supplies.

The team reviewed the compensatory measures for the TWOC, station general operating and administrative procedures, and PT-211, "Wet Pipe Sprinkler Test," (Attachment 14) to develop a basis for further evaluations. This was followed by interviews with management, shift supervision, and operators.

General administrative controls for testing and surveillance are contained in the licensee's general operating and administrative procedures. Controls for fire protection and deluge system testing are found in the specific surveillance procedures. The team found that the controls in PT-211 were adequate, but noted that the procedure lacked requirements to notify fire protection personnel when testing is to be conducted and guidance on silencing of alarms. The review of the compensatory measures revealed that controls were imposed on emergency diesel generator, electrical distribution system, and other safety system maintenance and testing. No specific controls were imposed on fire protection or deluge system testing nor were there any requirements to evaluate maintenance or testing activities for potential impact on electrical systems. While the terms of the TWOC did not specifically address fire protection or deluge, their intent was clear: to curtail activities which might hazard the electrical distribution system. The team viewed this as a weakness in the TWOC compensatory measures.

To ensure that station personnel were aware of the terms of the TWOC, two methods were used. First, Standing Order 91-07 (Attachment 12) was issued which listed the operational restrictions from the compensatory measures. This order is distributed to the Control Room, Assistant Superintendent - Operations, Training, Procedure Coordinator, Assistant Superintendent - Maintenance, and the Technical Staff Supervisor. The second method was to have the Regulatory Assurance Supervisor discuss the TWOC and its associated compensatory measures at the regular morning meeting. Interviews with operators and management personnel confirmed that the station staff was generally aware of the the TWOC and its compensatory measures. This was further confirmed by reviewing the Unit 2 Supervisor Turnover Sheets for three shifts (Attachment 13), including the shift on which the event occurred.

The decision to perform PT-211 was made by the oncoming and offgoing Shift Engineers and the Unit 1 Operating Engineer at the 6:30 a.m. work planning meeting. The team found that this was an adequate management level to make a decision regarding the performance of a quarterly Technical Specification surveillance. The decision to perform PT-211, even though the TWOC was in effect did not involve any evaluation of a linking between the fire protection system and the electrical distribution system. During interviews the Shift Engineer stated that he was aware of the TWOC and that he believed that it provided him with a set of activities that could not be conducted, all of which involved safety related equipment; since fire protection was not safety related, he did not connect it with the TWOC. He further stated that there was no history of deluge actuations associated with PT-211 and that he considered it a routine test. Given that PT-211 was a Technical Specification test, that it was routine (quarterly) and that there was no prior history of problems with the test, the team found that the decision to perform PT-211 was not imprudent.

The team was concerned by the station's failure to terminate testing after the first deluge occurred at 9:30 a.m. The team was especially disturbed by the failure of the Operating Engineer to question the cause for the deluge and terminate the testing until the cause was determined. At this point, energized transformers had been sprayed down and the question of risk to the electrical distribution system should have been apparent. While the team could understand the link not being made between PT-211 and a hazard to the electrical system at the 6:30 a.m. meeting, it could not understand the failure to make that link after the 9:30 a.m. deluge actuation. The failure of the station staff to take prudent actions after the deluge actuation confirms the validity of the Diagnostic Evaluation Team finding with regard to the lack of a questioning attitude on the part of the station staff and highlights the need for continued mangement attention to this area.

IV. LICENSEE INVESTIGATION

A. AIT assessment

On March 22, 1991, the licensee established a root cause investigation committee to review the event, identify root causes, and provide recommendations for corrective actions. The committee was well-staffed with both station and corporate personnel. The committee's task was similar to that of the AIT with regard to developing a sequence of events and establishing the causes for the deluge actuation, SAT trip, and reactor trip. To ensure a proper root cause analysis was performed, two members of the committee were certified INPO Human Performance Enhancement (HPES) System evaluators; one of them was the Corporate HPES Coordinator.

The root cause methodology used by the committee to evaluate this event differed sharply from that used to evaluate the November 27, 1990, SAT trip. In that case a potential cause for the event was postulated and then evidence was examined in an attempt to support this hypothesis. When the evidence could not support the postulated cause, the analysis was ruled inconclusive. In this case, the team postulated as many possible scenarios as could be conceived and then evaluated each scenario against all the evidence. If a scenario could not possibly fit the evidence then the scenario was discarded. This was a more fundamental analysis approach and the AIT felt that it was more likely to reach a correct conclusion.

To assess their performance the AIT met twice daily with the root cause committee for a status update, to raise questions and concerns, and to get answers to previous questions. AIT members also participated in all interviews conducted by the root cause committee to evaluate the manner in which the interviews were handled and to ensure that agency concerns were fully addressed.

The licensee's root cause investigation was aggressive, thorough, and fundamentally sound. Committee members were cooperative with the AIT and candid in their assessments of causes and conditions. Although conclusions had been reached for the majority of the issues, the committe had not completed all of its investigations nor issued its report when the AIT was terminated. Based on observed performance, the team is confident that the committee's final conclusions and report will be thorough and accurate.

B. Licensee Conclusions

The licensee's conclusions paralleled the AIT's with regard to the causes of the deluge, SAT trip, and reactor trip. The committee acknowledged the deficencies in the November 27, 1990, SAT trip analysis and the failure to terminate the fire protection testing after the 9:30 a.m. deluge actuation.

Some of the recommendations the committee provided included an independent design evaluation of the fire protection system by a consultant, revisions to fire protection procedures, modifications to the plant computer system, and testing of the SAT deluge system.

V. SUMMARY

A. Safety Significance

The March 21, 1991, parital loss of offsite power event at Zion Unit 2 did not endanger the health and safety of the public. From a risk assessment viewpoint, the plant was not in danger of losing core cooling or inventory makeup capability. Core cooling was maintained and primary system inventory was protected because AC and DC power remained available to Unit 2 and shared systems from Unit 1 could have mitigated the expected dominant sequences leading to core damage from a station blackout event.

Following the failure of the Unit 2 SAT, EDGs 2A and 2B operated as expected and powered 4160kV buses 248 and 249 respectively. Because of a design feature for Zion Station, the SAT at each unit is capable of powering the other unit's ESF buses. Following the loss of the Unit 2 SAT and with the 0 EDG inoperable, ESF bus 247, normally powered by the 0 EDG, was realigned by operators and powered by the Unit 1 SAT. Throughout the event, both AC and DC power were available to Unit 2. Unit 2 would have had to suffer at least three additional single failures to have had a station blackout.

The leading contributor to core damage following a station blackout is a RCP seal LOCA caused by loss of cooling to the seals. At Zion the RCP seal thermal barrier cools reactor coolant system inleakage up the RCP shaft. The inleakage is cooled in the thermal barrier heat exchanger by the component cooling water (CCW) system. The seals also receive an injection flow from the charging pumps, which are part of the Chemical and Volume Control System (CVCS). RCP seal cooling was maintained throughout the event by the CCW system. The CCW and the Service Water Systems are shared systems between Units 1 and 2 with some pumps receiving power off ESF buses from one unit and some from the other.

At most power plants, having only one transformer capable of providing incoming power (immediate or within a short period) would significantly increase the plant's chances of experiencing a loss of offsite power and possible station blackout. While each of the Zion units has only one incoming source of offsite power (disconnecting the main generator from the main transformer takes at least 12 hours), the capability of each SAT to crossfeed to the other unit's 4160kV ESF buses provides significant additional protection against station blackout. The swing diesel generator provides additional station blackout mitigation capability. On the negative side, the EDGs at the Zion Station have been unreliable in the recent past. If the 0 EDG is unavailable, both units have to shutdown causing additional thermal cycling of the units. When the EDGs at Zion are operating properly, the design of the units is such that their chance of undergoing a station blackout is comparable or lower than that of most other commercial nuclear power plants in the United States.

B. Concerns

The AIT identified a number of concerns during the inspection. Some of these concerns were specific to equipment or programs, some were general and applied to overall station performance.

Specific Equipment or Program

The fire protection system does not appear to meet the design requirement of NFPA 15 in that the spray nozzles were not properly positioned to protect the hazard and that the control and alarm panels are not Underwriters Laboratory "listed" systems.

PT-211, "Wet Pipe Sprinkler Test," was not clear with regard to what alarms should occur during the test and when they should occur.

The annual spray system full flow test had not been conducted since November 1988.

Station security personnel did not respond appropriately to the turbine block lockout and key operating shift and management personnel do not have keys to allow access under these circumstances.

The plants process computer was unable to handle all the data generated by the event. The typers lacked power supply diversity and the prime computer power supply was not stable enough to accomodate the voltage transient. Sequence of events data was listed as third priority for output to the typers. These weaknesses may result in the SOE recording system being unable to meet the requirements of Generic Letter 83-23.

Early in the event, operators were forced to deal with distractions from telephone calls to the control room from people wanting information and from unnecessary personnel in the control room.

The team was concerned with the loss of information caused by operators silencing alarms and clearing annunciators without ensuring the information was tracked or recorded.

General Concerns

Zion Station has had a Probabilistic Risk Assessment (PRA) since the early 1980s and has made little use of it for either maintenance planning or validity tests for modifications.

Operators continued to perform PT-211, even though they did not understand the cause for the deluge actuation which occurred at 9:30 a.m. The team was concerned that an Operating Engineer was aware of the inadvertent deluge and did not question its cause or terminate the testing activities until the the reason for the deluge was determined.

The team was concerned that although root cause has been a priority issue at Zion Station, the root cause methodology used to investigate the November 27, 1990, deluge was fundamentally flawed.

The compensatory measures implemented to support the TWOC were designed to ensure the stability of the electrical distribution system. They contained no provisions requiring a review of testing to identify potential hazards to the electrical system.

C. Conclusi ./Recommendations

The team concluded that there was a lack of management attention in the fire protection area. This was indicated by the lack of equipment maintenance, deviation from fire codes, and an apparent tendency to treat fire protection alarms as nuisance alarms. The team further notes that fire protection equipment and procedures need upgrading and that additional management attention is needed to heighten the station staff's awareness of the importance of fire protection. The team recommends that a currently scheduled NRC fire protection inspection be performed without delay.

The team concluded that the station's SOE recording system lacked the capacity and flexibility needed to respond to complex, long-duration events. The AIT recommends that the licensee consider modifications to the plant computer system to enhance its capability for dealing with these types of events.

The team concluded that although security personel did not respond in a manner that allowed key personnel into the power block, the significance of this was mitigated by the unrestricted access to all parts of the plant by personel already in the turbine building. The notable exception to this is the "crib house" where the Service Water pumps are located. The AIT recommends that a controlled key program be established to ensure that necessary personnel can get into the power block under any conditions.

The team concluded that operators were silencing alarms as a reflex action rather than as a considered response. The AIT recommends that the licensee establish a policy on the silencing of alarms and resetting of targets to ensure that this information is acknowledged and tracked.

The team concluded that unnecessary personnel and telephone calls to the control room are a distraction with which operators should not have to deal during an event. The team recommends that the licensee publish guidelines on control room access during events to minimize these distractions.

The team concluded that the Zion PRA has not been used effectively and recommends that the licensee evaluate methods for more widespread use of the PRA, especially in the area of maintenance planning.

The team concluded that the flawed root cause analysis of the November 27, 1990, SAT trip contributed directly to this event. The team recommends that the licensee review the criteria for classifying events for root cause analysis. Because the classification of the event establishes the level of management involvement in the investigation and review, it is important that events be properly classified to ensure an adequate management evaluation.

The team concluded that the compensatory measures in the TWOC were weak in that only safety-related equipment was addressed and there was no requirement to evaluate maintenance and testing activities for potential impact. As a result the compensatory measures did not fully protect the electrical distribution system. The AIT recommends that compensatory measures for future TWOCs contain provisions requiring that all maintenance and testing activities planned for performance during the period of the waiver be evaluated for potential impact on the systems covered by the waiver.

The team concluded that failure to terminate fire protection testing activities contributed directly to this event. The team recommends that the licensee place a renewed emphasis on developing a questioning attitude among members of the station staff.

VI. CHARTER COMPLETION

The AIT concluded that the sequence of events, as developed by the licensee and the AIT using available logs, strip charts, alarm and computer printouts, and operator interviews, is an accurate description of the event.

The AIT concluded that the most probable cause of the deluge system actuation was a hydraulic perturbation of the fire protection supply piping which lifted the clapper valve in the deluge actuation valve. These hydraulic perturbations were the result of performing the fire protection header drain valve surveillance. This cause is subject to confirmatory testing during the licensee's planned SAT outage.

The AIT concluded that the reactor trip was caused by a low-low SG signal following loss of the motor-driven main feedwater pump. All plant systems operated as expected.

The AIT concluded that only the Unit 2 SAT suffered a failure. The SAT tripped as a result of a 345kV to ground fault across the "C" phase bushing which resulted from the spray from the inadvertent deluge actuation. The team determined that both switchyard and in-plant electrical distribution protective relay systems functioned properly. No anomalous interractions between transformers or between the electrical distribution system and the fire protection system occurred during or after the event.

The AIT concluded that operator response during and after the event was appropriate. The team also concluded that the licensee's overall response to this event was satisfactory.

The AIT concluded that adequate controls had been implemented with regard to the TWOC compensatory actions. No specific controls on testing of the fire protection or deluge systems were implemented. Management involvement in the decision to conduct the fire protection testing included the Shift Engineer and an Operating Engineer and was considered adequate.

The AIT concluded that weaknesses existed in the fire protection and deluge system. The fire alarm system panels were not an Underwriters Laboratory "listed system." The design of these systems did not appear to be in compliance with the fire code as committed by the licensee.

The AIT found that the licensee implemented the terms of the TWOC through the issuance of a Standing Order listing the terms. The Standing Order had a distribution beyond the control room, ensuring that other departments in the station were aware of the waiver's existence. Additionally, the terms of waiver were addressed by the Regualtory Assurance supervisor in both of the station's morning planning meetings.

VII. EXIT INTERVIEW

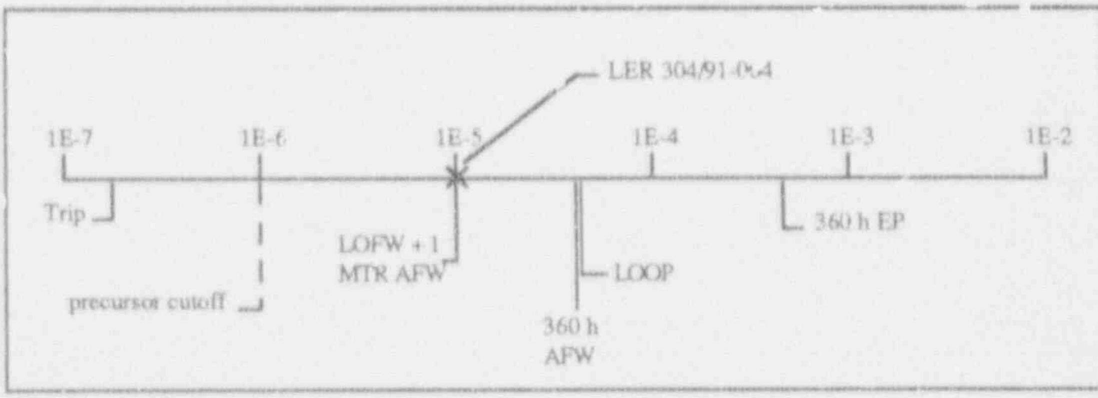
The AIT met with licensee representatives (denoted in paragraph 1.C) throughout the inspection and on March 26, 1991, after the AIT was terminated. The team summarized the scope and findings of the Augmented Inspection Team's activities. The licensee acknowledged these findings. The team also discussed the likely informational content of the inspection report with regard to documents and processes reviewed by the the inspectors during the inspection. The licensee did not identify any documents or processes as proprietary.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	304/91-004
Event Description:	Main feedwater pump trip with one AFW pump failed
Date of Event:	June 11, 1991
Plant:	Zion 2

Summary

Failure of a capacitor in the steam generator (SG) level controller power supply caused an SG overfeed during a startup. As a result of the high SG level, a main feedwater (MFW) pump trip and reactor trip occurred. During the startup, one of the auxiliary feedwater (AFW) pumps had failed to start. The conditional core damage probability estimated for this event is 1.0×10^{-5}. The relative significance of this event compared to other postulated events at Zion 2 is shown below.



Event Description

During a Zion 2 startup on June 11, 1991, the AFW pumps were being used to feed the SGs. MFW pump 2C had been started and was being aligned to feed the SGs. The bypass feedwater regulating valves (FRVs) were placed in automatic to control the SG level. Failure of a capacitor in the SG level controller power supply circuitry resulted in overfeed of the SGs. MFW pump 2C tripped on a high SG level signal resulting in a turbine and reactor trip. During the startup attempt, one of the AFW pumps had failed to start (reason unspecified). Prior experience with leakage from the FRVs led operators to conclude that the overfeed event had resulted from valve leakage, thereby confounding accurate diagnosis of the event. Several attempts at startup were made over two shifts, and each resulted in a high SG level trip, before the problem was correctly diagnosed.

Additional Event-Related Information

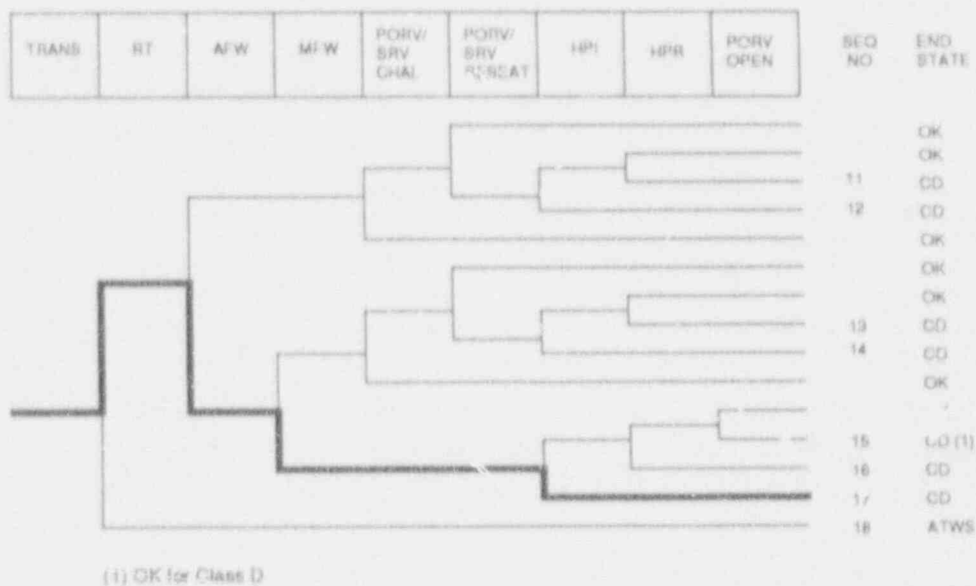
Zion 2 has two motor-driven AFW pumps and one turbine-driven AFW pump. The AFW success criterion for decay heat removal is one pump out of three.

ASP Modeling Assumptions and Approach

The event has been modeled as a potentially recoverable loss of feedwater with one motor-driven AFW pump unavailable. The event was analyzed assuming it had occurred at power, although it actually occurred during startup, when decay heat loads were less.

Analysis Results

The conditional core damage probability for this event is conservatively estimated at 1.0×10^{-5}. The estimate is conservative because of the analysis assumption that the event occurred at power, when it actually occurred during startup. The dominant core damage sequence, highlighted on the following event tree, involves a reactor trip with unavailable secondary-side cooling and failure of bleed and feed.



Dominant core damage sequence for LER 304/91-004

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 304/91-004
Event Description: MFW pump trip and reactor trip with one AFW pump failed
Event Date: 06/11/91
Plant: Zion 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.0E-05
Total	1.0E-05
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
17	trans -rt AFW MFW hpi(f/b)	CD	5.1E-06	7.4E-02
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	4.8E-06	8.8E-02
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	5.3E-07	8.8E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	4.8E-06	8.8E-02
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	5.3E-07	8.8E-02
17	trans -rt AFW MFW hpi(f/b)	CD	5.1E-06	7.4E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\zion.all
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch System Non-Recov Opr Fail

Event Identifier: 304/91-004

trans	1.5E-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	5.4E-04	8.0E-01	
AFW	3.8E-04 > 5.3E-03	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
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	3.1E-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	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Minarick
05-26-1992
09:18:47

Event Identifier: 304/91-004

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Zion Unit 2	0 5 0 0 0 3 0 4	1 of 0 5

Title (4)

Unit 2 Reactor Trip Due to a Failed Capacitor in the Steam Generator Automatic Feedwater Control Circuitry

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 Names	Docket Number(s)
0 6	1 1	9 1	9 1	0 0 4	0 0	0 7	1 1	9 1		

OPERATING MODE (9): 1

POWER LEVEL (10): 0 1 7

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

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

LICENSEE CONTACT FOR THIS LER (12)

Name: Suzanne L. Mika ext. 2323

TELEPHONE NUMBER: AREA CODE 7 0 8 7 4 6 - 2 0 8 4

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
X	J B	[illegible] L C	H 0 1 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On June 11 1991, during Unit 2 plant startup, several unsuccessful attempts were made to use the bypass Feedwater Regulating Valves (FRV) [SJ] in the automatic mode to control steam generator (S/G) level [JB] while the unit operators were aligning the main feedwater pumps. The main feedwater system [SJ] was successfully aligned with the bypass FRVs in the manual mode and the main turbine speed was increased to 1800 rpm. After the main generator was synchronized to the grid, the unit operators attempted to place the main FRVs in automatic and to close the bypass FRVs in manual. The main FRVs filled the S/Gs to 70% which then generated a turbine trip signal which then generated a reactor trip because reactor power was greater than 10%.

This event was caused by a failed capacitor in the power supply circuitry of the S/G level controller. Contributing to this event was a history of problems with leaking bypass FRVs. This lead to the incorrect diagnosis by the unit operators that the leaking bypass FRVs were causing the S/G level control problems. During this event all actions taken were within the bounds of the Technical Specification Limiting Conditions for Operation and there was no safety significance to this event. Corrective actions included determining the root cause of the capacitor failure, reviewing the S/G level control system to determine what information should be provided to the unit operators, identifying recurring feedwater System problems, and verifying the calibration of the bypass FRV controller.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)		
		Year	///	Sequential Number	///	Revision Number			
Zion Unit 2	0 5 0 0 0 3 0 4	9 1	-	0 0 4	-	0 0	0 2	OF	0 5

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

A. CONDITION PRIOR TO EVENT

MODE 1 - Power Operation RX Power 17% RCS [AB] Temperature/ Pressure 549 °F/ 2235 psig

B. DESCRIPTION OF EVENT

On June 11, 1991, Unit 2 plant startup was in progress. The Reactor was critical with the secondary plant components being started up per General Operating Procedure (GOP)-2 "Plant Startup". Auxiliary Feedwater Pumps (AFP) [BA] were feeding the steam generators (S/G). At 0935, 2C Main Feedwater Pump (MFP) [SJ] was being started and lined up to feed the S/Gs. The Bypass Feedwater Regulating Valves (FRV) [SJ] were placed in automatic to control S/G level [JB]. S/G levels increased and the bypass FRVs were still going open which was contrary to system design. The operators were involved in aligning AFPs for power operation which requires the AFPs to be started and the AFP discharge throttle valves set to produce 110 gpm flow to each S/G. While the operators were concentrating on aligning the AFP for power operation, one AFP failed to start and was declared inoperable at 0946. While the AFPs were being aligned for power operation, the S/Gs were continuing to fill due to improper operation of the bypass FRV. At 0957, S/G 2A reached 70% level and the High Steam Generator Level Permissive (P-14) signal was generated. P-14 is a turbine protection signal which automatically trips the main feed pumps and main turbine, and automatically closes the main FRVs and bypass FRVs on the affected S/G when two out of three level transmitters on the affected S/G are greater than 70%. A turbine trip will generate a reactor trip if power is greater than 10%. When 70% was reached in 2A S/G, the 2C main feedwater pump (MFP) tripped and the bypass FRVs closed as designed. Although the operators had noticed improper operation of bypass FRVs, the consensus of the Control Room personnel was that it was the distraction of aligning the AFP for power operation, along with feedwater valve leakage that caused the high level in the S/Gs. Feedwater valve leakage has been a historical problem at Zion. Operator experience lead to the assumption that most problems with automatic controls at low power levels were due to leakage. Since an AFP had been declared inoperable, Technical Specification Limiting Condition for Operation (LCO) 3.7.2 was entered and therefore the mode change to power operations could not be performed until the AFP was declared operable.

The AFW pump was repaired and declared operable at 1745 (DVR 2-91-044). The plant startup was recommenced and the 2C MFP was again started at 1830. Automatic operation of the bypass FRVs was attempted several times. However, when the bypass FRVs were placed in automatic, they continued to fill the S/Gs above their normal operating level. At 2010, 2C MFP was manually tripped to prevent reaching 70% in 2 S/Gs. A second attempt was made to start 2C MFP at 2035. Bypass FRVs were kept in manual although automatic operation was attempted. Turbine rollup commenced at 2054 and the turbine reached 600 RPM. Different feedwater controls were operated in manual including feedwater containment isolation valves, bypass FRVs, and MFP speed. Although the turbine reached 600 RPM, 70% level was reached on 2D S/G and a P-14 signal was generated. The 2C MFP tripped along with the main turbine.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION						Form Rev 2.0		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (4)	
		Year	///	Sequential Number	///	Revision Number		
Zion Unit 2	0 | 5 | 0 | 0 | 0 | 3 | 0 | 4	9 | 1	-	0 | 0 | 4	-	0 | 0	0 | 3	OF 0 | 5

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

B. <u>DESCRIPTION OF EVENT (CONT)</u>

A new shift came on at 2300. The feedwater containment isolation valves were throttled for A, B, and C S/G and the D S/G containment isolation valve was 3-5 seconds open (60 seconds is full stroke time). The bypass FRVs were in manual and the shift turnover report stated that the bypass FRVs would not control in automatic and were leaking severely. The feedwater pump differential pressure control was considered difficult to control. At 2111, 2C MFP was started again. Although difficult to control, the main feedwater system was placed in service and the main turbine speed was increased to 1800 RPM. After these evolutions, the S/G levels were considered to be fairly stable. At 2346, the main generator was energized and synchronized to the grid. With reactor power increasing, GOP-2 required main FRVs to be placed in automatic and bypass FRVs to be closed. In anticipation of this evolution, the feedwater containment isolation valves were fully opened. The turbine ramp rate was increased from .5%/min to 1%/min. As the main FRVs were placed in automatic to open, the bypass FRVs were closed in manual per procedure. The main FRVs ramped open above program and filled the S/Gs to 70%. S/G 2D reached 70% first and a P-14 signal was generated at 2355. This tripped the main turbine and the 2C MFP, and closed the main FRV and bypass FRV. Since power was greater than 10%, a reactor trip also occurred. The plant emergency procedures were entered and the reactor was stabilized in Hot Shutdown.

C. <u>APPARENT CAUSE OF EVENT</u>

The primary cause of this event was the failure of a capacitor in the power supply circuitry of the S/G level controller. This capacitor filtered AC ripple voltage to provide DC voltage that was then supplied to the rest of the level controller's internal components. When the capacitor failed, AC ripple voltage was supplied directly to the controller's internal components causing the limiting components to fail. Because the limiting components provide a reference level signal to the S/G level controllers, when these components failed, the level controller supplied the S/Gs with a reference level of 100%. When the main FRVs were placed in automatic and the bypass FRVs were placed in manual, the 100% level signal from the level controller caused the main FRVs to continue to fill the S/Gs until the 70% setpoint level was exceeded. When S/G level reached 70%, a P-14 signal caused the main turbine to trip which then caused the Unit 2 reactor to trip since reactor power was greater than 10%.

Contributing to this event was a history of problems with leaking main and bypass FRVs. The unit operators determined that leaking bypass FRVs were causing the S/G level control problems. This diagnosis was passed from shift to shift without any additional independent assessments forming a different conclusion. HPES interviews were held with many operating personnel following the event and all write-ups of operating personnel were reviewed. During the initial stages of the FW system startup, problems with S/G level control were encountered and the problem was diagnosed as leaking bypass FRVs. However, post trip discussions revealed that the control board indications did not completely agree with this diagnosis (i.e. bypass FRVs went open when placed in auto even while at or above program level and the ±5% deviation alarm never cleared when program level and S/G level were in agreement). The complexity and level of activity associated with FW control during start-up, coupled with this activity being spread over several shifts, and operators' intuition based on a history of problems with valves leaking through, may have compromised a thorough diagnosis of the event. Additionally, when information was passed from shift to shift and/or operator to operator the original diagnosis was always accepted.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION						Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)				Page (5)
		Year		Sequential Number	Revision Number	
Zion Unit 2	0 5 0 0 0 3 0 4	9 1	-	0 0 4	- 0 0	0 4 OF 0 5
TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]						

C. APPARENT CAUSE OF EVENT (CONT)

Also contributing to this event was that the S/G reference level indication was removed from the control board and replaced with indication of the differential pressure between the FW System and Steam pressure. This was done because the differential pressure indicator is more useful during power operations than the S/G reference level indicator. If this indicator had still been on the control board, the unit operator may have recognized that the automatic S/G level controller had failed high.

A review of GOP-2 revealed that step 60, which requires bypass FRVs to be placed in automatic, was not initialed. The procedure required that if a step cannot be complete as required it may be exempted provided two Licensed Shift Supervisors (LSS) sign off on the "Exemption/Deletions" page. In this case, this was not done. Had two LSSs made the necessary evaluation to approve bypassing step 60, the level program error may have been recognized.

D. SAFETY ANALYSIS OF EVENT

During this event all failures and actions taken were within the bounds of the Technical Specification Limiting Conditions for Operation. There was therefore no safety significance to this event. All safe shutdown features worked as designed. Steam Generator Hi-Hi Override (P-14) is a turbine protection signal to prevent damage from moisture impinging the blades.

E. CORRECTIVE ACTIONS

Human Performance Evaluation System (HPES) investigation 91-14 was performed immediately following this event, and also a team investigation was conducted which generated the following corrective actions:

1. Tech Staff, Mechanical Maintenance and Operating verified that all mechanical overrides were intact and not impeding the proper operation of the valves. Additionally, with no demand on the M/A stations, 0 psi diaphragm pressure was verified on all the valves per design.

2. The calibration of the loop D Bypass FRV Controller was verified by simulating inputs and verifying proper outputs. No problems were found. Additionally, the valve was stroked and proper movement was observed.

3. A root cause analysis of the capacitor failure will be performed. (304-180-91-04301)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION						Form Rev 2.0		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)				Page (6)		
		Year		Sequential Number	Revision Number			
Zion Unit 2	0 5 0 0 0 3 0 4	9 1	-	0 0 4	0 0	0 5	OF	0 5
TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]								

E. CORRECTIVE ACTIONS (CONT)

4. A review of the S/G level control system will be performed to determine what control information should be provided to the operators. (304-180-91-04302)

5. Station management will review expectations desired from operators when performing tasks per approved procedures. (e.g. Instructions for Using GOP-2. EXCEPTIONS/DELETIONS and response to equipment which does not respond as expected.) (304-180-91-04303)

6. Training on this event will be given to the Operating Department to emphasize the need for an independent [illegible] when information is relayed among shift personnel. (304-180-91-04304)

7. A multi-department walkdown and review of the FW system will be performed to identity any recurring FW problems. Based on this review and walkdown, any necessary actions to correct these problems will be resolved and the resolutions will be distributed to the appropriate personnel. (304-180-91-04305)

8. SOER 84-4 "Reactor Trip caused by Main Feedwater Control Problems" gives recommendations on switching feedwater control between manual and automatic. An effectiveness review of SOER 84-4 will be conducted based on this event. (304-180-91-04306)

F. PREVIOUS EVENTS

A search was conducted of the LER/DVR Database using the System code of Feedwater. LER 1-88-005 describes a Reactor Trip which occured due to slow response time of a Main Feedwater Regulating Valve. None of the corrective actions taken would have prevented this event.

DVR 1-88-137N1 documents an event where failed capacitors in the S/G level controller nearly caused a reactor trip. The corrective actions from DVR 1-88-137N1 would not have prevented this event.

G. COMPONENT FAILURE DATA

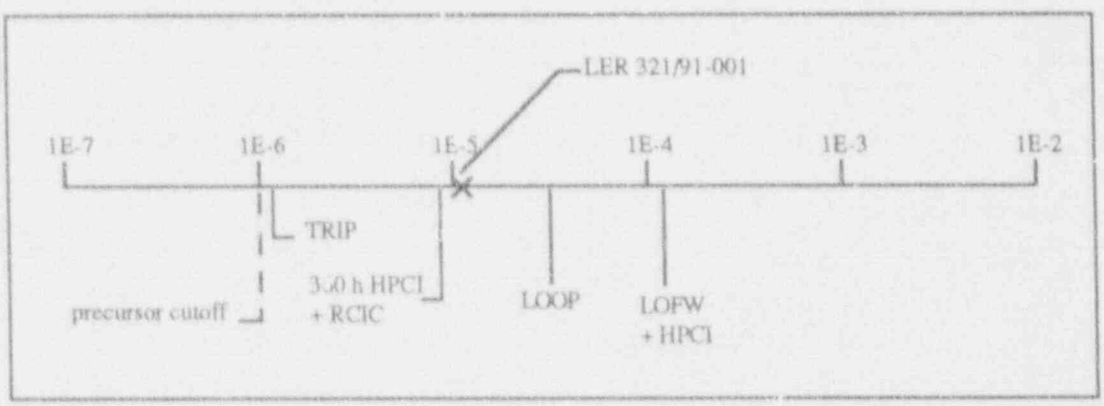
Manufacturer	Nomenclature
Hagan Controls	Summator

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	321/91-001
Event Description:	Loss of feedwater with HPCI degraded and RCIC failed
Date of Event:	January 18, 1991
Plant:	Hatch 1

Summary

The reactor scrammed from 100% power following the loss of an offsite transmission line and failure of a switchyard breaker, which resulted in unavailability of nonessential power supplies and a subsequent loss of feedwater (LOFW). The high-pressure coolant injection (HPCI) system tripped multiple times on overspeed and required manual control to inject into the reactor pressure vessel (RPV). Following initial recovery of RPV level, the reactor core isolation cooling (RCIC) system inboard isolation valve failed, preventing further use of RCIC. The conditional core damage probability estimated for this event is 1.1×10^{-5}. The relative significance of this event compared to other postulated events at Hatch 1 is shown below.



Event Description

Hatch 1 was operating at 100% of rated power at 1500 hours on January 18, 1991, when an offsite 230-kV transmission line failed, causing initially a phase-to-phase fault followed by a phase-to-ground fault when the line came in contact with its support tower. The fault caused a main transformer lockout relay to trip, which, in turn, caused a generator load reject, turbine trip, and reactor scram. Following the transmission line failure and subsequent electric power transfer, a 230-kV switchyard breaker did not fully open when it tripped, resulting in the loss of nonessential loads. Among the nonessential loads lost were the condensate, condensate booster, and the circulating water pumps as well as the reactor recirculation pump motor-generator set.

The loss of the condensate pumps caused the reactor feed pumps to trip on low suction pressure and resulted in low reactor water level, which autom ally initiated both HPCI and RCIC. HPCI tripped on overspeed more tha once (the result of a failed speed controller), and the operators placed HPCI control in manual for RPV level restoration. Power was restored to nonessential loads about 2-3 min after the scram, and HPCI and RCIC were shut down when vessel level returned to normal.

Later, during the scram recovery, RCIC was restarted, but the operators noticed that the valve position indication for the . oard injection valve had failed and RCIC did not appear to be restoring level fast enough. A control power fuse for the valve actuator was found failed with the isolation valve in mid-position. HPCI was used in manual control until feedwater (FW) flow was reestablished approximately 47 min after the scram.

Additional Event-Related Information

The HPCI system is a high-pressure injection system designed for small-break loss-of-coolant accidents (LOCAs) that do not depressurize the reactor. HPCI is an independent system, using a turbine-driven pump, and automatically initiates on reactor low water level. HPCI can deliver 4250 gpm of makeup water to the vessel through the FW piping.

The RCIC system is a lower-flow system that also uses a turbine-driven pump. RCIC can provide sufficient makeup for decay heat removal following a LOFW with successful closure of all open relief valves.

ASP Modeling Assumptions and Approach

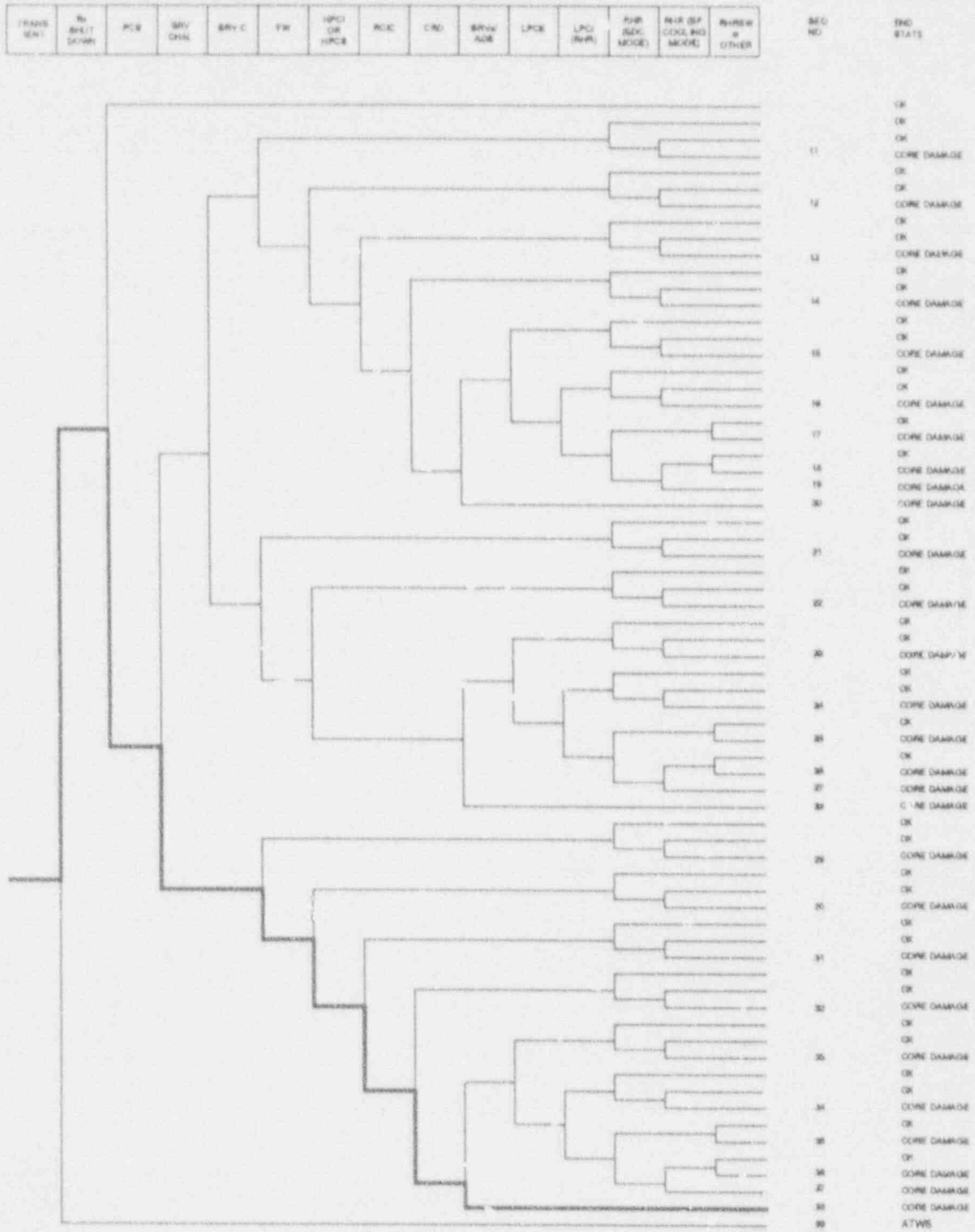
The event has been modeled as a recoverable LOFW with HPCI failed but recoverable from the control room [p(nonrecovery) = 0.04] and RCIC failed and not recoverable. The observed time to recovery of feedwater (47 min) was assumed to represent the mean recovery time. Assuming an exponential model, a probability of failing to recover feedwater within 30 min of 0.53 was estimated. No safety relief valves (SRVs) lifted during the event, and the model was modified to reflect this.

An additional calculation was performed to assess the potential impact of nominal Accident Sequence Precursor (ASP) assumptions regarding SRV lift and FW recovery.

Analysis Results

The conditional probability of subsequent core damage estimated for this event is 1.1×10^{-5}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated failure to recover feedwater and HPCI, failure of RPV makeup using the control rod drive pumps, and failure to depressurize to allow use of the low-pressure systems.

An alternate analysis, based on the assumption that SRVs are always challenged (this is assumed in the ASP models for boiling-water reactor transients and LOOPs), and utilizing the feedwater nonrecovery probability currently included in the ASP model for Hatch, results in a conditional core damage probability estimate of 1.5×10^{-5}.



Dominant core damage sequence for LER 321/91-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 321/91-001
Event Description: LOFW with HPCI degraded and RCIC failed
Event Date: 01/18/91
Plant: Hatch 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1. -05
Total	1.1E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
99 trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
99 trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrcaeal.cmp
BRANCH MODEL: c:\asp\1989\hatch.all
PROBABILITY FILE: c:\asp\1989\bwr_call.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.1E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	

Event Identifier: 321/91-001

PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
SRV.CHALL/TRANS.-SCRAM	1.0E+00 > 0.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E+00 > 0.0E+00		
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	5.4E-04	8.0E-01	
ep.rec	1.6E-01	1.0E+00	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 5.3E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
fw/pcs.loca	1.0E+00	3.4E-01	
HPCI	2.9E-02 > 1.0E+00	7.0E-01 > 4.0E-02	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-02 > Failed		
RCIC	6.0E-02 > 1.0E+00	7.0E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > Failed		
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

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08-06-1992
10:09:13

NRC Form 366 (6-89) FEB 28 1991 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
PLANT HATCH, UNIT 1	05000321	1 OF 8

TITLE (4)
REMOTE TRANSMISSION LINE FAILURE COUPLED WITH SWITCHYARD BREAKER FAILURE CAUSES REACTOR SCRAM

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ NUM	REV	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
01	18	91	91	001	00	02	11	91	PLANT HATCH, UNIT 2	05000366
										05000

OPERATING MODE (9): 1

POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[X] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below)
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
STEVEN B. TIPPS, MANAGER NUCLEAR SAFETY AND COMPLIANCE, HATCH	912	367-7851

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORT TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORT TO NPRDS
X	BJ	SC	W290	YES		X	BN	FU	B569	NO
X	BD	DMP	B237	NO		X	FK	BKR	N/A	NO

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (16)

On 01/18/91, at approximately 1500 CST, Unit 1 was in the Run mode at an approximate power level of 2436 CMWT (approximately 100% rated thermal power). At that time, a remote power transmission line failed at its attachment point to the supporting electrical tower. In addition, a breaker in the Plant Hatch 230 kV switchyard failed to fully open in response to the sensed electrical fault conditions resulting in the trip of the Unit 1 main transformer auxiliary lockout relay. This resulted in main generator and main turbine trips, which, in turn, resulted in a reactor scram. This also resulted in a loss of power to the Unit 1 nonessential electrical busses and the prevention of the normal automatic transfer to the alternate supply due to the transfer logic. Power was manually restored to nonessential loads within approximately 2 to 3 minutes allowing for the initiation of operator actions to restore feedwater flow. In the interim, to recover reactor water level, the High Pressure Coolant Injection system (HPCI) automatically initiated. Although it exhibited erratic behavior in the automatic mode, it was successfully controlled manually and water level was restored and maintained with HPCI until feedwater flow was restored. Reactor pressure was controlled by the turbine bypass valves.

The root causes of the scram were the failure of the high tension power line and the failure of the main breaker to fully open. The root cause of the erratic HPCI operation was component failure in the HPCI speed controller.

Corrective actions included repairing the failed power line, repairing the failed breaker, and replacing the failed HPCI speed controller.

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NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO 3150-0104 EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (5) YEAR	SEQ NUM	REV	PAGE (3)
PLANT HATCH, UNIT 1	0 5 0 0 0 3 2 1	9 1	0 0 1	0 0	2 OF 8

TEXT

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes are identified in the text as (EIIS Code XX).

SUMMARY OF EVENT

On 01/18/91, at approximately 1500 CST, Unit 1 was in the Run mode at an approximate power level of 2436 CMWT (approximately 100% rated thermal power). At that time, a power transmission line failed at its attachment point to the supporting electrical tower, which was located approximately 21.4 miles from Plant Hatch. In addition, a breaker in the Plant Hatch 230 kV switchyard failed to fully open in response to the sensed electrical fault conditions resulting in the trip of the Unit 1 main transformer auxiliary lockout relay. This resulted in main generator and main turbine trips, which, in turn, resulted in a reactor scram. This also resulted in a loss of power to the Unit 1 nonessential electrical busses and the prevention of the normal automatic transfer to the alternate supply due to the transfer logic. Power was manually restored to nonessential loads within approximately 2 to 3 minutes allowing for the initiation of operator actions to restore feedwater flow. In the interim, to recover reactor water level, the High Pressure Coolant Injection system (HPCI, EIIS Code BJ) automatically initiated on low level. Although it exhibited erratic behavior in the automatic mode, it was successfully controlled manually and water level was restored and maintained with HPCI until feedwater flow was restored. Reactor pressure was controlled by the turbine bypass valves (BPV, EIIS Code JI).

The root causes of the scram were the failure of the high tension power line and the failure of the main breaker to fully open. The root cause of the erratic HPCI operation was component failure in the HPCI speed controller.

Corrective actions included repairing the failed power line, repairing the failed breaker, and replacing the failed HPCI speed controller.

DESCRIPTION OF THE EVENT

On 01/18/91, at approximately 1500 CST, Unit 1 was in normal full power operation when the phase 1 portion of a 230 kV transmission line failed at its attachment point to the supporting electrical tower, located approximately 21.4 miles from the plant. As the phase 1 line fell away from the break location, it briefly contacted phase 2, creating a phase 1-2 fault. This fault was sensed and resulted in a trip signal being sent to power circuit breakers (PCB, EIIS Code FK) 490 and 500 in the Plant Hatch 230 kV switchyard. Phase 2 of PCB 500 did not successfully open at this time due to a failed current limiting resistor in the breaker control circuit. However, as phase 1 opened, the phase 1-2 fault cleared since the current loop between phases 1 and 2 had been interrupted. At this point in the transient, the electrical output of Plant Hatch Unit 1 was flowing through other circuits in the switchyard and for the next few milliseconds, no other electrical fault existed.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT

Continued movement of the failed phase 1 line resulted in it again contacting phase 2 and this time contacting the electrical tower as well. This provided a conducting path between phase 2 and the electrical tower, creating a phase 2 to ground fault. This fault current was supplied through the still-closed pole of phase 2 in PCB 500. The resumption of fault current through this breaker resulted in the breaker failure relay being tripped. The breaker failure relay tripped a lockout relay in the Unit 1 main transformer control circuitry which, in turn, initiated a main generator and main turbine trip. This turbine trip occurred at greater than 30% reactor power, resulting in a reactor scram per design. The main turbine bypass valves opened, as designed, to mitigate the reactor pressure transient, limiting reactor pressure during the transient to a maximum of approximately 1095 psig. No safety relief valves (SRV, EIIS Code JE) opened and post-event investigation confirmed none were required to open.

With the main transformer disconnected from the grid, nonessential site electrical loads were automatically disconnected since they are normally supplied through the main transformer. The nonessential loads are designed to automatically transfer to their alternate supply. However, in order for this transfer to occur, the transfer logic circuit must sense all phases of both PCBs 500 and 510 open. Because one phase of PCB 500 did not open and indication for the PCB was lost (explained later in this report), automatic transfer to the alternate supply was prevented and Unit 1 nonessential loads remained deenergized. Among these loads were the condensate pumps (EIIS Code SD), condensate booster pumps (EIIS Code SD), main circulating water pumps (EIIS Code SD), and reactor recirculation system motor-generator sets (EIIS Code AD).

Without the condensate booster pumps, the reactor feedpumps tripped on low suction pressure. Lacking normal reactor feedwater flow, reactor water level decreased to approximately 12 inches above instrument zero by approximately 15:01 CST, initiating a Primary Containment Isolation System (PCIS, EIIS Code JM) Group II isolation and another scram due to low reactor water level. All required Group II valves closed as designed. At approximately 15:03 CST, reactor water level reached 35 inches below instrument zero, resulting in an automatic initiation of the HPCI and the Reactor Core Isolation Cooling systems (RCIC, EIIS Code BN), as well as PCIS Group V and secondary containment isolations. The PCIS Group V isolation occurred as designed. Both Unit 1 and Unit 2 Standby Gas Treatment Systems (SGTS, EIIS Code BH) started and functioned as designed. Upon receipt of the auto start signal, the HPCI system demonstrated erratic operation resulting in more than one HPCI turbine overspeed trip. The control room operators took manual control of HPCI. The RCIC system functioned normally. Thus, with the HPCI and RCIC systems injecting, reactor water level recovered. The minimum water level observed during the transient was approximately 38 inches below instrument zero, which is approximately 126.5 inches above the top of active fuel.

NRC Form 366A (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO 3150-0104 EXPIRES: 4/30/92			
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PLANT HATCH, UNIT 1	05000321	91	001	00	4 OF 8

TEXT

A post-event review team observed that a secondary containment damper, 1T41-F043B, failed to close when the secondary containment isolation signal was received. However, the inoperable damper did not prevent successful secondary containment isolation because the redundant damper in that same duct did close.

At approximately 2 to 3 minutes after the initial scram, power was manually restored to nonessential site load. At this point, activities were initiated to restore normal feedwater flow.

Between 15:05 CST and 15:10 CST the control room received a report of a fire in the switchyard. The fire brigade responded, but found the fire had already been extinguished by a member of the switchyard maintenance crew using a portable carbon dioxide fire extinguisher. The source of the fire was a damaged current limiting resistor in the control circuitry of the failed PCB 500. The damage to the control circuitry had already caused the loss of PCB indication alluded to earlier in this report.

The licensed reactor operator assigned to control reactor water level reduced the flowrate and then tripped the HPIC and RCIC systems to stabilize reactor water level at approximately 43 inches above instrument zero. This occurred at approximately 15:23 CST. Although not recognized at the time, position indication was lost on the RCIC inboard injection valve, 1E51-F013, as it began to close as designed on a RCIC trip signal. As decay heat caused reactor pressure to increase and the bypass valves opened to control reactor pressure, reactor water level again began to decrease. At approximately 15:35 CST, with reactor water level at approximately 15 inches above instrument zero and decreasing slowly, RCIC was restarted. It was at this time that the licensed operator noticed that position indication had been lost on 1E51-F013. The operating crew concluded that the valve was only partially open since it appeared to them that reactor water level was not being restored as quickly as expected. The operators decided to secure RCIC and investigate the valve indication problem. A plant equipment operator was dispatched to the valve breaker, but the breaker would not reset.

At approximately 15:40 CST, reactor water level reached approximately 12.5 inches above instrument zero, and another scram signal was received due to low reactor water level. Plant operators then started HPCI in the manual control mode and recovered reactor vessel water level. HPCI would have been restarted earlier to recover level, but operations personnel believed the restoration of feedwater was imminent. By approximately 15:47 CST, a reactor feed pump was returned to service, and water level was controlled thereafter using the normal reactor level control system.

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TEXT

CAUSE OF THE EVENT

The direct cause of the first scram was a turbine trip which occurred above 30% rated thermal power. The root causes of the first scram were the failed remote power transmission line and the failed current limiting resistor in PCB 500. The failed current limiting resistor prevented the tr[illegible] signal from reaching phase 2 of PCB 500 which caus[illegible] the redundant breaker, PCB 510, to open to clear the fault. The opening of PCB 510 resulted in a main turbine trip, which led to the scram.

The cause of the failure of the HPCI system to properly inject in the automatic mode was a failed speed controller. Post-event maintenance attempted to recalibrate the controller, but the controller would not retain its recalibration. However, it should be noted that the failure mode of the speed controller, due to the configuration of the control logic, did not preclude successful control of HPCI in the manual mode.

The cause of the lost valve indication on 1E51-F013 was a blown fuse in the valve actuator control power circuit. This interrupted control power to the valve, preventing the valve from being moved. The fuse failure was investigated by the architect/engineer and was determined to have been a random failure.

The cause of the failure of damper 1T4[illegible]-F043B was water-induced corrosion on the pneumatic actuator. It appears that due to the location of this damper on the outside of the reactor building, the damper was exposed to environmental conditions which fostered the condensation and accumulation of moisture and the resultant corrosion over time. It should be noted that the air quality, specifically dewpoint, particulate content, and oil content, has been sampled as part of Georgia Power Company's response to Generic Letter 88-14 regarding instrument air supply system problems affecting safety related equipment. The results of the sampling met the requirements ANSI/ISA S7.3-1975, Reaffirmed 1981. As part of the ongoing Plant Hatch program for maintaining proper instrument air quality, air quality is periodically sampled and evaluated against the same standard.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This event is reportable per 10 CFR 50.73(a)(2)(iv) because an unplanned actuation of the Reactor Protection System (RPS, EIIS Code JC) and Engineered Safety Features (ESF) occurred. Specifically, tripping of a main transformer lockout relay resulted in a turbine trip above 30% rated thermal power, which in turn resulted in a reactor scram. This event is also reportable per 10 CFR 50.73(a)(2)(v) because an event occurred which could have prevented the fulfillment of the safety function of a system which is intended to mitigate the consequences of an accident. Specifically, a failed HPCI speed controller caused the HPCI system to trip repeatedly due to overspeed, with the result that operators were required to take manual control of HPCI in order to restore reactor water level.

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TEXT

A post-event review team observed that a secondary containment damper, 1T41-F043B, failed to close when the secondary containment isolation signal was received. However, the inoperable damper did not prevent successful secondary containment isolation because the redundant damper in that same duct did close.

At approximately 2 to 3 minutes after the initial scram, power was manually restored to nonessential site loads. At this point, activities were initiated to restore normal feedwater flow.

Between 15:05 CST and 15:10 CST the control room received a report of a fire in the switchyard. The fire brigade responded, but found the fire had already been extinguished by a member of the switchyard maintenance crew using a portable carbon dioxide fire extinguisher. The source of the fire was a dameged current limiting resistor in the control circuitry of the failed PCB 500. The damage to the control circuitry had already caused the loss of PCB indication alluded to earlier in this report.

The licensed reactor operator assigned to control reactor water level reduced the flowrate and then tripped the HPIC and RCIC systems to stabilize reactor water level at approximately 43 inches above instrument zero. This occurred at approximately 15:23 CST. Although not recognized at the time, position indication was lost on the RCIC inboard injection valve, 1E51-F013, as it began to close as designed on a RCIC trip signal. As decay heat caused reactor pressure to increase and the bypass valves opened to control reactor pressure, reactor water level again began to decrease. At approximately 15:35 CST, with reactor water level at approximately 15 inches above instrument zero and decreasing slowly, RCIC was restarted. It was at this time that the licensed operator noticed that position indication had been lost on 1E51-F013. The operating crew concluded that the valve was only partially open since it appeared to them that reactor water level was not being restored as quickly as expected. The operators decided to secure RCIC and investigate the valve indication problem. A plant equipment operator was dispatched to the valve breaker, but the breaker would not reset.

At approximately 15:40 CST, reactor water level reached approximately 12.5 inches above instrument zero, and another scram signal was received due to low reactor water level. Plant operators then started HPCI in the manual control mode and recovered reactor vessel water level. HPCI would have been restarted earlier to recover level, but operations personnel believed the restoration of feedwater was imminent. By approximately 15:47 CST, a reactor feed pump was returned to service, and water level was controlled thereafter using the normal reactor level control system.

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			APPROVED OMB NO 3150-0104 EXPIRES: 4/30/92	
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (5) YEAR / SEQ NUM / REV		PAGE (3)
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TEXT

CAUSE OF THE EVENT

The direct cause of the first scram was a turbine trip which occurred above 30% rated thermal power. The root causes of the first scram were the failed remote power transmission line and the failed current limiting resistor in PCB 500. The failed current limiting resistor prevented the trip signal from reaching phase 2 of PCB 500 which caused the redundant breaker, PCB 510, to open to clear the fault. The opening of PCB 510 resulted in a main turbine trip, which led to the scram.

The cause of the failure of the HPCI system to properly inject in the automatic mode was a failed speed controller. Post-event maintenance attempted to recalibrate the controller, but the controller would not retain its recalibration. However, it should be noted that the failure mode of the speed controller, due to the configuration of the control logic, did not preclude successful control of HPCI in the manual mode.

The cause of the lost valve indication on 1E51-F013 was a blown fuse in the valve actuator control power circuit. This interrupted control power to the valve, preventing the valve from being moved. The fuse failure was investigated by the architect engineer and was determined to have been a random failure.

The cause of the failure of damper 1T41-F043B was water-induced corrosion on the pneumatic actuator. It appears that due to the location of this damper on the outside of the reactor building, the damper was exposed to environmental conditions which fostered the condensation and accumulation of moisture and the resultant corrosion over time. It should be noted that the air quality, specifically dewpoint, particulate content, and oil content, has been sampled as part of Georgia Power Company's response to Generic Letter 88-14 regarding instrument air supply system problems affecting safety related equipment. The results of the sampling met the requirements ANSI/ISA S7.3-1975, Reaffirmed 1981. As part of the ongoing Plant Hatch program for maintaining proper instrument air quality, air quality is periodically sampled and evaluated against the same standard.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This event is reportable per 10 CFR 50.73(a)(2)(iv) because an unplanned actuation of the Reactor Protection System (RPS, EIIS Code JC) and Engineered Safety Features (ESF) occurred. Specifically, tripping of a main transformer lockout relay resulted in a turbine trip above 30% rated thermal power, which in turn resulted in a reactor scram. This event is also reportable per 10 CFR 50.73(a)(2)(v) because an event occurred which could have prevented the fulfillment of the safety function of a system which is intended to mitigate the consequences of an accident. Specifically, a failed HPCI speed controller caused the HPCI system to trip repeatedly due to overspeed, with the result that operators were required to take manual control of HPCI in order to restore reactor water level.

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TEXT

The Reactor Protection System (RPS, EIIS Code JC) automatically initiates a reactor scram to ensure the radioactive materials barriers, such as fuel cladding and pressure system boundary, are maintained, and to mitigate the consequences of transients and accidents. Closure of the turbine stop valves can result in an addition of positive reactivity to the core as the reactor pressure rise collapses steam voids. Turbine stop valve closure initiates a scram prior to the Neutron Monitoring System or Reactor High Pressure; however, it is required to provide a satisfactory margin to core thermal-hydraulic limits. The high-pressure scram in conjunction with the pressure relief system is adequate to preclude overpressurizing the pressure system boundary; however, the turbine stop valve closure scram provides additional margin. In the event described in this report, the RPS actuated per design. Reactor pressure was controlled by the turbine bypass valves alone. Consequently, reactor pressure was maintained well below the vessel design pressure.

The HPCI system is provided to assure the reactor is adequately cooled to limit fuel-clad temperature in the event of a small break in the nuclear boiler system causing a loss of coolant which does not result in rapid depressurization of the reactor vessel. The Automatic Depressurization System (ADS, EIIS Code JE) is a backup for the HPCI system. Upon ADS initiation, the reactor vessel is depressurized to a point where either the Low Pressure Coolant Injection system (LPCI, EIIS Code BO) or the Core Spray System (CSS, EIIS Code BM) can operate to maintain adequate core cooling. In this event, due to a controller malfunction in the HPCI system, HPCI tripped more than once on turbine overspeed and had to be manually controlled in order to complete an injection into the reactor pressure vessel. During this event, the ADS, LPCI system, and CSS remained operable. Based upon the Unit 1 Final Safety Analysis Report (FSAR), either loop of the CSS or the LPCI system can supply sufficient cooling to the reactor for any rupture of the nuclear system boundary up to and including the Design Basis Accident (DBA).

The function of the secondary containment is to limit ground level releases of airborne radioactive materials, and to provide a means for the controlled, elevated release of the building atmosphere so that off-site doses from a design basis fuel handling or loss of coolant accident (LOCA) will be below the limits stated in 10 CFR 100. The secondary containment system consists of three subsystems: the reactor building, the Standby Gas Treatment System, and the main stack. In this event, secondary containment damper 1T41-F043B failed to close upon receipt of an isolation signal. However, as previously noted, the redundant damper in the same duct closed so that secondary containment integrity was successfully established.

Based on the above analysis, it is concluded that this event had no adverse impact on nuclear safety. Since the scram occurred from full power operation, it is concluded that the event would not have been more severe had it occurred under other operating conditions.

TEXT

CORRECTIVE ACTIONS

Corrective actions for this event included:

1. Repairing the fallen 230kV transmission line. This action is complete.
2. Repairing PCB 500. This action is complete.
3. Replacing the HPCI speed controller and performing the HPCI operability test per 34SV-E41-002-1S, "HPCI Pump Operability." This action is complete.
4. Replacing the failed fuse in the control power circuit for 1E51-F013. This action is complete.
5. Repairing the failed damper actuator for 1T41-F043B. This action is complete.
6. One additional secondary containment isolation damper actuator located outside the reactor building will be inspected during the 1991 Unit 1 outage to determine if moisture-induced corrosion is evident. The remaining similar dampers will be inspected if corrosion is found. This action will be complete by 12/17/91.

ADDITIONAL INFORMATION

1. Other Systems Affected: No systems other than those described in this report were affected by the event.
2. Previous Similar Events: No events were identified in which failures in the switchyard led to reactor trips in the past two years. One event during this time frame was identified in which the HPCI system received a valid automatic initiation signal but failed to inject into the reactor vessel. This event was described in LER 50-366/1991-001, Revision 1. Corrective action for that event (related to the HPCI system failure) included replacing thermal overload relays for the HPCI injection valve motor starter. That corrective action would not have prevented this event because the causes of the injection system failures were different.
3. Failed Components Identification:

   A. Master Parts List Number: 1E41-R764-1
      Manufacturer: Woodward Governor Company
      Model Number: EG-M
      Type: Electronic Governor Magnetic Pickup
      Manufacturer Code: W290
      EIIS System Code: BJ
      Reportable to NPRDS: Yes
      Root Cause Code: X
      EIIS Component Code: SC

NRC Form 366A (5-89) U.S. NUCLEAR REGULATORY COMMISSION
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION
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TEXT

B. Master Parts List Number: 1E51-F231
Manufacturer: Bussman
Model Number: KTN-R-6
Type: Fuse
Manufacturer Code: B569
EIIS System Code: BN
Reportable to NPRDS: No
Root Cause Code: X
EIIS Component Code: FU

C. Master Parts List Number: 1T41-F043B
Manufacturer: Bettis Corporation
Model Number: 522C-SR-72
Type: Air Operated Damper Actuator
Manufacturer Code: B237
EIIS System Code: BD
Reportable to NPRDS: No
Root Cause Code: X
EIIS Component Code: DMP

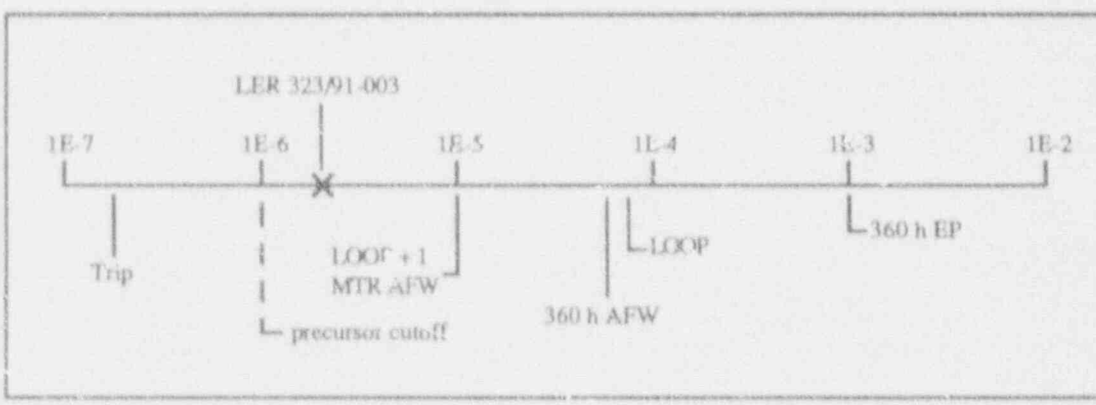
D. Master Parts List Number: None
Manufacturer: Unknown (unreadable on burned resistor)
Model Number: 132A1220-32
Type: Current Limiting Resistor
Manufacturer Code: Unknown
EIIS System Code: FK
Reportable to NPRDS: No
Root Cause Code: X
EIIS Component Code: BKR

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	323/91-003
Event Description:	Containment sump isolation valves and containment spray pumps deenergized during hot shutdown
Date of Event:	September 1, 1991
Plant:	Diablo Canyon 2

Summary

Both Diablo Canyon 2 residual heat removal (RHR) containment sump isolation valves were depowered for 6 h in mode 4 by locally opening the valve breakers. In this mode, power should have been interrupted by opening series contactors in the control room, which would have allowed rapid restoration of power to the valves if their operation was required following a loss-of-coolant accident (LOCA). The conditional core damage probability estimated for the event is 2.1 x 10^{-6}. The relative significance of this event compared to other postulated events at Diablo Canyon 2 is shown below.



Event Description

While Diablo Canyon 2 was in hot shutdown, a walkdown of the control room boards revealed that power had been removed from both RHR containment recirculation sump suction valves, 8982A and B. The cause of power loss was that the 480-V breakers serving the RHR valves had been opened locally in preparation for entering cold shutdown. A procedure had been revised in 1986 in violation of Technical Specification (Tech Spec) requirements, to require local opening of the breakers associated with the valves. The Tech Specs require control room operation of the valves while the plant is in hot shutdown — the procedure should have specified use of the contactor located in the control room for removing power from the valves. The valve breakers were open for approximately 6 h.

The walkdown also revealed that, due to personnel error, the control power to both containment spray (CS) pumps had been deenergized. The CS pumps were deenergized for approximately 1.5 h before power restoration.

Additional Event-Related Information

The RHR system consists of two trains. During high-pressure recirculation (HPR), each RHR pump takes suction from the containment sump via separate containment isolation valves. After the sump water is cooled by the RHR heat exchangers, it is supplied to the suctions of the safety injection (SI) and charging pumps. RHR pump 1 provides flow to SI pump 1 and both charging pumps; RHR pump 2 provides flow to SI pump 2.

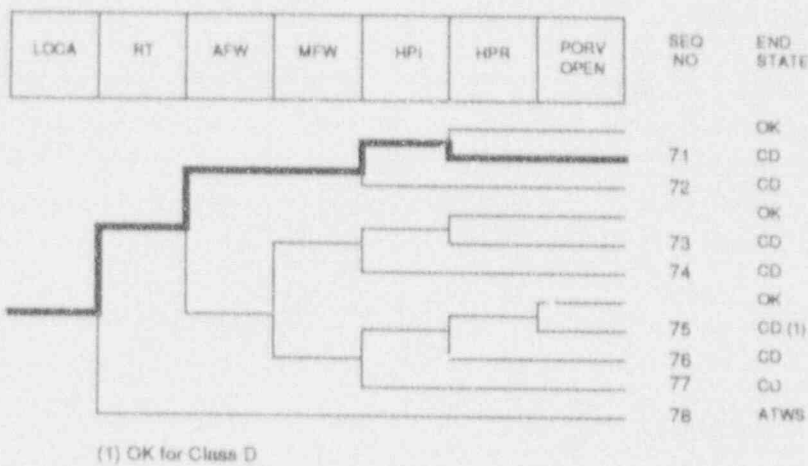
The CS system is also a two-train system that initially provides water from the reactor water storage tank (RWST) to two spray ring headers for containment pressure suppression following a LOCA. After the RWST is empty, CS flow is provided from the RHR system.

ASP Modeling Assumptions and Approach

The event has been modeled as a 6-h unavailability of HPR. Local recovery of HPR at the recirculation valve breakers was assumed to be possible (the utility estimated this would take ~15 min). Since the Accident Sequence Precursor (ASP) models only address core damage, the unavailability of the CS pumps was not considered.

Analysis Results

The core damage probability estimated for the event is 2.1×10^{-6}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated small-break LOCA with successful high-pressure injection and failure of HPR. This estimate is believed to be conservative, since the actual event occurred in mode 4 and the ASP model success criteria and timing assume operation at power.



Dominant core damage sequence for LER 323/91-003

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 323/91-003
Event Description: Containment surp isolation valves deenergized
Event Date: 09/01/91
Plant: Diablo Canyon 2

UNAVAILABILITY, DURATION= 6

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.5E-03
LOOP	6.8E-05
LOCA	6.2E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.0E-08
LOOP	3.6E-09
LOCA	2.1E-06
Total	2.1E-06
ATWS	
TRANS	0.0E+00
LOOP	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	2.1E-06	1.5E-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	2.1E-06	1.5E-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:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\diablo2.s11
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

Event Identifier: 323/91-003

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.5E-04	1.0E+00	
loop	2.0E-05	5.8E-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	5.4E-04	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	3.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	3.0E-02	1.0E+00	
seal.loca	3.2E-01	1.0E+00	
ep.rec(sl)	6.5E-01	1.0E+00	
ep.rec	1.1E-01	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 > 1.0E+00	1.0E+00 > 3.4E-01	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Minarick
05-26-1992
10:46:03

Event Identifier: 323/91-003

LICENSEE EVENT REPORT (LER)

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TITLE (4) INADVERTENT ENTRIES INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR AND INADEQUATE PROCEDURE REVIEW

EVENT DATE (5) MON	DAY	YR	LER NUMBER (6) YR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MON	DAY	YR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER (5)
09	01	91	91	- 0 0 3 -	0 0	10	01	91	DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5
										0 5 0 0 0

OPERATING MODE (9)	4
POWER LEVEL (10)	0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73(a)(2)(i)(B)
OTHER (Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
MARTIN T. HUG, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4005

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

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

ABSTRACT (16)

On September 1, 1991, two events of inadvertent entry into Technical Specification (TS) 3.0.3 occurred: 1) at 0535 PDT, while in Mode 4 (Hot Shutdown) at 0 percent power, Unit 2 inadvertently entered TS 3.0.3 when the requirements of TS 3.5.3.d and TS 3.6.2.1 were determined to have not been met following removal of power from both Residual Heat Removal (RHR) pump suction valve operators before entry into Mode 5 (Cold Shutdown); and 2) at 1013 PDT with Unit 2 still in Mode 4, Unit 2 again entered TS 3.0.3 when TS 3.6.2.1 was not met because control power for both Containment Spray (CS) pumps was deenergized. Both events were identified on September 1, 1991, at 1130 PDT during a walkdown of the control room boards. By 1145 PDT, the RHR suction valves and the CS pumps were returned to an operable status. A four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(iii)(b) at 1409 PDT. Unit 2 entered Mode 5 on September 1, 1991, at 1435 PDT.

The root cause for the RHR pump suction valves having been deenergized in Mode 4 was inadequate procedure revision review. The root cause for the CS pumps being deenergized in Mode 4 was personnel error, inattention to detail by the licensed operator issuing clearances.

Corrective actions included revising Operating Procedure L-5 and reviewing all other "L" series procedures, preparation of an Operations Incident Summary, and sending memorandums to appropriate personnel to clarify when clearances will be approved and to emphasize responsibilities for thorough preparation and review of procedure revisions.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

I. Plant Conditions

Unit 2 was in Mode 4 (Hot Shutdown) at 0 percent power with the reactor coolant system (RCS) (AB) at approximately 340°F and 350 psig. Residual Heat Removal (RHR) Pumps 2-1 and 2-2 (BP)(P) were in service and taking suction from the RCS hot leg of Loop 4. A forced oxygenation and steam generator hideout return soak was being performed for Unit 2 in preparation for the Unit 2 fourth refueling outage (2R4).

The control room operators were using Operating Procedure (OP) L-5, "Plant Cooldown from Minimum Load to Cold Shutdown," to perform the shutdown.

II. Description of Events

A. Events:

On September 1, 1991, at 1130 PDT, during a routine control board walkdown, licensed control room operators determined that both RHR pump Containment Recirculation Sump Suction Valves 8982A and B (BE)(BP)(RVR)(V) and both containment spray (CS) pumps (BE)(P) were inoperable. RHR Valves 8982A and B were determined to be inoperable because the 480V breakers that supply power to the valve operators had been opened locally instead of having been opened by use of the series contactor from the control room (Event 1). The CS pumps were inoperable because control power to the pump breakers had been removed (Event 2). The RHR and CS systems were returned to an operable status at 1145 PDT on September 1, 1991.

In both of these instances, Unit 2 entered Technical Specification (TS) 3.0.3. In the first event, which occurred at 0535 PDT, Unit 2 entered TS 3.0.3 because the RHR Valves 8982A and B had been made inoperable in Mode 4 and therefore the requirements of TS 3.5.3.d and TS 3.6.2.1 were not met. In the second event, Unit 2 entered TS 3.0.3 again at 1013 PDT when power was removed from both CS pumps while in Mode 4, and therefore the requirements of TS 3.6.2.1 were not met. A four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(iii)(b) on September 1, 1991, at 1409 PDT. A detailed explanation of the RHR Valves 8982A and B event (Event 1) and the CS pump event (Event 2) leading to the TS 3.0.3 entries is presented in the following sections.

Event 1: RHR Valves 8982A and B Deenergization

TS 3.5.3.d requires an operable flow path capable of taking suction from the containment sump during the recirculation phase of operation when in Mode 4. TS 3.6.2.1 requires that the CS system be capable of transferring spray function to an RHR system taking suction from the containment sump in Mode 4. TS 4.5.3.1 requires that the emergency core cooling system (ECCS) be demonstrated operable per the applicable

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

Surveillance Requirements (SR) of TS 4.5.2. TS 4.5.2 requires that RHR Valves 8982A and B be closed with power to the valve operators (84) removed in Modes 1 through 4.

There are two methods which have been used during outages to remove power to the RHR valve operators. The first method requires opening of series contactors (MCTR) 42-8982A and B. Series contactor toggle switches are located on the vertical control board in the control room. Closing of the series contactors from the control room permits rapid restoration of power to the valves when operation of the valves are required.

The second method requires opening of the valve operator 480V breakers (BKR) locally. If the RHR valves must be operated, an operator must be dispatched to close the 480V breakers. Opening the valve operator 480V breakers is the method for removing power to the valve operators after reaching Mode 5.

Safety Evaluation Report (SER), Supplement 4, requires that the capability exist to restore power to these valve operators from the control room. FSAR Update Table 6.3-12 lists valves 8982A and B as valves that must have power restorable from the control room. This requirement is implemented by Surveillance Test Procedure (STP) I-1A, "Routine Shift Checks Required by Licenses." STP I-1A requires that once every 12 hours, valves 8982A and B are verified closed and series contactors 42-8982A and B are open.

OP L-5 was revised in November 1988. One of the changes in this revision was inserting Step 6.3.2, which required operators to locally open the 480V valve operator breakers while the plant was still in Mode 4. Therefore, OP L-5 did not meet the requirements of TS 3.5.3.d, TS 3.6.2.1, and SER Supplement 4 following this revision.

On September 1, 1991, at 0535 PDT, while in Mode 4, Step 6.3.2 of OP L-5 was performed.

Previous Events: RHR Valves 8982A and B

A review of operating records after discovery of the current events indicated that the RHR Valves 8982A and B from the containment sump have had their circuit breakers opened locally while in Mode 4 on two previous occasions:

1. During the Unit 1 third refueling outage, the valves were deactivated at 0610 PDT on October 7, 1989, and Unit 1 entered Mode 6 at 2350 PDT on that same day.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	
DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3	91	-	0 0 3	-	0 0	4 OF 8

TEXT (17)

2. During the Unit 1 fourth refueling outage, the valves were deactivated at 0548 PST on February 2, 1991, and Unit 1 entered mode 5 at 1400 PST on that same day.

It was not recognized on either of these occasions that the plant had entered into a condition causing requirements of TS 3.5.3.d and TS 3.6.2.1 to not be met.

Event 2: CS Pumps Deenergization

TS 3.6.2.1 requires that two CS trains be operable with each CS system being capable of transferring spray function to an RHR system by taking suction from the containment sump in Modes 1 (Power Operation) through 4.

On September 1, 1991, at 1013 PDT, while in Mode 4, both CS pumps were made inoperable when an operator deenergized their control power. The clearance to perform this activity had been issued by the Senior Control Operator prior to the procedural step in OP L-5 that specified deenergization of the pumps.

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

None.

C. Dates and Approximate Times for Major Occurrences:

1.	Nov. 1, 1988:	OP L-5, Unit 1 Rev. 14, Unit 2 Rev. 0, was approved with instructions to verify closed valves 8982A and B and locally open their 480V breakers while still in Mode 4.
2.	Sept. 1, 1991, 0455 PDT:	Unit 2 entered Mode 4.
3.	Sept. 1, 1991, 0535 PDT:	Event 1 Date: TS 3.0.3 entered when the 480V breakers were opened.
4.	Sept. 1, 1991, 1013 PDT:	Event 2 Date: TS 3.0.3 entered when control power for the CS pumps was deenergized.
5.	Sept. 1, 1991, 1130 PDT:	Discovery Date: A control board walkdown discovered the discrepancies.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

6. Sept. 1, 1991, 1145 PDT: Power was restored to the affected equipment, returning it to an operable status.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

Events 1 and 2 were discovered by l..ensed control room personnel during routine control board walkdowns.

F. Operators Actions:

Upon discovery of both events, opera‘ors closed the local breakers on the RHR Valves 8982A and B (series contactors were already open) and the DC control power switches on the CS pumps within 15 minutes, returning the RHR valves and the CS pumps to operable status.

G. Safety System Responses:

None.

III. <u>Cause of the Event</u>

A. Immediate Causes:

1. The immediate cause for Event 1, RHR Valves 8982A and B bei..g made inoperable, was that OP L-5 incorrectly required local opening of the 480V breakers for the valves prior to placing the unit in Mode 5.

2. The immediate cause for Event 2, CS pumps being made inoperable, was that the Senior Control Operator issued the clearance to daenergize the pumps prior to the procedural steps in OP L-5 that specified deenergization of the pumps.

B. Root Causes:

1. The root cause for Event 1, RHR Valves 8982A and B being made inoperable in Mode 4, was inadequate procedure review when the step requiring opening of the valve breakers locally was added to the procedure in late 1988. Review of the procedure revision did not identify that addition of this step was not in accordance with TS requirements.

2. The root cause for Event 2, CS pumps being made inoperable in Mode 4, is personnel error, inattention to detail by the Senior

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

Control Operator issuing clearances to the field. In this case, inadequate attention to the details of the CS pump clearance form allowed the clearance to be issued for processing prior to Unit 2 entering Mode 5. The clearance clearly specified that it was implementing Step 6.3.9.a of OP L-5, and the operator issued the clearance prior to reaching that procedure step.

C. Contributory Cause:

The practice of pre-approving clearances for the refueling outage contributed to Event 2. If the on-shift foreman had been asked to approve the clearance for deenergizing the CS pumps just before the clearance was processed, the request would have been rejected based on TS requirements.

IV. Analysis of the Event

Event 1: TS 3.5.3.d and TS 3.6.2.1 require an operable flow path capable of taking suction from the containment sump during the recirculation phase of operation. Because the 480V breakers to the valves had been opened locally (the series contactors were already open with closure possible by use of the toggle switches in the control room), an operator would have to be dispatched to close the breakers locally in order to open the valve. The Operations Department believes that the breakers can be closed and the valves opened within 15 minutes. For the case of a design basis loss-of-coolant-accident, over 19 minutes are available to open the valves (FSAR Update Table 6.3-5). In Mode 4, even more time should be available.

Event 2: The CS pumps serve to mitigate pressure increases in containment during accident conditions. The containment fan cooling units (CFCU) (BK) serve essentially the same purpose. During the time the CS pumps were deenergized, the CFCUs were operable. Because of the limited energy available in Mode 4, containment integrity would not have been compromised.

Since an operable flow path could have been established within an acceptable time period and containment integrity would not have been compromised, the health and safety of the public were not adversely affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

1. Events 1 and 2: The RHR valves and CS pumps were restored to an operable condition.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

2. Event 1: OP L-5 for Units 1 and 2 were revised to move the step concerning local deenergization of the RHR suction valves into the section of the procedure that follows Mode 5 entry.

3. Event 1: All of the L-series operating procedures were reviewed to ensure that no other similar problems existed.

B. Corrective Actions to Prevent Recurrence:

1. Events 1 and 2: An Operations Incident Summary was prepared regarding this event, stressing proper clearance review and processing.

2. Event 2: A memorandum was sent to all Shift Foremen, Shift Supervisors, and Operations Clearance Coordination personnel explaining the intent of the "shift foreman approval" signature on a clearance. This memorandum clarified that the approval shall not take place until immediately before the clearance is processed.

3. Event 1: A memorandum will be sent to all Operations procedure sponsors and reviewers stressing the significance of this event and the importance of ensuring that TS requirements and other commitments are met. This memorandum is applicable to the biennial review as well as procedure revision review. No specific corrective actions will be taken concerning the procedure review and approval process. The process has been upgraded considerably since the incorrect change to OP L-5 was made, and it appears that the increased depth of the present process will prevent recurrence of problems of this type.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Problems:

LER 1-91-001 Entry into Technical Specification 3.0.3 when both RHR pumps were de-energized due to personnel error.

RHR Pump 1-2 was rendered unavailable when its control power was de-energized during a time when Diesel Generator (EK) 1-1 was removed from service. This resulted in ECCS inoperability, violation of TS 3.5.2, and entry into TS 3.0.3.

The root cause of the event was personnel error due to miscommunication. Although a tailboard was conducted on the actions

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

required for the surveillance procedure, the auxiliary operator did not understand his actions following the meeting. The corrective action was to prepare an Operating Incident Summary which stressed the importance of performing a proper tailboard and the "two train" concept for Engineered Safety Features systems at Diablo Canyon.

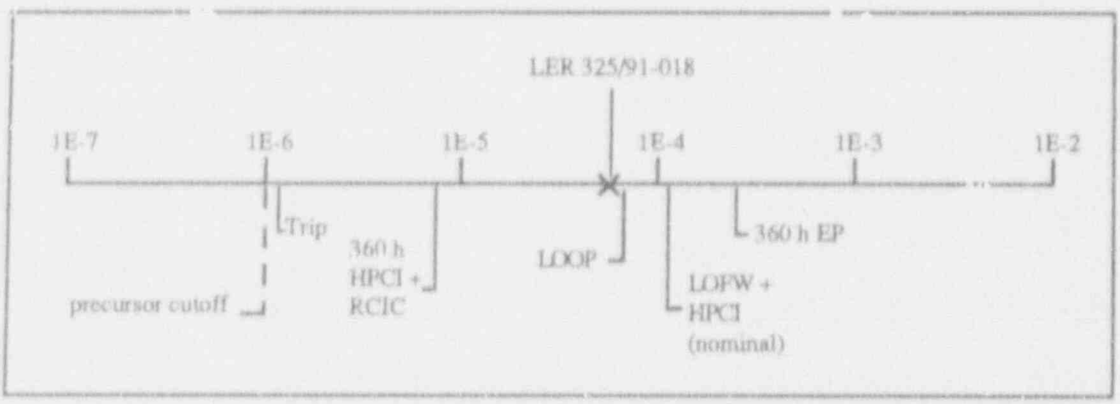
The root cause of LER 1-91-001 was not the same as in the event of LER 2-91-003. Therefore, the corrective actions of LER 1-91-001 could not have prevented the current event from happening.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	325/91-018
Event Description:	Loss of feedwater with degraded HPCI system
Date of Event:	July 18, 1991
Plant:	Brunswick 1

Summary

The reactor scrammed from 100% power during surveillance on a reactor water level transmitter. A spurious low water level signal resulted in main steam isolation valve (MSIV) closure and initiated the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems, which provided reactor vessel makeup. HPCI had an oil leak that would have degraded HPCI performance if left uncorrected. The conditional core damage probability estimated for this event is 6.0×10^{-5}. The relative significance of this event compared to other postulated events at Brunswick is shown below.



Event Description

Brunswick 1 scrammed from 100% power on July 18, 1991. The scram occurred while preparing to return a reactor vessel level transmitter to service. Leakage by the instrument manifold isolation valve for the transmitter resulted in a pressure transient on the common instrument variable leg header, which serves instruments for both reactor protection divisions, when the transmitter's drain valve was opened. The erroneous level signal closed all MSIVs and actuated the HPCI, core spray (CS), RCIC, and emergency power systems. The MSIV closure generated a full reactor scram, and all control rods fully inserted. The reactor power decrease and MSIV closure caused an actual momentary reactor water level decrease due to steam void collapse. Safety relief valves (SRVs) operated as designed to control reactor pressure. During the event, an ~0.4 gpm oil leak on the HPCI turbine oil filter inlet pressure gage drained ~10 gal of oil before being isolated by closing a manual isolation valve. HPCI operation was not affected by the loss of oil (78 of 88 gals of oil were still available). However, if the oil leak had not been detected and isolated, HPCI would have been rendered unavailable.

Additional Event-Related Information

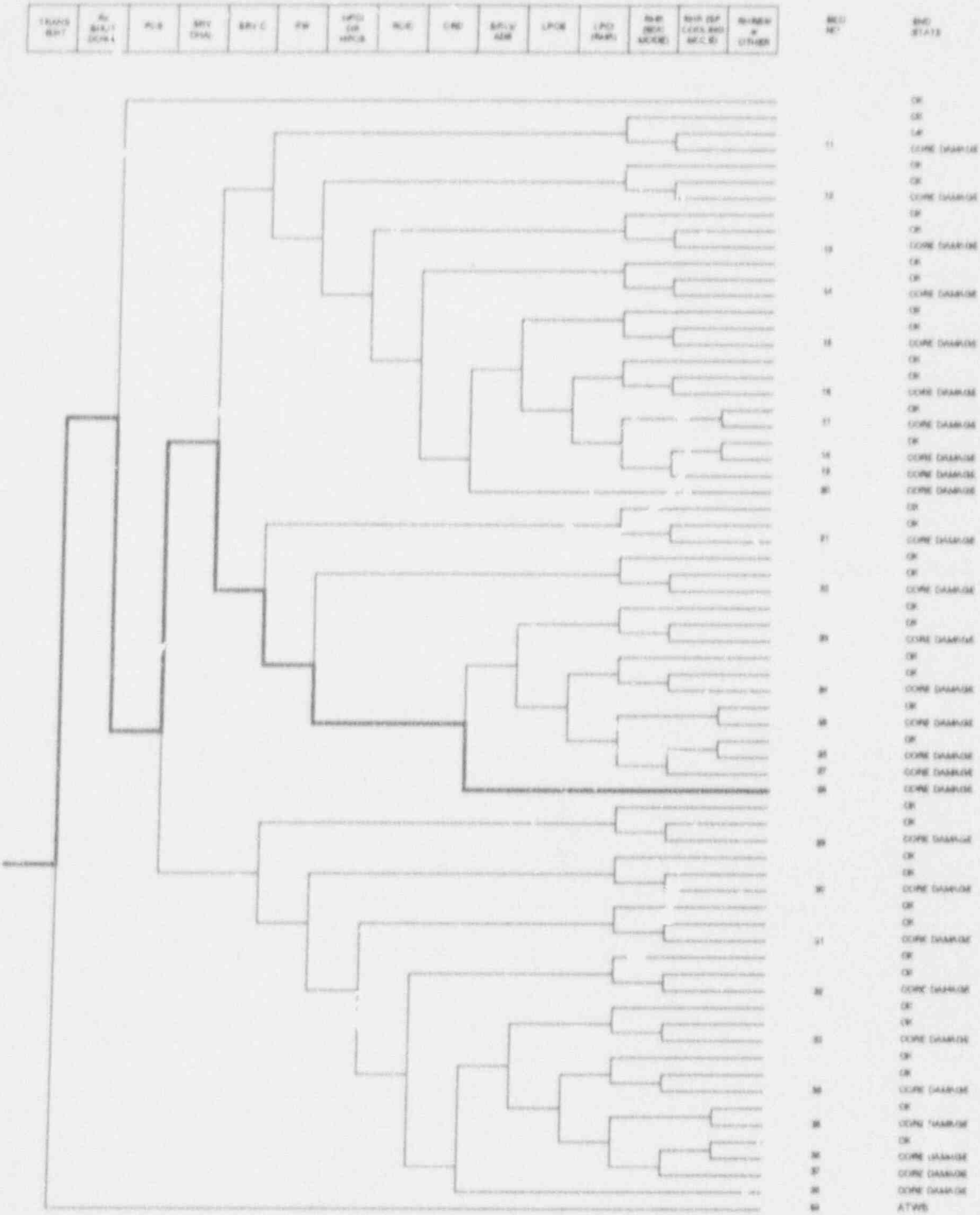
The HPCI system is a high-pressure injection system designed for small-break loss-of-coolant accidents (LOCAs) that do not depressurize the reactor. HPCI maintains sufficient reactor vessel inventory during plant shutdown until the vessel is depressurized. HPCI is an independent system, uses a turbine-driven pump, and automatically initiates on reactor low water level. HPCI can deliver 4250 gpm of makeup water to the vessel through the feedwater piping. There are two sources of water for the HPCI system. Initially, the system uses demineralized water from the condensate storage tank (CST). When the CST reaches a low level, the system automatically transfers to the suppression pool.

ASP Modeling Assumptions and Approach

In this event, if the HPCI oil leak had not been isolated, the oil-operated trip valve would have closed due to low oil pressure, and the HPCI turbine would have stopped prior to bearing damage. However, at the leakage rate for this event, it would take more than 60 min for the oil level in the reservoir to drain down to the low level alarm setpoint and more than 1 h and 20 min for the level to drop to the point where the oil pressure was low enough to close the trip valve. This assumes that nothing is done by the operators or that the HPCI room is inaccessible. This event was modeled as a loss of feedwater (due to MSIV closure) with HPCI inoperable but with a nonrecovery factor of 0.34.

Analysis Results

The conditional probability of core damage estimated for this event is 6.0×10^{-5}. The dominant core damage sequence, highlighted on the following event tree, involves a loss of feedwater, a stuck-open SRV (transient-induced LOCA), failure of HPCI, and failure to depressurize using the automatic depressurization system to allow use of the low-pressure injection systems.



Dominant core damage sequence for LER 325/91-018

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 325/91-018
Event Description: Loss of feedwater with degraded HPCI
Event Date: 07/18/91
Plant: Brunswick 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	6.0E-05
Total	6.0E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS HPCI srv.ada	CD	5.3E-05	8.2E-02
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	3.5E-06	7.6E-02
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	3.5E-06	7.6E-02
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS HPCI srv.ada	CD	5.3E-05	8.2E-02
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\brunswck.sll
PROBABILITY FILE: c:\asp\1989\bwr_csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 325/91-018

Branch	System	Non-Recov	Opr Fail
trans	2.3E-04	1.0E+00	
loop	1.6E-05	3.4E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	1.4E-03	8.0E-01	
ep.rec	1.6E-01	1.0E+00	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
fw/pcs.loca	1.0E+00	3.4E-01	
HPCI	2.9E-02 > 1.0E+00	7.0E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-02 > Failed		
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Minarick
06-07-1992
21:55:18

Event Identifier: 325/91-018

NRC FORM 366 — U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant Unit 1	05000325	1

TITLE (4) Reactor Scram Resulting From Common Instrument Header Pressure Perturbation

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQ. NO.		REV. NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET # / ASSOR
07	18	91	91	-	018	-	00	8	16	91		

OPERATING MODE (9): 1
POWER LEVEL (10): 100

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Glen M. Thearling, Regulatory Compliance Specialist	(919) 457-2038

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
X	BJ	PI	A501	Y	X	JM	33	N007	Y
X	BLR	ISV	D232	Y	B	JM	ISV	A391	Y

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

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

On July 18, 1991, Unit 1 reactor was at 100% power when it scrammed as the result of a Main Steam Line Isolation signal, inadvertently generated during surveillance 1MST-RSDP-21Q for reactor water level transmitter B21-LT-N026B, which was being returned to service. After extensive investigation it is suspected that an instrument isolation valve leaked-by, resulting in a pressure transient on the common instrument header which has instruments feeding both reactor protection divisions. The resulting erroneous level signals caused the following system actuations: Isolations - Group 1 (Main Steamlines), Group 3B (1/2 Reactor Water Cleanup System), and Initiations - Reactor Core Isolation Cooling (RCIC), High Pressure Coolant Injection (HPCI), Standby Gas Treatment (SBGT), Core Spray (CS), Emergency Diesel Generators (EDG).

The Emergency Core Cooling Systems (ECCS) were operable.

The safety significance of this event is minimal as plant safety systems responded as required.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQ NO	REV NO	
Brunswick Steam Electric Plant Unit 1	05000325	91	018	0	2

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

INITIAL CONDITIONS

On July 18, 1991, Unit 1 was at 100% power and had been synchronized to the grid for 72 days. All Emergency Core Cooling Systems were operable. Surveillance 1-MST-RSDP-21Q was almost complete and the reactor vessel level transmitter B21-LT-N026B was being returned to service. The level transmitter B21-LT-N026B was isolated with the calibration equipment connected to its drain/calibration lines.

EVENT NARRATIVE

At 17:20 on July 18, 1991, while preparing to return the 1-B21-LT-N026B instrument transmitter to service a pressure transient on the common instrument variable leg header resulted in a reactor scram and Primary Containment Isolation System (PCIS) group isolations. The instrument variable leg drain valve was being opened to pressurize the instrument, when leakage by instrument manifold isolation valve 1-B21-LT-N026B-4 resulted in the pressure transient on the common instrument variable leg header, whose instruments feed both reactor protection divisions.

The 1-B21-LT-N026B transmitter (see attachment A) is connected to common variable and reference leg headers through root isolation valves (normally left open during calibrations), and instrument manifold block isolation valves (used to isolate the instrument during calibration). The instrument manifold block contains: both instrument transmitter isolation valves, an equalizing valve that can cross-tie the two headers at the transmitter, and a line from each side of the transmitter that through a pair of drain valves connect to the drain/calibration headers.

In accordance with the surveillance, the instrument reference leg drain valve was being opened to pressurize the instrument prior to opening the manifold isolation valves. This process minimizes the differential pressure across the isolation valve and should prevent a pressure transient on the common instrument header. The gauge connected to the drain/calibration header initially indicated 20 psig prior to the drain valve being opened. While opening the drain valve the technician became aware of the transient and had the second technician verify that his hand remained on the correct valve. It was also noted that the gauge on the drain/calibration header had increased to approximately 70 psig. This supports that the variable leg manifold isolation valve had leaked-by into the transmitter. When the transmitter drain valve was opened a path to depressurize the transmitter and perturbate the common instrument variable leg header through the leaking isolation valve was created. The pressure transient was sensed as an erroneous level decrease actuating PCIS and Emergency Core Coolant Systems (ECCS). The PCIS Group 1 isolation command closed all Main Steamline Isolation Valves (MSIV) and the PCIS Group 3B isolation command closed the Outboard Reactor Water Cleanup Isolation Valve. The following systems received start commands: CS, HPCI, RCIC, and the four EDG's. Due to the brevity of the erroneous level spike the RHR system did not have time to latch-in a start command. The MSIV closure generated a full reactor scram and all control rods fully inserted.

The combination of reactor power decrease and a closure of the MSIV's caused an actual momentary reduction in reactor vessel water level due to steam void collapse. PCIS Groups 2, 3, 6 and 10 isolations were received for the actual reactor vessel low level signals. The Group 8 isolation was present prior to the event due to normal operating reactor pressure and the associated valves were closed. Safety Relief Valves operated as designed to control reactor pressure. PCIS isolations and ECCS initiations occurred as designed.

Additional problems identified during the event were:

1. A limit switch problem on the outboard MSIV 1-B21-F028B resulted in dual indication for two and one-half minutes after its closure.

NRC FORM 366A	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQ NO.	REV NO.	PAGE (3)
Brunswick Steam Electric Plant Unit 1	05000325	91	018	0	3

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

2. An oil leak of approximately 0.435 gpm on the HPCI Turbine Oil Filter Inlet Pressure Gauge E41-PI-5549, drained about 10 of the approximately 88 gallons available during the 23 minutes prior to the leaks isolation. The leakage rate would have allowed another 45 minutes prior to the low level alarm and 60 minutes prior to a loss of oil pressure. If the oil leak had not been isolated eventually the oil operated HPCI trip valve would have closed due to low oil pressure, and the HPCI turbine would have stopped prior to bearing damage. This failure is actually less significant than most HPCI failure modes in that, if HPCI had been needed, it would have allowed significant HPCI operation prior to the actual system loss.

3. The Main Steamline Drain Inboard Isolation Valve, 1-B21-F016 motor breaker tripped on thermal overload when it was being opened to equalize pressure around the MSIV's. This Anchor-Darling, 3-inch, double-disc gate valve when disassembled for inspection/repair was found to have cuts, at the same height, in the valve body's four disc guides caused by the valve discs. The height of the cuts, the direction of the deformed metal and the shape of the cuts showed that the valve discs had jammed while opening, at about 75% open. The root cause was determined to be the sharp edges on the valve discs. The sharp edges are a generic concern which is only applicable to the 3-inch Anchor-Darling double-disc gate valves. While this is a generic concern, it is not a generic Safety Issue because the safety function of each of the valves used on both Units is to close. The valves of concern are: Main Steamline Drain Isolation Valves 1/2-B21-F016 and 1/2-B21-F019, and RCIC Steamline Isolation Valves 1/2-E51-F007 and 1/2-E51-F008.

CAUSE OF EVENT

The pressure transient on the common variable leg instrument header, was caused by the leaking isolation valve (1-B21-LT-N026B-4) on Reactor Water Level Transmitter B21-LT-N026B. While the valve was found fully closed and testing could not recreate the transient it is felt that this is the only cause that the data collected during the investigation will support. Four possible causes for the event were exhaustively pursued:

1) For the 1-B21-LT-N026B-4, a valve failure mode was not found even though it was destructively tested.

2) If debris kept the 1-B21-LT-N026B-4 from properly seating closed it may have been flushed out during the transient and was therefore not recovered.

3) The possibility of the 1-B21-LT-N026B-4 not being fully closed during the initial valving out process was investigated, but due to the technicians use of double verification and that a wrench was used to insure full closure of the instrument isolation valves a human error was considered unlikely.

4) That human error resulted in a valve being repositioned out-of-sequence during the surveillance was considered unlikely, due to the technicians performing self checking and double verification prior to the valve operation. Additionally valves that could have been manipulated to cause this are not configured such that it is likely a wrong valve was repositioned.

CORRECTIVE ACTIONS

1) The isolation valve 1-B21-LT-N026B-4 was removed for testing and replaced along with the transmitter isolation valve manif[illegible] and both transmitter drain valves.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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Brunswick Steam Electric Plant Unit 1	05000325	91	018	0	4

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

2) The surveillance procedures 1/2MST-RSDP21Q will be revised to provide closure of root valves in order to provide a better isolation during future surveillances. (Due 8/30/91)

3) Prior to testing a review will be conducted of the other level calibration procedures performed at power, to identify those requiring root valve closure.

4) To minimize other possible valve leakage problems on this rack, an evaluation will be performed on the common instrument rack drain/calibration headers being be left vented. (Due 10/26/91)

5) To minimize other possible valve leakage problems on this rack, an evaluation will be performed for the common instrument rack drain/calibration headers permanent removal. (Due 11/27/91)

6) Review the Scram event with appropriate Instrumentation and Control (I&C) personnel prior to the next performance of the 1/2MST-RSDP21Q. (Due 8/22/91)

7) Review industry data related to the instrument valve leakage during similar events. (Due 9/26/91)

8) Unit 2's B21-LT-N026B valves will be inspected for leaks during the next scheduled outage. (Due 11/27/91)

9) During the next refueling outages the seven other 3-inch Anchor-Darling double-disc gate valves will be inspected. (Due 11/27/91 on Unit 2 and 12/6/92 on Unit 1)

10) Anchor-Darling has been requested to review the existing design for their 3-inch double-disc gate valves and provide suitable replacement discs with an improved edge configuration, if appropriate. (Due 9/11/91)

11) The Main Steamline Drain Inboard Isolation Valve 1-B21-F016 was temporarily repaired/tested with the raised metal on the four disc guides removed (to prevent possible foreign-object damage within the system), and the open limit switch reset to 60% so as to avoid the degraded guide area where jamming is possible. The safety function, which is to close, is unaffected.

12) The MSIV 1-B21-F028B closed limit switch was adjusted.

13) A Technical Specification change will be evaluated to allow the remote shutdown panel reactor level instrument surveillances to be performed at a refueling frequency.

14) The HPCI oil pressure gauge has been isolated and placed under clearance pending replacement.

SAFETY ASSESSMENT

The instrument header pressure transient event posed minimal safety significance since all systems performed their safety related functions.

The HPCI oil leak was of minimal safety significance as the 60 minutes between the time the alarm would have come in and the system shutdown would have been adequate for Operations to prevent loss of the system by investigating the cause and closing the gauge isolation valve. If the HPCI room had been inaccessible, HPCI would have been lost after approximately 1 hour and 20 minutes. As HPCI is a single train system and is not single failure proof the availability of the Automatic Depressurization System (ADS) with the low pressure ECCS systems would have assured adequate safe shutdown capability for this failure mode. This failure is actually less significant than most HPCI failure modes in that it would allow significant HPCI operation prior to the actual loss of the system.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQ NO	REV NO	PAGE (3)
Brunswick Steam Electric Plant Unit 1	05000325	91	018	0	5

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

The failure of the Main Steamline Drain Inboard Isolation Valve 1-B21-F016 is not significant in that the safety function of the valve is to close (if open) during an accident. The valve has no specific safety function to open, and receives no automatic open signals. The inability to open this valve would prevent reestablishing the Condenser as a heat sink. While this is desirable, it is not required for a safe reactor shutdown. The other identical valves which are currently installed,also only have a safety function to close. Since the potential sharp edges of the discs for these valves would only affect the opening stroke, the safety function of these valves would not be compromised. The valve design problem is not reportable per 10 CFR 21, because of our plants application. Anchor-Darling has been notified of the problems we are having with this valve.

PREVIOUS SIMILAR EVENTS

Other instrument perturbations have been reported under LER's 1-90-006, 2-89-017, 1-87-017, and 2-86-020.

COMPONENT IDENTIFICATION

System/Component	EIIS Code
Primary Containment Isolation System	JM
High Pressure Coolant Injection	BJ
Reactor Protection System	JE
Emergency Diesel Generator	EK
Reactor Core Isolation Cooling System	BN
Residual Heat Removal/Low Pressure Coolant Injection	BO
Core Spray	BM
Standby Gas Treatment System	BH
Safety Relief Valve	*/RV

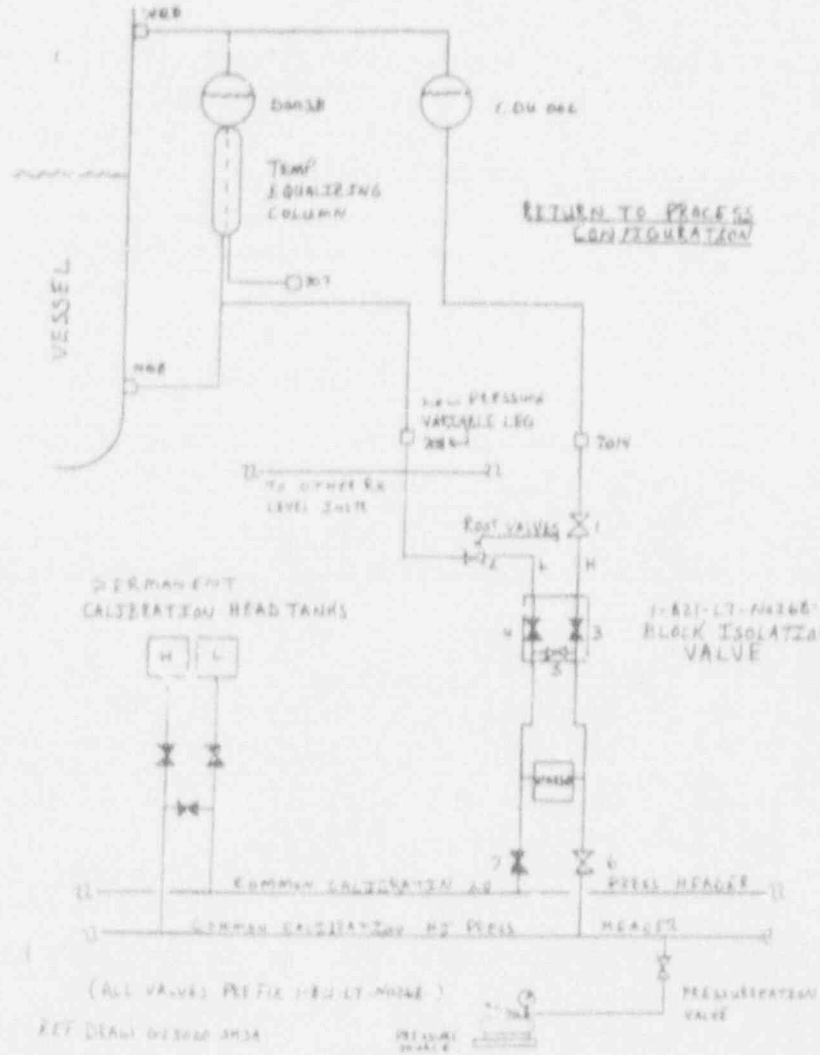
* No EIIS System Identifier Found

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQ NO.	REV NO.	
Brunswick Steam Electric Plant Unit 1	05000325	91	018	0	6

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

ATTACHMENT 4



ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

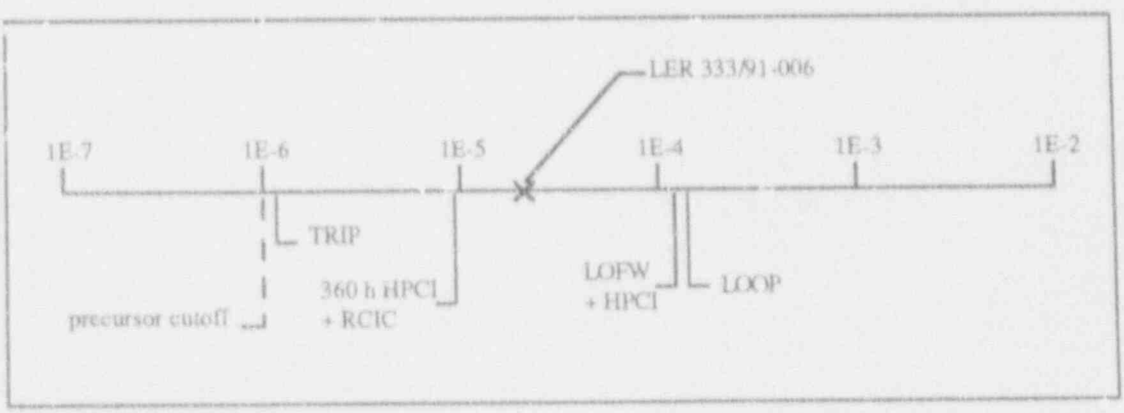
LER No.:	333/91-006
Event Description:	Trip with both LPCI trains inoperable
Date of Event:	May 7, 1991
Plant:	Fitzpatrick

Summary

During a surveillance test, the "A" residual heat removal (RHR) / low-pressure coolant injection (LPCI) outboard containment isolation valve failed to provide required containment isolation. Later, it was found that the valve stem had fractured and the valve disk and seat had sustained severe damage.

Subsequently, the same surveillance procedure was performed on the "B" RHR/LPCI train. When the inboard RHR/LPCI containment isolation valve was operated, it opened partially and stopped. Efforts to further open or close it were unsuccessful. Plant operators then reduced power and scrammed the unit so that repairs could be made.

The conditional core damage probability for this event is estimated at 2.0×10^{-5}. The relative significance of the event compared to other postulated events at Fitzpatrick is shown below.



Event Description

While preparing to demonstrate operability of the loop "A" RHR/LPCI inboard containment isolation valve, 10MOV-25A, plant personnel attempted to pressurize the space between the inboard valve and the outboard valve, 10MOV-27A, to facilitate opening the inboard valve. When these attempts were unsuccessful, it was determined that the outboard LPCI loop "A" isolation valve was incapable of performing its isolation function.

When the "B" train valves were tested, the inboard isolation valve, 10MOV-25B, opened partially and then failed. Subsequent attempts to open and close the valve were unsuccessful. Attempts at manual operation of the valve also failed.

Subsequently, power was reduced and the plant was scrammed to allow repairs to the RHR/LPCI system. RHR loop "A" was placed in service for shutdown cooling. Testing revealed that it was possible to force approximately 5000 gpm past the defective loop "A" outboard isolation valve.

The loop "B" inboard isolation valve, 10MOV-25B, was isolated for repair. Its valve stem threads were found to be worn and broken, and pieces of the threads were found in the fixed valve stem nut. When repairs to the loop "B" inboard isolation valve were completed, shutdown cooling (SDC) was transferred from loop "A" to loop "B". Investigation revealed that the loop "A" outboard isolation valve had sustained severe seat, disk, and disk guide rib damage. In addition, the valve stem was fractured.

Additional Event-Related Information

The definition of LPCI success may vary with circumstances. However, the minimum requirement when LPCI is demanded is that full flow from one pump be provided, approximately 7000 gpm. As the loop "A" flow was determined to be 5000 gpm and only limited flow through loop "B" was possible, it appears that neither LPCI loop was capable of performing its safety function.

ASP Modeling Assumptions and Approach

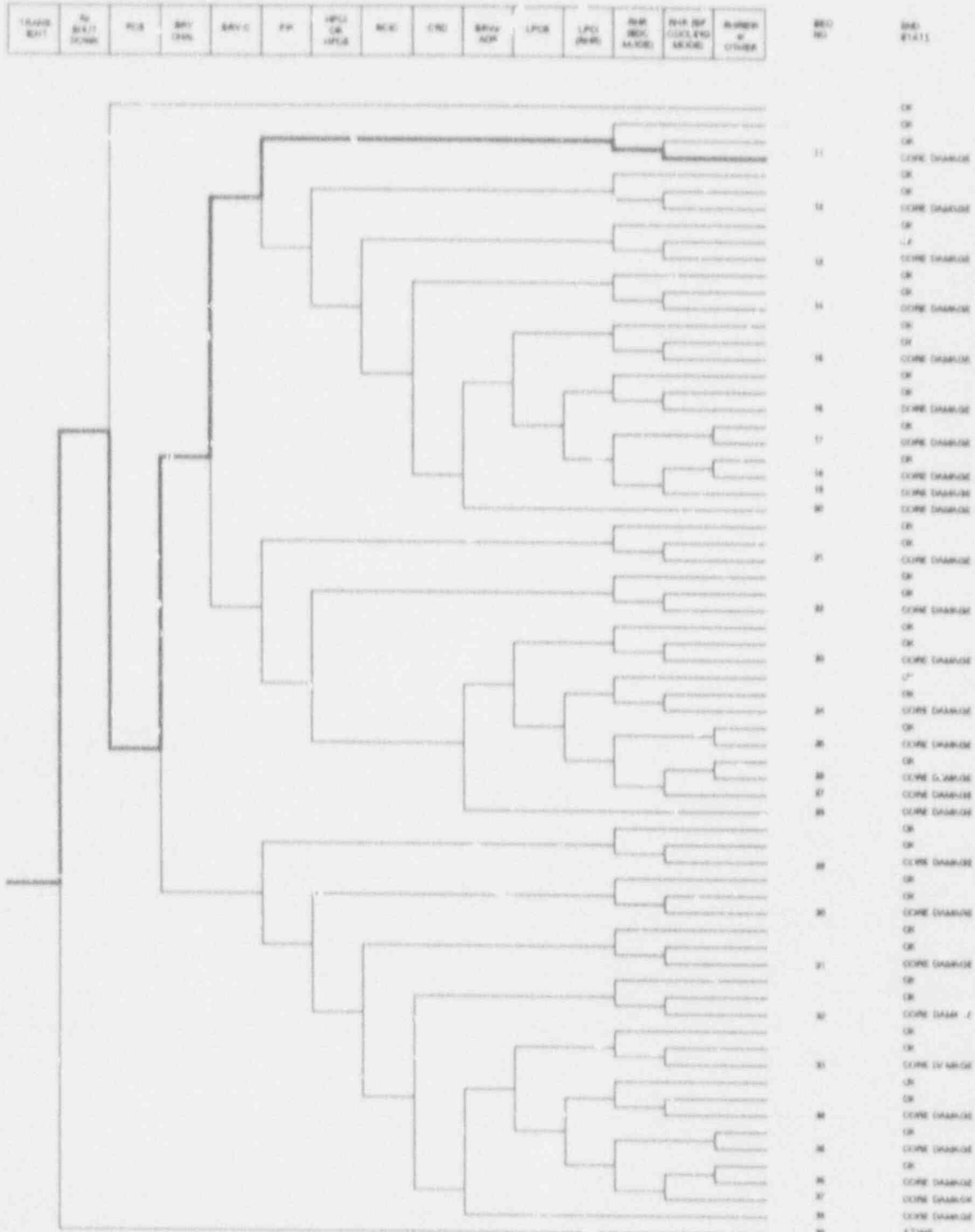
This event was modeled as a scram with LPCI and one train of RHR unavailable. Although one train of RHR functioned during the event, its injection valve was found to be significantly damaged. A failure probability of 0.5 was assumed for this train.

The Accident Sequence Precursor (ASP) models assume that RHR-suppression pool cooling is more likely to fail if LPCI and RHR-SDC are failed. In this event, the suppression pool cooling function should not have been impacted by the failure of the LPCI isolation valves. Therefore, the failure probability for suppression pool cooling given unavailability of LPCI and RHR(SDC) was reduced to 2.0×10^{-3}. This value is consistent with values used elsewhere in the model.

The ASP models also address the potential use of RHR service water (RHRSW) for low-pressure injection, given that LPCI is failed. In this event, the dominant failure mode for LPCI is failure of both injection valves. If these valves fail, RHRSW is also failed. A failure probability of 1.0 was assumed in this analysis.

Analysis Results

The conditional core damage probability for this event is estimated at 2.0×10^{-5}. The dominant sequence, as highlighted on the following event tree, involves trip, failure of the power conversion system, successful safety/relief valve operation, feedwater success, and failure of both shutdown cooling and suppression pool cooling in the long term.



Dominant core damage sequence for LER 333/91-006

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/91-006
Event Description: Trip with both LPCI trains and one RHR train unavailable
Event Date: 05/07/91
Plant: Fitzpatrick

INI ATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	2.0E-05
Total	2.0E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	1.6E-05	1.0E-01
12	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close fw/pcs.trans -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	3.0E-06	3.9E-02
21	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	6.2E-07	1.0E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	1.6E-05	1.0E-01
12	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close fw/pcs.trans -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	3.0E-06	3.9E-02
21	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	6.2E-07	1.0E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrseal.bmp
BRANCH MODEL: c:\asp\1989\fitzpatr.sll
PROBABILITY FILE: c:\asp\1989\[illegible] 1.pro

Event Identifier: 333/91-006

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	3.4E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+0	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
ep.rec	1.6E-01	1.0E+00	
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
hpci	2.9E-02	7.0E-01	
rcic	6.0E-02	7.0E-01	
srd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	1.0E-03 > 5.0E-01	7.1E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > 5.0E-01		
RHR(SDC)	2.1E-02 > 5.1E-01	3.4E-01	1.0E-03
Branch Model: 1.OF.2+ser+opr			
Train 1 Cond Prob:	3.0E-03 > Failed		
Train 2 Cond Prob:	3.0E-01 > 5.0E-01		
Serial Component Prob:	2.0E-02		
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
RHR(SPCOOL)/LPCI.RHR(SDC)	9.3E-02 > 2.0E-03 **	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	9.3E-02		
RHRSW	2.0E-02 > 1.0E+00	3.4E-01 > 1.0E+00	2.0E-03
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	2.0E-02 > 1.0E+00		

* branch model file
** forced

Minarick
03-16-1992
18:03:34

Event Identifier: 333/91-006

NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): JAMES A. FITZPATRICK NUCLEAR POWER PLANT

DOCKET NUMBER (2): 0 5 0 0 0 3 3 3 | PAGE (3): 1 OF 0 6

TITLE (4): Manual Reactor Shutdown Due to Inoperability of Both Low Pressure Coolant Injection Subsystems Due to Mechanical Failure of One Valve in Each of the Two Systems

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 NAMES	DOCKET NUMBER(S)
0 5	0 7	9 1	9 1	— 0 0 6 —	0 0	0 6	0 6	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11): X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Hamilton C. Fish | TELEPHONE NUMBER: AREA CODE 3 1 5 | 3 4 9 — 6 0 1 3

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
X	B O	E 4	L 2 0 0	Y					
X	B O	I S V	P 3 0 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) | NO

EXPECTED SUBMISSION DATE (15): MONTH 0 9 | DAY 3 0 | YEAR 9 1

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

EIIS Codes are in []

Between 0400 and 0500 on 5/7/91 a monthly Technical Specification check found one of the two primary containment isolation valves in each of the two independent residual heat removal [BO] low pressure coolant injection (LPCI) [BO] subsystems to be inoperable. A valve operator torque switch tripped in both the open and close directions preventing both full closure and full opening one valve. The other valve had excessive seat leakage. The inoperability of both RHR-LPCI systems required a reactor shutdown within 24 hours which was initiated and an Unusual Event declared at 1237. The reactor was manually scrammed at 1820. Cold shutdown condition was achieved on 5/8/91 at 0330. The Unusual Event was terminated at 0400. In LPCI loop B the threads of the gate valve stem nut in the motor operator were worn and broken causing the valve to lock in a partially open position. The stem nut was replaced and LPCI loop B restored to service at 1410 on 5/12/91. The stem of an angle globe throttle valve in loop A was severed inside the valve body. The disc, disc guides, and seat were severely damaged. The valve was removed from the system. The plant remains shutdown until the valve is repaired. Root cause failure analysis is in progress for both valves.

NRC Form 366
(9-83)

EIIS Codes are in [ ]

Description

The reactor was operating at full power. In accordance with Technical Specifications, a scheduled monthly surveillance test was performed on 5/7/91. Two motor operated primary containment isolation valves failed to meet the operability test acceptance criteria. Each of these valves is located in a separate and redundant low pressure coolant injection (LPCI) [BO] subsystem of the residual heat removal (RHR) [BO] system which provides emergency core cooling (ECCS). The RHR system is divided into two redundant loops. Each of the two loops contained one of the two valves that were not operable. Therefore, both RHR-LPCI loops were inoperable. The reactor was shutdown within 24 hours in accordance with Technical Specification Requirement 3.5.A.6.

In each of the two RHR system loops, two pumps discharge through a 24-inch diameter common header to the discharge piping of the reactor water recirculation system [AD] piping. The isolation protection for the penetration of the primary containment for each loop is provided by three valves. An air operated testable check valve is used inside containment. This check valve is permitted to have a higher leak rate than other containment isolation valves. Therefore, primary containment isolation capability outside of the drywell is provided by two motor operated valves. Closest (inboard) to containment is a gate valve, 10MOV-25. Next outboard is an angle globe valve, 10MOV-27, which may also used for throttling RHR flow.

Technical Specification surveillance requirement Section 4.5.A.3 requires testing of the RHR-LPCI subsystem as specified in Section 4.5.A.1.d which requires a monthly operability test of motor operated valves (MOVs). The test on May 7, 1991 was conducted in accordance with Operations Department surveillance test procedure ST-2B, "RHR Pump and MOV Operability and Keep Full Level Switch Functional Test". To open the normally closed inboard valve 10MOV-25, the differential pressure across the gate disc is first equalized by pressurizing the space between 10MOV-25 and outboard valve 10MOV-27. During the performance of ST-2B at 4:05 A.M. on May 7, 1991, operators were unable to obtain this equalization pressure across the closed 10MOV-25A valve. RHR header pressure upstream of 10MOV-27A increased when the space between 10MOV-27A and 10MOV-25A was pressurized. These observations indicated that outboard angle globe valve 10MOV-27A was leaking at an undetermined rate. The valve (10MOV-27A) was therefore not able to perform the primary containment isolation function and was declared to be inoperable. This placed the plant in a seven-day Limiting Condition for Operation (LCO) as specified in Technical Specification Section 3.5.A.3.a. Performance of ST-2B on the RHR LPCI loop A was necessarily suspended.

NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1	— 0 0 6	— 0 0	0 3 OF 0 6

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

At 4:45 A.M., while performing ST-2B on the RHR LPCI B loop, the normally closed LPCI inboard injection gate valve 10MOV-25B failed to open fully and then failed to fully close. The motor operator torque switch tripped the power supply to the operator motor prior to completion of attempts to both open and close the valve. Operators were also unable to operate the valve using the manual handwheel because t e motor operator could not be manually declutched.

Both the A and B loops of the LPCI mode of the RHR system were now in an inoperable condition due to one inoperable valve in each loop. Technical Specification 3.5.A.6 requires that the reactor be placed in a cold condition within 24 hours whenever both LPCI subsystems are inoperable.

At 12:37 P.M. a reactor shutdown to the cold condition was started. The emergency plan was initiated at the Unusual Event level. The NRC was notified by use of the emergency notification system (ENS) at 12:55 P.M. The main generator was disconnected from the electrical transmission system (line) at 5:45 P.M. In accordance with procedures, the reactor was manually scrammed at 6:20 P.M. from approximately 15 percent power. RHR system A was placed in service in the shutdown cooling mode at 2:56 A.M. on May 8, 1991. A reactor coolant temperature of less than 212 degrees fahrenheit (cold condition) was achieved at 3:30 A.M. The Unusual Event was formally terminated at 4:00 A.M.

At 9:55 A.M. a test determined that the rate of leakage past the seat of angle globe valve 10MOV-27A was approximately 5,100 gallons per minute (gpm). The RHR A loop continued to be used for shutdown cooling to remove decay heat. A damaged stem nut was found on 10MOV-25B. On May 12th at 1041 the repairs and post-work testing of LPCI inboard injection gate valve 10MOV-25B were completed.

Shutdown cooling was then transferred from the RHR A loop to the RHR B loop at 1410 to permit investigation of the seat leakage in RHR A loop valve 10MOV-27A. Inspection of the internals of angle globe valve 10MOV-27A found fracture of the valve stem and severe damage to the seat, disc, and disc guide ribs. It was necessary to remove the valve from the system to facilitate internal machining and welding repairs. As of the date of this report, the plant remains shutdown while valve repairs are in progress.

<u>Cause</u>

Valve 10MOV-25B failed to fully open or close due to the excessive force required to move the valve stem which in turn tripped the motor torque switch. This switch then interrupted the motor power supply in accordance with design. The cause of the excessive torque was excessive friction between the mating acme screw threads of the fixed stem nut and the moving valve stem. Inspection of the internal thread

NRC FORM 366A

of th: stem nut found severe wear and missing, broken, and jammed pieces of the thread. The stem nut is machined from soft (relative to steel) bronze. The valve stem iw machined from stainless steel. The moving stem mechanism had been lubricated on a regular basis. The stem nut had not been replaced since manufacture of the valve. Determination of the cause of the wear and ultimate failure of the stem nut is currently in progress.

Investigation and determination of the cause of the failure of the valve stem and damage to the disc guide ribs, disc, and seat of the angle globe valve 10MOV-27A is currently in progress.

Analysis - Reportability

One primary containment isolation valve in each of the two redundant ECCS RHR systems was inoperable. Therefore, both trains of the RHR LPCI subsystem were inoperable. Technical Specification 3.5.A.6 requires reactor shutdown to the cold condition within 24 hours if both LP I subsystems are inoperable. Accordingly, this event is reported under the provisions of 10CFR50.73(a)(i)(A) as a completion of a reactor shutdown required by Technical Specifications.

Analysis - Containment Isolation

Technical Specification Table 3.7-1, "Primary Containment Isolation Valves", lists three valves in each RHR LPCI subsystem to maintain isolation of the primary containment if it is required. Air operated testable check valve (10AOV-68) is designated inside the primary containment. To reduce maintenance and associated personnel radiation exposure, Technical Specification Amendment 40 in 1978 increased the permitted pneumatic leak rate for this valve to 11 cfm. The valves are tested to this criteria in accordance with Technical Specification Section 4.7.A.d (1). This leak rate is on the order of 100 times the leak rate permitted for other containment isolation valves of a similar size. To compensate for this increase in the permitted leak rate, an additional valve (10MOV-27) was added to the list of designated primary containment isolation valves. Both (one in each loop) of the air operated testable check valves inside primary containment were operable. Outside the containment two motor operated valves (10MOV-25 and -27) are designated in each loop. One of these two valves remained operable in each of the two loops. Therefore, a double valve primary containment isolation function was always available and operable.

Analysis - Removal of Residual Heat

The operation of the B loop was impaired by the inability to fully open gate valve 10MOV-25B. Subsequent testing did demonstrate that the valve could be fully opened (if required) by momentarily bypassing the torque switch and thermal overload protection. The fully redundant A loop was always available for operation. This was demonstrated by actual use of the A loop to remove reactor decay heat over a period of more than four days until the B loop was restored to operation.

Corrective Action

1. The reactor was shutdown to cold condition within 24 hours.

2. The stem nut on the isolation gate valve 10MOV-25B was replaced and the valve returned to service within 5 days of discovery of the inoperability.

3. The throttle globe angle valve 10MOV-27A has been removed from the system for repair. Repairs are in progress as of the date of the report. Upon completion of repairs, the valve will be reinstalled in the system.

4. A root cause investigation for both valve failures is in progress. Findings resulting from these investigations will be reported in a supplemental (revised) LER.

Additional Information

1.	Component:	Motor Operator
	Component Identification:	10MOV-25B
	System:	RHR B LPCI
	Function:	Inboard Injection & Primary Containment Isolation
	IEEE Function Codes:	84
	NPRDS Component Code:	VALVO
	Manufacturer:	Limitorque
	NPRDS Vendor Code:	L200
	Model:	SMB-4T Old Style with Thrust Adaptor Pre-1967 Design No Longer Manufactured
	Size:	4
	Power Ratio:	32.8 HP
	Design Current:	35.8 Amps
	Voltage:	575 Volts
	Closing Time:	24 Seconds
2.	Component:	Globe Angle Valve, Motor Operated
	Component Identification:	10MOV-27A
	System:	RHR A LPCI
	Function:	Outboard Throttle Injection & Primary Containment Isolation
	IEEE Function:	INV & ISV
	NPRDS Component Code:	VALVE
	Manufacturer:	Powell

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1 — 0 0 6 — 0 0	0 6 OF 0 6

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

NPRDS Vendor Code:	P305
Model:	19053
Type:	Globe Angle
Size:	18 Inch
Pressure:	900 psig
Motor Operator Type:	Limitorque SMB-4T
	Old Style with Thrust Adaptor
	Pre-1967 Design No Longer Manufactured

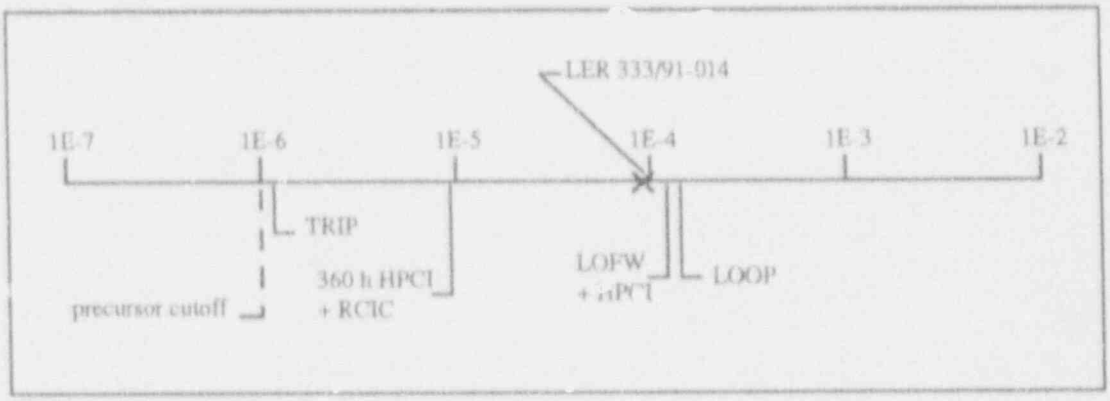
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	333/91-014
Event Description:	Hydraulic pressure locking of two low-pressure ECCS injection valves
Date of Event:	August 5, 1991
Plant:	Fitzpatrick

Summary

Following repairs to an outboard low-pressure coolant injection (LPCI) valve, and with the plant shut down, the inboard injection valve failed to open. This failure was the result of hydraulic locking of the valve bonnet. Both the two LPCI and the two core spray (CS) injection valves were determined to be susceptible to this failure mechanism.

Based on leak rate testing results, two of the four valves could fail to open if the reactor vessel was rapidly depressurized as it would be following a large-break loss-of-coolant accident (LOCA). The conditional core damage probability for this event is estimated to be 9.5×10^{-5}. The relative significance of the event compared to other postulated events at Fitzpatrick is shown below.



Event Description

The plant was shut down on May 7, 1991, to repair valves in both LPCI injection lines. On July 17, 1991, following corrective maintenance for valve and actuator problems with the outboard LPCI injection valve, a hydrostatic test of the piping between the inboard (MOV-25B) and outboard (MOV-27B) LPCI injection valves was performed. The hydrostatic test pressure was ~2100 psig. Upon completion of the test, the piping between valves was depressurized. A fill and vent of the system was initiated in preparation for returning the loop to service in the shutdown cooling (SDC) mode.

Approximately 9 to 10 h after the completion of the test, the loop had been filled to the inboard LPCI injection valves. The operators attempted to open the 24-in. flexible wedge gate valve (MOV-25B) from the control room. The actuator remained energized for approximately 30 s after which the motor actuator circuit breaker tripped. The normal stroke time for this valve is 120 s.

Utility personnel suspected that the valve failure was the result of hydraulic "pressure locking," where excessive pressure is trapped between the wedges of a flexible wedge gate valve such as MOV-25B. This valve design is used in both the LPCI and CS injection lines, rendering these systems susceptible to failure. The hydraulic pressure locking phenomenon is illustrated in Fig. 1.

A second hydrostatic test was performed on July 28, 1991. Instrumentation installed during this test confirmed that hydraulic locking was taking place. During this test, as pressure was increased to 850 psig, the rate of pressurization dropped to zero for approximately 30 min, indicating compression of air in the valve bonnet. Target test pressure of 2100 psig was held for 10 min and released. Thirty minutes after depressurization, operators attempted to open the valve from the control room. The actuator motor line current went to locked-rotor current, and the circuit breaker was manually opened by an electrician monitoring line current. The bonnet was vented through the stem packing gland, and air escaped. Coincident with the bonnet depressurization, valve position indication in the control room changed from closed to intermediate. The valve then stroked normally from the control room.

All four LPCI and CS injection valves were modified, prior to plant start-up, to incorporate a bonnet vent to the high-pressure side of the valve.

Additional Event-Related Information

Following the determination that the motor failure was caused by pressure locking of the valve, an analysis was performed by a consultant to the utility to determine the impact on other motor-operated, flexible wedge gate valves. Three scenarios were examined for each of these valves:

1) Water trapped in the valve bonnet "expands" as a result of heating during normal plant start-up.

2) Water trapped in the valve bonnet "expands" as a result of heating during a postulated high-energy line break.

3) One side of the valve is initially pressurized by check valve leakage and then suddenly depressurized as a result of a loss-of-coolant accident (LOCA) or automatic depressurization system (ADS) actuation.

The analysis performed for the utility indicated that thermally-induced bonnet pressurization (scenarios 1 and 2) did not appear to be a concern. These two scenarios were not addressed in this analysis.

In the RHR and CS systems there are testable check valves between the reactor and the normally closed isolation valves. Leakage past the check valves will eventually place reactor pressure on one side of the flexible wedge disc. The wedge will then flex, allowing reactor pressure into the bonnet. Pressures on the order of 1,000 psig could become trapped in the bonnets of all four low-pressure emergency core cooling system (ECCS) injection valves following vessel depressurization during a LOCA. The utility stated that calculations taking into account the installed actuator size and past Local Leak Rate Test (LLRT) data showed that bonnet pressures in the range of 600 to 700 psig would be sufficient to lock the affected valves shut.

After the valves lock shut, there is a finite period of time before the bonnet pre[illegible] decays to a level less than the maximum bonnet pressure the valve actuato[illegible] to open the valve. This period of time depends on the leak [illegible]a of the bo[illegible]et, the disk seating surface, the valve size, and the differen[illegible] pressure [illegible]. Lower bonnet leak rates will result in longer periods that the valve will [illegible]sed in the shut position. Considering the time period from LOCA initiation until the low-pressure ECCS injection valves [illegible] their open signal, the analysis estimated that, for the existing valves, the pressure within the bonnets of two out of four valves would have decayed to within the capability of the valve actuator.

ASP Modeling Assumptions and Approach

The event was modeled as an unavailability of two of the four LPCI and CS injection paths. Both LPCI valves were assumed to be unavailable. Conditional failure probabilities of 0.3 and 0.5 were assigned to the two potential operable CS injection trains. (Assuming both LPCI trains are initially unavailable results in an event significance estimate that is somewhat higher than assuming one LPCI and one CS train were initially unavailable.)

The unavailability existed since initial criticality. To estimate the relative significance of the event within a 1-yr observation period (the interval between precursor reports), a 1-yr unavailability was utilized in the analysis (6132 h, assuming the plant was critical or at hot shutdown for 70% of the year).

In the analysis, residual heat removal (RHR) SDC was also assumed to be unavailable because of the unavailable LPCI valves. It is possible that the valve bonnets would depressurize prior to the need for these valves to open for RHR (SDC) (typically 6-12 h following scram) in sequences where low-pressure injection was not demanded. If this were the case, such sequences would not be impacted by this event. A sensitivity analysis was performed to determine the impact on event significance if RHR (SDC) were available for these sequences.

Two additional changes were made in model probabilities to reflect the specifics of the event:

- The Accident Sequence Precursor (ASP) models assume that RHR suppression pool (SP) cooling is more likely to fail if LPCI and RHR (SDC) are failed. In this event, the SP cooling function should not have been impacted by the failure of the LPCI injection valves. Therefore, the failure probability for SP cooling given unavailability of LPCI and RHR (SDC) was reduced to 2.0×10^{-3}. This value is consistent with values used elsewhere in the model.

- The ASP models also address the potential use of RHR ice water (RHRSW) for low-pressure injection, given that LPCI is failed. In this event, the dominant failure mode for LPCI is failure of both injection valves. If these valves fail, RHRSW also fails. A failure probability of 1.0 was assumed in this analysis.

The impact of the valve failures on large-break LOCA sequences was also addressed. For a large-break LOCA, successful operation of one LPCI train or one CS train, combined with long-term heat removal using the RHR SP cooling mode, was assumed to provide successful mitigation.

The core damage probability contribution from large-break LOCA sequences can therefore be approximated by

p(large-break LOCA in 1-yr time period) *
[p(LPCI fails | observed valve failures) *
p(CS fails | observed valve failures)
p(RHR SP cooling fails | observed valve failures)]
$= 1.0 \times 10^{-4} * [1.0 * 0.15 + 2.0 \times 10^{-3}]$
$= 1.5 \times 10^{-5}$.

A second sensitivity analysis was performed assuming all four ECCS valves were failed.

Analysis Results

The conditional core-damage probability for this event is estimated at 9.5×10^{-5}. This includes the sequences documented on the calculation sheets included with this analysis, plus the contribution from postulated large-break LOCAs, as described above. The dominant sequence, highlighted on the following event tree, involves a postulated small-break LOCA with failure of high-pressure coolant injection, successful depressurization to allow use of the low-pressure systems, and failure of low-pressure injection (LPI).

Assuming all four ECCS valves were failed results in an estimated conditional probability of 3.9×10^{-4}, a factor of 4 higher than the nominal conditional probability estimated for the event. This small difference is primarily a result of the conditional probabilities assumed for the two CS trains, given the failed LPCI trains.

Assuming RHR(SDC) would not be impacted in sequences where LPI is not demanded (sequences 11, 40, 12, 71, and 21 on the following calculation sheet, plus lower probability sequences) results in an estimated conditional probability of 5.2×10^{-5}, about half of the nominal conditional probability estimated for the event.

Attachment 1
IN 92-26
April 2, 1992
Page 1 of 1

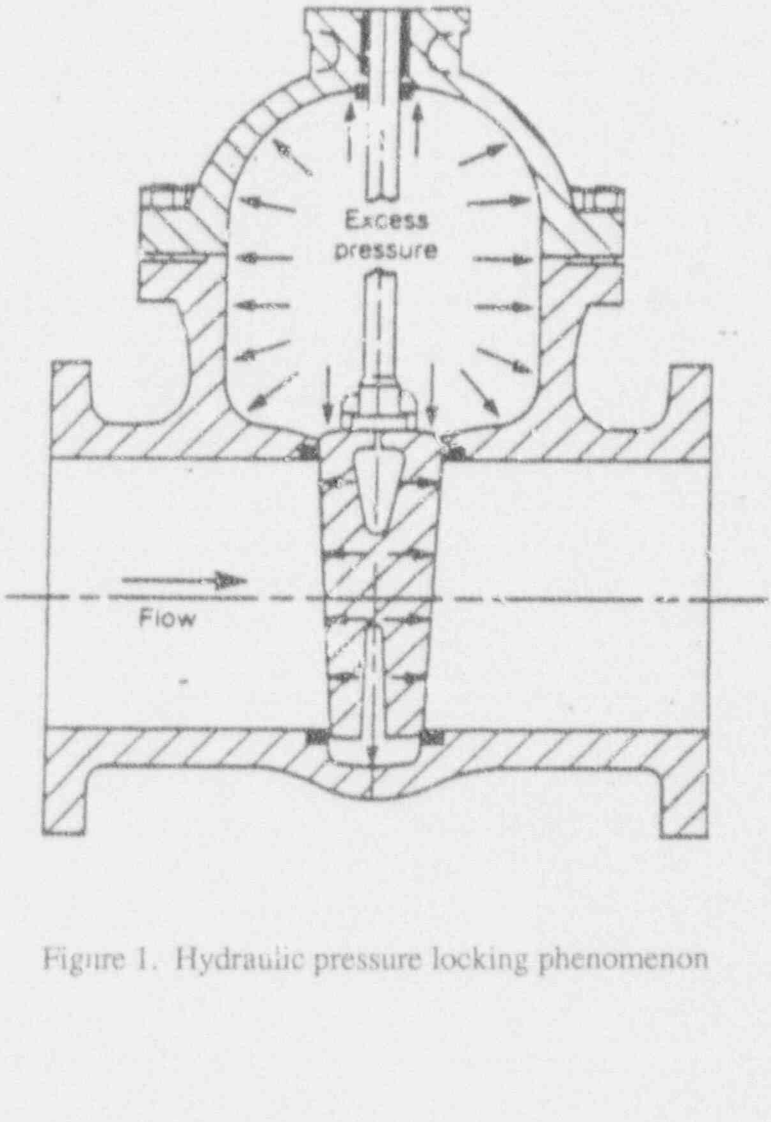
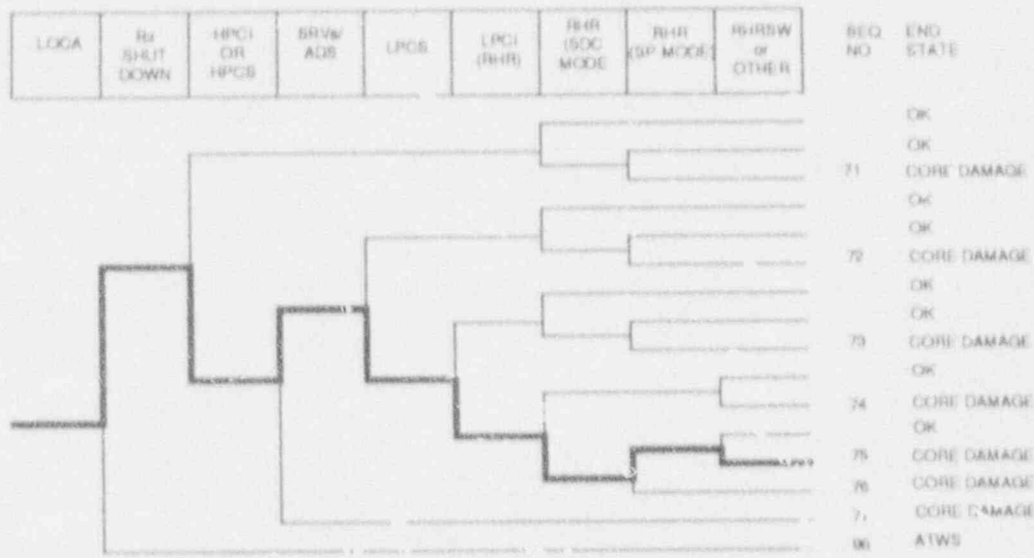


Figure 1. Hydraulic pressure locking phenomenon



Dominant core damage sequence for LER 333/91-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/91-014
Event Description: Low pressure ECCS valve hydraulically locked (LPCI failed)
Event Date: 08/05/91
Plant: Fitzpatrick

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	2.1E+00
LOOP	3.6E-02
LOCA	1.0E-02

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	?.6E-05
LOOP	1.7E-05
LOCA	3.2E-05
Total	8.0E-05
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
75	loca -rx.shutdown hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc) /lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	3.0E-05	3.5E-01
11	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.7E-05	1.0E-01
40	loop -emerg.power -rx.shutdown srv.chall/loop.-scram -srv.close -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	7.3E-06	4.1E-02
12	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close fw/pcs.trans -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	5.0E-06	3.9E-02
53	loop -emerg.power -rx.shutdown srv.chall/loop.-scram srv.close hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	3.7E-06	2.5E-01
26	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close fw/pcs.trans hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	2.5E-06	2.4E-01
71	loca -rx.shutdown -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.2E-06	5.7E-02
21	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	1.0E-06	[illegible]E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Event Identifier: 333/91-014

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.7E-05	1.0E-01
12	trans -rx.shutdown pcs/trans srv.chall/trans.-scram -srv.close fw/pcs.trans -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	5.0E-06	3.9E-02
21	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close -fw/pcs.trans RHR(SDC) rhr(spcool)/rhr(sdc)	CD	1.0E-06	1.0E-01
26	trans -rx.shutdown pcs/trans srv.chall/trans.-scram srv.close fw/pcs.trans hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	2.5E-06	2.4E-01
40	loop -emerg.power -rx.shutdown srv.chall/loop.-scram -srv.close -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	7.3E-06	4.1E-02
53	loop -emerg.power -rx.shutdown srv.chall/loop.-scram srv.close hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	3.7E-06	2.5E-01
71	loca -rx.shutdown -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.2E-06	5.7E-02
75	loca -rx.shutdown hpci -srv.ads LPCS LPCI(RHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPCI.RHR(SDC) RHRSW	CD	3.0E-05	3.5E-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:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\fitzpatr.all
PROBABILITY FILE: c:\asp\1989\bwr_call.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	3.4E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
ep.rec	1.6E-01	1.0E+00	
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
hpci	2.9E-02	7.0E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
LPCS	3.0E-03 > 1.5E-01	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	3.0E-02 > 3.0E-01		
Train 2 Cond Prob:	1.0E-01 > 5.0E-01		
LPCI(RHR)/LPCS	1.5E-03 > 1.0E+00	7.1E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
RHR(SDC)	2.1E-02 > 1.0E+00	3.4E-01	1.0E-03

Event Identifier: 333/91-014

Branch Model: 1.OF.2+ser+opr			
Train 1 Cond Prob:	3.0E-03 > Failed		
Train 2 Cond Prob:	3.0E-01 > Failed		
Serial Component Prob:	2.0E-02		
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
RHR(SPCOOL)/LPCI.RHR(SDC)	8.3E-02 > 2.0E-03	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	8.3E-02 > 2.0E-03		
RHRSW	2.0E-02 > 1.0E+00	3.4E-01 > 1.0E+00	2.0E-03
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	2.0E-02 > Failed		

* branch model file
** forced

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Event Identifier: 333/91-014

NRC Form 366

SEP 25 1991

LICENSEE EVENT REPORT (LER)

U.S. NUCLEAR REGULATORY COMMISSION

GE

FACILITY NAME (1): JAMES A. FITZPATRICK NUCLEAR POWER PLANT

DOCKET NUMBER (2): 0 5 0 0 0 3 3 3

PAGE (3): 1 OF 0 5

TITLE (4): Bonnet Pressure Locking of Low Pressure ECCS Injection Valves

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 8	0 5	9 1	9 1	— 0 1 4 —	0 0	0 9	0 4	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): R

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: X 50.73(a)(2)(v)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Mike Grady

TELEPHONE NUMBER: AREA CODE 3 1 5 | 3 4 9 — 6 5 8 8

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	B O	I S V	P 3 0 5	Y						
B	B O	I S V	V 0 8 0	Y						

SUPPLEMENTAL REPORT EXPECTED (14): X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

EIIS Codes are in []

On July 17, 1991 with the plant shutdown for maintenance while filling and venting the Residual Heat Removal (RHR) [BO] system following repairs to the outboard Low Pressure Coolant Injection (LPCI) [BO] valve, the inboard LPCI injection valve failed to open. The failure of the Limitorque SMB-4 actuator motor was due to sustained operation at locked-rotor current.

On August 5, 1991 the root cause of the actuator motor failure was determined to be hydraulic locking of the valve bonnet. Both LPCI and core spray inboard injection valves were determined to be susceptible to this failure mechanism. All four valves were modified to place a bonnet vent to the high pressure side of the valves.

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NRC Form 366

NRC Form 366A (6-89)	LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR / SEQUENTIAL NUMBER / REVISION NUMBER · PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1 — 0 1 4 — 0 0 · 0 2 OF 0 5

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

EIIS Codes are in []

Description

The plant was shutdown on May 7, 1991 (LER-91-006) when one of the two primary containment isolation valves in each of the two independent Residual Heat Removal (RHR) [BO] Low Pressure Coolant Injection (LPCI) [BO] subsystems was found to be inoperable due to mechanical failures.

On July 17, 1991, following corrective maintenance for valve and actuator problems with the outboard LPCI injection valve, a hydrostatic test of the piping between the inboard (10MOV-25B) and outboard (10MOV-27B) LPCI injection valves was performed. The hydrostatic test pressure was 2100 +/-25 psig. Upon completion of the test, the piping between valves was depressurized. A fill and vent of the system was initiated in preparation for returning the loop to service in the shutdown cooling mode.

Approximately 9 to 10 hours after the completion of the test, the loop had been filled to the inboard LPCI injection valve. The operators attempted to open the 24-inch flex wedge gate valve (10MOV-25B) from the control room (normal stroke time approximately 120 seconds). The actuator remained energized for approximately 30 seconds, after which the motor actuator circuit breaker tripped.

On August 5, 1991 an evaluation of the root cause and the susceptibility of other components to the failure mechanism was completed. It determined that the cause was a design problem that was shared by the LPCI inboard valves in both loops and both inboard injection valves of the Core Spray (CS) [BO] system. The problem could potentially prevent the operation of all four Emergency Core Cooling System (ECCS) low pressure injection subsystems. Accordingly, the event was determined to be reportable on that date.

Cause of Event

On July 28, 1991, to verify the hypothesis that pressure locking of the valve wedge discs resulted in motor failure, a special test was performed to reestablish the conditions that existed after completion of the July 17th hydrostatic test. Another hydrostatic test was performed while a strain gauge on the yoke of the valve was monitored. As test pressure increased to 500 psig, it was reported that sounds came from the affected valve. At the same time, the net compressive stress on the valve stem dropped from 62,000 to 42,000 lbf. This was the most dramatic change during the test. At 850 psig test pressure, the rate of pressurization dropped to zero for approximately 30 minutes, indicating compression of air in the valve bonnet. Target test pressure of 2100 psig was held for 10 minutes and released. Thirty minutes after depressurization, operators attempted to open the

NRC FORM 366A (6-89)

NRC Form 366A
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION
U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1	— 0 1 4	— 0 0	0 3 OF 0 5

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

valve from the control room. The actuator motor line current went to locked-rotor current and the circuit breaker was manually opened by an electrician monitoring line current. The bonnet was vented through the stem packing gland and air escaped. Coincident with the bonnet depressurization, valve position indication in the control room changed from closed to intermediate. The valve then stroked normally from the control room.

The root cause of the sustained operation at locked rotor current and subsequent failure of the Limitorque SMB-4 actuator motor was pressure trapped between the wedges of a flex wedge disc gate valve of a design susceptible to hydrostatic locking.

Analysis of Event

The potential loss of ability to open all four low pressure ECCS inboard injection valves to provide core flooding capability is reported under the provisions of 10 CFR 50.73(a)(2)(vii)(B) as an event where a single cause resulted in two independent trains becoming inoperable in a system designed to mitigate an accident.

The RHR system is capable of performing multiple functions (e.g., shutdown cooling, low pressure ECCS, containment cooling). The system consists of two independent loops, each comprised of two pumps, a heat exchanger, and the associated valves and piping necessary to accommodate each design function. The valve involved in this event was the B loop inboard (toward containment) LPCI injection valve. The inboard valve is a normally closed, live-load packed, 24" flex-wedge gate valve. The design differential pressure against which the inboard injection valve must open is 326 psid.

Following the determination that the motor failure was caused by pressure locking of the valve, calculations were performed by a consultant to determine the impact on other motor operated, flex wedge gate valves. Three scenarios were examined for each of these valves:

1) Water trapped in the valve bonnet "expands" as a result of heating during normal plant start-up.

2) Water trapped in the valve bonnet "expands" as a result of heating during a high energy line break (HELB) event.

3) One side of the valve is initially pressurized by check valve leakage and then suddenly depressurized as a result of a loss of coolant accident.

The analysis eliminated thermally induced bonnet pressurization (scenarios 1 and 2) as a concern based upon distance from the heat source (reactor) and peak area temperature (duration) following a HELB.

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1	0 1 4	0 0	0 4 OF 0 5

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

In the RHR and Core Spray systems there are testable check valves between the reactor and the inboard isolation valves (flex wedge gates). The check valves are only required to reduce reverse flow to less than 10 gallons per minute. Small amounts of leakage past the check valves will eventually place reactor pressure on one side of the flex wedge disc. The wedge will then flex, allowing reactor pressure into the bonnet. Pressures on the order of 1,000 psig could become trapped in the bonnets of all four low pressure ECCS injection valves (RHR and Core Spray systems) following vessel depressurization during a LOCA. Calculations taking into account the installed actuator size and past Local Leak Rate Test (LLRT) data showed that bonnet pressures in the range of 600 to 700 psig would be sufficient to lock the affected valves shut, preventing low pressure ECCS injection.

After the valves lock shut, there is a finite period of time where the bonnet pressure decays to a level less than the maximum bonnet pressure the valve actuator can overcome to open the valve. This period of time is based on the leak area on the flex wedge disc to seat surface. The leak area is estimated using local leak rate test data. Lower leak rates will result in longer periods that the valve will be locked in the shut position. Considering the time period from LOCA initiation until the ECCS injection valves receive their open signal, the analysis conservatively estimated that the pressure within the bonnets of two out of four low pressure ECCS injection valves would have decayed within the capability of the valve actuator. If the valves had had extremely low local leak rates, there could have been no low pressure ECCS capability following a large break LOCA.

Corrective Action

Short-term corrective action was to modify all four of the normally closed low pressure ECCS injection valves, prior to plant start-up, to incorporate a bonnet vent to the high pressure side of the valve.

Long-term corrective actions will be the following:

1) Revise the plant hydrostatic test procedures to req post-test venting of the bonnets of any flex-wedge or double gate valves used as hydrostatic test boundaries.

2) Engineering will evaluate the future modification of other valves identified as susceptible to pressure locking but do not have to open to perform a safety function.

NRC FORM 366A (9-83)

NRC Form 366A
(9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	9 1	— 0 1	— 0 0	0 5 OF 0 5

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

Additional Information

Component:	Flex Wedge Gate Valve, Motor Operated
Component Identification:	10MOV-25A/B
System:	RHR LPCI
Function:	Inboard Injection & Primary Containment Isolation
IEEE Function:	INV & ISV
NPRDS Component Code:	VALVE
Manufacturer:	POWELL
NPRDS Vendor Code:	P305
Model:	19023WE
Type:	Flex Wedge Gate
Size:	24-Inch
Pressure	900 psig
Motor Operator Type:	Limitorque SMB-4T Old Style with Thrust Adaptor Pre-1967 Design No Longer Manufactured

Component:	Flex Wedge Gate Valve, Motor Operated
Component Identification:	14MOV-12A/B
System:	Core Spray
Function:	Inboard Injection and Primary Containment Isolation
IEEE Function:	INV and ISV
NPRDS Component Code:	VALVE
Manufacturer:	VELAN
NPRDS Vendor Code:	V080
Model:	B16-2A5PS-24TS
Type:	Flex Wedge Gate
Size:	10-Inch
Pressure	900 psig
Motor Operator Type:	Limitorque SMB-2

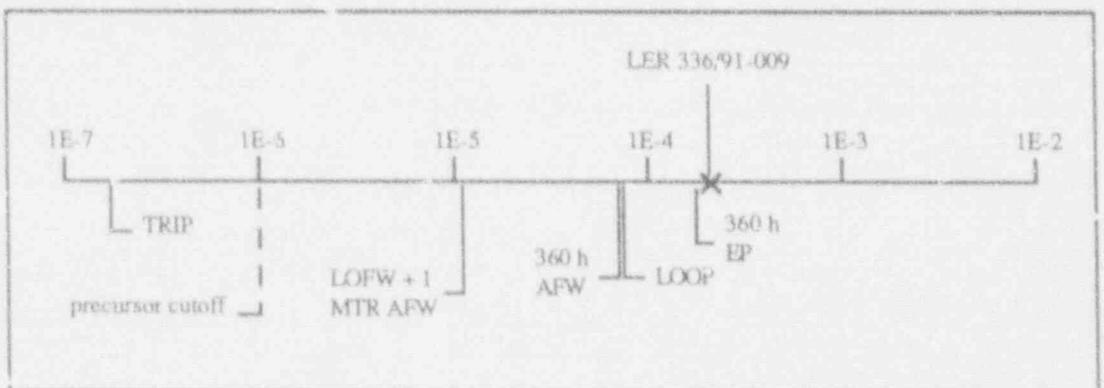
NRC FORM 366A
(9-83)

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	336/91-009
Event Description:	Both diesel generators unavailable and unit shutdown
Date of Event:	August 21, 1991
Plant:	Millstone 2

Summary

Both emergency diesel generators (EDGs) were found to exhibit erratic load control, a result of either a resistance change in the "droop" potentiometers in the electronic governor controls or contaminated oil in the hydraulic actuator units. This second cause would result in EDG inoperability under all circumstances; the first cause would only impact paralleled operation. Assuming, for the purposes of this analysis, that the EDGs would be inoperable following a postulated loss of offsite power (LOOP), a conditional core damage probability of 2.1×10^{-4} is estimated. The relative significance of the event compared to other postulated events at Millstone 2 is shown below.



Event Description

On August 21, 1991, with the plant at 90% power and EDG 13U out of service for maintenance, redundant EDG 12U was running loaded and paralleled to offsite power to demonstrate operability. At the end of a 1-h run, the EDG load control became erratic. EDG 12U output breaker was opened, and the EDG was reparalleled, but erratic speed control caused load swings that prevented reloading. Maintenance on EDG 13U was completed, and its operability was demonstrated within 1-1/2 h.

Troubleshooting continued to determine the cause of the EDG 12U load swings, and operability of EDG 13U continued to be periodically verified. Two days later, during an operability run, EDG 13U output breaker opened on a reverse power trip. With both EDGs unavailable, unit shutdown was begun, and cold shutdown was reached the next day.

The failure of both EDGs was caused by erratic operation of each EDG's Woodward Governor EG-A electronic control unit. Two potential causes were identified. The first involves large resistance changes in the EG-A "droop" potentiometer, which can result in large load swings while the EDG is running paralleled to the grid. The "droop" potentiometer is not used when the EDG alone is supplying power to the safety-related buses, and its failure would not affect EDG operability during emergency operation. The second potential cause, which would impact EDG operability under all circumstances, involved contaminated hydraulic oil in the hydraulic actuator unit — foreign material was found when the unit was disassembled.

Additional Event-Related information

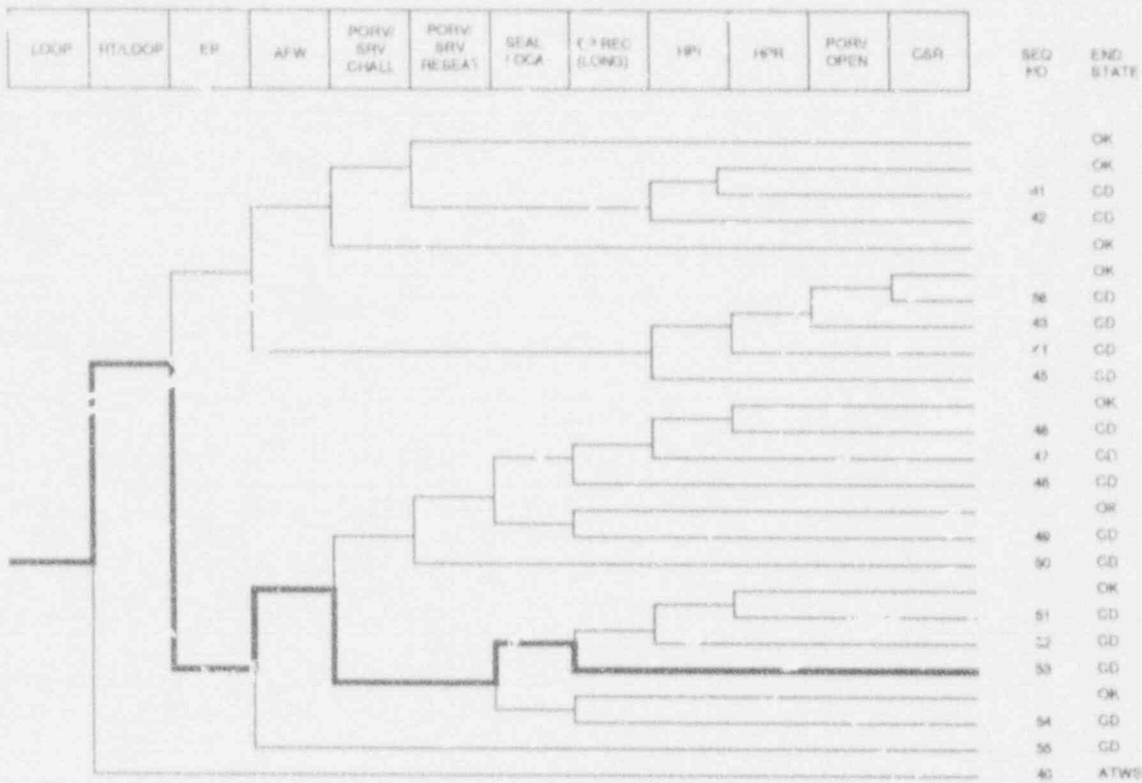
The Millstone 2 safety-related AC power system consists of two 4.16-kV buses, each supplied by an EDG rated at 2750 kW continuous duty. Each bus provides power to one service water pump, auxiliary feedwater pump, reactor building closed cooling water pump, high- and low-pressure safety injection pump, containment spray pump, and a 480-VAC emergency bus for lower voltage loads.

ASP Modeling Assumptions and Approach

The event has been modeled as a postulated LOOP during a one-half month period. As noted in the event description, it is possible that the EDG problems were caused by a change in resistance in the "droop" potentiometer. If this were the case, at least one EDG would have been available (except for a 1-1/2 h period) given an actual LOOP. However, since the cause of the EDG problems could not definitely be tied to the "droop" potentiometers and instead could have been caused by contaminated hydraulic oil, it was assumed for the purposes of this analysis that both EDGs were failed and not recoverable.

Analysis Results

The estimated conditional core damage probability associated with this event is 2.1×10^{-4}. The dominant core damage sequence is a station blackout sequence. This sequence is highlighted on the following event tree and involves failure of emergency power following a postulated LOOP, a reactor coolant pump seal loss-of-coolant accident (LOCA), and failure to recover AC power prior to core uncovery.



Dominant core damage sequence for LER 336/91-009

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 336/91-009
Event Description: Both diesel generators unavailable and unit shutdown
Event Date: 08/21/91
Plant: Millstone 2

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	2.1E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.1E-04
Total	2.1E-04
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	9.3E-05	3.3E-01
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	7.7E-05	3.3E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	3.6E-05	1.1E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE 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	9.3E-05	3.3E-01
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	7.7E-05	3.3E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	3.6E-05	1.1E-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:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\mill*tn2.s*1
PROBABILITY FILE: c:\asp\1989\pwr_b*.*1.pro

Event Identifier: 336/91-009

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	4.0E-04	1.0E+00	
loop	1.8E-05	3.3E-01	
-nca	2.4E-06	4.3E-01	
rt	2.8E-04	1.1E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 1.0E+00	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
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	2.0E-01	3.4E-01	
porv.or.srv.chall	2.0E-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	6.0E-02	1.0E+00	
ep.rec(sl)	7.6E-01	1.0E+00	
ep.rec	4.0E-02	1.0E+00	
hpi	1.0E-03	8.4E-01	
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.3E-04
hpr/-hpi	1.5E-04	1.0E+00	
csr	2.0E-03	3.4E-01	

* branch model file
** forced

Minarick
05-22-1992
15:29:44

Event Identifier: 336/91-009

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (P-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 2	0 5 0 0 0 3 3 6	1 OF 0 5

TITLE (4): Both Emergency Diesel Generators Inoperable

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 8	2 1	9 1	9 1	0 0 9	0 0	0 9	2 0	9 1		0 5 0 0 0
										0 5 0 0 0

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

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 0

20.402(b)	20.402(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Ralph W. Bates, Engineer, Ext. 5410	2 0 3	4 4 7 - 1 7 9 1

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
X	E K	6 5	W 2 9 0	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		1 2	3 1	9 2

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

On August 21, 1991, at 1804 hours, with the unit at 90% power, the 12U diesel generator exhibited erratic load control, while being operated in parallel with offsite circuits at 2100 KW load, at the end of its one hour surveillance run. The diesel generator was being run to verify its operability while its redundant diesel generator the 13U unit was out of service for maintenance. On noting the erratic load swings on the 12U Diesel Generator (D/G), the operator opened the output breaker to remove the load. The generator was then reparalleled to reload the 12U D/G, but erratic speed control caused load swings that prevented reloading at that time.

With both emergency D/Gs out of service, the 13U D/G maintenance was completed, and the operability of the 13U D/G maintenance was completed, and the operability of the 13U D/G was demonstrated satisfactorily within 1 and ½ hours, and the unit remained in compliance with Technical Specification, Section 3.8.1.1, action (d).

Troubleshooting continued to determine the cause of the 12U load swings by monitoring its governor control signals with additional instrumentation. The operability of the 13U D/G was periodically verified in accordance with Technical Specification requirements for one D/G being out of service. However, during the performance of an operability run on 8/23/91 at 05[illegible] hours, the 13U D/G output breaker opened on a reverse power trip. The second D/G was declared inoperable as a result of the reverse power trip and a unit downpower to cold shutdown was commenced in accordance with Technical Specification Action Statement 3.8.1.1(d). The unit reached cold shutdown at 1410 hours on 8/24/91, and verified compliance with the action statements of Technical Specifications 3.8.1.2.b (no core alternations permitted), and 3.8.2.2 (containment integrity) with both D/Gs inoperable.

NRC Form 366 (6-89)

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Millstone Nuclear Power Station Unit 2	0 5 0 0 0 3 3 6	9 1	— 0 0 9	— 0 0	0 2 OF 0 5

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

I. Description of Event

On August 21, 1991, at 1804 hours, with the unit at 90% power, the 12U diesel generator exhibited erratic load control, while being operated in parallel with offsite circuits at 2190 KW load, at the end of its one hour surveillance run. The diesel generator was being run to verify its operability while its redundant diesel generator, the 13U unit was out of service for maintenance. On noting the erratic load swings on the 12U Diesel Generator (D/G), the operator opened the output breaker to remove the load. The generator was then reparalleled to reload the 12U D/G, but erratic speed control caused load swings that prevented reloading at that time.

With both emergency D/Gs out of service, the 13U D/G maintenance was completed, and the operability of the 13U D/G was demonstrated satisfactorily within 1 and ½ hours, and the unit remained in compliance with Technical Specification section 3.8.1.1, action (d).

Troubleshooting continued to determine the cause of the 12U load swings by monitoring its governor control signals with additional instrumentation. The operability of the 13U D/G was periodically verified in accordance with Technical Specification requirements for one D/G being out of service. However, during the performance of an operability run on 8/23/91 at 0942 hours, the 13U D/G output breaker opened on a reverse power trip. The second D/G was declared inoperable as a result of the reverse power trip and a unit downpower to cold shutdown was commenced in accordance with Technical Specification Action Statement 3.8.1.1(d). The unit reached cold shutdown at 1419 hours on 8/24/91, and verified compliance with the action statements of Technical Specifications 3.8.1.2.b (no core alterations permitted), and 3.8.2.2 (containment integrity) with both D/Gs inoperable.

II. Cause of Event

The cause of the load swings was intermittent failure of the Woodward Governor EG-A electronic control unit in the governor system of each D/G.

Root Cause

Troubleshooting was performed on both diesel generator governor systems, which revealed the root cause to be erratic operation of the EG-A units in each D/G.

The 13U D/Gs EG-A unit input and output electrical signals were monitored during test runs in the loaded condition while paralleled with the grid. During observed load oscillations the EG-A output signal was recorded as making a corresponding change with no change in any input signals.

Further checks of EG-A internals identified the "droop" potentiometer as having large resistance value changes. The "droop pot" should not change in resistance once an initial setting has been made. A change in resistance in the "droop pot" will cause large load swings, either positive or negative, while the generator is carrying load in the "parallel" mode. Therefore, the data obtained identifies the root cause as the EG-A unit "droop pot."

The "droop pot" is out of the circuit when operating in the non-parallel or "isochronous" mode, and thus its failure or erratic operation would not have affected emergency operation of the D/Gs.

The EG-A and EGB-10C units from the 12U D/G were sent for testing and analysis at the vendor's factory test facility. During testing of the EG-A unit, unexplained EG-A output voltage swings were observed. Unfortunately, the voltage swings could not be duplicated again at the test facility, and no valuable information was gained.

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Millstone Nuclear Power Station Unit 2	0 5 0 0 0 3 3 6	9 1	0 0 9	0 0	0 3 OF 0 5

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

During disassembly of the EGB-10C hydraulic actuator unit, a small amount of foreign material was noted. Initially, this contamination was considered as a possible cause of the erratic operation. In the final report the vendor concluded the oil contamination was not the cause of the load swings seen at Millstone. This conclusion was based on the lack of any scoring of internal moving parts. This inconsistency between initial findings and final reports does not alter the facts of the abnormalities seen in the electronic controls performance and the contamination of the hydraulic oil that support the root cause conclusions.

The process of troubleshooting included checks of other governor control system components which could have created the load swings. Other items checked and eliminated were: Speed setting pot (motor operated pot), Isochronous-Parallel Switch and Relay (UPS), Generator Output Potential Transformers (PTs), and interconnecting cables for opens or grounds.

Thus, the final root cause of load swings on both diesel generators is erratic operation of the EG-A electronic governor unit, or contamination of the hydraulic oil, or a combination of both conditions.

III. Analysis of Event

This report is being submitted pursuant to requirements of paragraph 50.73(a)(2)(i), the completion of any nuclear plant shutdown required by the plant's Technical Specifications.

There were no safety consequences as a result of this event since at all times the unit was in compliance with Technical Specifications.

The safety significance was minimal because the final reviews show the 13U D/G would have been available had it been called upon to provide power in an emergency condition involving a loss of normal power.

IV. Corrective Action

The corrective action taken was to replace the governor EG-A and EGB-10C units on both the 12U and 13U D/Gs. Following replacement a full test program was conducted that subjected both D/Gs to a loss of normal power (LNP) start, with sequenced loading of the generator while running in the isochronous mode, followed by partial and full load rejection tests, full rated load runs at 2750 KW, and two hour runs at 3100 KW.

To preclude oil contamination as a cause of a recurrence, the Maintenance Department has been directed to add steps to flush the hydraulic actuator unit as part of the refueling maintenance effort.

To preclude a similar recurrence, plans have been initiated to upgrade the D/G controls with replacement systems of a newer design. Replacement is anticipated to be accomplished during the 1992 refueling outage.

V. Additional Information

Similar LERs: None

EIIS: EK - Emergency on-site power system
65 - Governor (diesel generator)
W290 - Woodward Governor Co.

NRC Form 366 (6-89)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6): YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Millstone Nuclear Power Station Unit 2	0 5 0 0 0 3 3 6	9 1	0 0 9	0 0	0 4 OF 0 5

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

Other:

Previous related events with observed load swings on the 12U D/G were noted in two cases on MP2, on August 15, 1989 and on April 3, 1990.

During the Fall 1989 refueling outage the EG-A unit was replaced on the 12U D/G.

Following load swings observed 4/3/90, the governor control system was checked, and as a result, settings for droop and speed on the EGB-10C actuator unit were adjusted, based on vendor recommendations.

Attachment: MP2 Diesel Generator Governor System Sketch

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

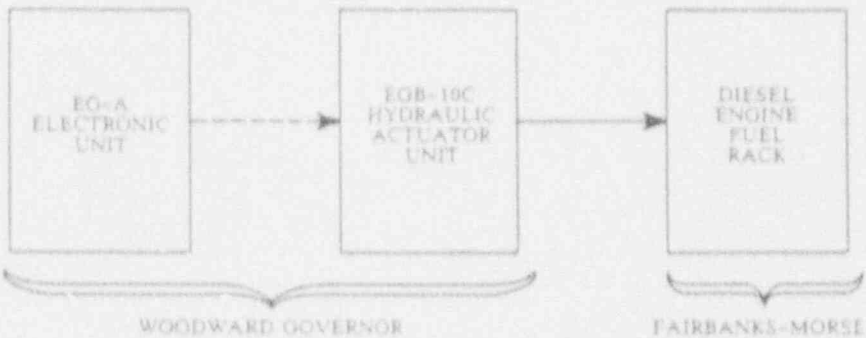
Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-630), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Millstone Nuclear Power Station Unit 2	0 5 0 0 0 3 3 6	9 1	— 0 0 9 —	0 0	0 5 OF 0 5

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

ATTACHMENT
MP2 DIESEL GENERATOR GOVERNOR SYSTEM SKETCH



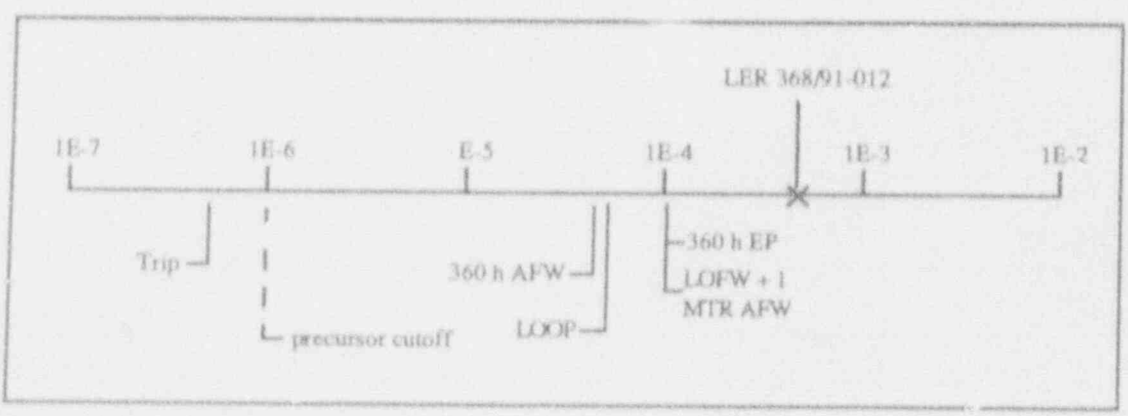
NRC Form 366 (6-89)

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	368/91-012
Event Description:	Both normal service water trains fouled by debris
Date of Event:	April 16, 1991
Plant:	Arkansas Nuclear One, Unit 2

Summary

Maintenance and operational errors at Arkansas Nuclear One, Unit 2 (ANO 2) resulted in rotation of debris-laden raw water traveling screens while the screen wash system was not operating. This permitted significant quantities of debris to carry over into the common service water (SW) pump suction pit and into the SW system. Pump discharge strainers on both operating SW trains quickly became fouled, and both trains were declared inoperable. A third (standby) pump was aligned to an alternate suction source and placed in service to supply loop I SW loads. The loop I normal supply pump SW strainer was cleaned, and the loop was restored to normal alignment. The standby pump was then aligned to supply loop II restoring the Tech Spec-required SW configuration approximately 2 h after the fouling occurred. The conditional core damage probability estimated for this event is 4.8×10^{-4}. The relative significance of this event compared to other postulated events at ANO 2 is shown below.



Event Description

While performing preventive maintenance on the SW traveling screens with the plant in startup, plant maintenance personnel rotated the screens without operating the screen wash system. The traveling screens serve to prevent debris from entering the SW pump suction pit, and this debris builds up on the screens over time. When the screens are rotated, screen wash sprays are normally operated to remove the debris. When the screens were rotated without operation of the screen wash system, the debris was carried over into the SW pump suction pit and was entrained in the SW pump suction supply. Pump discharge strainers in each of the two service water loops quickly became obstructed, rendering the trains inoperable.

Operators then started the standby SW pump to supply loop I, aligning its suction to the emergency cooling pond to prevent it from being fouled by the debris in the common SW pump bay. The normal loop I supply pump discharge strainer was cleaned, and the pump was returned to service. The standby pump was then aligned to supply loop II, restoring the plant to a normal configuration. The time required to clean the pump strainer and return loop I to service using that pump was ~90 min.

Additional Event-Related Information

The SW system at ANO 2 normally takes suction from the Dardenelle Reservoir, and an alternate supply is available from an emergency cooling pond (ECP). Two independent SW loops supply cooling water to engineered safety feature equipment, to component cooling heat exchangers, and to the nonsafety-related auxiliary cooling water system.

The service water system supplies the following major loads (partial listing):

emergency diesel generator (EDG) heat exchangers
component cooling water (CCW) heat exchangers,
shutdown cooling heat exchangers,
high-pressure safety injection (HPSI) pump coolers,
low-pressure safety injection (LPSI) pump coolers,
containment spray (CS) pump coolers,
charging pump room coolers,
containment cooling units, and
various safety-related room coolers.

At the time of the event, the reactor was in the startup mode at low power. Had the SW failure occurred during full-power operations, the consequences could have been more severe. This event could also have been more serious had the plant operators failed to recognize the need to align the remaining SW pump to its emergency suction supply before starting it.

ASP Modeling Assumptions and Approach

This event was modeled as a postulated loss of SW while at power. Given the loss of SW, successful operator action to align the standby pump to the ECP and start the pump (which requires an understanding of the cause of the loss of SW before pump start) will provide SW to one of the two SW loops. Loss of SW will result in the loss of the CCW heat sink. Loss of CCW cooling to the main feed pump lube oil coolers, instrument and

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

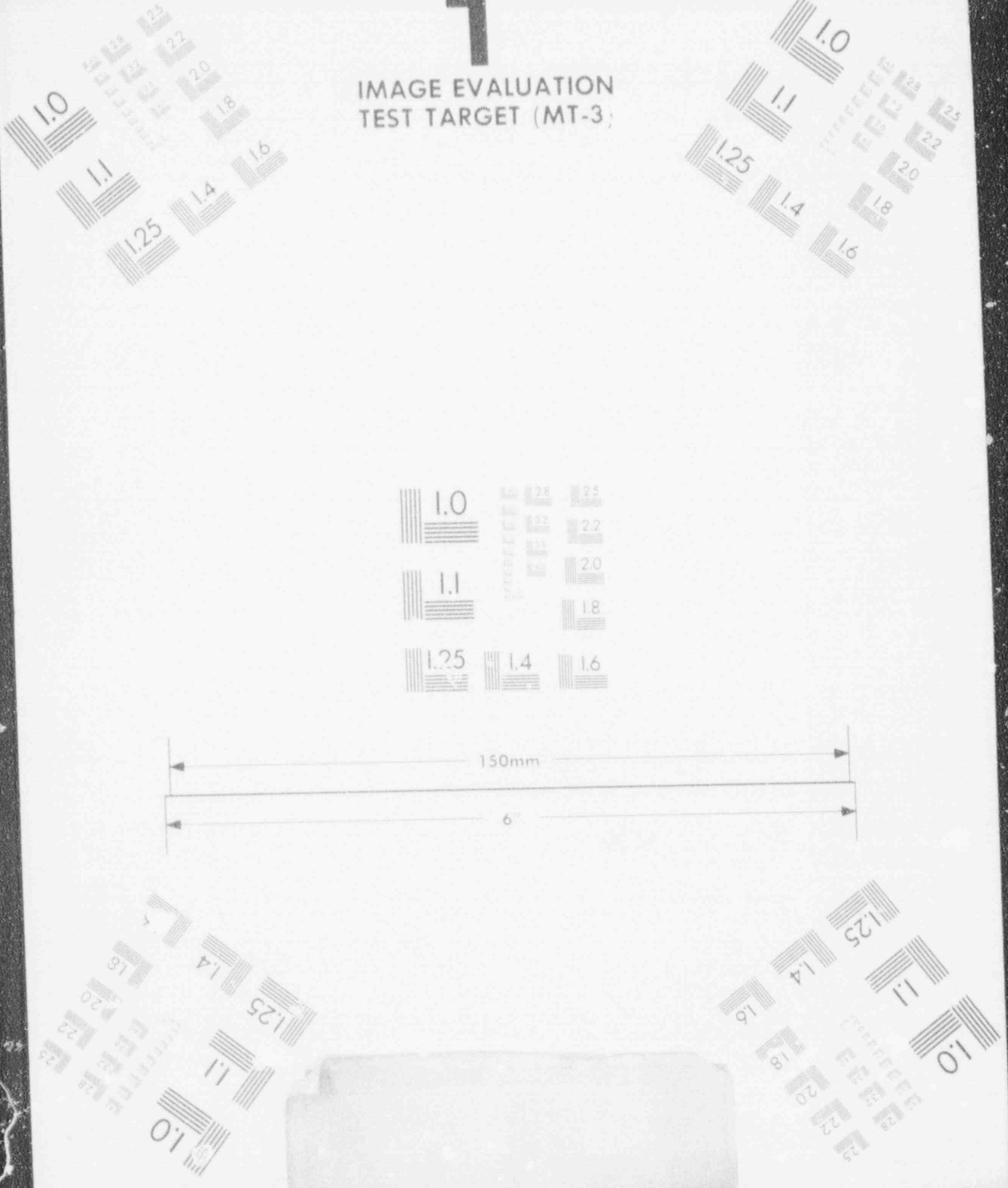
IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)



service air compressors, and the reactor coolant pump (RCP) motors is assumed to result in an automatic or manual scram and loss of feedwater (LOFW).

Both auxiliary feedwater (AFW) pumps on ANO 2 are self-cooled and were considered available without SW. SW cooling is provided to the charging pump room coolers and the high-pressure injection (HPI) pumps and room, but SW for this purpose was assumed to be required only in the recirculation phase following a loss-of-coolant accident (LOCA). Unlike many other RCP seals, which use both seal injection and thermal barrier cooling, the RCP seals at ANO-2 use only CCW for thermal barrier cooling. Unavailability of CCW for an extended period of time (as could be the case following a loss of SW) may result in a small-break LOCA.

The resulting core damage model used to analyze this event considered the potential failure of the operator to align the standby pump to the ECP, and the potential failure to clean the two service water strainers and return the two service water loops to service. The event was modeled assuming the plant was at power and that, had alignment of the standby pump to the ECP not been successful, a trip and loss of feedwater would have resulted from the loss of cooling to the RCP motors (which would require RCP trip for motor protection), main feed pump lube oil coolers, and air compressors.

If SW were not recovered within ~1 h, then the potential for an RCP seal LOCA was considered. In the event of a small-break LOCA from either a stuck-open relief valve (transient-induced LOCA) or an RCP seal failure, sump switchover was assumed to occur ~6 h after the LOCA. Unavailability of SW at this time was assumed to result in unavailability of containment spray recirculation (CSR) and high-pressure recirculation (HPR).

A conditioning event tree was used to characterize the plant status associated with success or failure in recovery of SW. This event tree is shown in Fig. 1. Successful alignment of the standby pump to the ECP was assumed to not result in a reactor trip (although plant shutdown may still be required). If the operator fails to align the standby pump to the ECP, then recovery of SW requires cleaning of the discharge strainers. Because of the length of time required for this, a small-break LOCA may result from the unavailability of RCP seal cooling. This is represented by the next branch on the event tree (occurrence of an RCP seal LOCA is associated with the "up" branch). The next two branches represent successful recovery of the first and second clogged strainer prior to switchover to sump recirculation, when SW is assumed to be required. For situations in which an RCP seal LOCA does not occur (RCP seal LOCA "down" branch), SW is assumed only to be necessary to mitigate a LOCA resulting from a stuck-open relief valve.

The transients associated with the six sequences involving failure to align the standby pump to the ECP are listed in Fig. 1, along with the probability of the conditioning sequence, the conditional probability of core damage given the conditioning sequence, and the core damage probability for the sequence. The follow assumptions were made to estimate the conditioning sequence probabilities:

a. The probability of the operator failing to correctly align the standby pump to the ECP was assumed to be 0.12.

b. The time required during the event to clean the first strainer (90 min) was assumed to consist of a 30-min preparation period and a 60-min time-to-repair after work orders were prepared, tools were drawn, and the repair crew reached the strainer. Assuming an exponential repair model with 1 h as the median repair time, the probability of not recovering one strainer at time t is $p_{1STR}(t)=e^{-.693(t-.5)}$, $t > 0.5$ h, and the probability of not recovering both strainers at time t is $p_{2STR}(t)=e^{-.693\,(t/2-.5)}$, $t > 1.0$ h.

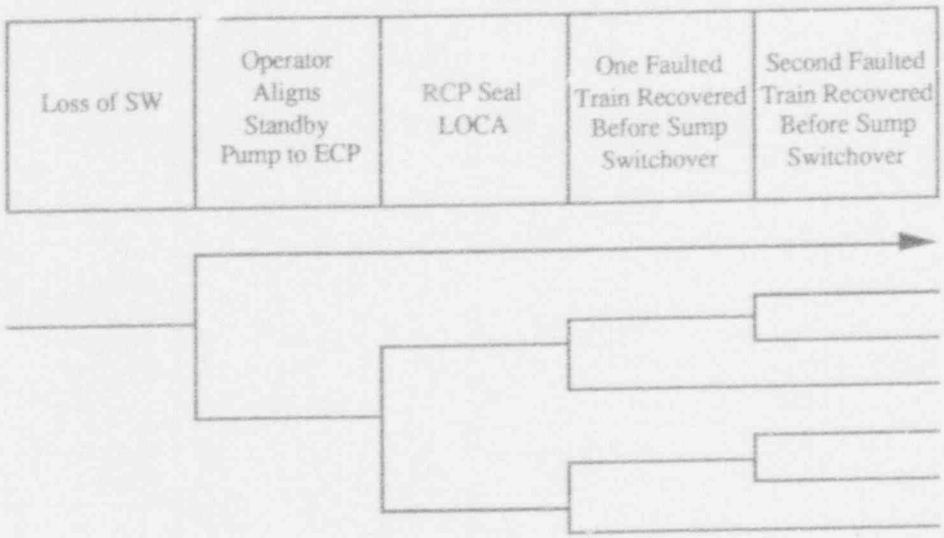
c. The ANO 2 safety analysis report (SAR) notes that experience with loss of cooling to RCP seals of the same design as used on ANO-2 indicates that the seals will continue to function for time periods up to 40 min. No data were provided for losses of cooling greater than 40 min. In this analysis, the probability of an RCP seal LOCA was assumed to be zero up to 1 h after seal cooling was lost. Beginning at 1 h, the probability of an RCP seal LOCA was assumed to increase linearly to 0.34 at 1.5 h, after which no additional seal failures were assumed to occur ($p_{SL} = 0$, $t < 1$ h; $p_{SL} = 0.68(t-1)$, $1 \le t < 1.5$ h; $p_{SL} = 0.34$, $t \ge 1.5$ h). This type of seal failure model is similar to that used in the Accident Sequence Precursor (ASP) Program for modeling station blackout sequences (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989). Using a convolution approach similar to that in ORNL/NRC/LTR-89/11 to combine the probability of failing to recover SW with the probability of an RCP seal LOCA allows the probability of the remaining portions of each sequence to be estimated. For example, the probability of the third sequence, which involves failure of the operator to align the standby pump to the ECP, an RCP seal LOCA due to unavailability of seal cooling, and failure to recover SW before sump switchover (assumed to occur 6 h after the RCP seal LOCA), is calculated as follows:

$$p(\text{seq.3}) = p(\text{opr fails to align standby pump to ECP}) \times \int p_{1STR}(t) \times f_{SL}(t) \times p_{1STR}(t+6 \mid t)\,dt$$

where $f_{SL}(t)$ is the probability density function for RCP seal LOCA and $p_{1STR}(t + 6 \mid t)$ is the probability of not recovering one train of SW at t + 6, given it was not recovered at t. Since $f_{SL}(t)$ is non-zero only between 1 and 1.5 h, and $p_{1STR}(t + 6 \mid t) = e^{-.693\,(t+6-.5)} / e^{-.693(t-.5)}$, the probability for this sequence is $0.12 \times \int_1^{1.5} 0.68 \times e^{-.693(t+5.5)}dt = 3.8 \times 10^{-4}$.

Analysis Results

The conditional core damage probability for this event is estimated to be 4.8×10^{-4}. This value is strongly influenced by assumptions made concerning recovery of the faulted SW trains and the probability of an RCP seal failure. The dominant sequence, highlighted on the following event tree, involves an RCP seal LOCA and failure of HPR and CSR due to unavailability of SW.



Sequence	Conditioning Sequence Probability	Resulting Transient and Transient Conditional Probability	Sequence Conditional Probability
no trip			
1	3.6×10^{-2}	Note 1	5.0×10^{-5}
2	4.7×10^{-3}	Note 2	5.2×10^{-5}
3	3.8×10^{-4}	Note 3	3.8×10^{-4}
4	7.8×10^{-2}	Note 4	6.1×10^{-7}
5	1.7×10^{-2}	Note 5	2.2×10^{-7}
6	2.2×10^{-3}	Note 6	7.3×10^{-7}
			4.8×10^{-4}

Note 1. Small-break LOCA with both SI trains available following sump switchover [p(cd | small-break LOCA and both SW trains available for recirculation) = 1.4×10^{-3}]

Note 2. Small-break LOCA with one SI train available following sump switchover [p(cd | small-break LOCA and one SW train available for recirculation) = 1.1×10^{-2}]

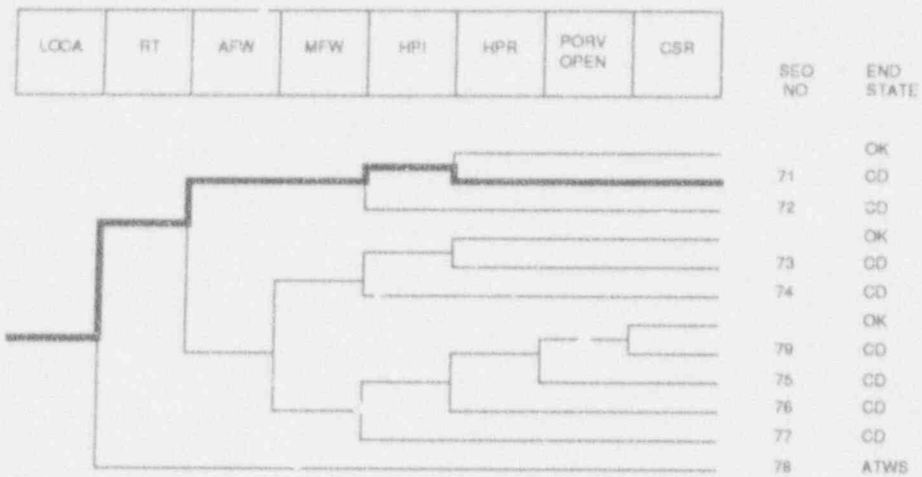
Note 3. Small-break LOCA with no SI train available following sump switchover [p(cd | small-break LOCA and no SW train available for recirculation) = 1.0]

Note 4. LOFW with both SI trains available following sump switchover in the event of a stuck-open primary relief valve [p(cd | trip with MFW unavailable and both SW trains available for recirculation) = 7.8×10^{-6}]

Note 5. LOFW with one SI train available following sump switchover in the event of a stuck-open primary relief valve [p(cd | trip with MFW unavailable and one SW train available for recirculation) = 1.3×10^{-5}]

Note 6. LOFW with no SI train available following sump switchover in the event of a stuck-open primary relief valve [p(cd | trip with MFW and both SW trains unavailable) = 3.3×10^{-4}]

Fig. 1. Conditioning event tree for LER 368/91-012



Dominant core damage sequence for LER 368/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 1)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	1.4E-03
Total	1.4E-03
ATWS	
LOCA	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
71	LOCA -rt -afw -hpi hpr/-hpi	CD	1.1E-03	1.0E+00
72	LOCA -rt -afw hpi	CD	2.5E-04	8.4E-01
78	LOCA rt	ATWS	3.4E-05	1.2E-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	1.1E-03	1.0E+00
72	LOCA -rt -afw hpi	CD	2.5E-04	8.4E-01
78	LOCA rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	

Event Identifier: 368/91-012

loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
porv.or.srv.chall	2.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	4.0E-02	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	2.1E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	02
porv.open	1.0E-02	1.0E+00	4.0E-04
hpr/-hpi	1.5E-04	1.0E+00	
csr	2.0E-03	9.4E-01	

* branch model file
** forced

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Event Identifier: 368/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 2)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	1.1E-02
Total	1.1E-02
ATWS	
LOCA	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
71 LOCA -rt -afw -hpi HPR/-HPI	CD	1.1E-02	1.0E+00
78 LOCA rt	ATWS	3.4E-05	1.2E-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	1.1E-02	.0E+00
78 LOCA rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	

Event Identifier: 368/91-012

```
    Branch Model:  INITOR
    Initiator Freq:                 2.4E-06
rt                                  2.8E-04                       3.2E-01
rt/loop                             0.0E+00                       1.0E+00
emerg.power                         2.9E-03                       8.0E-01
afw                                 1.3E-03                       2.6E-01
afw/emerg.power                     5.0E-02                       3.4E-01
MFW                                 2.0E-01 > 1.0E+00             3.4E-01 > 1.0E+00
    Branch Model:  1.OF.1
    Train 1  Cond Prob:             2.0E-01 > Unavailable
porv.or.srv.chall                   2.0E-02                       1.0E+00
porv.or.srv. eseat                  1.0E-02                       1.1E-02
porv.or.srv.reseat/emerg.power      1.0E-02                       1.0E+00
seal.loca                           4.0E-02                       1.0E+00
ep.rec(sl)                          5.9E-01                       1.0E+00
ep.rec                              2.1E-02                       1.0E+00
hpi                                 3.0E-04                       8.4E-01
hpi(f/b)                            3.0E-04                       8.4E-01                1.0E-02
porv.open                           1.0E-02                       1.0E+00                4.0E-04
HPR/-HPI                            1.5E-04 > 1.0E-02             1.0E+00
    Branch Model:  1.OF.2
    Train 1  Cond P ob:             1.0E-02
    Train 2  Cond  rob:             1.5E-02 > Unavailable
CSR                                 2.0E-03 > 2.0E-02             3.4E-01
    Branch Mo  l:  1.OF.2
    Train 1  Cond Prob:             2.0E-02
    Train    Cond Prob:             1.0E-01 > Unavailable

*  bra ch model file
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Event Identifier: 368/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 3)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	1.0E+00
Total	1.0E+00
ATWS	
LOCA	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
71	LOCA -rt -afw -hpi HPR/-HPI	CD	1.0E+00	1.0E+00
78	LOCA rt	ATWS	3.4E-05	1.2E-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	1.0E+00	1.0E+00
78	LOCA rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.all
PROBABILITY FILE: c:\asp\1989\pwr_bell.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	

Event Identifier: 368/91-012

Branch Model: INITOR			
Initiator Freq·	2.4E-06		
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
porv.or.srv.chall	2.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	4.0E-02	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	2.1E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.0E-04
HPR/-HPI	1.5E-04 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
CSR	2.0E-03 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

* branch model file
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Event Identifier: 368/81-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 4)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	7.8E-06
Total	7.8E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.all
PROBABILITY FILE: c:\asp\1989\pwr_ball.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		

Event Identifier: 368/91-012

rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
porv.or.srv.chall	2.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	4.0E-02	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	2.1E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.0E-04
hpr/-hpi	1.5E-04	1.0E+00	
csr	2.0E-03	3.4E-01	

* branch model file
** forced

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Event Identifier: 368/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 5)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.3E-05
Total	1.3E-05
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.all
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		

Event Identifier: 368/91-012

rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
porv.or.srv.chall	2.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	4.0E-02	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	2.1E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.0E-04
HPR/-HPI	1.5E-04 > 1.0E-02	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
CSR	2.0E-03 > 2.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

* branch model file
** forced

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Event Identifier: 368/93-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 368/91-012
Event Description: Both normal SW trains fouled (cond seq 6)
Event Date: 04/16/91
Plant: ANO - Unit 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.3E-04
Total	3.3E-04
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
18 trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1988\pwrgseal.cmp
BRANCH MODEL: c:\asp\1989\ano2.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.2E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		

Event Identifier: 368/91-012

rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
porv.or.srv.chall	2.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
seal.loca	4.0E-02	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	2.1E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
porv.open	1.0E-02	1.0E+00	4.0E-04
HPR/-HPI	1.5E-04 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
CSR	2.0E-03 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

* branch model file
** forced

Minarick
08-11-1992
15:20:41

Event Identifier: 368/91-012

NRC Form 366
(6-89)

U.S. Nuclear Regulatory Commission
Approved OMB No. 3150-0104
Expires: 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1) Arkansas Nuclear One, Unit Two

DOCKET NUMBER (2) 0|5|0|0|0| 3| 6| 8 PAGE (3) 1|OF|0|5

TITLE (4) Both Service Water Loops Declared Inoperable Due To Clogging Of Pump Discharge Strainers Caused By A Breakdown In The Implementation Of Procedural Controls

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 Names	Docket Number(s)
0 4	1 6	9 1	9 1	-- 0 1 2 --	0 0	0 5	1 5	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 2

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

POWER LEVEL (10): 0|0|0

_ 20.402(b)	_ 20.405(c)	_ 50.73(a)(2)(iv)	_ 73.71(b)
_ 20.405(a)(1)(i)	_ 50.36(c)(1)	_ 50.73(a)(2)(v)	73.71(c)
_ 20.405(a)(1)(ii)	_ 50.36(c)(2)	X 50.73(a)(2)(vii)	_ Other (Specify in Abstract below and in Text, NRC Form 366A)
_ 20.405(a)(1)(iii)	X 50.73(a)(2)(i)	_ 50.73(a)(2)(viii)(A)	
_ 20.405(a)(1)(iv)	_ 50.73(a)(2)(ii)	_ 50.73(a)(2)(viii)(B)	
_ 20.405(a)(1)(v)	_ 50.73(a)(2)(iii)	_ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name: Thomas r. Scott, Nuclear Safety and Licensing Specialist

Telephone Number: Area Code 5|0|1 9|6|4|-|5|0|0|0

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

SUPPLEMENT REPORT EXPECTED (14)

[ ] Yes (If yes, complete Expected Submission Date) [X] No

EXPECTED SUBMISSION DATE (15): Month | Day | Year

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

On April 16, 1991 both loops of the service water system were declared inoperable for approximately three minutes when a breakdown occurred in the implementation of procedural controls that resulted in debris bypassing screens at the pump suctions and clogging discharge strainers. The traveling screens were being rotated for inspection and lubrication. Sections of the procedure for this activity were performed out of sequence thereby allowing screen rotation without wash water flow. A contributing factor was ineffective communications. Throughout the event cooling water was supplied to both loops but at a reduced capacity. Restoration of one loop to normal pressure and flow conditions was accomplished in approximately three minutes by aligning the standby pump to the emergency cooling pond. Cleaning of debris from the pump discharge strainers restored both loops to an operable status in approximately two hours. The requirement to perform procedures in the proper sequence, unless specifically authorized otherwise, has been emphasized to appropriate maintenance personnel. Other corrective actions involve training of personnel concerning procedural compliance and effective communications.

NRC Form 366A
(6-89)

U. S. Nuclear Regulatory Commission
Approved OMB No. 3150-0104
Expires: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		Year	Sequential Number	Revision Number	
Arkansas Nuclear One, Unit Two	0|5|0|0|0| 3| 6| 8	9| 1 --	0 | 1| 2 --	0 | 0	0|2|OF|0|5

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

A. Plant Status

At the time of this event, Arkansas Nuclear One Unit 2 (ANO-2) was in startup conditions (Mode 2) with Reactor Coolant System (RCS) [AB] temperature at 545 degrees, pressure 2250 psia and power 8E-2. The traveling screen system for the Service Water System (SW) [BI] was tagged out for maintenance activities.

B. Event Description

On April 16, 1991 both SW loops were declared inoperable for approximately three minutes due to a breakdown in the implementation of procedural controls which resulted in a preventive maintenance (PM) procedure being worked with sections out of sequence. This resulted in debris bypassing SW pump suction screens and clogging the pump discharge strainers.

The SW system provides cooling for equipment essential to ensure safe operation and shutdown of the plant. During normal operation, the water supply is obtained from the Dardanelle Reservoir. An alternate supply for the system is available from the Emergency Cooling Pond (ECP). The system consists of two independent flow paths (Loop I and Loop II) which furnish water to Engineered Safety Features (ESF) equipment, a flow path to the non-safety-related Auxiliary Cooling Water system [KG], and Component Cooling Water (CCW) [CC] heat exchangers. (CCW removes heat from components in various reactor auxiliary systems which carry radioactive or potentially radioactive fluids.) During normal operation one pump supplies Loop I, another pump supplies Loop II, and a third pump (which can be aligned to either operating loop) serves as a standby. Before water from the Dardanelle Reservoir reaches the pump suctions it passes through bar grates and traveling water screens. A basket strainer is installed in the discharge line of each pump.

Mechanical maintenance personnel were performing quarterly preventive maintenance on one of the traveling water screens at the SW intake. In order to obtain access to a part of the screen for inspection and lubrication, maintenance personnel requested that operations personnel remove hold cards from the traveling screen motor. The hold cards were being controlled and outage work was being coordinated by a shift supervisor from the Control Room extension. The shift supervisor authorized the auxiliary operator (non-licensed) to remove the hold card from the traveling screen motor. This hold card removal allowed maintenance personnel to rotate the screen without the normal cleaning spray (wash) being in operation.

NRC Form 366A
(6-89)

U. S. Nuclear Regulatory Commission
Approved OMB No. 3150-0104
Expires: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	PAGE (3)
Arkansas Nuclear One, Unit Two	0|5|0|0|0| 3| 6| 8	9| 1	0 | 1| 2	0 | 0	0|3 OF 0|5

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

When the maintenance personnel started screen rotation, they recognized that debris was traveling up the screen, stopped screen rotation, and contacted the Control Room extension. The message was relayed to licensed operators in the extension via a shift administrative assistant. Communication of the message from maintenance personnel was either not clear or was misunderstood. Permission was granted to continue screen rotation. Rotation of the screen without screen wash in service allowed debris to reach the SW pump suctions and begin to clog the discharge strainers. At approximately 1625 hours a high differential pressure alarm was received in the Control Room from the Loop I pump discharge strainer. Approximately two minutes later the high differential pressure alarm was received from the Loop II pump discharge strainer. Control Room operators noted a decrease in discharge pressure of the operating SW pumps. The high differential pressure condition of both operating SW pump discharge strainers resulted in both loops being declared inoperable.

C. Root Cause

The root cause of this event is a breakdown in the implementation of procedural controls which allowed PMs to be worked with sections out of sequence. This resulted in debris bypassing SW pump suction screens and clogging the pump discharge strainers. The procedure being used for the maintenance activity was written with the assumption that each section would be performed in the sequence specified. If this had been done, the screen wash flow would have been established prior to rotating the screen and debris would have been prevented from reaching the pump suctions. Personnel performing the activity believed that it was an acceptable practice to work PM procedures with sections arranged at the discretion of the performer as long as steps within each section were followed in the indicated order. The re-arrangement of sections was believed to be acceptable for more efficient performance of the activity. A contributing factor to this event was ineffective communication between operations and maintenance personnel concerning debris carry-over. Other procedural controls were reviewed and determined to contain adequate instructions concerning procedure implementation.

D. Corrective Actions

The Control Room licensed operator aligned the standby pump to the ECP and restored normal pressure and flow to Loop I at approximately 1630 hours. The normal Loop I pump strainer was cleaned and the pump was started to supply Loop I from the ECP at approximately 1752 hours. The standby pump was shifted to supply Loop II from the ECP to restore both loops to normal pressure and flow at 1813 hours.

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(6-89)

U. S. Nuclear Regulatory Commission
Approved OMB No. 3150-0104
Expires: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	PAGE (3)
Arkansas Nuclear One, Unit Two	0 5 0 0 0 3 6 8	9 1	-- 0 1 2 --	0 0	0 4 OF 0 5

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

Other corrective actions include:

1. A caution card was installed on each traveling screen jog button and a hold card was installed on the traveling screen motor breaker to prevent screen operation without shift supervisor approval. This is a temporary measure until follow-up training has been completed.

2. Training of operations personnel was performed stressing the importance of not operating SW traveling screens without wash flow via the Operations Night Orders. The Operations Manager is also providing additional training to all operations personnel during the current requalification training cycle regarding this event and emphasizing the importance of proper communication. This follow-up training is expected to be completed by May 31, 1991.

3. Unit 2 maintenance personnel were informed via a memorandum that PM procedures must be followed in the written sequence unless exceptions are specified in the procedure. Specific training concerning this event has been provided to first line supervisors by the Unit 2 Maintenance Manager. The Unit 2 Maintenance Manager is also meeting with each individual crew to provide additional training concerning effective communication between maintenance and operations, as well as PM procedure compliance. This crew training is expected to be complete by May 31, 1991.

4. The SW intake design has been evaluated against those from a selection of other nuclear power plants. The ANO-2 design was found to be similar with respect to separation of intake bays, interlocks and maintenance procedures. The SW system has also been reviewed to determine if other changes to equipment or procedures are necessary to minimize the possibility for introducing debris into the system. The results of this review are being finalized and documented. Completion of this effort is anticipated by May 31, 1991.

5. Evaluation of the event revealed that it could be applicable to Unit 1. The Unit 1 Maintenance Manager provided training to maintenance personnel via a memorandum describing the event and issuing guidance concerning PM performance standards.

6. Subsequent to this event, additional guidance was issued to all site personnel regarding who is authorized to operate plant equipment.

NRC Form 366A
(6-89)

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year		Sequential Number		Revision Number	PAGE (3)
Arkansas Nuclear One, Unit Two	0|5|0|0|0| 3| 6| 8	9| 1	--	0 | 1| 2	--	0 | 0	0|5|OF|0|5

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

E. Safety Significance

Both SW loops were declared inoperable for approximately three minutes while the standby pump was being placed into service. Throughout the event cooling water was being supplied to both loops, but at a reduced capacity. The safety significance of this event was reduced by several factors such as reduced lake water temperature, low reactor power level, and the reduced decay heat load present after a refueling outage. However, consequences of the results of the reduced cooling capability could have been more significant if initial SW inlet temperature were higher (as is the case during the hotter summer months) or if operation of ESF equipment had been required.

F. Basis For Reportability

Technical Specification 3.7.3.1 provides an action requirement for having only one SW loop operable but does not provide an action if both loops are inoperable. Declaration of both SW Loops inoperable resulted in entry into Technical Specification 3.0.3. Having been in a condition with both SW loops inoperable is an operation prohibited by Technical Specifications and is therefore reportable pursuant to 10CFR50.73(a)(2)(i)(B).

Two independent trains of SW having been declared inoperable due to a single cause or event (debris bypassing the traveling screens) is a condition reportable pursuant to 10CFR50.73(a)(2)(vii).

G. Additional Information

There have been no previous events of this nature reported as Licensee Event Reports at ANO.

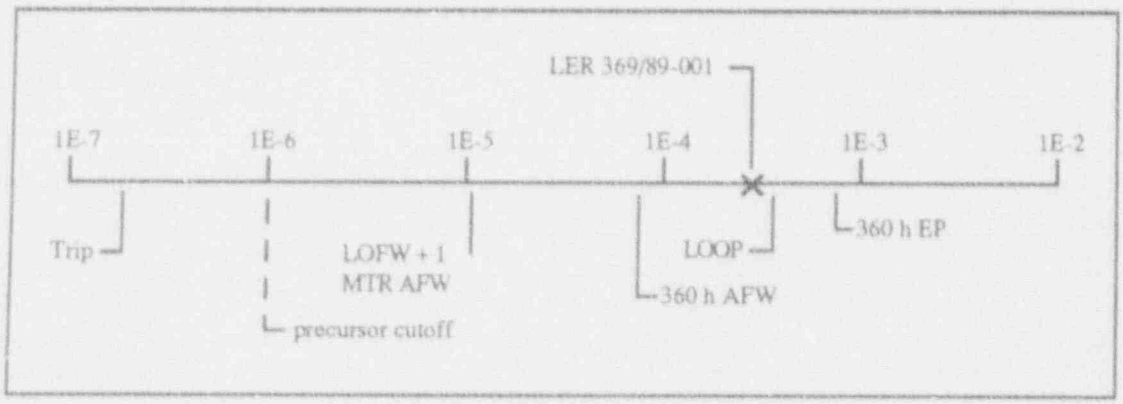
Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	369/91-001
Event Description:	Switchyard breaker test results in loss of offsite power
Date of Event:	February 11, 1991
Plant:	McGuire 1

Summary

Errors and equipment failures during installation of new switchyard relay protection resulted in the opening of all switchyard breakers connecting Unit 1 to the grid. Reactor and turbine trips followed, and both diesel generators (DGs) started and loaded. An excessive cooldown rate resulted in safety injection (SI) actuation and main steam isolation valve (MSIV) closure. Subsequently, reactor coolant pressure increased, and two pressurizer power-operated relief valves (PORVs) actuated. Containment pressure increased to 0.76 psig. Offsite power was restored, and operators began unloading the DGs after about 1.25 h. The conditional core damage probability estimated for the event is 2.6 x 10^{-4}. The relative significance of this event compared to other postulated events at McGuire 1 is shown below.



Event Description

Prior to the event, Unit 1 was operating at 100% power while relay protection modifications for the switchyard autotransformer were in progress. At McGuire, the autotransformer serves to crosstie the Unit 1 230-kV switchyard to the Unit 2 525-kV switchyard. A sudden pressure fault detection relay had been added to the autotransformer, and testing was in progress to verify that operation of the relay would properly isolate the autotransformer. The autotransformer feeder breakers' trip coil circuits were blocked to prevent their actuation, and a simulated fault pressure signal was introduced. Additional protective relaying that had not been blocked detected the simulated sudden pressure relay operation and the failure of the autotransformer breakers to open. This actuated a breaker failure scheme that cleared both main buses in the 525-kV and 230-kV switchyards. Each McGuire unit remained connected to the grid through two transmission lines, which connect directly to the main transformer outputs, bypassing the switchyard buses.

The output from the Unit 1 generator was directed to the Craighead and Mecklenburg transmission lines. The increased current in the Craighead line was detected by relay protection as an overcurrent condition. This, in conjunction with a failed distance relay for the Craighead line, resulted in opening of the Craighead line feeder breaker. The entire output of the unit was then directed to the Mecklenburg line, which was sized for only one-half of the unit's output. The feeder breaker for this line tripped on overcurrent, and all offsite power was lost to Unit 1.

When all connections to the grid were lost, the generator output frequency rose, increasing reactor coolant pump (RCP) speed and flow. The resulting increase in reactor power initiated a high flux rate reactor trip, which was followed by a turbine trip. DGs 1A and 1B started and automatically picked up their emergency loads.

The loss of power to nonsafety-related valves prevented operators from isolating certain main steam loads, and excessive cooling of the reactor coolant system (RCS) resulted. Low steamline pressure initiated a SI and automatic isolation of the MSIVs. RCS temperature and pressure then began rising until limited by operation of two PORVs (a third valve was unavailable because of maintenance). Containment pressure began rising, ultimately reaching 0.76 psig.

The SI signal was reset, and power was restored to the switchyard. About 75 min into the event, operators began removing loads from the DGs and restoring the plant to a normal alignment.

Additional Event-Related Information

The utility reported that 4 min into the event, the condenser "was in full load rejection mode." It was also reported that an inability to isolate steamline drains and other main steam valves contributed to excessive steam demand and cooldown.

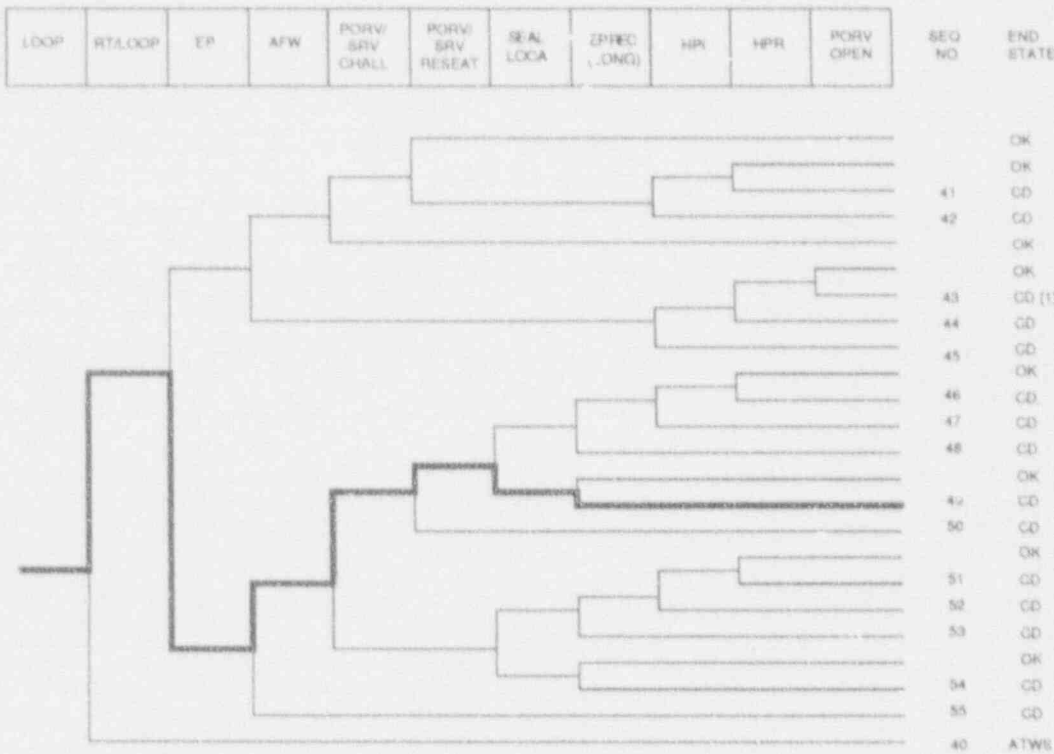
At McGuire, air is removed from the condenser by steam-jet air ejectors. This system might not be impacted by a loss-of-offsite power (LOOP). Condenser cooling is provided by the condenser circulating water system (CCW). The CCW system is crosstied between Units 1 and 2 via an 84-in. line. As power to Unit 2 was apparently maintained during the event, some CCW may have been available to the Unit 1 condenser. These features may have contributed to the excessive cooldown of the main steam system.

ASP Modeling Assumptions and Approach

This event was modeled as a plant-centered loss of offsite power with pressurizer PORVs demanded. Probabilities for LOOP non-recovery (short term) and failure to recover AC power prior to battery depletion 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 two operable PORVs were assumed to be adequate for feed and bleed.

Analysis Results

The estimated core damage probability associated with this event is 2.6×10^{-4}. The dominant core damage sequence, shown on the following event tree, involves a postulated loss of emergency power following the LOOP, and failure to recover AC power prior to battery depletion. If the unavailable PORV is assumed to fail feed and bleed, the resultant core damage probability is estimated to be 2.9×10^{-4}.



(1) OK for Class D

Dominant core damage sequence for LER 369/91-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 369/91-001
Eve... Description: Switchyard breaker test results in a LOOP
Event Date: 02/11/91
Plant: McGuire 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.6E-04
Total	2.6E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
49	LOOP -rt/loop emerg.power -afw/emerg.power PORV.OR.SRV.CHALL -porv.or.srv.reseat/emerg.power -seal.loca EP.REC	CD	2.3E-04	2.4E-01
50	LOOP -rt/loop emerg.power -afw/emerg.power PORV.OR.SRV.CHALL porv.or.srv.reseat/emerg.power	CD	2.0E-05	2.4E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.2E-05	8.2E-02

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
49	LOOP -rt/loop emerg.power -afw/emerg.power PORV.OR.SRV.CHALL porv.or.srv.reseat/emerg.power -seal.loca EP.REC	CD	2.3E-04	2.4E-01
50	LOOP -rt/loop emerg.power -afw/emerg.power PORV.OR.SRV.CHALL porv.or.srv.reseat/emerg.power	CD	2.0E-05	2.4E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.2E-05	8.2E-02

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\mcguire.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 369/91-001

Branch	System	Non-Recov	Opr Fail
trans	4.3E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	3.[illegible] > [illegible].0E-01	
Branch Model: INITOR			
Initiator Freq:	1.6E-05		
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	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	1.0E-03
PORV,OR,SRV,CHALL	4.0E-02 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.0E-02 > 1.0E+00		
porv.or.srv.reseat	3.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	3.0E-02	1.0E+00	
seal.loca	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
EP.REC	4.5E-01 > 3.5E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.5E-01 > 3.5E-01		
hp	1.0E-03	8.4E-01	
hpi(f/b)	[illegible].2E-03	8.4E-01	1.0E-02
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

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03-11-1992
12:32:35

Event Identifier: 369/91-001

NRC Form 366 (9-83) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): McGuire Nuclear Station, Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 3 6 9 PAGE (3): 1 OF 18

TITLE (4): A Unit 1 Reactor Trip Occurred Due to A Loss Of Offsite Power Caused By An Inappropriate Action, A Management Deficiency, and An Equipment Failure

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 NAMES	DOCKET NUMBER(S)
0 2	1 1	9 1	9 1	0 0 1	0 0	0 3	1 3	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

X OTHER (Specify in Abstract below and in Text, NRC Form 366A): Special Report

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Alan Sipe, Chairman, McGuire Safety Review Group	7 0 4 8 7 5 - 4 1 8 3

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)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

On February 11, 1991, A Unit 1 Reactor Trip occurred at 1355:13. Prior to the event, Unit 1 was operating in Mode 1 (Power Op tion) at 100% power. The Reactor was tripped by a Nuclear Instrumentation (NI) Power Range Hi Flux Rate signal. The trip signal was initiated when offsite power to the unit was lost because a blackout occurred in the KV switchyard. The blackout occurred as a result of a failed relay in co anction with a post modification test being performed on a newly added relay circuit in the switchyard. Subsequent depres ization of the Main Steam (SM) system resulted in a Safety Injection (SI). An Unusual Event was declared at 1420 due to Loss of Power and SI. The Technical Support Center (TSC) was activated as a conservative measure and TSC personnel made the required notification to the NRC. A thorough technical review was performed on the event and, consequently, a decision was made by Station Management (with concurrence of the NRC) to restart the Reactor. Unit 1 was returned to Mode 2 (Startup) operation on February 13, 1991, at approximately 0345. This event is assigned causes of Inappropriate Action, Management Deficiency, and an Equipment Failure.

NRC Form 366A
U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
McGuire Nuclear Station	0 5 0 0 0 3 6 9	9 1	0 0 1	0 0	12 OF 18

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

EVALUATION:

Background

McGuire Nuclear Station consists of two generating units and the auxiliary equipment for the two units. It functions in association with the McGuire 230 KV and 525 KV Switchyards [EIIS:FK].

Each unit generates power at a voltage of 24 Kilovolts (KV) that is delivered through two half-size step-up transformers [EIIS:XFMR] to the McGuire Switchyard by overhead transmission lines. Unit 1 is connected to the 230 KV switchyard, while Unit 2 is connected to the 525 KV switchyard. The output of each unit is then delivered into Duke's transmission system through switchyard power circuit breakers [EIIS:52] (PCB) in a breaker and a half configuration and transmission lines. (See page 18 of 18.)

Normal auxiliary power on each unit is supplied by two auxiliary power transformers (24 KV/6.9 KV) each rated at 100 kilovolt amperes (KVA). Each auxiliary transformer has two secondary output windings, supplying normal power to two sections of 6.9 KV switchgear [EIIS:SWGR] and standby power to two other sections.

The 230 KV and 525 KV switchyards have two electrical buses [EIIS:BU] and a number of circuit breakers that connect the generators [EIIS:GEN] with the transmission system. The buses provide junction points for the power exchange between generators and the system. PCBs interrupt flow of power and isolate any section that may be faulted. To distinguish between the two buses in each switchyard, they are designated as the red bus and the yellow bus. In addition to naming the buses, each power circuit breaker is assigned a number, which aids in identifying the individual breakers. Both switchyards are used to connect two circuits between the red and yellow buses.

The 525 KV and 230 KV switchyards are connected through an autotransformer which permits power distribution between the two voltage levels.

Seven pairs of transmission lines connect the 230 KV switchyard at McGuire with the rest of the Duke system. The Craighead Lines and the Mecklenburg Lines connect with Harrisburg Tie Substation near Charlotte, N.C. The Norman lines and the Schoonover lines tie with Riverbend Steam Stations switchyard. The Blackburn lines feed the Longview Tie Station near Hickory, NC. The Westport Lines tie with Marshall Steam Stations switchyard and the Cowans Ford Lines connect with Cowans Ford Hydro Plant.

Fault Pressure Relaying [EIIS:RLY] is used on the switchyard autotransformer as a supplement to the primary protective relaying. When internal transformer winding faults become severe, they produce large amounts of gases from the breakdown of the insulation [EIIS:ISL] materials. The expanding gases cause a rapid rise in the pressure on the insulating oil. Fault

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pressure relays can sometimes detect these faults before the primary protective relays can.

Fault pressure relays are mounted on the outside of a transformer casing and use a bellows [EIIS:BE] mechanism to detect sudden changes in the transformer oil pressure.

If the fault pressure relay(s) on the transformer detects a high rate of pressure rise on the insulating oil, indicating an internal winding fault, it will operate, through tripping logic, to initiate Lockout Relays [EIIS:86]. These lockouts will clear the faulted transformer by totally clearing and de-energizing the feeder breakers.

A breaker failure relaying scheme is provided for backup autotransformer fault protection. It ensures isolation of the autotransformer if the feeder breakers fail to trip when initiated for a fault condition. This is accomplished by opening all red and yellow bus PCBs in the 525 KV and 230 KV switchyards.

The directional distance phase relay [EIIS:21] 21LC is the primary fault protection of a transmission line. It protects all three phases of a transmission line for phase-to-phase, three-phase, and two-phase-to-ground faults. This relay is directional in that it will respond to fault current flow in one direction only. This direction is determined by comparing the line current flow with the bus voltage. The bus voltage is the non-changing quantity, or reference voltage. The directional distance relay detects faults within a certain distance of a lines local terminal by measuring the line impedance.

When directional distance relays are deprived of their operating voltage, it is possible that these relays will pick up from load current only. The loss of operating voltage is usually due to the malfunction of the voltage device or its associated circuits supplying this voltage. To prevent an undesirable trip from this occurrence, an instantaneous overcurrent phase relay [EIIS:67] 50P is installed to supervise each directional distance relay.

The directional distance phase relays (21LC), its associated overcurrent (50P) relay and its associated carrier (85) [EIIS:85] relay must be picked up to initiate tripping. No tripping will take place if the 21LC relay picks up, but the 85 relay and the 50P relay does not pick up.

The purpose of the Excore Instrumentation System (ENB) [EIIS:IG] is to monitor Reactor [EIIS:RCT] core leakage neutron flux and generate appropriate trips and alarms [EIIS:ALM] for various phases of Reactor Operation. The outputs of the source, intermediate, and power range detectors [EIIS:DET] are used to limit the maximum power output of the Reactor within their respective ranges and are used as inputs to monitor neutron flux from a completed shutdown condition up to 120 percent of full power. The power range detector provides power level indication and trip signals for Reactor protection, NRC Form 366A (9-83) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES 8/31/88

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alarms to warn of abnormal conditions, and signals for remote recording, indicating, and computing [EIIS:CPU] equipment.

Description of Event

On February 11, 1991, at approximately 1030, while Units 1 and 2 were operating at 100% power, Transmission Department personnel began conducting a test of a modification which installed a new relay circuit. The relay circuit is a fault pressure relay switch 63FPX on the autotransformer which ties the 230KV switchyard to the 525KV switchyard. The scope of the testing involved simulating a fault pressure relay trip of the switchyard autotransformer bank. Since the system dispatcher would not allow the autotransformer to be deenergized because of system load, the test was conducted with the feeder breakers to the transformer closed. The trip coil [EIIS:CL] circuitry was blocked on the feeder breakers to prevent their tripping as a result of the test. Transmission personnel failed to open all affected downstream relay contacts which would have completely blocked the actuation of the autotransformer breaker failure relay scheme. This scheme is redundant to the primary lockout scheme (which was blocked) and is designed to clear a zone around a fault even if the PCBs fail to open. The next zone of protection in this case is to open all PCBs tied to the red and yellow bus. What follows is the sequence of events that occurred after the planning and implementation of the relay scheme blocking:

1) At approximately 1350, Transmission personnel initiated a simulated fault pressure relay operation by placing a jumper across appropriate terminals located in the autotransformer control panel.

2) The associated lockout relays (86AT and 86ATS) actuated as expected and did not open the autotransformer feeder breakers (as expected because they were blocked).

3) The breaker failure scheme recognized the fact that the autotransformer feeder breakers remained closed and assumed that a fault was still present that had not been cleared and opened the autotransformer feeder breakers.

4) The breaker failure scheme operated as designed and opened 28 PCBs clearing both red and yellow buses in the 525KV and 230KV switchyards.

5) At this point, Units 1 and 2 remained connected to the grid through their associated "half" breakers which connect the unit bus lines directly to outgoing transmission tie lines. (Craighead White and Mecklenburg Black, for Unit 1). (See page 18 of 18.) Each outgoing line is sized to handle approximately one half of full unit output.

6) At an unknown time before/during the event, distance relay 21LC failed closed. This is a distance relay which monitors the

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Craighead White transmission line. This defective relay satisfied the logic required to trip PCB8 when the red and yellow bus cleared. This provided abnormally high current through the line and completed the permissive to trip PCB8. Thus, the PCB tripped clearing the Craighead line and eliminated 1 of the 2 remaining Unit 1 ties to the grid. (See page 18 of 18.)

7) The loss of the Craighead White transmission line caused full load current to be diverted through PCB11 to the Mecklenburg Black line. This caused an overload condition on PCB11.

8) PCB11 tripped 0.2 seconds later at 1355:04, on overcurrent which cleared the Mecklenburg Black line. This was the only remaining connection of Unit 1 to the grid resulting in a loss of all off site power to Unit 1.

9) The unit had not received a runback signal at this point and full load current from Unit 1 was subsequently redistributed to unit auxiliaries. This induced a voltage transient in the station electrical distribution system.

10) Since the generator was now producing more electricity than required by station loads, frequency began to rise. This increased Reactor Coolant (NC) [EIIS:AB] pump speed.

11) The Nuclear Excore Instrument System (NI) recognized a change in Reactor power from 100 percent to 104 percent power in approximately 1 second and initiated a high flux rate Reactor Trip signal. The Reactor tripped at 1355:13, followed by a Turbine [EIIS:TRB] trip at 1355:14.

Following the Reactor and Turbine Trips, Diesel Generators (D/G) [EIIS:DG] 1A and 1B started and began sequencing on blackout load groups.

Seconds later, the Control Room [EIIS:NA] Senior Reactor Operator (SRO) initiated emergency procedure EP/1/A/5000/01, Safety Injection or Reactor Trip, which requires manually exercising the Reactor Trip switches and performing other actions to stabilize the unit. He also verified that a Safety Injection (SI) [EIIS:BG] had not occurred.

NC system temperature and Main Steam (SM) system [EIIS:SB] pressure started decreasing. NC system temperature was trending toward 557 degrees Fahrenheit as expected. The NC system was now being cooled by natural circulation.

Operations (OPS) personnel realized that SM system pressure was decreasing below no load value. They attempted to reset the Moisture Separator Reheaters (MSRs) [EIIS:MSR] and remotely close valve 1SM-15, SM to Second Stage Reheaters. They were unsuccessful in this attempt because was no power available. Also, steam line drain valves were open and could not be remotely closed. This contributed to high SM system cooldown rate.

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OPS personnel throttled the Auxiliary Feedwater Control valves [EIIS:BA] to the full closed position to limit cooldown. Also, they were in the process of manually closing valves 1SM-15 and 1SP1, SM to Feedwater Pump Turbine 1A, and 1SP2, SM to Feedwater Pump Turbine 1B, when, at 1412, approximately 17 minutes after the Reactor Trip, the low steam line pressure SI setpoint was reached.

After the SI, a SM Isolation signal automatically initiated which caused the Main Steam Isolation Valves (MSIV) to close. This stopped heat removal from the NC system and caused pressure and temperature to increase, and NC system Power Operated Relief Valves (PORV) 1NC-32 and 1N 36 opened. PORV 1NC-34 did not lift due to being jumpered closed per worn request 142869. No Pressurizer [EIIS:PZR] code safety valves lifted.

Lower Containment [EIIS:NH] temperature and pressure started increasing due to loss of containment ventilation. This caused the lower ice condenser [EIIS:BC] doors to briefly open. OPS personnel then exited procedure EP/1/A/5000/01 and entered procedure EP/1/A/5000/02, High Energy Line Break Inside Containment. Containment pressure eventually peaked at 0.76 psig.

An Unusual Event was declared at 1420. Concurrently, OPS personnel verified that all SI termination criteria as described in procedure EP/0/A/5000/02 were met. The SI signal was reset at 1422.

By 1435, power was fully restored to the switchyard and was available to the 6.9 KV buses in the plant. Shortly afterwards, OPS personnel began transferring loads from the D/G supply to the normal 4160 volt supply bus.

The Technical Support Center (TSC) and Operations Support Center (OSC) were activated as a conservative measure and subsequently fully activated at 1503 with the Station Manager as Emergency Coordinator.

TSC personnel determined that there was no radiological concern and decided to enhance unit cooling by venting steam through the SM system atmospheric PORVs. The Main Condenser had been made unavailable as a result of the unit blackout.

By 1630, the unit was stabilized to a point that allowed the unit to be shutdown in a routine manner. Subsequently, TSC personnel directed OPS personnel to commence procedure OP/1/A/6100/02, Controlling Procedure for Unit Shutdown.

The OSC and TSC were deactivated at 1735.

The Station Manager called for an independent review to evaluate the event prior to restarting the unit. Many station groups, Design Engineering, and Transmission Department personnel participated in this technical review. This technical review encompassed the following items:

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- NC system radiochemistry samples were taken and found to be within normal parameters. This indicated Reactor Core integrity was maintained.
- A visual survey of Unit 1 Containment was performed by OPS personnel and no problems were found.
- Design Engineering ..partment and Maintenance Engineering Services (MES) personnel walked down the PZR PORV discharge pipe and no problems were found.
- The ice condenser, ice bed, and doors were surveyed by MES personnel and were determined to be undamaged.
- Design Engineering Department personnel evaluated the temperature spike in containment and determined there was no immediate equipment/structural damage.
- OPS personnel cycled the PZR PORV a number of times and there was no evidence of high discharge pipe temperature which would have indicated NC system leakage through the valve seat.
- One malfunctioning lower Containment Ventilation (VL) power supply was repaired as directed by Work Request 144402.
- MES and Performance (PERF) personnel began performing an evaluation of the high flux rate trip signal.
- Steam Generator blowdown valve 1BB-8 did not operate properly. This was repaired and functionally verified as directed by Work Request 144386.
- The Operator Aid Computer (OAC) was down intermittently during the event. Instrument and Electrical (IAE) personnel repaired and returned the OAC to service.
- OPS personnel reviewed Emergency Operating Procedures on closure of MSIVs to evaluate the need for adding steps to manually shutoff steam line drains.
- Relay 21LC in the switchyard was repaired by Transmission Department personnel.
- No other electrical problems were found.
- The Chemical and Volume Control (NV) system was surveyed and all was determined to be normal.

After evaluating the facts associated with the event and correcting all equipment problems identified, it was determined that it was safe and prudent

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to restart the Reactor. Startup activities continued on a continuous basis and Unit 1 was returned to Operation on February 13, at 0345.

Conclusion

A cause of Misunderstood Verbal Instructions and Lack of Attention to Detail is assigned. Just prior to start of the modification, Charlotte Area Operating Center (AOC) and Transmission personnel anticipated that the autotransformer could be de-energized long enough to perform a post modification test within a short time of completing the job. It is Transmission Department policy to test new devices on operating equipment as soon as possible after they are installed to provide maximum assurance that the equipment is safe. The Relay crew performing the test was aware of this policy and was anxious to complete the checkout. The Relay Supervisor contacted the AOC several times that day and asked him to clear the autotransformer and grant permission to proceed with the test. At 1200, the Relay Supervisor contacted the AOC for permission to remove the autotransformer from service. The AOC in consultation with the System Operating Center (SOC) determined that the autotransformer should not be taken out of service at that time due to system load conditions. A discussion between the AOC and Relay Supervisor followed. They discussed performing the test with the autotransformer energized. The AOC was confident that the Relay crew personnel had the knowledge and expertise to perform the test with the autotransformer energized. They were faced with an unusual testing situation that they had not previously planned for and were reluctant to proceed. They had hoped that the autotransformer could be cleared before the end of the day.

The Relay Supervisor was mindful that (since the autotransformer was still energized) the downstream relay logic must be blocked to prevent the autotransformer from detecting a fault and tripping the feeder breakers during the test. He directed the Relay crew personnel to develop a plan to open the relay contacts so that simulating a transformer fault pressure signal would actuate the relay logic but would not open PCBs 1, 3, 52, 53 to lockout the autotransformer. The Relay crew personnel then held a brainstorming session on how to perform the test with the autotransformer energized. The Relay crew technicians researched the drawings and reviewed their plan with the Relay Supervisor. The relay drawings were complicated, confusing, and hard to read. There were two separate downstream relay contacts that should have been opened to block PCBs, 1, 3, 52, 53 opening. However, the field crew failed to find one of these logic protection paths in their search of the drawings. The Relay Supervisor did not identify this during his review. Therefore, only one of these paths was identified and only one of the contacts was opened. Both contacts should have been opened to block the trip.

A mitigating factor is that at 1300, the Relay Supervisor noticed that another Transmission Department crew had arrived and was working in the near vicinity of the autotransformer. He knew the autotransformer fault protection was questionable since the circuit had not been tested yet. He

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also was aware that the autotransformer was in a loaded condition and if the circuit did not work properly under fault conditions, that the autotransformer could fail catastrophically, endangering the second Transmission Department crew. He also realized that the end of the work day was approaching and he did not want to leave the autotransformer protective relaying in a degraded state overnight. At 1339, he asked the onsite Operations Department Service Representative to call the AOC and grant permission to proceed with the test.

A three party conversation followed with instructions being relayed between the Operations Department Service Representative and the Relaying Supervisor. The AOC believed that the Relay Supervisor was to make a decision regarding the test and call him back before proceeding. The Relay Supervisor believed that he had been given permission to proceed with the test.

A cause of Management Deficiency is assigned due to a Lack of Policy and Inadequate Groups Interface. The majority of the McGuire switchyard was controlled by Transmission Department Operating Division and System Operating Center Department personnel. Only the four PCBs (PCB8, 9, 11, 12 for Unit 1 and PCB58, 59, 61, 62 for Unit 2) that directly connect the Units to the grid were controlled by McGuire OPS Control Room personnel. Traditionally, only work on the four Unit related PCBs had required concurrence from System or Area Operations personnel plus the additional concurrence by McGuire OPS Control Room personnel. Since this modification was outside the traditional boundary of plant owned equipment, it was considered exempt from the Nuclear Station Modification program and the station work control process. Transmission Department and AOC personnel did not consider it appropriate to notify McGuire OPS Control Room personnel that work was in progress in the switchyard since it was out of their field of expertise. Consequently, this activity was in progress without any knowledge by McGuire OPS Control Room personnel. However, switchyard activities outside this boundary can and do impact the station. Also, had the plant electrical system been in a degrade state (i.e., 1 D/G out of service), the Duke System load dispatchers would not have been aware of this. Prior to this event, due to the existing division of equipment ownership, there was no agreement between Station Operations, Transmission Department, AOC and SOC of how activities in the switchyard outside plant owned equipment boundaries should be handled.

Transmission Department personnel have historically avoided errors in the switchyard through a variety of informal means such as training on switchyard equipment and controls, verification of wiring by an independent worker, strict communication discipline including repeatback for breaker alignment orders, and coordination through experienced dispatchers. Verbatim procedure compliance has normally not been required, and complete procedures with specific testing guidance have not usually been available. The technician crews are expected to utilize their extensive collective experience and training to determine the best methods for installing modifications and performing tests.

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This event is also assigned a cause of Equipment Failure because the switchyard blackout and subsequent Unit trip would not have occurred if protective relay 21LC had not failed. During normal system conditions, the 85 relay is closed and the 21LC relay trip contact is held open by voltage present in the relay. This open contact verifies there is not a fault present on the transmission line. However, after the event, the 21LC relay contact was found stuck closed. This closed contact provided a trip path through the 85 relay and the 50P overcurrent relay on the Craighead White transmission line. One half of Unit 1 current (1500 Amps) flowing through the transmission line exceeded the overcurrent trip setpoint (1200 Amps) of the 50P relay. This combination of factors satisfied the logic which indicated that a fault was being fed on the Craighead White transmission line and PCB8 opened to clear the indicated fault. The switchyard was designed to handle a single failure which included a lockout of the main buses; however, the addition of a latent relay failure exceeded the capability of the switchyard design to maintain power.

Transmission Department personnel attempted to determine why relay 21LC was stuck closed. System operating data indicated that there had not been any faults on the transmission line (since the relay preventative maintenance) which would have caused the contact to pick up. The status indicator on the relay did not show a trip coil activation. The relay was disassembled and inspected by knowledgeable Transmission Relaying and Metering Department personnel. They could find no magnetic, mechanical, or electrical abnormality that attributed to the contacts closing and remaining stuck closed. However, they suspected the cause to be a deposit of organics onto the contacts due to either outgassing caused by heat from internal electrical components or improper lubrication. This investigation is ongoing and the 21LC relay may be sent to a relaying manufacturer for further analysis of the defective components.

PERF personnel theorized that the high flux rate trip signal was initiated because the NI system recognized a change in Reactor power due to the thermalization process in the NC system. MES personnel theorized that the high flux rate trip signal was initiated due to the voltage transient in the station electrical distribution system. Neither of those theories have been proven and the investigation of same is ongoing.

OPS personnel responded to the transient in a timely manner. With the exception of relay 21LC, all equipment and systems operated within specifications as expected during this Reactor Trip. The TSC and OSC activation went very well. Concurrence to restart the unit was received by the NRC based on evidence that:

1. The plant equipment operated properly,

2. Plant OPS personnel responded correctly using appropriate procedures, and

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3. A careful approach to restart was demonstrated by doing a comprehensive inspection of the plant, and any needed corrective actions were taken.

The boron injection safety nozzle usage factor for this event was 0.017. The cumulative nozzle usage factor for all Unit 1 safety injection events to date is 0.102 with 7 significant safety injection events. The total allowable nozzle usage factor is 1.0 with NRC notification required at 0.70.

A review of the Operating Experience Program (OEP) data base for the previous 24 months prior to this event revealed no events involving a Reactor Trip in which the cause was an Inappropriate Action, A Management Deficiency, or an Equipment Failure where Transmission Department personnel were performing switchyard modification work. However, two previous events were documented in Problem Investigation Report (PIR) 2-M89-0233 and 2-M89-0209 involving the Transmission department where written communication was inadequate. Therefore, this problem is considered recurring.

This event is not Nuclear Plant Reliability Data system reportable.

There were no personnel injuries, radiation exposures, or uncontrolled releases of radioactive material as a result of this event.

CORRECTIVE ACTIONS:

Immediate:

1) OPS personnel implemented emergency shutdown and accident mitigation procedures EP/1/A/5000/01, Safety Injection or Reactor Trip, and EP/1/A/5000/02, High Energy Line Break Inside Containment.

2) The OSC and TSC were activated.

3) Offsite power was restored to the unit within 40 minutes (essential bus).

Subsequent:

1) An independent techaical review of plant equipment was performed. This review revealed that the plant equipment operated properly and there was no major damage to it.

2) An interim switchyard work control policy to increase the offsite power system reliability was implemented. This policy requires the AOC Dispatcher to notify McGuire Control Room personnel of any activities in the switchyard that could affect the station. Also, when the station enters a degraded electrical system configuration, the McGuire Control Room SRO will notify the AOC Dispatcher. This will heighten the awareness of all work groups of increased station vulnerability during the degraded condition.

3) Chemistry samples of the NC system were taken and found to be within normal parameters. This indicated that the Reactor Core was not damaged.

4) A survey of Unit 1 Containment was performed and no problems were found.

5) The ice condenser ice bed, and doors were surveyed and no problems were found.

6) Design Engineering Department personnel evaluated the temperature spike in containment and determined that there was no immediate equipment or structural damage.

7) Design Engineering Department and MES personnel surveyed the PZR PORV and discharge pipe and determined that there was no leakage through the valve seat.

8) Relay 21LC was repaired by Transmission department personnel.

9) The unit secondary side was surveyed and no problems were found.

10) Signs were placed on the switchyard gate which state: ATTENTION all circuits in this switchyard can affect McGuire plant operation. Notify AOC at 382-0383/0384 prior to beginning any work in the switchyard.

11) Transmission Department personnel suspended all non-emergency work in the switchyard until a complete policy controlling switchyard activities is formulated.

12) Transmission Management personnel reviewed this event with appropriate personnel.

Planned:

1) MES, IAE, and PERF personnel will continue the evaluation of the cause for the NI high flux rate trip.

2) A multidepartmental task force has been set up to review administrative control of switchyard activities and develop a policy for control of the same.

3. Transmission Department personnel will complete the post modification test on the 63FPX relay circuit.

4) MES and Design Engineering personnel will evaluate the setpoint for acoustic monitoring of the PZR code safety valves for PZR PORV cycling events and determine if the setpoint should be changed.

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5) Transmission Department personnel will continue evaluation of the failed 21LC relay contact. This may include sending the relay to A. Brown Boveri, Inc. for analysis. They will also investigate other modifications performed earlier to determine if this could have caused failure of the relay.

6) General Office OPS personnel will verify that an adequate emergency plan exists to restore power to the station in the event of a loss of both switchyards.

SAFETY ANALYSIS:

This event resulted in a Reactor Trip with the plant being capable of returning to operation.

When the blackout logic was initiated, D/Gs 1A and 1B started, and all 10 load groups were sequenced on within 11 seconds (after the load sequencer initiated). The total load was well below the D/G capacity. If the D/Gs had not started and loaded properly, OPS personnel would have referred to emergency procedures which provide instruction to energize the 4.16 KV buses from Unit 2 if necessary. Offsite power was available to both essential 4.16 KV buses from Unit 2 through standby transformers SATA and SATB.

Upon loss of power to the NC pumps, coolant flow necessary for core cooling and the removal of residual heat was maintained by natural circulation in the NC system, aided by Auxiliary Feedwater in the secondary system. OPS personnel were aware of this and were monitoring subcooling parameters. Adequate subcooling margin was always maintained during the event.

Offsite power was restored within 40 minutes of the loss of power.

Approximately 17 minutes into the event an SI occurred due to low steam line pressure. Both NI pumps and 1 NV pump (1NV pump was already running) started. Low steam line pressure resulted when a steam header isolation valve remained partially open while steam pressure continued to be reduced by steam usage on the secondary side. OPS personnel were aware of decreasing steam pressure and were in the process of securing steam usage and isolating leaks when the SI occurred. It has been determined that there was no equipment or structural damage as a result of the SI.

Pressurizer PORVs 1NC-32 and 1NC-36 opened as required to maintain NC system pressure at approximately 2335 psig. The Pressurizer and Steam Generator code safety valves were not challenged during the event. Integrity of the Pressurizer Relief Tank Rupture Disk was not challenged.

An Unusual Event was declared and the TSC was activated as a precaution because of the loss of offsite power and SI.

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The lower containment air temperature spiked at 140 degrees Fahrenheit due to the VL air handling units tripping off during the loss of power. A visual inspection was performed and it has been determined that there was no equipment or structural damage as a result of the SI. These units are not powered by the D/Gs. The increased temperature resulted in an air volume expansion in lower containment. This caused the Ice Condenser Doors to open briefly as designed. Maximum pressure experienced was 0.76 psig which is well below the 3 psig setpoint for actuation of containment spray.

All Secondary system and accident mitigation equipment functioned as expected and no nuclear safety concerns occurred as a result of this incident. There were no challenges to fission product barriers as a result of this event.

There were no personnel injuries or radiological releases as a result of the event.

The health and safety of the public were unaffected by this event.

ADDITIONAL INFORMATION:

Sequence Of Events:

TR - Trip Report
PR - Personnel Recollection
ER1 - Switchyard Events Recorder
LB - Logbooks (TSC, OSC, SRO, etc.)
WR - Work Request History
ER2 - Plant Events Recorder

Date	Time	Event
8/21/90		Relay 21LC preventative maintenance was performed by Transmission Department personnel. (WR)
2/11/91	~0730	The load dispatcher was contacted by the Relay crew. The load dispatcher stated a 35 minute outage of the autotransformer would be acceptable later in the day. (PR)
	~1000	The new 63FPX relay circuit was installed for the autotransformer bank. (PR)
	~1001	The load dispatcher was contacted about testing the relay. System load had increased and it was not possible to perform the post modification (mod) test at that time with the autotransformer isolated. (PR)
	1200	The modification crew brainstormed a test method that could be implemented while the autotransformer was energized. (PR)

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≈1300	The Relay Supervisor noticed another crew working near the transformer. (PR)
1339	The onsite Operating Department Representative called the AOC to get permission for the Relay crew to proceed with the test. (PR)
≈1340	The post mod test was implemented but problems were encountered due to the blocking switch being labeled backwards. (PR)
≈1350	The blocking switch was re-labeled and the test resumed. (PR)
1355:01	The 86 relay detected a fault on the autotransformer bank and cleared both switchyard buses. (ER1)
1355:02	The Craighead White line was cleared due to failed 21LC relay and overload. (ER1)
1355:04	The Mecklenburg Black line was cleared due to overload. (ER1)
1355:13	NI power range initiated a Reactor Trip due to high flux rate. (ER2)
1355:14	The Turbine tripped due to a reactor trip. (ER2)
****	D/Gs 1A and 1B started. (ER2)
1355:19	OPS personnel manually opened the Reactor Trip Breakers. (ER2)
1355:34	OPS personnel manually started NV pump B. (TR)
****	The Turbine Driven Auxiliary Feedwater pump (TD AFWP) started. (ER2)
1359	The condenser was in full load rejection mode. (ER2)
1400	Feedwater isolated due to Tavg less than 553 degrees Fahrenheit. (ER2)
1402	NC system letdown was isolated. (TR)
1412	An SM line isolation signal was initiated due to low pressure in loop A. SI was initiated. The ice condenser doors opened. (ER2)
1420	An Unusual Event was declared. (LB)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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1422:33 The SI signal was reset. (ER2)

1435 Power was fully restored to the unit and available to the NC pump motors. (LB)

1452 Both VC/YC chillers were down. The OAC was down. (LB)

1503 The OSC and TSC were activated. (LB)

1505 A Train VC/YC was running. (LB)

1510 The TD AFWP was stopped. (LB)

1513 OPS personnel began swapping loads from the D/G supply buses to the normal 4160 volt supply buses. (LB)

1520 SM header was pressurized. (LB)

1529 The OAC was placed back in service.

1537 Containment pressure increased to approximately 0.5 psig. Lower containment temperature increased to 140 degrees Fahrenheit. (LB)

1539 Containment pressure increased to 0.7 psig. (LB)

1544 TSC personnel decided to cool the unit by venting steam through the SM atmospheric PORVs. (LB)

1600 PZR pressure was 2240 psi and NC loop B temperature was 554.7 degrees Fahrenheit. (LB)

1607 NC Pump B was started. (LB)

1612 Two lower containment ventilation units are in service. (LB)

1622 Containment pressure decreased to 0.3 psig. High pressure station air was available. (LB)

1629 Low pressure station air was available. (LB)

1637 Control Room OPS personnel moved into the normal shutdown procedure. (LB)

1643 The Unusual Event was de-escalated. (LB)

1649 Two Condenser Circulating Water System [EIIS:KG] pumps were available and OPS personnel were preparing to dump steam to the condenser. (LB)

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
McGuire Nuclear Station	0 5 0 0 0 3 6 9	9 1	— 0 0 1	— 0 0	1 7 OF 1 8

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

	1701	NC Pump A was running. Management personnel discussed sending an inspection team into containment. (LB)
	1724	OPS personnel started Hotwell pump A. (LB)
	1735	The OSC and TSC were de-activated. (LB)
2/13/91	0345	The Reactor was re-started. (LB)

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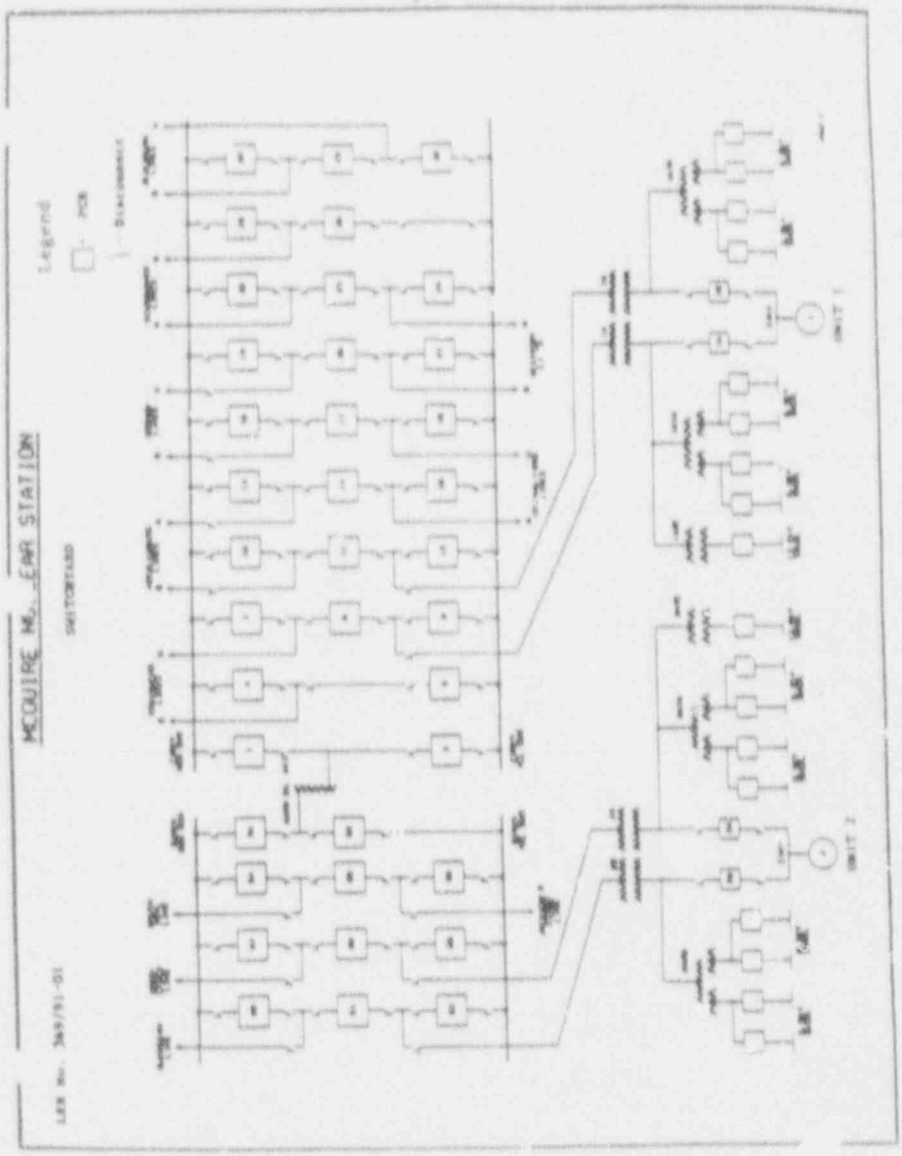
(9-83)

NRC Form 366A | LICENSEE EVENT REPORT (LER) TEXT CONTINUATION | U.S. NUCLEAR REGULATORY COMMISSION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
McGuire Nuclear Station, Unit 1	0 5 0 0 0 3 6 9	9 1	0 0 1	0 0	1 8 OF 1 8



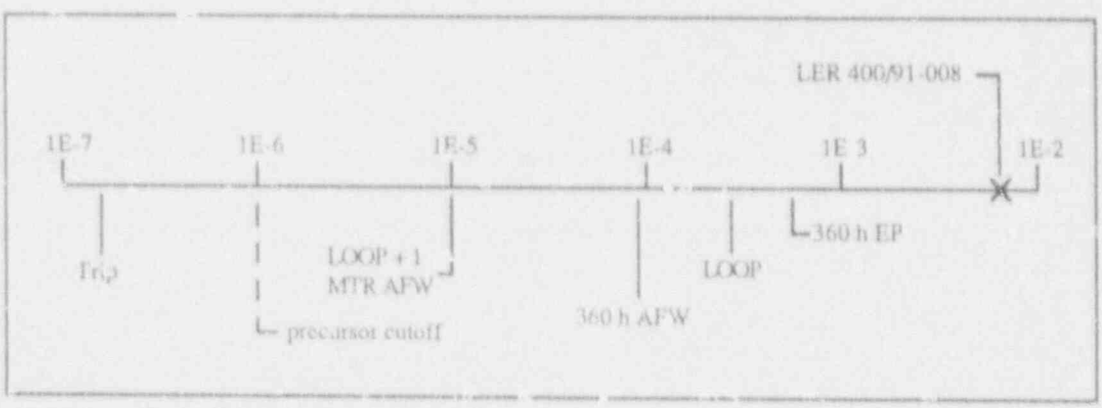
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	400/91-008
Event Description:	HPI unavailability for one refueling cycle because of inoperable miniflow lines
Date of Event:	April 3, 1991
Plant:	Harris 1

Summary

Harris is equipped with three charging/safety injection pumps (CSIPs) that provide charging and seal flow during normal operation and provide high-pressure injection (HPI) during accidents. Each pump is provided with a normal minimum flow path and an alternate minimum flow path for pump protection. During normal operations, the minimum flow path is via the seal water heat exchanger back to the pump suction. During safety injection (SI) operation, this path is isolated, and two alternate paths via relief valves to the reactor water storage tank (RWST) are aligned. Tests conducted during a refueling outage revealed that both relief valves were failed, as well as associated piping. Had HPI been demanded during the operating cycle, sufficient flow would have been diverted via the alternate miniflow system to fail the injection function. Under some circumstances, pump runout and failure could also have resulted.

The conditional core damage probability estimated for this event is 6.3×10^{-3}. The relative significance of the event compared to other postulated events at Harris 1 is shown below.



Event Description

The CSIPs provide charging and reactor coolant pump seal injection flow during normal operation at Harris. Under accident conditions the CSIPs act as HPI pumps, providing high-pressure makeup to the reactor coolant system (RCS). While acting as charging pumps, the CSIPs are protected against deadhead operation by normal minimum flow lines that are capable of returning 60 gpm through the seal water heat exchanger to the pump suction. On an SI, these lines are automatically isolated, and two alternate minimum flow lines are aligned. Relief valves 1CS-744 and 1CS-755 are located respectively in these lines. They are designed to lift at approximately 2300 psig to recirculate water back to the RWST.

During outage testing, these relief valves were both found to be damaged, along with associated piping. Relief valve 1CS-755 failed to hold any pressure during bench testing, and 1CS-744 lifted at 1100 psig. Piping upstream of valve 1CS-755 was found to be cracked; this piping failed during testing. In addition, a weld indication was identified upstream of 1CS-744. Utility investigation determined that the damage was a result of water-hammer effects. Gas accumulations, believed to be air, were thought to have developed in the alternate miniflow lines during previous testing or maintenance. Displacement of this air during earlier system testing apparently resulted in water-hammer and damage to the piping and valves.

The utility reported that, had HPI been demanded, the failures in the alternate miniflow lines would have diverted sufficient flow that the system would not have been able to perform its safety function. It was also reported that, in the event of a large-break loss-of-coolant accident (LOCA), the additional flow through the alternate miniflow system would have resulted in CSIP runout.

Additional Event-Related Information

A drawing of the Harris charging/SI system is shown in Fig. 1.

EOP-FRP-C.2, "Response to Degraded Core Cooling," provides instructions for RCS depressurization and use of the accumulators and low-pressure injection (LPI) pumps if the high-pressure system is unavailable. This alternate mitigation method would only be effective if secondary-side cooling were available and if the RCS could be depressurized prior to core uncovery. The Accident Sequence Precursor (ASP) models, described in Appendix A, do not currently address the potential use of secondary-side depressurization and LPI for core cooling success.

ASP Modeling Assumptions and Approach

This event was modeled as an unavailability of the CSIPs for SI. The failures were assumed to be nonrecoverable. Since the procedures require SI to be initiated prior to opening the PORVs for feed and bleed, the failed relief valves would also have resulted in a failure of that function as well as SI in the event of a LOCA.

The unavailability existed throughout the refueling cycle. To estimate the relative significance of the event within a 1-yr observation period (the interval between precursor reports), a 1-yr unavailability period was utilized in the analysis (6132 h, assuming the plant was critical or at hot shutdown for 70% of the year).

Two sensitivity analyses were also performed. The first involved the potential use of steam generator (SG) depressurization and the LPI system for sequences in which secondary-side cooling was available. A failure probability of 0.12 was assumed for this alternate core cooling method. As described in Appendix A, a failure probability of 0.12 is used in the ASP Program for situations in which action could be taken from the control room, but which are not routine or involve substantial operator burden. (Use of SG depressurization and LPI as an alternate to HPI is not addressed in the current ASP models.) The second sensitivity analysis addressed the possibility that two CSIPs would be effective in providing high-pressure makeup.

Analysis Results

The conditional core damage probability associated with this event was estimated to be 6.3×10^{-3}. The dominant core damage sequence, highlighted on the following event tree, involves a LOCA, reactor trip and auxiliary feedwater success, and failure of HPI.

If SG depressurization and LPI is assumed to provide successful core cooling with a failure probability of 0.12, then the conditional probability for the event is reduced to 7.8×10^{-4}, still a significant event.

It is possible that use of two charging pumps would provide adequate injection flow even with the failed relief valves, but no information is available that would permit this to be confirmed. If this were the case, the conditional probability estimated for the event would be $\sim 1.3 \times 10^{-4}$ without the use of SG depressurization, and 2.3×10^{-5} if SG depressurization and LPI were effective in providing core cooling.

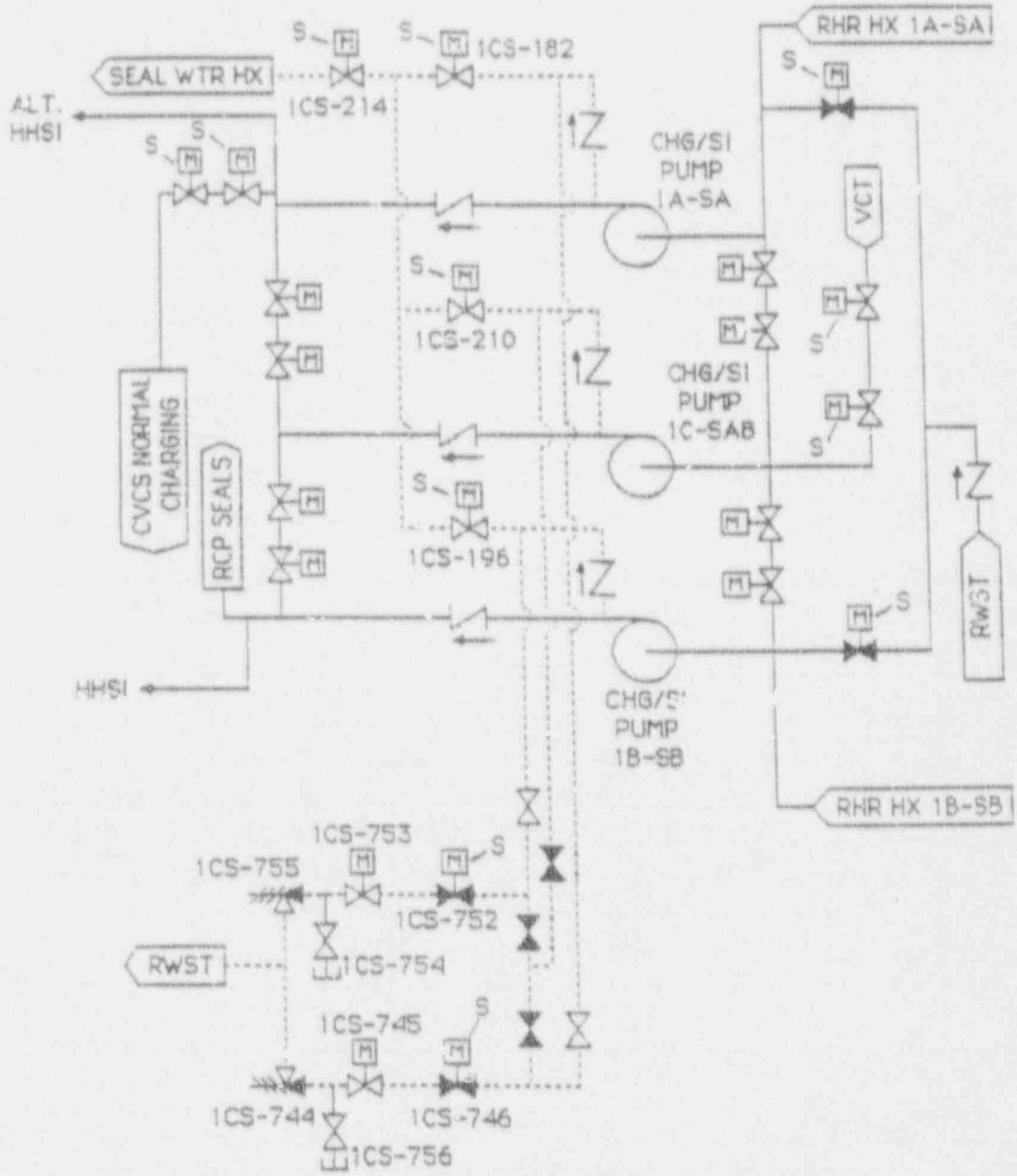
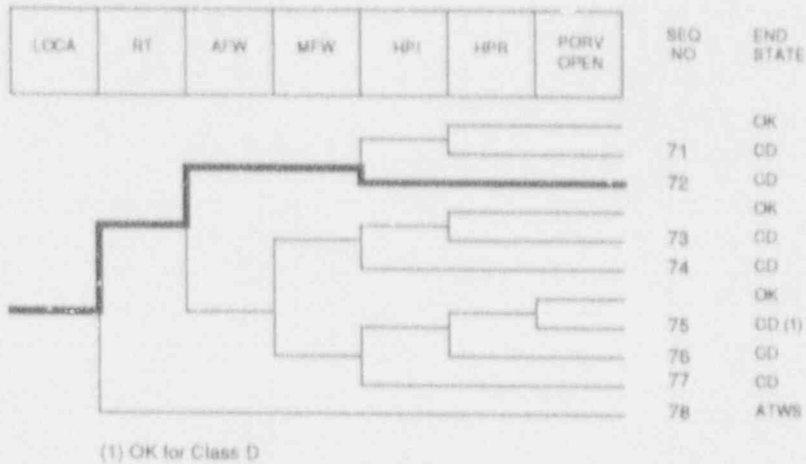


Fig. 1. Harris 1 charging/safety injection system



Dominant core damage sequence for LER 400/91-008

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 400/91-008
Event Description: HPI unavailable due to inoperable mini-flow lines
Event Date: 04/03/91
Plant: Harris 1

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.4E+00
LOOP	5.3E-02
LOCA	6.3E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.5E-05
LOOP	1.8E-05
LOCA	6.3E-03
Total	6.3E-03
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	6.3E-03	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	6.3E-03	4.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the addwd 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:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\harris.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

Event Identifier: 400/91-008

BRANCH FREQUENCIE./PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	5.5E-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	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	1.0E-03
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	3.0E-04 > 1.0E+00	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
Train 3 Cond Prob:	3.0E-01 > Failed		
HPI(F/B)	3.0E-04 > 1.0E+00	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.3+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > ,ailed		
Train 3 Cond Prob:	3.0E-01 > Failed		
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

Minarick
03-15-1992
18:03:31

Event Identifier: 400/91-008

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Shearon Harris Nuclear Power Plant Unit #1

DOCKET NUMBER (2): 0 5 0 0 0 4 0 0

PAGE (3): 1 OF 0 6

TITLE (4): Common Cause Failure of High Head Safety Injection Alternate Miniflow

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 4	0 3	9 1	9 1	0 0 8	0 1	0 5	1 5	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 6

POWER LEVEL (10): 0 0 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: M. R. Hamby, Project Specialist - Regulatory Compliance

TELEPHONE NUMBER: AREA CODE 9 1 9 | 3 6 2 - 2 2 0 4

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
X	B Q	R V	C 7 1 1	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15): Month | Day | Year

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

Common-cause failures, which would have affected both trains of High Head Safety Injection, were identified during testing while the plant was in a refueling outage. The failures involved alternate miniflow lines for both Charging/Safety Injection Pumps (CSIPs). These alternate miniflow lines are designed to protect the CSIPs for accidents where the RCS repressurizes after safety-injection is actuated. Water hammer in these lines had damaged relief valves and test connections on these alternate miniflow lines such that a significant portion of the safety injection flow would be diverted from the RCS.

This event is being reported in accordance with 10CFR50.73(a)(2)(v) as an event that alone could have prevented the fulfillment of a safety function.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Shearon Harris Nuclear Power Plant	0 5 0 0 0 4 0 0	9 1	— 0 0 8	— 0 1	0 2 OF 0 6

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

EVENT DESCRIPTION:

On April 3, 1991, during the third refueling outage (RFO-3), it was determined that High Head Safety Injection (HHSI) had been in a degraded condition during Cycle 3. This degraded condition resulted from relief valve and drain line failures in the Charging/Safety Injection Pump (CSIP) alternate miniflow lines which would have diverted a portion of the safety injection flow.

The CSIPs provide charging flow and Reactor Coolant Pump seal injection during normal plant operation. While operating in this mode, the CSIPs are protected from pump deadhead operation by normal miniflow lines that are designed to provide a minimum flow of 60 gpm. During accident conditions, the CSIPs provide High Head Safety Injection to the RCS. While operating in this safety injection mode of operation, the normal miniflow lines are automatically isolated to ensure all safety injection flow is provided to the RCS.

If the plant accident is a secondary side break, safety injection will be automatically actuated. After the secondary side of the steam generator is dry, the excess heat removal would end and the RCS would repressurize. To prevent CSIP failure from deadhead operation in this event, an alternate miniflow is placed into service when the normal miniflow is isolated (see Attachment 1). This alternate miniflow path is through relief valves (1CS-744 and 1CS-755) which are set to open at 2300 +/- 69 psig and recirculate to the Refueling Water Storage Tank.

During RFO-3, testing identified damage to the alternate miniflow relief valves, 1CS-744 and 1CS-755, and test connections 1CS-754 and 1CS-756, immediately upstream of 1CS-755 and 1CS-744 respectively. Relief valve 1CS-755 was removed to test its relief setpoint in accordance with Inservice Inspection requirements. In its place, an orificed spool piece is installed to support integrated Engineered Safety Features (ESF) testing. The relief setpoint of 1CS-755 could not be determined on the available testing equipment because excessive valve seat leakage prevented pressurization. 1CS-755 was subsequently repaired and reset. The ESF testing that is performed during the outage actuates flow through the orificed spool piece that is installed to replace the relief valve. During the RFO-3 ESF testing, water hammer caused the piping connection upstream of 1CS-754 to fail. A small leak had previously existed in this weld, repair of this leak was scheduled for this outage. This piping has been rewelded and the welds upstream of the other test connection (1CS-756) were inspected by NDE. One weld indication near 1CS-756 was repaired. Supports were designed and installed to prevent recurrence of this event. Based on the failure of 1CS-755, the other relief valve in this system (1CS-744) was selected for testing. The lift setpoint of 1CS-744 was determined to be 1100 psig, normal setpoint is 2300 psig. This valve was disassembled and inspected. Damage to the valve actuation components was identified during this inspection. This valve will be repaired and reset, or replaced prior to plant entry into Mode 3.

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NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Shearon Harris Nuclear Power Plant	0 5 0 0 0 4 0 0	9 1	— 0 0 5	— 0 1	0 3 OF 0 6

EVENT DESCRIPTION (continued)

The physical layout of the piping upstream of the alternate miniflow relief valves is shown in Attachment 2. This piping arrangement results in an air void being trapped below the relief valves when they are installed in the system. After the relief valves are installed and the clearance is removed, one of the upstream valves remains closed. This prevents water from refilling this piping. In addition, the piping upstream of the relief valves does not have a high point vent to remove the trapped air. Procedures are being developed to refill and vent this piping.

CAUSE:

The cause of this event was water hammer that apparently occurred because of an air void that remained in the alternate miniflow lines following previous testing and maintenance. Previous to this outage, 1CS-744 was tested in May 1989. At that time, the as found relief setpoint was less than one percent below the acceptable range.

There have been no similar events reported.

SAFETY SIGNIFICANCE:

The amount of safety-injection flow diverted by the failures identified would have resulted in the HNP FSAR LOCA flow requirements not being met. In addition, for a large break LOCA, the additional flow through the alternate miniflow line would have resulted in CSIP runout conditions.

The consequences of the small or medium break LOCA may have been mitigated by local operator inspection in this area. This inspection would have occurred as a result of inadequate high head safety injection flow being indicated in the Control Room. If this inspection had not been successful in identifying the diversion, then plant conditions would have advanced until actions were initiated per EOP-FRP-C.2, "Response to Degraded Core Cooling." This procedure directs cooling and depressurizing of the RCS to inject the accumulators and to place Low-Head Safety Injection (LHSI) into service. Once this was accomplished, core cooling would be adequate and the plant would have been stabilized for recovery.

For a large break LOCA, if the CSIPs fail, LHSI Pumps would still function and would recover core cooling as decay heat production decreased. Potentially the operators would have detected CSIP runout prior to pump damage. Guidance on detecting potential CSIP runout is included in the EOP User's Guide and the indications of CSIP runout were included in operator training prior to Cycle 2.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Shearon Harris Nuclear Power Plant	0 5 0 0 0 4 0 0	9 1	— 0 0 8	— 0 1	0 4 OF 0 6

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

C...CTIVE ACTIONS:

1) The broken piping upstream of test connection, 1CS-754 was repair...d by rewelding the line. The weld indication upstream of 1CS-756 was also repaired.

2) Supports were added to test connection lines upstream ... 1CS-754 and 1CS-756 to prevent future cracking.

3) Relief valves 1CS-744 and 1CS-755 are being rebuilt and will be retested, or replaced prior to entry into Mode 3.

4) Maintenance instructions for installation of these relief valves (1C... 744 and 1CS-755) are being changed to refill the piping prior to installation and to vent the piping through the relief valves by hydraulic pressure following installation, thereby eliminating the air void.

5) A procedure is being prepared to ensure this piping remains full of water following any activity that could potentially drain this piping.

6) The procedure described in corrective action 5 will be performed quarterly during Cycle 4 to ensure this piping remains full. Following Cycle 4, if it is determined that corrective actions 4 and 5 maintain this piping full, then this quarterly testing will be terminated.

EIIS CODE INFORMATION:

BQ - High Pressure Safety Injection System

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

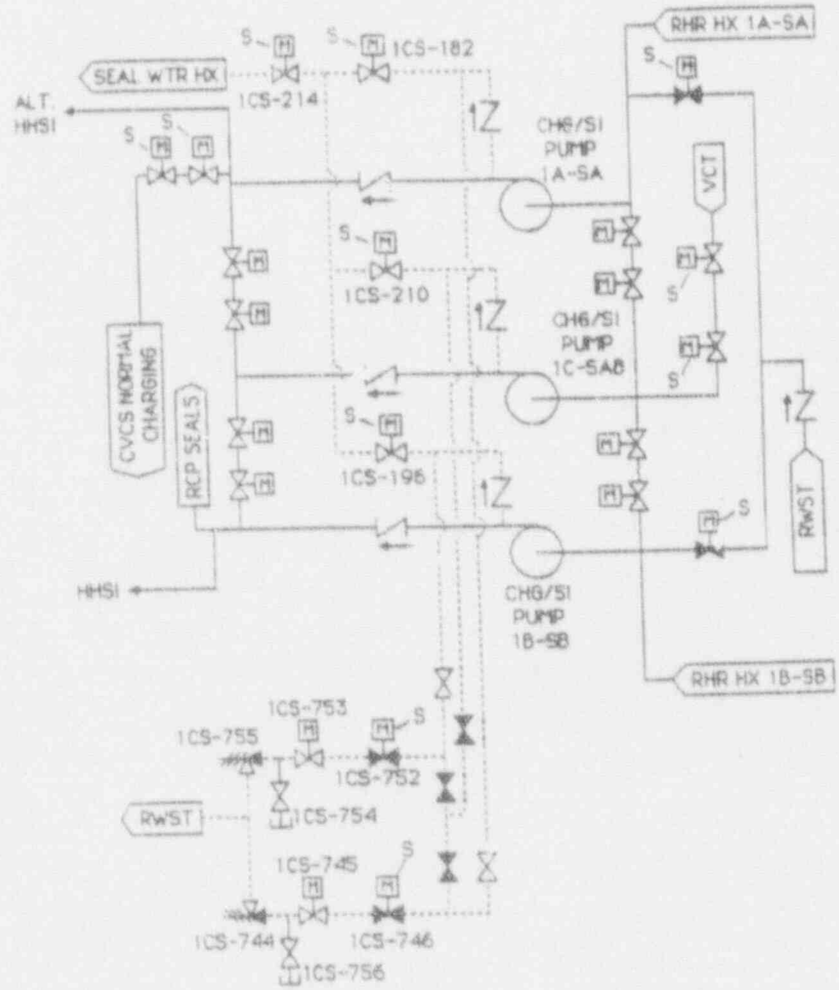
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Shearon Harris Nuclear Power Plant	0 5 0 0 0 4 0 0	9 1	0 0 8	0 1	0 5 OF 0 6

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

LER 91-008

ATTACHMENT 1



NRC Form 366A (6-89)

NRC FORM 366A | U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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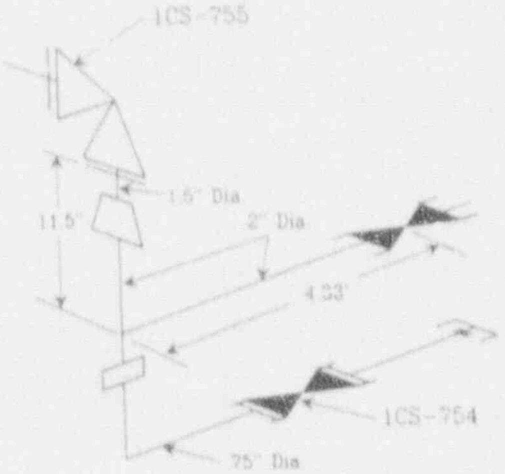
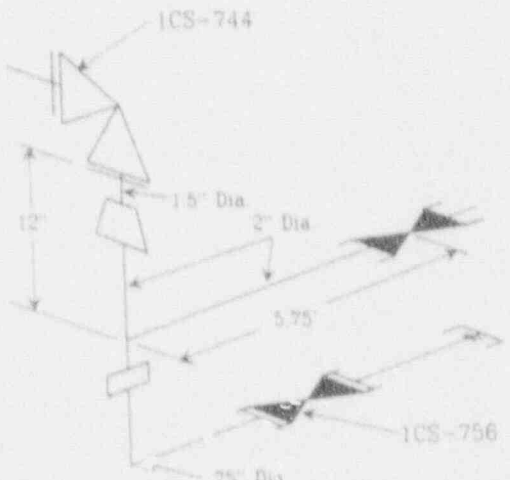
Shearon Harris Nuclear Power Plant	0 5 0 0 0 4 0 0	9 1	— 0 0 8	— 0 1	0 6 OF 0 6

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

LER 91-008

ATTACHMENT 2





NRC Form 366A (6-89)

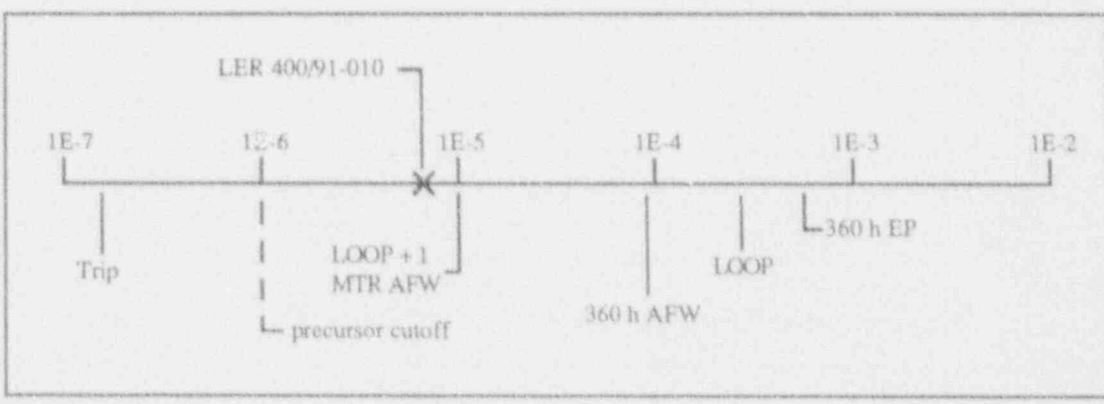
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 400/91-010
Event Description: Reactor trip breaker fails to open on trip
Date of Event: June 3, 1991
Plant: Harris 1

Summary

During performance of a calibration procedure on reactor coolant system (RCS) flow instrumentation, a reactor trip signal was inadvertently generated. The "B" reactor trip breaker correctly responded to the signal, opening to cause insertion of control rods, but the "A" reactor trip breaker failed to operate. It was subsequently determined that circuitry in the "A" train solid state protection system (SSPS) had failed in a way that prevented it from responding to automatic reactor trip signals.

The conditional probability of subsequent core damage estimated for the event is 6.6×10^{-6}. The relative significance of the event compared to other postulated events at Harris 1 is shown below.



Event Description

While performing a calibration procedure on an RCS loop "A" flow instrument, personnel at Harris inadvertently caused a pressure spike in the common reference leg to the three "A" loop flow transmitters. The two inservice flow transmitters falsely sensed a low-flow condition and generated a reactor trip signal. "B" reactor trip breaker responded correctly, opening to deenergize the control rod drives and allowing the control rods to insert. "A" reactor trip breaker failed to open, however.

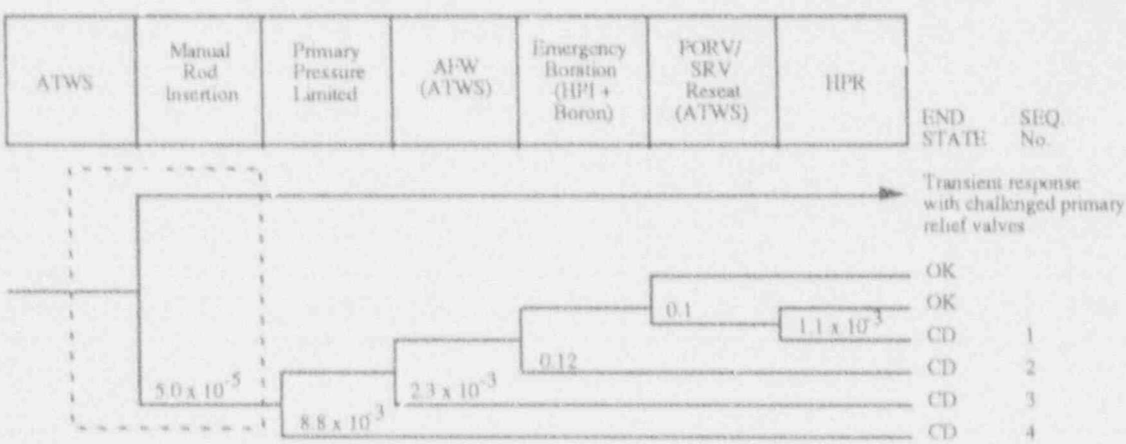
Investigation revealed that the "A" reactor trip breaker failed to respond to the automatic trip signal because an undervoltage output driver circuit board in the SSPS had failed as a result of previous improper maintenance actions performed on the breaker. This type of failure, discussed in IEN 85-13, Westinghouse Technical Bulletin NSID-TB-85-16, and NUREG-1341 (*Regulatory Analysis for the Resolution of Generic Issue 115, Enhancement of the Reliability of the Westinghouse Solid State Protection System*, January 1989), results in output voltage being maintained from the SSPS even if automatic trip signals are present. This failure prevents both automatic undervoltage and automatic shunt trips of the associated reactor trip breaker, although manual trips are still possible.

While little information was available concerning the specific maintenance procedure that caused the failure of SSPS "A", NUREG-1341 indicates that a number of earlier failures resulted from "... poor maintenance and test related practices." "These practices involved the inadvertent shorting of the scram breaker's [undervoltage] UV trip coil, causing a shorted failure of the output transistor in the UV driver card." In 1985, as a result of the earlier failures, Westinghouse recommended that maintenance practices be changed and that the UV driver card be replaced with a new card containing a fuse that would open if the UV coil was shorted. Corrective actions identified by the utility indicate that the existing UV driver cards are to be replaced with fused cards.

ASP Modeling Assumptions and Approach

While the initial reactor trip demand resulted from a spurious signal, the assumption was made that, once trip was demanded, a trip or shutdown by alternate means was required to prevent core damage.

The current Accident Sequence Precursor (ASP) models do not address the anticipated transient without scram (ATWS) issues of concern in this event. Instead, the following model was used to estimate the conditional core damage probability associated with the event:



In this model, branches and associated probabilities were defined as follows.

Branch	
Anticipated Transient Without Scram (ATWS)	Scram demand with failure of the control rods to automatically insert into the core. A combined probability was calculated for this branch and the next branch and is discussed under Manual Rod Insertion.
Manual Rod Insertion	Failure of the operator to manually scram the reactor or failure of both trip breakers to open after manual actuation. A combined probability for this branch and ATWS was calculated by assuming that the probability for both scram breakers failing to open (either automatically or manually) is 1.0×10^{-5}. Since the manual trip function was not impacted during the event, this probability was also not impacted by the SSPS circuit board failure. The conditional probability of SSPS "B" failing, given SSPS "A" failed, was assumed to be 0.1. Manual scram as a backup to automatic scram was considered highly reliable (it is proceduralized, addressed extensively in training, and practiced at each scram); a failure probability of 4.0×10^{-4} was assumed. The resulting probability of failing to automatically or manually trip the reactor during this event is therefore p(fail of SSPS "B") * p(fail to manually trip) + p(fail of both scram breakers) = $0.1 * 4.0 \times 10^{-4} + 1.0 \times 10^{-5} = 5.0 \times 10^{-5}$.
Primary Pressure Limited	Unfavorable moderator temperature coefficient results in RCS pressures greater than ~3200 psi. Above this pressure, unpredictable pressure boundary and component failures are assumed to occur. A branch probability of 8.8×10^{-3} was assumed, based on information provided in the NUREG-1150 probabilistic risk assessment for Sequoyah.
AFW (ATWS)	Failure of auxiliary feedwater (AFW) flow and secondary heat removal using the steam generator relief valves and atmospheric dump valves. Flow from at least two AFW pumps was assumed to be required. A branch probability of 2.3×10^{-3} was estimated.

Emergency Boration (HPI + Boron)	Failure to inject concentrated boric acid via the charging/HPI system to terminate the fission process. A failure probability of 0.12 was used in this analysis. This probability was assumed to be dominated by operator error in a high-stress situation.
PORV/SRV reseat (ATWS)	Failure of one or more primary relief valves to close following ATWS pressure relief. A branch probability of 0.1 was assumed.
Failure of high-pressure recirculation (HPR)	A failure probability of 1.1×10^{-3} was used in the analysis, consistent with the nominal ASP model value for Harris.

Analysis Results

Based on the event tree model and branch probabilities described above, a conditional probability of subsequent core damage of 6.6×10^{-6} was estimated. The dominant core damage sequence (sequence 2 on the previous event tree) involves failure of automatic and manual trip, and failure to initiate emergency boration.

NRC FORM 366 (9-83) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Shearon Harris Nuclear Power Plant

DOCKET NUMBER (2): 0 5 0 0 0 4 0 0

PAGE (3): 1 OF 0 5

TITLE (4): Reactor Trip During Surveillance Testing and One Reactor Trip Breaker Failed To Open

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 NAMES	DOCKET NUMBER(S)
0 6	0 3	9 1	9 1	0 1 0	0 0	0 7	0 3	9 1	N/A	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: M.R. Hamby - Project Specialist - Regulatory Compliance

TELEPHONE NUMBER: AREA CODE 9 1 9 | 3 6 2 - 2 2 0 4

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)

YES (If yes, complete EXPECTED SUBMISSION DATE)	NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR

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

The plant received an automatic Reactor Trip on RCS Low Flow during the performance of a maintenance calibration procedure on an RCS flow transmitter. All rods fully inserted on the trip signal. The "A" Reactor Trip Breaker did not open on the automatic reactor trip signal but did open on a subsequent manual trip signal. The failure of the "A" Reactor Trip Breaker to open was due to a failed undervoltage output driver card in the "A" Solid State Protection System. The failure of the undervoltage output driver card was the same as described in IE Notice 85-13 and had apparently occurred during maintenance on May 18, 1991. The failed undervoltage output driver card was replaced with a modified card which prevents this failure mechanism.

This event is being reported as a Technical Specification violation and Engineered Safety Features actuation per 10CFR50.73 (a)(2)(i)(B) and 10CFR50.73 (a)(2)(iv).

NRC Form 366 (9-83)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

EVENT DESCRIPTION:

At 1533, on June 3, 1991, an automatic Reactor Trip occurred due to a pressure spike in the flow transmitter common reference leg for "A" reactor coolant loop low flow. All rods fully inserted on the reactor trip signal. The "A" reactor trip breaker failed to open on the automatic reactor signal but did open on a subsequent manual reactor trip signal. An Auxiliary Feedwater (AFW) actuation signal was initiated on low steam generator water level. All AFW pumps started as required and were later secured.

The low loop flow signal occurred during the performance of surveillance test MST-I0056, Reactor Coolant Flow Instrument (F-0415) Calibration, on one of the three "A" reactor coolant loop flow transmitters. Manipulation of a transmitter isolation valve caused a pressure perturbation in the sensing lines of the two inservice transmitters, resulting in the generation of the low flow signal. MST-I0056 was recently revised because the RCS flow transmitters were changed to a new type during the previous refueling outage. As required for the new type of flow transmitter, steps to correct for instrument zero shift at pressure were added to the procedure. It appears the reactor trip occurred when the high side (common to all three flow transmitters) isolation valve was opened to perform this zero shift check. Procedures have since been revised to use the low side (non-common) isolation valve to perform this zero shift check.

The failure of the "A" reactor trip breaker to open on the automatic reactor trip signal was caused by a failed undervoltage output driver circuit board in the Solid State Protection System (SSPS). The failure of the undervoltage output driver card was initially determined to be a random failure. The undervoltage output driver card was replaced. "A" train SSPS was tested and the plant was restarted. During subsequent investigation it was determined that random failure was probably not the cause of the undervoltage output driver card failure and that it apparently failed during maintenance performed to correct a breaker closing problem on the "A" reactor trip breaker on May 18, 1991. The failure that prevented the "A" reactor trip breaker from opening was the same as described in IEN 85-13 and Westinghouse Technical Bulletin NSID-TB-85-16. This failure mechanism results in the output voltage from SSPS being maintained even if an automatic trip signal is present. This prevents both the automatic undervoltage and automatic shunt trips. Manual trips remained available during this time period.

CAUSE:

The reactor trip was caused by a perturbation in the sensing lines during isolation valve manipulation while performing MST-I0056, Reactor Coolant Flow Instrument (F-0415) Calibration. This perturbation was caused either by opening the isolation valve too quickly or because the high side (common reference leg) isolation valve was used. Engineer review determined that using the high side isolation valve should be acceptable but that using the low side isolation causes less perturbations and is acceptable for the zero shift check. The failure of "A" Reactor Trip Breaker

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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

CAUSE: (continued)

to open was a result of a failed undervoltage output driver card in the "A" Solid State Protection System. This failure apparently occurred during maintenance on the "A" reactor trip breaker closing circuitry on May 18, 1991. The post-maintenance testing performed after this maintenance verified the close circuit problem was corrected but failed to detect the problem in the SSPS undervoltage output driver card.

There has been one previous event, reported in LER 91-009, where manipulation of instrument valves resulted in an Engineered Safety Features actuation when a common reference leg was affected. In that event, Auxiliary Feedwater actuated on a low steam generator level signal. There have been no previous events that were similar to the "A" Reactor Trip Breaker failure.

SAFETY SIGNIFICANCE:

During this event all systems functioned properly except for the failure of the "A" Reactor Trip Breaker to open. The safety significance of the "A" Reactor Trip Breaker to open on an automatic signal is mitigated by the fact that the "B" Reactor Trip Breaker was always available for automatic actuation and that manual actuation of both Reactor Trip Breakers was always available. Additionally, emergency procedures require that the operator immediately verify all rods fully inserted on a reactor trip signal, if not the operator immediately inserts a manual reactor trip signal. This would have been performed if the "B" Reactor Trip Breaker had not opened automatically.

The reactor trip and AFW actuation are reported as an Engineered Safety Feature actuation per 10CFR50.73 (a)(2)(iv).

The failure of the "A" Reactor Trip Breaker to open is being reported as a Technical Specification violation per 10CFR50.73 (a)(2)(i)(B).

CORRECTIVE ACTIONS:

1. Revise the Reactor Coolant System flow calibration procedures to perform the zero shift check using the low side (non-common) pressure and include precautions to perform valve manipulation very slowly to prevent perturbations in the sensing lines.

2. Replaced the failed undervoltage output driver card with a new fused card as recommended by Westinghouse Technical Bulletin NSID-TB-85-16.

3. Placed non-fused undervoltage output driver cards on administrative hold and ordered additional fused undervoltage output driver cards.

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LICENSEE EVENT REPORT (LER)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS: (continued)

4. The SSPS Logic test will only be deleted as a post-maintenance testing requirement for reactor trip breaker work with the Manager - Operations approval.

5. Additional troubleshooting guidance is being developed and will be incorporated into appropriate procedures.

6. An umbilical cord will be manufactured to supply 125V DC for reactor trip breaker maintenance and troubleshooting. This umbilical cord will not connect to the 48V SSPS output. A temporary 48V power supply will be used to supply a simulated SSPS input signal for any future reactor trip breaker work.

7. Appropriate site personnel involved in maintenance and modification work onsite will be sensitized to this event and the requirement that post-maintenance/post-modification testing be extensive enough to ensure no additional problems are created by the maintenance or modification activities.

NRC Form 366A (6-89)

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Shearon Harris Nuclear Power Plant

DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
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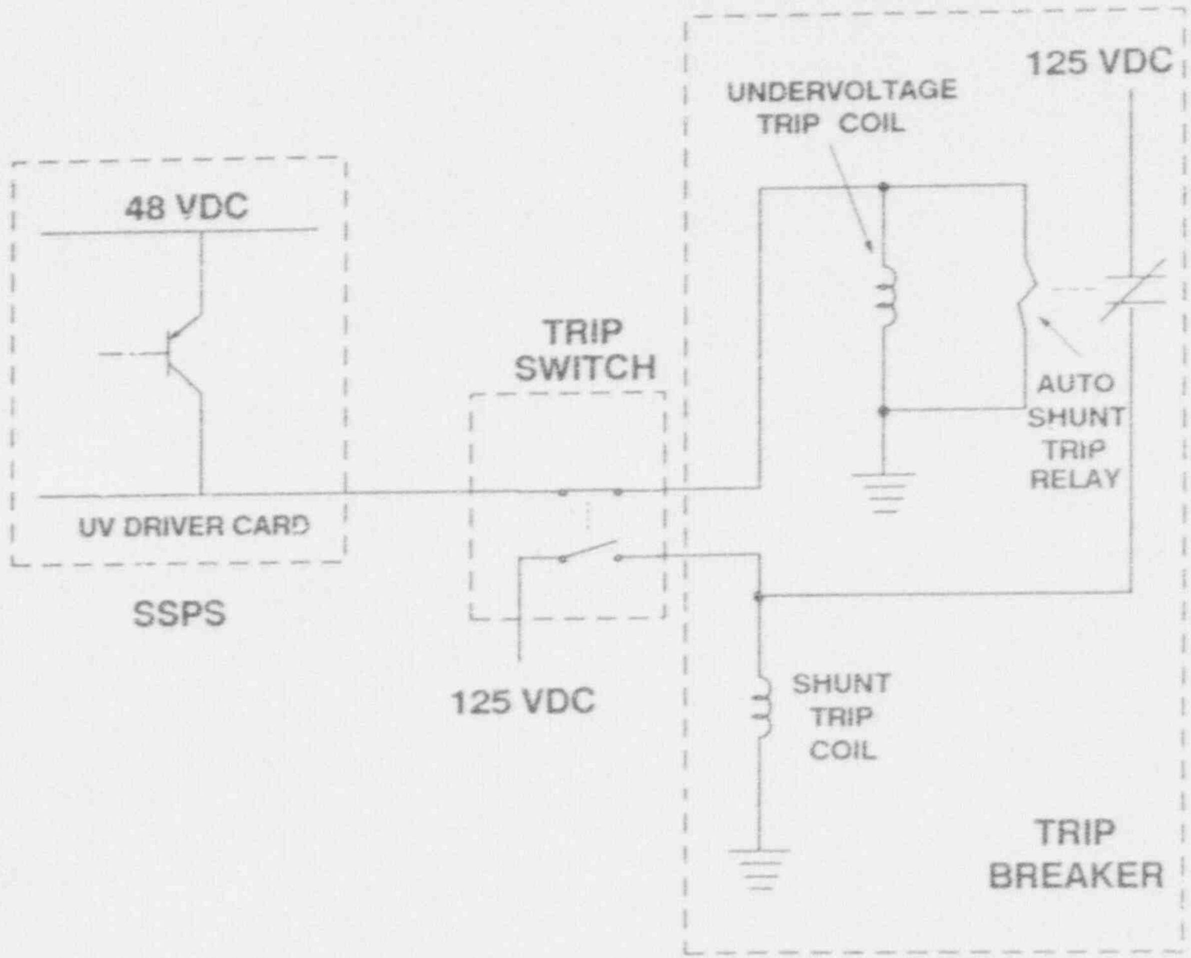
SIMPLIFIED CIRCUIT DIAGRAM



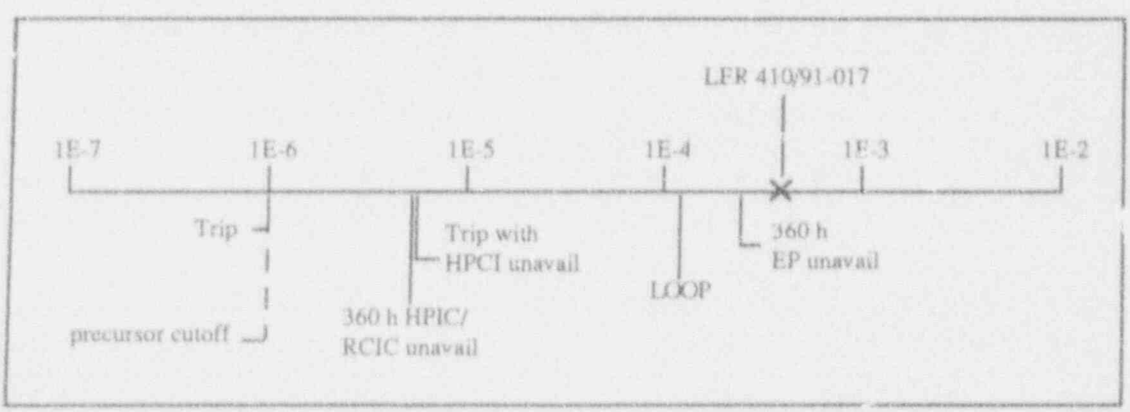
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

Event No.:	410/91-017
Event Description:	Loss of five nonsafety uninterruptible power supplies
Date of Event:	August 13, 1991
Plant:	Nine Mile Point 2

Summary

A main transformer fault occurred, resulting in turbogenerator trip and reactor scram. Following the transformer fault, five uninterruptible power supplies (UPS) deenergized, removing power from nonsafety-related instrumentation and equipment. Equipment affected included rod position indicators, control room annunciators, lighting, and communications systems. Two of three trains of the low-pressure coolant injection (LPCI) system were initially unavailable, having previously been removed from service for maintenance.

Plant operators started the reactor core isolation cooling (RCIC) system for reactor vessel level control. Since rod position could not be verified, the automatic depressurization system (ADS) was inhibited. Approximately one-half hour after the scram, power was restored to the UPS buses, and the plant proceeded to cold shutdown. The conditional probability of subsequent core damage associated with the event is estimated to be 3.8×10^{-4}. The relative significance of this event compared to other postulated events at Nine Mile Point 2 is shown below.



Event Description

Nine Mile Point 2 was operating at 100% power when one phase of the main transformer faulted. The main generator and turbine tripped, and the reactor scrammed. Simultaneously, power was lost from five uninterruptible power supplies (UPS 1A, 1B, 1C, 1D, and 1G). Power was lost from the UPS units as a result of the impact of the transformer fault on plant electrical systems combined with the unavailability of backup control power batteries in the five units.

As a result, the following was lost:

- all indications of reactor control rod position, resulting in the operators' inability to verify that the reactor would remain shut down;
- condensate and feedwater system controls, resulting in main feedwater pump trips and loss of normal feedwater to the reactor;
- virtually all control room annunciators (alarms), hampering the operators' ability to monitor post-scram operation of the plant;
- both the in-plant radios and the page telephone communications systems, limiting control room communications with in-plant personnel;
- control room indications of plant fire alarms, requiring local monitoring of fire alarm panels;
- almost all plant computers that perform monitoring, alarm, protection, and data recording functions, reducing the operators' ability to monitor plant status, disabling some minor automatic functions, and making reconstruction of the event difficult;
- multiple control systems, resulting in a loss of normal containment space cooling and requiring that operators divert some attention to monitoring containment temperature;
- many other parameter displays on the main control board, limiting the operators' ability to monitor plant conditions, particularly for balance-of-plant (BOP) equipment;
- the safety parameter display system, removing an aid to operators for analyzing plant conditions and reducing information that was available in Unit 2's technical support center; and
- some plant lighting that posed a personnel safety hazard but did not significantly affect plant personnel.

Specific loads powered by the failed UPS units are listed in Table 1.

Following a scram, operators normally refer to the rod position indicating system (RPIS) to verify that the control rods have all inserted properly. With the RPIS unavailable, the operators entered contingency procedure EOP-C5, "Level/Power Control," and blocked ADS, since rod position could not be verified. The operators suspected the unit had scrammed because:

- scram pilot lights were deenergized (indicating scram circuits deenergized, which allows scram valves to operate);
- scram discharge volume was full (indicating that control rods have inserted, displacing water from the CRD over-piston area to the scram discharge volume); and
- flux level was indicated on the source range monitor scale and was decreasing.

However, since the potential for recriticality existed during cooldown (since rod position was unknown), ADS was inhibited until power was restored to the UPS buses. After power restoration, multiple rods did not indicate full-in. The rod drive control system was reset, after which six rods still did not indicate full-in. The scram signal was subsequently reset by placing jumper wires in the reactor protection system, after which all rods indicated full-in.

Subsequent to the loss of load and reactor scram, two safety relief valves operated to relieve steam from the reactor to the suppression pool. In addition, turbine steam bypass valves opened to relieve to the main condenser.

The RCIC system was placed in service to provide vessel makeup. Its automatic control system experienced flow oscillations, and operators placed RCIC in manual control to ensure stable flow to the reactor. Residual heat removal (RHR) pump "A" was then placed in service in suppression pool cooling mode. Reactor pressure was rapidly reduced, and a condensate booster pump was aligned to supply condensate to the reactor.

Approximately one-half hour after the scram, the deenergized UPS buses were repowered. Specific procedures to restore power to the UPS buses did not exist and the procedure for UPS startup was unsuccessfully attempted. One operator recalled from startup testing performed with the UPS system engineer how to lift the motor operator from the UPS maintenance supply breaker and manually close the breaker. This action was successful in restoring power to the UPS buses.

About 2-1/2 h after the scram, RHR loops B and C, which had been unavailable at the time of the scram for preventive maintenance, were restored to op ability. Ten minutes later, the ADS inhibit switch was returned to normal.

RHR pump B was subsequently started in the shutdown cooling mode, and the reactor was placed in cold shutdown.

Additional Event-Related Information

The Nine Mile Point 2 Final Safety Analysis Report indicates that ten UPS power supplies are utilized at the plant. UPS power supplies 2VBB-UPS1A, 1B, 1C, 1D, and 1G are all 75-kVA, 1-series 120/208-V, 3-phase, nonsafety-related units. Loads supplied by these units are indicated in Table 1. Nonsafety-related supply 2VBB-UPS1H is a 5-kVA, single-phase, 120-V unit that supplies the gaseous effluent radiation monitor in the plant stack. Reactor protection system (RPS) supplies 2VBB-UPS3A and 3B are 10-kVA, 120-V, single-phase units. These units feed all RPS logic trip channel loads and MSIV control solenoids and are considered nonsafety-related as their loads "fail safe" (deenergize to operate).

Two UPS supplies are safety-related: 2VBA-UPS2A and 2B. These units are 25-kVA, 120-V, single-phase systems that supply emergency core cooling system (ECCS) instrumentation and control loads. These units are of a different design from the 1-series units that failed during the event.

A simplified one-line diagram of the 75-kVA 1-series UPS units is shown in Fig. 1. A 600-VAC 3-phase input power source from the in-plant electrical distribution system provides the normal AC input power to the UPS unit. When CB-1 is closed, 600-VAC 3-phase power is applied to the input of an AC-to-DC converter. This converter, consisting mainly of transformers, silicon-controlled rectifiers (SCRs), and filtering circuits, provides a regulated DC voltage source output.

This output is the normal power source input to the DC-to-AC inverter. If the 600-VAC source of power is unavailable, the DC power source is provided by a 5100-A/h battery. This source of power to the inverter is by way of CB-2 and a blocking diode. The diode prevents the converter from charging the storage battery. Similarly, if the output section of the converter is unavailable, circuit elements prevent discharging the storage battery.

The DC-to-AC inverter, consisting primarily of interconnecting transformers, SCRs, and filtering circuit elements, provides a high-quality AC output from an UPS unit and is provided to the critical loads by way of CB-3. The inverter regulates its output voltage to 1% of a nominal value.

An alternate source of UPS power output is a maintenance supply. This supply is provided by in-plant electrical distribution buses that are different from those for normal UPS AC input. The maintenance supply is applied to the UPS unit by way of a stepdown transformer and a regulator. The regulator is designed to maintain its output voltage within 2% of nominal for a range of input voltages. When CB-4 is closed and CB-3 is opened, the regulated maintenance supply is the power output for a UPS unit. CB-3 and -4 are motor-operated circuit breakers and receive automatic electrical signals from the UPS unit's control logic to appropriately open and close.

UPS control logic provides automatic electrical signals to the converter, inverter, circuit breakers, and static power transfer switch, which are necessary for proper operation of the UPS unit. For conditions that could result in improper UPS operation, the control logic provides automatic electrical signals to open CB-1, -2, and -3, thus isolating the converter and the inverter. The control logic also provides an electrical signal that permits CB-3, -4, and the static power transfer switch to be operated when the UPS power output source is automatically transferred from the inverter to the maintenance supply.

The control logic power supply provides the required power to the unit's control logic. Should this power supply degrade below prescribed values, the unit is designed to open CB-1, -2, and -3, thus isolating the UPS inverter. If the maintenance supply is available and within specification, electrical signals are provided to operate the static switch and close CB-4, thus providing power to critical loads from the maintenance supply.

Figure 2 shows a simplified diagram of the control logic power supply for a 1-series UPS unit. With switch S1 closed, the K5 relay is energized, and phase B of the maintenance power supply is applied to the inputs of the control logic power supplies. The solid-state power supplies and the parallel battery circuits form the power supply for the control logic required to operate the UPS 1-series unit.

When the electrical fault occurred in the main power transformer, in-plant B phase electrical distribution bus voltages were reduced by approximately 50% for about 200 ms. When the voltage reduction occurred, the comparator circuitry within the UPS units detected this out-of-tolerance condition for the maintenance supply and precluded transfers to these sources by locking out electrical signals that operate each UPS unit CB-4 and parallel static switch. At the same time, the B phase maintenance supply continued to provide the AC power input to the control logic power supply since the degraded voltage values applied to the K5 relays were above the drop-out voltages for these relays. Because of this degraded AC input voltage and the severely degraded batteries, the DC output voltage of the control logic power supply decreased to below the logic trip setpoints for the UPS units and isolated the normal power output sources for each of the five units. Isolation of these sources, along with a transfer lockout, resulted in the loss of power outputs from the five UPS units.

The simultaneous loss of power outputs from the five UPS units would not have occurred if the degraded voltage condition had not existed, or if the AC input power to the control logic power supplies was provided by the inverter power outputs, or if functional control logic power supply batteries had been installed in the units.

ASP Modeling Assumptions and Approach

The event has been modeled as a loss of feedwater with two trains of LPCI and one train of RHR unavailable. These unavailable trains were restored during the event. To reflect this and the long time period before RHR is required, a nonrecovery likelihood of 0.12 was assumed for RHR. Because of the requirement to inhibit ADS due to the lack of control rod position indication, this system was also assumed to be unavailable. A non-recovery probability for ADS of 0.12 was utilized, to reflect the possibility of recovery in the control room under burdened conditions.

Analysis Results

The conditional probability of subsequent core damage for the event is estimated to be 3.8×10^{-4}. The dominant sequence, highlighted on the following event tree, involves a loss of feedwater with unavailable long-term core cooling.

Additional information concerning this event is included in NUREG-1455, *Transformer Failure and Common-Mode Loss of Instrument Power at Nine Mile Point Unit 2 on August 13, 1991*, October 1991.

Table 1. Major loads on failed uninterruptible power supplies (UPSs)

UPS 1A

1. Control rod reed switches
2. Rod position indication system (RPIS)
3. Rod sequence control system (RSCS) — UPS 1B backup
4. Rod worth minimizer (RWM)
5. Digital memory module (DMM) — UPS 1 backup
6. Four rod display
7. Rod withdrawal inhibit
8. Gaseous effluent monitoring system (GEMS)
9. Vent GEMS
10. Liquid rad waste system (LWS) computer
11. LWS control
12. Safety parameter display system (SPDS)
13. Emergency response facility functions
14. Emergency operating facility computer link
15. Controllers to condensate booster, condensate and feedwater miniflow valves — UPS 1B backup
16. Fourth-point heater drain pump controls — UPS 1B backup
17. Partial control room annunciators — see note
18. Cooling water bypass gates (MOV 52s)
19. Partial paging system (Gaitronics)
20. Partial reactor recirculation control
21. Post-accident sampling system (PASS — A train)
22. Partial drywell cooling
23. Steam bypass control — motor generator backup
24. Turbine E/H and trip functions — motor generator backup
25. SRM recorder — UPS 1B backup
26. IRM/APRM, IRM/APRM/RBM recorder — UPS 1B backup
27. Recirculation flow recorder — UPS 1B backup
28. Safety-relief valve temperature recorder
29. Cooling water monitoring
30. Jet pumps monitoring
31. CRD monitoring
32. Turbine monitoring
33. Condenser monitoring

Table 1. Major loads on failed uninterruptible power supplies (cont.)

UPS 1B

1. Digital memory module (DMM) — UPS 1A backup
2. Rod sequence control system (RSCS) — UPS 1A backup
3. Rod withdrawal inhibit
4. Feedwater control system (FWCS)
5. Controllers to condensate booster, condensate and feedwater miniflow valves — UPS 1A backup
6. Partial reactor recirculation control
7. Fourth-point heater drain pump controls — UPS 1A backup
8. GE transient analysis recorder system (GETARS)
9. Partial control room annunciators — see note
10. Partial walkie talkies (leaky wire radio system)
11. Partial paging (Gaitronics)
12. Control room fire protection panel
13. Partial drywell cooling
14. Post-accident sampling station (PASS-B train)
15. SRM recorder — UPS 1A backup
16. IRM/APRM, IRM/APRM/RBM recorders — UPS 1A backup
17. Off gas radiation monitor
18. Recirculation flow recorder — UPS 1A backup
19. Radiation area monitoring
20. Radwaste radiation monitoring
21. Radon area monitoring
22. Turbine monitoring
23. Generator monitoring
24. RCS monitoring
25. RPV normal monitoring
26. RHR monitoring
27. RWCU monitoring

UPS 1C

1. Partial essential lighting
2. Partial egress lighting
3. Partial paging
4. Stack GEMS

Table 1. Major loads on failed uninterruptible power supplies (cont.)

UPS 1D

1. Partial essential lighting
2. Partial egress lighting
3. Partial paging
4. Dial telephone

UPS 1G

1. Plant process computer
2. Digital radiation monitoring computer (DRMS)
3. Meteorological monitor
4. Fire panel computer
5. 3-D Monicore computer

Note: This table does not include all the circuits associated with balance-of-plant instruments. Control room annunciator circuits powered by UPS 1A will switch to UPS 1B when UPS 1A fails. Control room annunciator circuits powered by UPS 1B will switch to UPS 1A when UPS 1B fails.

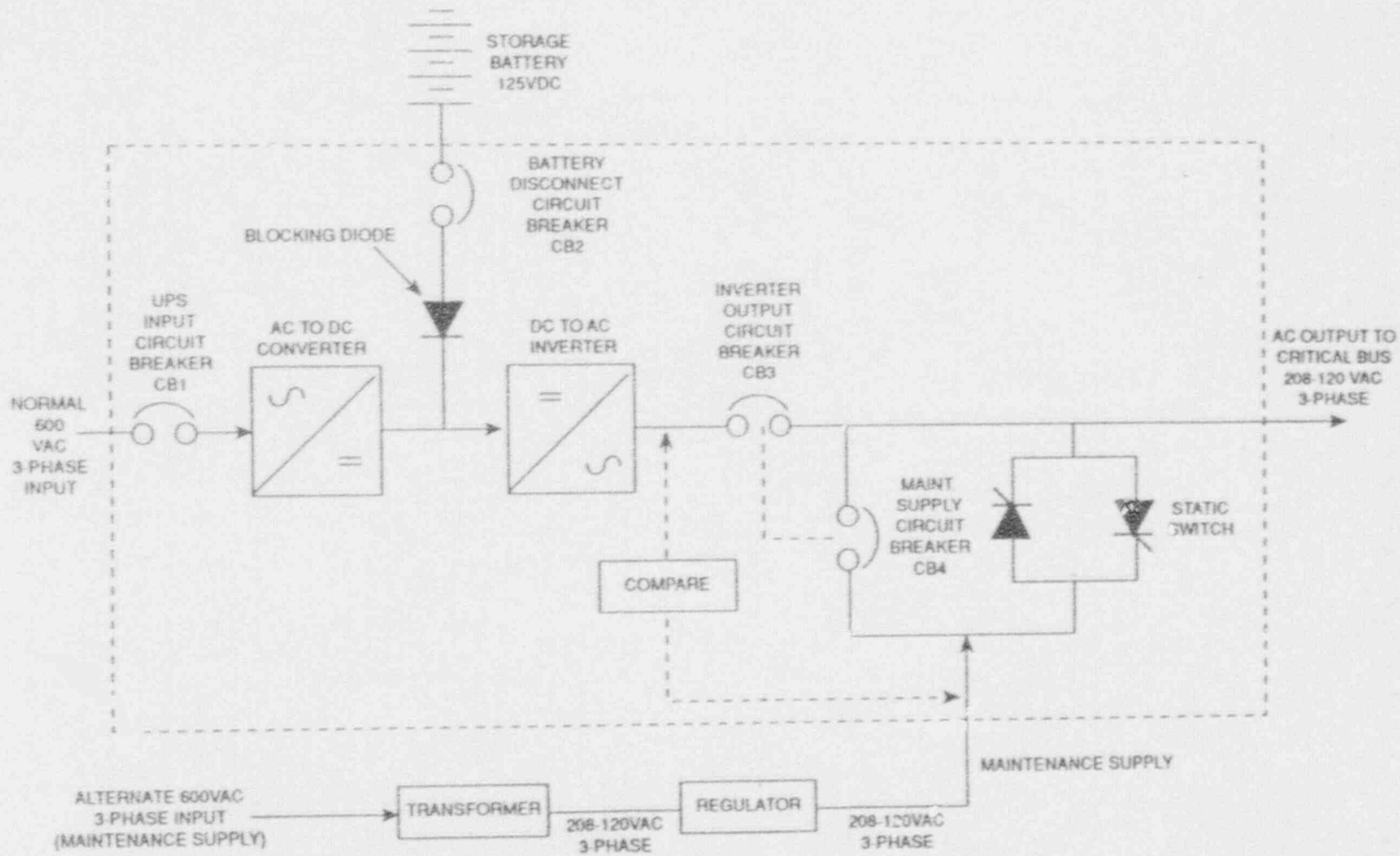


Fig. 1. Simplified electrical single line diagram for a 75-kVA 1-series UPS unit

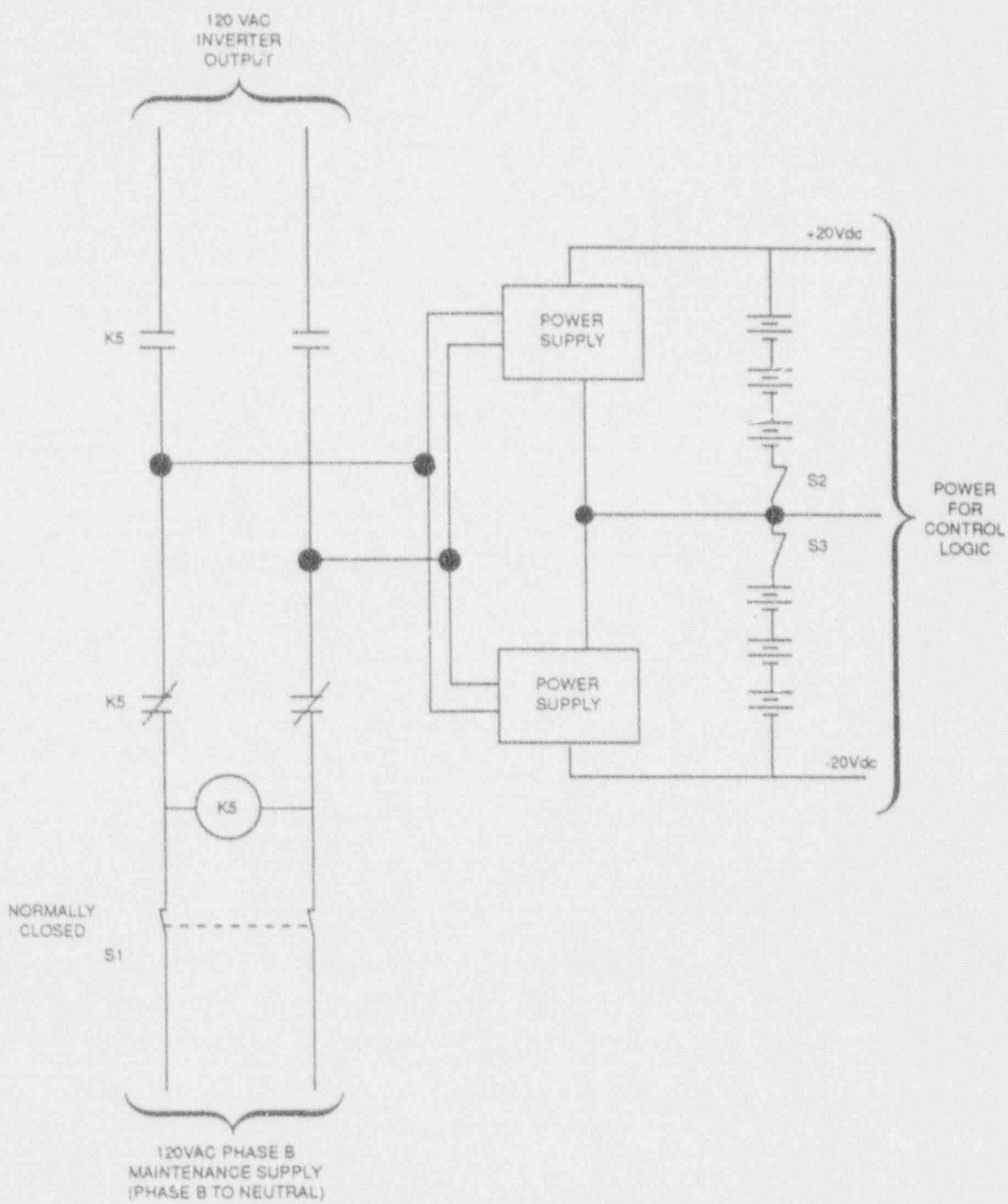
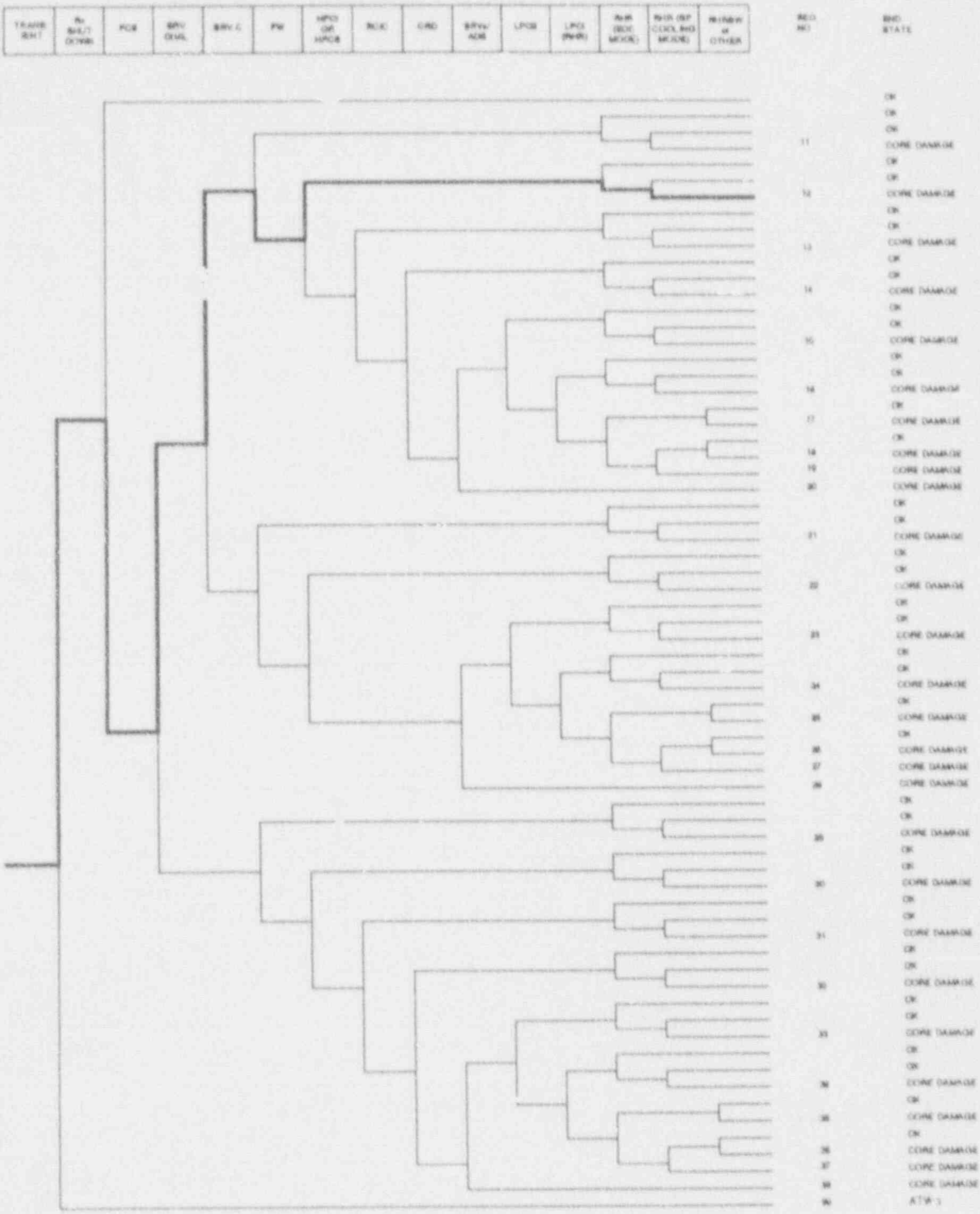


Fig. 2. Simplified diagram for UPS control logic power supply
(shown at time of ev it)



Dominant core damage sequence for LER 410/91-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 410/91-017
Event Description: Loss of five non-safety uninterruptible power supplies
Event Date: 08/13/91
Plant: Nine Mile Point 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.8E-04
Total	3.8E-04
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci RHR(SDC) RHR(SPCOOL)/RHR(SDC)	CD	3.1E-04	1.4E-02
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci SRV.ADS	CD	4.8E-05	4.1E-02
22	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS -hpci RHR(SDC) RHR(SPCOOL)/RHR(SDC)	CD	2.0E-05	1.4E-02
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec *
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci RHR(SDC) RHR(SPCOOL)/RHR(SDC)	CD	3.1E-04	1.4E-02
22	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS -hpci RHR(SDC) RHR(SPCOOL)/RHR(SDC)	CD	2.0E-05	1.4E-02
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci SRV.ADS	CD	4.8E-05	4.1E-02
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\ninemi2.sll
PROBABILITY FILE: c:\asp\1989\rwr_csll.pro

Event Identifier: 410/91-017

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.1E-03	1.0E+00	
loop	1.6E-05	2.4E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
srv.chall/trs s.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	5.9E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
ep.rec	2.1E-01	1.0E+00	
FW/PCS.TRANS	2.9E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-01 > Unavailable		
fw/pcs.loca	4.0E-02	3.4E-01	
hpci	2.0E-02	3.4E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
SRV.ADS	3.7E-03 > 1.0E+00 **	7.1E-01 > 1.2E-01	1.0E-02 > 0.0E+00
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	3.7E-03		
lpcs	2.0E-02	3.4E-01	
LPCI(RHR)/LPCS	6.0E-04 > 2.0E-02	7.1E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
RHR(SDC)	2.3E-02 > 4.9E-02	3.4E-01 > 1.2E-01	1.0E-03
Branch Model: 1.OF.2+ser+opr			
Train 1 Cond Prob:	3.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailabl.		
Serial Component Prob:	2.0E-02		
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
RHR(SDC)/LPCI	1.0E+00 > 5.0E-01	1.0E+00 > 1.2E-01	1.0E-03
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E+00 > 5.0E-01		
RHR(SPCOOL)/RHR(SDC)	2.0E-03 > 4.0E-01	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-03 > 4.0E-01		
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-03 > 1.0E-02	3.4E-01 > 1..E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-03 > 1.0E-02		
RHR(SPCOOL)/LPCI.RHR(SDC)	9.3E-02 > 5.0E-01	1.0E+00 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	9.3E-02 > 5.0E-01		
rhrsw	2 0E-02	3.4E-01	..0E-03

* branch model file
** forced

Minarick
05-30-1992

Event Identifier: 410/91-017

NRC Form 366

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	1 OF 5

TITLE (4) Transformer Fault Causes Reactor Scram and Uninterruptible Power Supply Failure Causes Loss of Annunciation Which Led to Declaration of a Site Area Emergency

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 8	1 3	9 1	9 1	0 1 7	0 0	0 9	1 2	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

X 50.73(a)(2)(i)

X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
E. S. Tomlinson, Supervisor Reactor Engineering, NMP2	315 349-7340

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	E L	X F M R	M 1 7 5	N	B	E E	U J X	E 3 5 3	Y

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) NO

EXPECTED SUBMISSION DATE (15): Month 0 8 Day 1 3 Year 9 2

ABSTRACT (16)

At 0548 hours on August 13, 1991, Nine Mile Point Unit 2 (NMP2) experienced a turbine trip and reactor scram when the "B" Phase Main Transformer developed an internal fault. The transformer fault c ated an electrical disturbance throughout the normal electrical distribution system, resulting in the loss of five non-safety related Uninterruptible Power Supplies (UPS). As a result, the Control Room lost annunciation and most Balance of Plant (BOP) instrumentation. The conditions described in this report mandated entry into a Site Area Emergency as specified by the Site Emergency Plan. Prior to the event, NMP2 was in operational condition 1 (RUN) at 100% rated thermal power.

The root cause of the transformer ult is still under investigation.

Control Room operators verified the reactor scram, identified and re-energized the failed UPS's, identified the cause of the reactor scram, and cooled down the reactor to terminate the emergency event. Other corrective actions included: 1) replacing the "B" phase transformer with the installed spare; 2) modifying the UPS's; 3) replacement of back-up batteries in the UPS's; 4) developing a back-up battery replacement schedule; and 5) revision of the Reactor Water Cleanup Operating Procedure.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	0 1 7	0 0	0 2 OF 2 5

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

I. DESCRIPTION OF EVENT

At 0548 hours on August 13, 1991, Nine Mile Point Unit 2 (NMP2) experienced a turbine trip and reactor scram when the "B" Phase Main Transformer developed an internal fault. The transformer fault also created an electrical disturbance throughout the normal electrical distribution system. This electrical disturbance resulted in the loss of five non-safety related Uninterruptible Power Supplies (UPS). As a result, the Control Room lost most Balance of Plant (BOP) instrumentation and all annunciation which created several conflicting indications of reactor status. The conditions described in this report mandated entry into a Site Area Emergency as specified by the Emergency Plan.

Prior to the event, NMP2 was in operational condition 1 (RUN) at 100 percent rated thermal power. The following Feedwater System (FWS) and Condensate System (CNM) pumps were running at the time of the event: Feedwater pumps 2FWS-P1B and P1C; Condensate Booster pumps 2CNM-P2A and P2B; and Condensate Pumps 2CNM-P1A, P1B, and P1C. Residual Heat Removal System (RHR) Loops "B" and "C" (also serve as Low Pressure Coolant Injection) were removed from service for scheduled maintenance on various valves and instruments. Several Technical Specification (T.S.) Limiting Conditions for Operation (LCO's) were entered for various liquid process effluent monitors. Aside from the LCO's and the RHR outage, plant operating conditions were normal.

The following sequence of events is a reconstruction of the events which occurred. Due to the loss of UPS power, the normal means of recording events of this nature were initially unavailable (process computer, recorders, and alarm typer). Control Room meters and recorders, powered from the affected UPSs, were inoperable during the first thirty four minutes of the event. The plant process computer was unavailable an additional forty nine minutes. This sequence of events is based on operator interviews and written statements, operator logs, Post Accident Monitoring (PAM) recorded plots and operating crew debriefs.

After evaluation of plant conditions following the transient, the Station Shift Supervisor (SSS) ordered the reactor mode switch be placed in the SHUTDOWN position and commenced responding to plant conditions. The Control Room operators recognized that the two operating Reactor Feedwater pumps had tripped and manually initiated the Reactor Core Isolation Cooling System (ICS) to control decreasing reactor water level. Reactor systems responded to the turbine trip as expected. At 1050 pounds per square inch gauge (psig) reactor pressure, the PAM recorders shifted to fast speed and continued to provide reactor pressure and water level indication throughout the event, and an Alternate Rod Insertion (ARI) was initiated. Two Main Steam System (MSS) Safety Relief Valves (SRVs) lifted to limit reactor pressure to 1070 psig. The Emergency Operating Procedures were entered when entry conditions were met for decreasing reactor water level.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7	— 0 0	0 3 OF 2 5

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

I. DESCRIPTION OF EVENT (cont.)

0548 hours

- The main turbine tripped as a result of an internal fault in the "B" Phase Main Transformer.
- Turbine Stop Valve (TSV) closure and Turbine Control Valve (TCV) fast closure signals resulted in a reactor scram and Reactor Recirculation pump downshift to slow speed due to the End-Of-Cycle Recirculation Pump Trip (EOC-RPT) signal.
- Turbine Bypass Valves opened to control reactor pressure.
- Normal station power fast transferred to reserve power.
- Uninterruptible Power Supplies (2VBB-UPS 1A-1D, 1G) failed to provide power to their respective loads resulting in:
    - Loss of the plant Radio Communication System (Radiax).
    - Loss of Control Room annunciators.
    - Cooling Tower bypass valves opened on loss of power to temperature monitoring instrumentation (valve motive power is from station reserve power).
    - Loss of Plant Process Computer (PCS), Safety Parameter Display System (SPDS), Emergency Response Facility (ERF) computer, General Electric Transient Analysis Recording System (GETARS), Gaseous Effluent Monitoring System (GEMS) computer, 3D-Monicore computer, and the Digital Radiation Monitoring System (DRMS) computer.
    - Loss of plant GAitronics communication and paging system.
    - Partial loss of the plant telephone system.
    - Loss of Balance of Plant (BOP) instrumentation.
    - Loss of Essential Lighting (normal system lighting remained operational).
    - Non-safety related Control Room recorders failed as is.

NRC FORM 366A (6-89)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7	— 0 0	0 4 OF 2 5

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

I. DESCRIPTION OF EVENT (cont.)

- Reactor Feedwater level control valves locked up in the open position.
- Loss of Drywell cooling (unit cooler fans only).
- Loss of Control Rod Position Indication.
- Condensate Booster Pump and Reactor Feedwater pump minimum flow valves failed open.

- At 1037 psig a reactor scram signal was generated by the Reactor Protection System (RPS) logic on high reactor vessel pressure.
- At 1050 psig an ARI signal was initiated, and the PAM recorders switched to fast speed.
- At 1070 psig, two MSS, SRV's, 2MSS*PSV128 and 2MSS*PSV133, lifted for approximately 30 seconds.
- Condensate Booster Pump 2CNM-P2A tripped on low suction pressure and pump 2CNM-P2C automatically started.
- The two operating Reactor Feedwater pumps tripped on low suction pressure.
- The Division II Primary Containment Hydrogen/Oxygen sample pump tripped spuriously.

The Control Room operators made the following observations indicating that an automatic reactor scram had occurred:

- Scram pilot lights were extinguished.
- Average Power Range Monitor (APRM) Meters on Control Room auxiliary panels were operable and indicating downscale (with front panel recorders failed at 100%).

0549 hours

- Reactor mode switch was placed in the "SHUTDOWN" position on orders from the SSS. This was a conservative action which would have generated a reactor scram if an automatic reactor scram had not yet occurred.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	0 1 7	0 0	0 5 OF 2 5

I. DESCRIPTION OF EVENT (cont.)

- Scram Discharge Volumes were indicating full on Control Room auxiliary panels.

0555 hours

- In order to maintain reactor water level without Reactor Feedwater pumps operating, ICS was manually initiated. The ICS turbine experienced flow, speed, and pressure oscillations while in automatic and was transferred to manual control. Subsequently the ICS turbine performance parameters stabilized.
- Reactor Recirculation flow control valves experienced an automatic runback at reactor water Level 4 (178.3 inches) as designed.

0556 hours

- At reactor water Level 3 (159.3 inches), a scram signal was generated by RPS on low vessel water level. Additionally, the RHR sample and discharge to radwaste containment isolation valves (Group 4) isolated.
- Emergency Operating Procedure N2-EOP-RPV, "RPV Control" was entered due to lowering reactor water level (159.3 inches and decreasing). Additionally, Control Room operators entered Emergency Operating Procedure N2-EOP-C5, "Level/Power Control" due to the lack of control rod position indication. Per N2-EOP-C5, the Automatic Depressurization System (ADS) was manually inhibited to prevent automatic initiation.
- RHR train A was placed in suppression pool cooling to support ICS operation.

0600 hours

- Due to loss of Control Room annunciation with a plant transient in progress, the SSS assumed the role of Site Emergency Director (SED) and declared a Site Area Emergency in accordance with Site Emergency Action Procedure S-EAP-2, "Classification of Emergency Conditions".
- Operators were dispatched to investigate UPS operation.

0608 hours

- State and local authorities were notified of the Emergency declaration.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	0 1 7	0 0	0 6 OF 2 5

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

II. DESCRIPTION OF EVENT (cont.)

0612 hours

- Nuclear Regulatory Commission was notified via the Emergency Notification System.

0614 hours

- ICS injection to the reactor was secured and the system realigned to full flow test (condensate storage tank to condensate storage tank). This line up leaves the ICS pump readily available for injection.

0615 hours

- Reactor vessel water level reached Level 8 (202.3 inches).
- The Condensate Booster pumps were secured to limit the reactor vessel cooldown rate and to control reactor water level.
- Plant operators reported that 2VBB-UPS1A through 1D and 1G had tripped.

0620 hours

- Condensate pumps 2CNM-P1B and P1C were secured (2CNM-P1A remained in service). Reactor vessel water level began to decrease and reactor pressure stabilized.

0622 hours

- The SSS directed restoration of 2VBB-UPS1A through 1D and 1G by manually transferring to the maintenance bus power source. As a result, Control Room annunciators and other indications were restored.
- A Group 9 Primary Containment isolation occurred (Primary Containment Purge and Vent System [CPS] valves). The isolation occurred when power was restored to the isolation logic before the Standby Gas Treatment (GTS) radiation monitor power was restored.

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I. DESCRIPTION OF EVENT (cont.)

0630 hours

- The full core display, when restored, indicated that all rods were fully inserted except six which had no indication. Operators also observed that one rod had no indication on the Rod Worth Minimizer (RWM) and that 15 rods were without indication on the Rod Sequence Control System (RSCS).

- Drywell unit cooler fans were restored. The highest individual Drywell temperature recorded was 165 degrees Fahrenheit. The highest average Drywell temperature remained below 150 degrees Fahrenheit.

0640 hours

- Condensate Booster Pump 2CNM-P2A was started to maintain reactor water level within a band of 165 inches to 180 inches. Control Room operators attempted to open the Reactor Feedwater pump suction valves 2CNM-MOV84A and B without equalizing the pressure across the valve (at SSS direction due to unknown radiological conditions in the Turbine Building). The valves would not open precluding flow to the reactor. As a result, reactor water level decreased to Level 3 (159.3 inches) and operators re-entered Emergency Operating Procedure N2-EOP-RPV. Operators subsequently used the Reactor Feedwater pump bypass valve 2CNM-LV137 to control reactor vessel water level.

0650 hours

- Jumpers were installed to bypass the RPS interlocks per Emergency Operating Procedure N2-EOP-6, "NMP2 EOP Support Procedure", attachment 14, to reset the reactor scram with a scram signal still present. This action was performed to permit, draining the scram discharge volume and performing additional scrams to insert control rods had it been required.

0653 hours

- The scram was reset per Emergency Operating Procedure N2-EOP-RPV section RQ, "Power Control".

- All rods indicated full in. The SSS directed exit from Emergency Operating Procedure N2-EOP-C5. Reactor pressure was controlled using the turbine bypass valves.

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I. DESCRIPTION OF EVENT (cont.)

0700 hours

- Commenced manual monitoring of various plant effluents due to the loss of DRMS and GEMS computers.

0711 hours

- Plant process computer was restored.
- Restarted the Division II Primary Containment Hydrogen/Oxygen sample pump.

0729 hours

- Started mechanical air removal pumps to maintain condenser vacuum (reactor pressure was being controlled using the turbine bypass valves).

0738 hours

- Condensate pump 2CNM-P1B was started due to a high stator temperature on the operating Condensate pump 2CNM-P1A.

0740 hours

- ICS was secured to reduce the cooldown rate.

0750 hours

- The Safety Parameter Display System was restored.

0805 hours

- A stack GEMS computer reboot was initiated to re-establish Control Room indication.

0806 hours

- Reactor Recirculation System flow control valves were fully opened.

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I. DESCRIPTION OF EVENT (cont.)

0810 hours

- RHR loops B and C were returned to operable status.

0821 hours

- The ADS inhibit was removed, returning the system to automatic, and the jumpers were removed, restoring RPS interlocks.

0834 hours

- Verified that no adverse radiological conditions existed on site.

0847 hours

- The Stack GEMS computer was declared operable.

0857 hours

- Initial reports from Offsite Radiological Assessment Teams indicated readings were normal at background levels.

0937 hours

- ICS outboard containment isolation check valve 2ICS*AOV156 did not indicate fully closed. Operators de-energized the motor operated injection shutoff valve 2ICS*MOV126 shut per Technical Specifications and declared ICS inoperable. (ICS was not required at this time for reactor water level control).

0950 hours

- 2VBB-UPS 1C & 1D were restored to their normal power sources. 2VBB-UPS 1A & 1B could not be transferred to their normal power supply; therefore, they were left on their maintenance supply.

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I. DESCRIPTION OF EVENT (cont.)

1000 hours

- The Control Room operators determined that two SRVs had lifted at the beginning of the event (0548 hours). Operations Surveillance Procedure N2-OSP-ISC-M@002, "Drywell Vacuum Breaker Operability Test", which is a test required by Technical Specifications following a lift of SRV's, was initiated by 1006 hours.

1020 hours

- 2VBB-UPS 1G was restored to its normal power supply.

1031 hours

- The Group 9 isolation was reset.

1055 hours

- Reactor Water Cleanup System (WCS) pump 2WCS-P1B was started and the system lined up to purify and reject reactor water to the condenser hotwell. This action was performed to maintain reactor water chemistry and reduce reactor water level.

1056 hours

- WCS isolated (Group 6 and 7 isolation) due to a high Delta Flow signal, tripping pump 2WCS-P1B.

1151 hours

- Operations Surveillance Procedure N2-OSP-ISC-M@002, "Drywell Vacuum Breaker Operability Test", was completed.

1158 hours

- RHR loop "A" was secured from the suppression pool cooling mode and pump 2RHS*P1A was secured.

1217 hours

- Group 4 isolation, RHR sample and discharge to radwaste isolation valves, was reset.

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I. DESCRIPTION OF EVENT (cont.)

- Group 5 isolation, shutdown cooling isolation valves, was reset to establish shutdown cooling lineup (this isolation signal is present when reactor pressure is above 128 psig).
- Group 6 and 7 isolations, WCS inboard and outboard isolation valves, were reset.

1415 hours

- Condensate demineralizer bypass valve 2CNM-AOV1C9 was closed to minimize reactor water chemistry concerns.

1458 hours

- Reactor Recirculation pump 2RCS*P1B was secured to prepare for initiating shutdown cooling.

1506 hours

- Residual Heat Removal pump 2RHS*P1B was started in the shutdown cooling mode.

15'9 hours

- Condensate Booster pump 2CNM-P2A was secured per the normal shutdown Operating Procedure, N2-OP-101C, "Plant Shutdown".

1520 hours

- Condensate pump 2CNM-P1A was secured.

1846 hours

- Reactor water temperature dropped below 200 degrees Fahrenheit. Cold Shutdown condition (Mode 4) was established.

1943 hours

- SED terminates the Site Area Emergency.

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II. CAUSE OF EVENT

Transformer Fault

The initiating event discussed in this LER is the failure of the "B" Phase Main Generator Step-up Transformer (2MTX-XM1B) which developed an internal fault. The "B" Phase transformer differential and the overall unit differential relays activated to isolate the fault by disconnecting the main generator from the 345 KV line. This resulted in a turbine trip causing a reactor scram from Turbine Control Valve fast closure/Turbine Stop Valve closure.

Presently, an actual root cause of the transformer failure cannot be suggested and when established, will be submitted in a supplement to this report.

UPS Failure

Subsequent to the internal fault which occurred on the main step up transformer, five Exide UPS's (2VBB-UPS1A, 1B, 1C, 1D, and 1G) tripped resulting in loss of power to their respective loads. A root cause evaluation has been completed in accordance with Nuclear Division Procedure NDP-16.01, "Root Cause Evaluation".

Extensive analysis and testing has concluded that all five Exide UPS units shutdown as a result of a logic initiated trip. The failure of the "B" Phase Main Transformer caused a voltage dip on the maintenance power supply to all five UPS units. The degraded voltage on the maintenance power supply caused the voltage on the UPS logic power supply to decrease below its trip setpoint, causing the units to trip. Concurrently, the automatic load transfer to the maintenance supply was prevented by design due to the degraded voltage conditions on the maintenance power supply.

The root cause for the simultaneous tripping of the five UPS units is improper design. The UPS is not designed to accommodate a degraded voltage condition of the maintenance power supply. The following design factors allowed the UPS logic power supply voltage to decrease below its trip setpoint as a result of the "B" Phase Main Step-up Transformer fault.

- The logic power supply is normally energized from the maintenance power supply with the inverter output as a backup versus inverter preferred.
- Under degraded voltage conditions, the logic power supply switching circuit does not actuate until the supply voltage has decreased to well below the level that will cause the logic to trip.

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II. CAUSE OF EVENT (cont.)

Although degraded batteries (internal to the UPS units) were discovered during the course of this evaluation, it was concluded that this condition was not the cause of the simultaneous tripping of the five UPS units. However, fully charged batteries may have prevented the tripping of the units even though that is not part of their design basis.

Reactor Scram

A reactor scram occurred as a result of a main turbine trip (Turbine Control Valve fast closure/Turbine Stop Valve closure) initiated from the "B" Phase Main Generator Step-up Transformer fault. This is an expected function through the generator protective relay scheme. A turbine trip and subsequent reactor scram is an expected response and consistent with station design when reactor power is above 30 percent of rated.

Group 4 Containment Isolation

Subsequent to the reactor scram, the Residual Heat Removal System sample and discharge to Radwaste valves isolated when reactor water level reached Level 3 (159.3 inches).

The Group 4 isolation is an expected response to reactor water level dropping below 159.3 inches. Decreasing water level is a normal function of a reactor scram from full power (reactor vessel water level shrinks due to a rapid reduction in reactor steam flow), coupled with a loss of Reactor Feedwater flow. All systems functioned as required.

Group 6-7 Isolation

The root cause investigation into the WCS high differential flow isolation was performed utilizing Nuclear Division Procedure NDP-16.01, "Root Cause Evaluation". The root cause has been determined to be procedural inadequacy. Specifically, Operating Procedure N2-OP-37, Rev. 3, "Reactor Water Cleanup System", Section E.4.0 had instructional steps in the wrong sequence. In this section the WCS is started from no pumps in operation to one pump running, one filter/demineralizer in service, with all system flow directed to either the Liquid Radwaste System or to the main condenser. This section also delineates steps to be performed if venting of this system is required.

After reviewing N2-OP-37 and ascertaining the pump casing temperature was within 100 degrees Fahrenheit of reactor water temperature, the Control Room operator determined the appropriate procedural step to use. He then instructed a plant operator to shut the WCS pump discharge valve to aid in the system venting evolution. This action isolated the piping

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II. CAUSE OF EVENT (cont.)

downstream of the pump from reactor pressure. The Control Room operator then aligned this piping to the main condenser, which was at a vacuum. The Control Room operator started the WCS pump and opened the reject flow control valve 2WCS-FV135, exposing the pump discharge piping to condenser vacuum. This caused the hot water in the pump discharge piping to flash to steam, resulting in the reject flow transmitter sensing line flashing and a very low (zero) reject flow signal. When the plant operator began to open the pump discharge valve and WCS inlet flow rose to over 150 gallons per minute, the high differential flow timers initiated (inlet flow signal > 150 gallons per minute and reject flow signal at 0 gallons per minute). The Control Room operator attempted to reduce system flow but the 45 second timer elapsed and the high differential flow isolation occurred. If the procedure had left 2WCS-FV135 shut until the system venting was complete, the isolation would not have occurred.

Group 9 Isolation

When the UPS failure occurred, GTS Effluent Monitor 2GTS-RE105 defaulted to a de-energized state; however, the trip relay was also de-energized, preventing the isolation signal. When power was restored, the GTS high radiation level trip logic sensed the tripped condition of 2GTS-RE105 and initiated a Group 9 containment isolation. This condition occurred consistent with station design where a tripped condition at 2GTS-RE105 conservatively results in a containment isolation. The root cause of the isolation has been determined to be the loss of UPS1A and UPS1B.

Technical Specification Concerns

The root cause evaluation for missed Technical Specification surveillance 4.6.4.b.1, requiring the drywell vacuum breakers be cycled within 2 hours of any SRV discharging steam to the suppression pool is continuing. Also, the root cause evaluation for the deviation from Technical Specifications section 3.3.1 ACTION statement b. and Table 3.3.1-1 ACTION Statement 2 is continuing. These ACTION statements required that the reactor mode switch be locked in the "SHUTDOWN" position and one logic channel of RPS be placed in the tripped condition within one hour of removing both logic channels of RPS from service with the RPS jumpers. The results of these evaluations will be reported in a supplement to this report.

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III. ANALYSIS OF EVENT

The following conditions are reportable in accordance with 10CFR50.73 (a)(2)(iv), "Any event or condition that resulted in manual or automatic activation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS)":

- Automatic reactor scram.
- Group 6 and 7 (WCS) Primary Containment isolation.
- Group 9 (Primary Containment vent and purge) Primary Containment isolation.
- Group 4 (RHR sample and radwaste discharge) Primary Containment isolation.

The remaining conditions are reportable in accordance with 10CFR50.73 (a)(2)(i)(B), "Any operation or condition prohibited by the plant's Technical Specifications":

- Missed Technical Specification surveillance - 4.6.4 b.1.
- Deviation from Technical Specifications section 3.3.1 ACTION statement b and Table 3.3.1-1 ACTION statement 2, during implementation of the Emergency Operating Procedures.

ESF Actuations

The reactor scram occurred as designed. When the turbine tripped on generator protective relaying, an automatic reactor scram occurred to counter the positive reactivity added by the pressure excursion. Therefore, the automatic reactor scram occurred in accordance with the system design described in the Updated Safety Analysis Report (USAR).

A Reactor Water Cleanup isolation occurred at 1056 hours. The WCS isolation (Groups 6 and 7) is an ESF function of the Primary Containment and Reactor Vessel Isolation Control System. Even though the WCS is classified as a primary power generation system, the inboard and outboard isolation valves are included in the Primary Containment Isolation System, which is designed to protect against a radioactive release to the environment during accidents involving reactor coolant pressure boundary breaches. The differential flow measurement method (flow into the WCS compared to flow out of the WCS) is used to detect system leakage and provide a system isolation signal. The WCS isolation was a conservative action and did not impair the station's ability to achieve a safe shutdown condition, nor was there any impact to plant personnel or public safety stemming from the isolation.

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III. ANALYSIS OF EVENT (cont.)

A Group 9 Primary Containment isolation signal occurred at 0622 hours when power was restored to the UPS System. No actual valve movement occurred due to the purge and vent valves already being shut. Even though no high radiation level trip would have occurred, two other trip signals (low reactor water level and high drywell pressure) remained operable on loss of UPS power. When UPS power was initially lost, power was interrupted at 2GTS-RE105 which resulted in the radiation element defaulting to a de-energized state. Power was subsequently restored to the trip logic prior to restoring power to the radiation element, and the Group 9 trip logic initiated upon sensing 2GTS-RE105 in a de-energized state. A Group 9 isolation is a conservative action and had no impact on the course of the event.

The RHR sample and radwaste discharge valves (Group 4) isolation signal was generated when reactor vessel water level dropped below Level 3 (159.3 inches) at 0556 hours. The lowering reactor vessel water level could indicate a breach in the Reactor Coolant Pressure Boundary, therefore, these valves receive a shut signal attempting to isolate the leak, conserve reactor coolant, and limit the escape of radioactive materials from the Primary Containment. In this event, the low water level occurred due to level shrink on a scram from high reactor power with a loss of Feedwater, therefore the Group 4 isolation was a conservative action.

Technical Specification Issues

As a function of the turbine trip and reactor scram at 0548 hours, two reactor vessel safety relief valves, 2MSS*PSV128 and 2MSS*PSV133, lifted discharging steam into the suppression pool. NMP2 Technical Specification section 3.6.4 requires that drywell vacuum breakers be cycled within two hours. It was not discovered that safety relief valves had lifted until 1000 hours during a strip chart review. The drywell vacuum breaker surveillance was implemented immediately upon discovery (initiated at 1006 hours, complete 1151 hours). The drywell vacuum breakers limit the upward forces on the drywell floor created by a higher pressure in the suppression chamber than in the drywell. When a safety relief valve lifts, discharging steam to the suppression pool, energy is added to the suppression chamber. The drywell vacuum breakers are required to be demonstrated operable in preparation for an extended safety relief valve lift or pressure control using safety relief valves for an extended period. In these cases the drywell vacuum breakers may be required to open. In this event, the lifting of two safety relief valves for 30 seconds had a negligible effect on the drywell/suppression chamber differential pressure. The time between the lifting of the safety relief valves and satisfactory performance of the drywell vacuum breaker operability test did not affect the ability of the drywell, suppression chamber, or vacuum breakers to perform their safety function. This condition had no effect on the safe shutdown of the plant or the health and safety of the public or plant workers.

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III. ANALYSIS OF EVENT (cont.)

During implementation of Emergency Operating Procedures, RPS jumpers were installed bypassing all but manual scram functions. Neither RPS trip system was placed in the trip condition nor was the reactor mode switch locked in "SHUTDOWN" as required by Technical Specification sections 3.3.1. ACTION statement b. and Table 3.3.1-1 ACTION statement 2. Using N2-EOP-6 attachment 14, operators had defeated all RPS interlocks except for the manual scram function for a period of approximately one and one half hours. This action was required in order to permit resetting the scram signal, allowing the scram discharge volume to drain, and subsequently allowing additional scrams to effect control rod insertion had it been required.

This action is directed by NMP2 EOP's and is consistent with the Boiling Water Reactor Owners' Group Emergency Program Guidelines, BWROG-EPG Revision 4 and is specifically recognized in the NRC Safety Evaluation for BWROG-EPG Revision 4, and in NMP2 plant specific Safety Evaluation (SER 90-145 attachment 4, event 15.8).

Overview

Based on evaluation of this transient against the Updated Safety Analysis Report (USAR) transient analysis, the following conclusions were made:

- Reactor pressure rise as shown on both PAM recorders is much less severe than the pressure rise shown on Figure 15.2.1 of the USAR (Generator Load Rejection with bypass) 1070 psig vs. 1150 psig.

- Reactor water level as shown on both PAM recorders is slightly lower than the USAR, however, this discrepancy was due to all feedwater pumps tripping during the transient.

- Neutron flux was not recorded; however, the assumptions made in the USAR which influence the neutron flux spike such as pressure rise, scram speed and void fraction are all more severe than actual conditions. In addition, Instrument Surveillance Procedure N2-ISP-NMS-W@007, "APRM Functional Test", was performed on August 14, 1991, verifying proper operation of APRM flux scrams.

- Based on personnel interviews and review of as-found conditions, it can be concluded that all systems which are designed to mitigate the severity of this type of event (i.e., EOC-RPT, Turbine Bypass Valves, SRVs, and ARI) functioned as required.

NRC Form 366A

III. ANALYSIS OF EVENT (cont.)

Based on the above items, it can be concluded that the results of this transient were within the bounds of the current transient analysis and at no time was the health and safety of the general public or plant personnel at risk.

USAR Section 7.4 indicates that instrumentation and controls of the following systems can be used to achieve safe shutdown:

- Reactor Core Isolation Cooling (ICS)
- Standby Liquid Control System (SLS)
- Residual Heat Removal (Shutdown Cooling Mode of RHR)
- Remote Shutdown System (RSS)

The sources which supply power to the safe shutdown systems listed above originate from onsite AC/DC safety related systems. Therefore, the loss of normal UPS's (2VBB-UPS1A, 1B, 1C, 1D, 1G) and failure of the "B" Phase main output transformer at no time adversely affected the safe shutdown capability of NMP2.

The duration of the event from the reactor scram until exiting the Emergency Action Procedure EAP-2 (termination of the Site Area Emergency) was 13 hours 55 minutes.

IV. CORRECTIVE ACTIONS

The immediate corrective actions taken were: normal operator response to the turbine trip and reactor scram; identifying the cause for the loss of Control Room indication and annunciation; restoring power to the failed UPS's; and identifying the cause of the turbine trip and reactor scram.

Follow-up corrective actions include:

1. The spare main transformer was connected to the "B" phase and pre-operational testing was completed.

2. The failed "B" phase main transformer has been disconnected and removed from its pedestal. Preparations are being made to ship it offsite for failure analysis.

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IV. CORRECTIVE ACTIONS (cont.)

3. The logic power supply for 2VBB-UPS1A through 1D and 1G has been modified to be inverter preferred with the maintenance supply as a back-up.

4. All the UPS internal batteries have been replaced.

5. An evaluation was performed on plant hardware that utilizes internal batteries. It was concluded that no control functions are dependent on any of these internal batteries.

6. Changes have been incorporated in the vendor manual to address the identified UPS design deficiencies.

7. An evaluation is in progress to assess further UPS logic power supply modifications.

8. A replacement schedule for the UPS internal batteries is being developed based on supplier recommendations and actual service conditions.

9. Operations Support personnel have changed Operating Procedure N2-OP-37, "Reactor Water Cleanup System", to re-order the steps to assure system back pressure is established prior to beginning flow rejection that could cause system depressurization.

V. ADDITIONAL INFORMATION

A. Failed components:

Component description	-	"B" phase Main Generator Step-up output transformer
Ratings	-	408KVA, 65 degree Celsius rise, FOA-1 phase - 60 Hz
Manufacturer	-	McGraw Edison
Mark number	-	2MTX-XM1B
Serial number	-	C-06607-5-2
Niagara Mohawk drawing	-	EE-N01A
Niagara Mohawk spec	-	E011A

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Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	0 1 7	0 0	2 0 OF 2 5

V. ADDITIONAL INFORMATION (cont.)

Component description	-	Uninterruptible Power Supply
Ratings	-	75KVA, 60KW
Manufacturer	-	Exide Electronics Corporation
Mark Number	-	2VBB-UPS1A, 1B, 1C, 1D and 1G
Model Number	-	Mark II
Niagara Mohawk drawing	-	EE-001BH
Niagara Mohawk spec	-	E035A

B. Previous similar events: none

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7	— 0 0	2 1 OF 2 5

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

V. ADDITIONAL INFORMATION (cont.)

C. Identification of components referred to in this LER:

COMPONENT	IEEE 803 EIIS FUNCTION	IEEE 805 SYSTEM ID
Control Room Annunciation	N/A	IB
Reactor Feedwater System	N/A	SJ
Condensate System	N/A	SD
Reactor Core Isolation Cooling System	N/A	BN
Reactor Recirculation System	N/A	AD
Reactor Protection System	N/A	JC
Main Steam System	N/A	SB
Plant Computer System	N/A	ID
Plant Communication System (Gaitronics)	N/A	FI
Containment Vent and Purge	N/A	VB
Reactor Water Cleanup System	N/A	CE
"B" Phase Main Transformer	XFMR	EL
Uninterruptible Power Supply	UJX	EE
Reactor Feedwater Pump	P	SJ
Condensate Pump	P	SD
Condensate Booster Pump	P	SD
Residual Heat Removal Pump	P	BO
Post Accident Monitoring Recorder	XR	IP
Reactor Recirculation Pump	P	AD
Safety Relief Valves	RV	SB

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

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Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	0 1 7	0 0	2 2 of 2 5

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

V. ADDITIONAL INFORMATION (cont.)

COMPONENT	IEEE 803 EIIS FUNCTION	IEEE 805 System ID
Plant Process Computer	CPU	ID
Alarm Typer	TTY	ID
Turbine Stop Valves	SHV	TA
Turbine Control Valves	FCV	TA
Turbine Bypass Valves	FCV	JI
Radio Leaky Wire	ANT	FI
Cooling Tower Bypass Valve	V	KE
Feedwater Level Control Valves	LCV	SJ
Minimum Flow Valve	FCV	SJ/SD
Average Power Range Monitor Recorders	MTR	IG
Average Power Range Monitor Meters	PR	IG
Reactor Recirculation Flow Control Valve	FCV	AD
Condensate Storage Tank	TK	KA
Containment Vent and Purge Isolation Valve	ISV	VB
Radiation Monitor	RIT	BH
Condenser Mechanical Air Removal Pump	P	SH
Reactor Water Cleanup Pump	P	BF
Drywell Vacuum Breaker	VACB	BF

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST. SEE HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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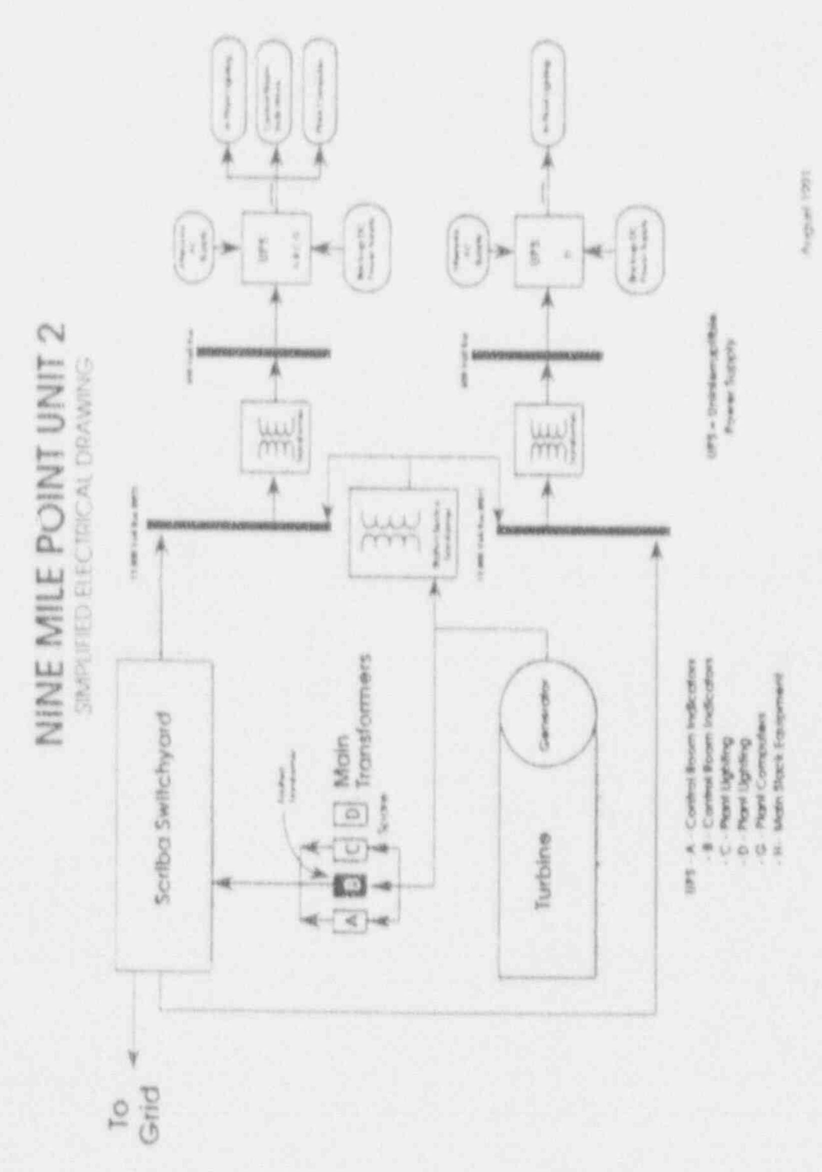
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7	— 0 0	2 3 OF 2 5

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

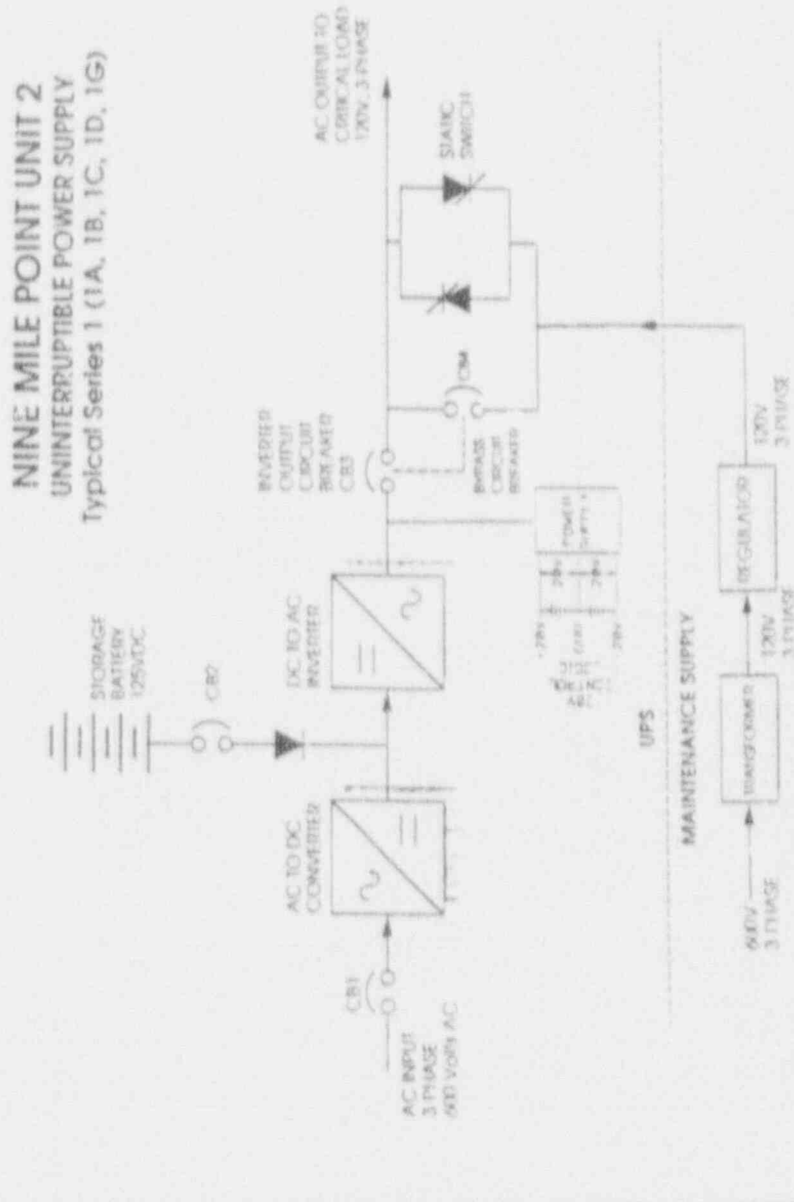


NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7	— 0 0	2 4 OF 2 5



NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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EXPIRES: 4/30/92

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Nine Mile Point Unit 2	0 5 0 0 0 4 1 0	9 1	— 0 1 7 —	0 0	2 5 OF 2 5

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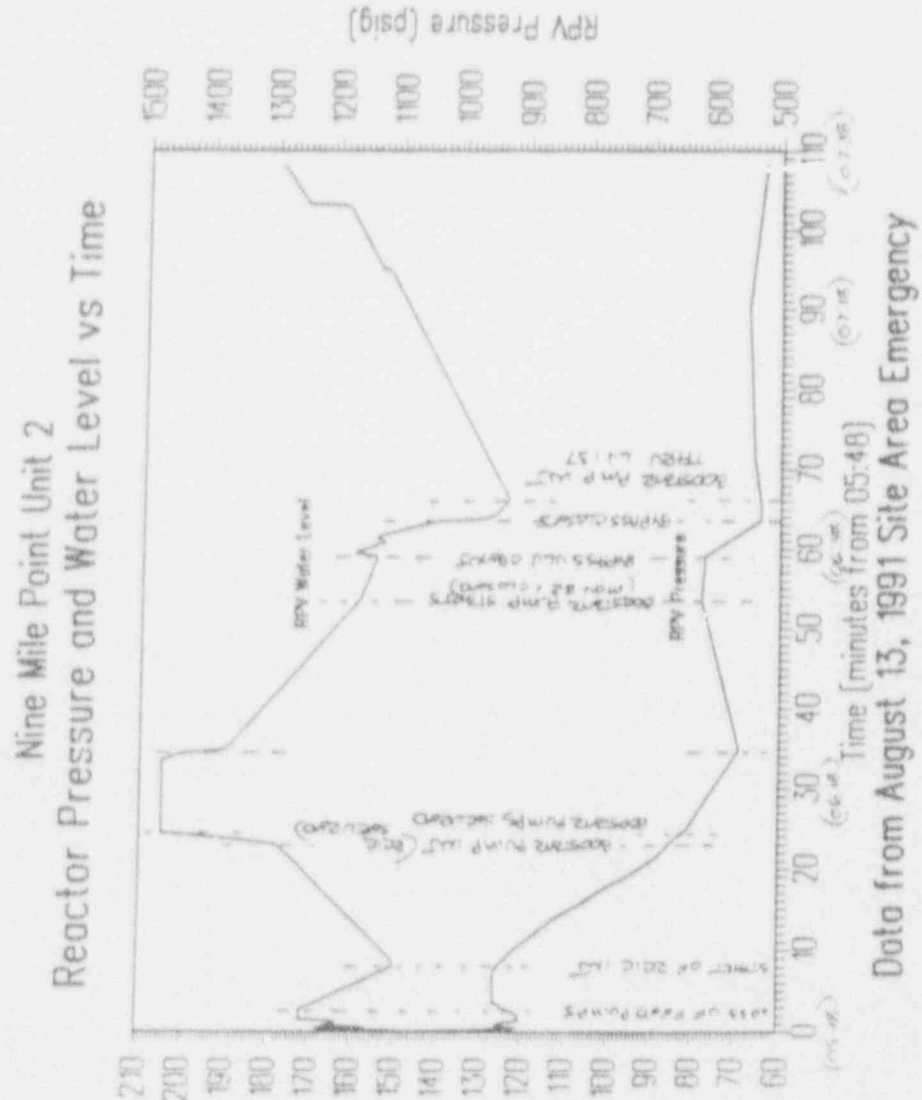


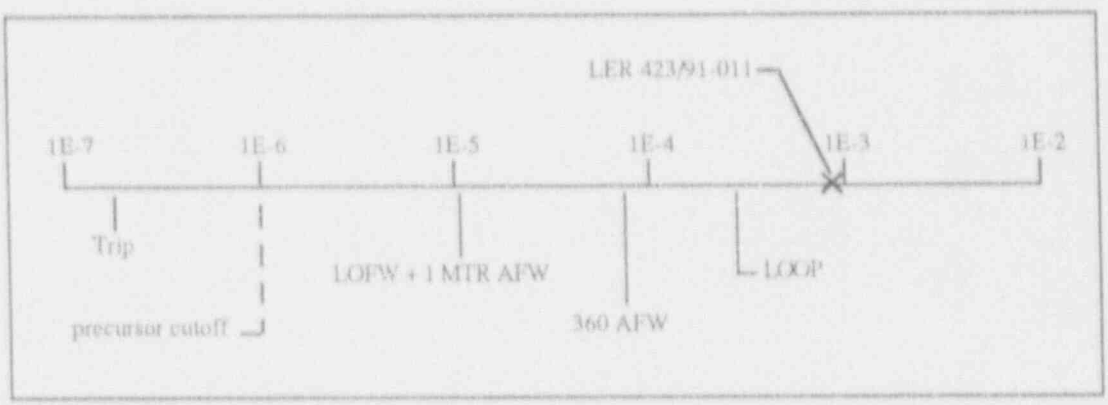
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 423/91-011
Event Description: Both trains of HPSI inoperable due to relief valve failures
Date of Event: April 10, 1991
Plant: Millstone 3

Summary

During testing of the high-pressure safety injection (HPSI) system while in Mode 3, the "A" HPSI relief valve lifted and would not reseat until the running HPSI pump was stopped. Flow loss through the stuck-open valve was 79 gpm. An investigation determined that the incident occurred because the design relief valve set pressure was too close to system operating pressure. A similar condition existed with the "B" HPSI relief valve; however, it was "gagged shut" during the test to prevent it from lifting, and therefore no failure of the "B" valve was noted. Had both valves lifted during accident conditions, the system would have been unable to perform its safety function.

The conditional core damage probability for this event is conservatively estimated to be 8.1×10^{-4}. The relative significance of the event compared to other postulated events at Millstone 3 is shown below.



Event Description

While the plant was in Mode 3, at 557°F and 2250 psia, a leak test surveillance procedure was initiated on the HPSI system. This test involved aligning "A" HPSI pump via a test line to the space between two check valves at the point where HPSI is supplied to reactor coolant system (RCS) loop 4 hot leg. Because of gradual leakage past the check valve closest to the RCS, the pressure between the two check valves was above 1765 psia, the setpoint of the relief valve protecting the "A" HPSI train. When the test line isolation valve was opened, the "A" relief valve lifted and began relieving approximately 79 gpm. It continued to relieve until the pump was stopped.

The utility stated that the root cause of the event was a design deficiency. The HPSI relief valve setpoints were at values only slightly above normal operating pressures. Perturbations in system pressure, including those resulting from operation at minimum flow conditions, would result in lifting of the relief valves. Noting that the plant design basis allows for no more than 50 gpm of loss from the system during accident operation, the utility indicated that the relief valve is expected to relieve only 40 gpm at pressures in the range of its 1765 psia setpoint. As system pressure should have promptly returned to this range once the test line was aligned and the relief valve lifted, it is unclear why a flow rate of 79 gpm was observed.

During the course of the test, the "B" train relief valve was "gagged" closed to prevent it from opening. As the setpoint of the "B" valve was the same as the "A" valve, it is reasonable to presume that it would also have opened if exposed to the system pressures observed. T tility noted that a number of similar failures have occurred in the past as a result of pressure surges, valve manipulations, and surveillance testing.

ASP Modeling Assumptions and Approach

As this failure could have occurred during any accident sequence in which HPSI was actuated while RCS pressure exceeded 1750 psig, "A" train of HPSI was assumed to be inoperable. The "gagging" of the "B" train relief valve corresponding to the failed valve on the "A" train implies that a similar failure mode was expected for the "B" train valve, had it been tested. The "B" train of HPSI was therefore also modeled as inoperable.

The unavailability period is difficult to estimate for this event. It is possible that the relief valve lift was caused by the system lineup used for testing, combined with backleakage through an injection line check valve. However, the LER noted a number of similar failures had previously occurred, and indicated that the problem was a result of relief valve setpoints too close to system operating pressure. In this case, the HPSI unavailability may have existed since initial criticality. For this analysis, a long-term unavailability of HPSI was assumed to have existed. To estimate the relative significance of the event within a 1-yr observation period (the interval being evaluated in this report), a 1-yr unavailability period was utilized (6132 h, assuming the plant was critical or at hot shutdown for 70% of the year).

Although the current Accident Sequence Precursor (ASP) model for Millstone 3 does not include use of the charging pumps as an alternate to the HPSI pumps for safety injection (SI) and bleed and feed, these pumps can be used for this purpose. The two normally available charging pumps were assumed capable of providing successful SI and feed and bleed for this analysis. The failure probability for high-pressure injection and feed and bleed was estimated assuming that the nonrunning charging pump had to start [.01] and one of the two isolation valves to the refueling water storage tank, volume control tank, and RCS cold legs had to operate [3 x .01 x .1]. Based on screening probabilities used in the ASP Program, this failure probability is estimated to be 1.3×10^{-2}.

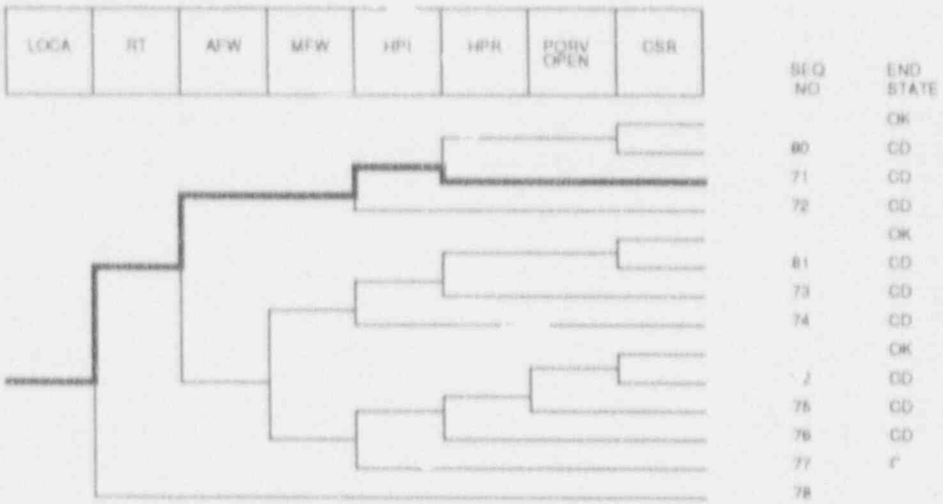
Note that while flow through the relief valve, during injection would render the HPSI ineffective (requiring the ch. ging pumps for injection), flow through the relief valves after sump switchover to hi. ı-pressure recirculation (HPR) would result in loss of containment sump invent and eventual failure of HPR. This situation could be detected through changes ... le el indication in auxiliary building tanks and sumps and in the containment sump. The HPSI pumps would have to be tripped and the charging pumps used for HPR as well. Because of the length of time available for this action, an operator failure probability of 0.12 was assumed (see Appendix A for a description of the operator action failure probabilities used in the ASP analysis).

Alternately, the plant could be cooled down and placed on the residual heat removal (RHR) system, with makeup provided by the charging system (this action is not addressed in the current ASP models).

Analysis Results

The conditional probability of subsequent core damage associated with this event was estimated to be 8.1×10^{-1}, assuming the charging pumps would be effective for safety injection. The dominant core damage sequence, shown on the following event tree, involves a postulated loss-of-coolant accident and HPR failure.

If the plant was cooled down and placed on the RHR system prior to draining the refueling water storage tank, the need for HPR would be eliminated (makeup using the charging system would still be required). Considering the RHR system as an alternate means of decay heat removal reduces the conditional core damage probability estimated for this event to 8.9×10^{-5}. (Modeling changes to address the use of the RHR system as an alternate means of decay heat removal following a small-break LOCA are currently being considered in the ASP program.)



Dominant core damage sequence for LER 423/91-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 423/91-011
Event Description: Both trains of HPSI unavailable (CPs provide success)
Event Date: 04/10/91
Plant: Millstone 3

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	2.9E+00
LOOP	3.6E-02
LOCA	6.3E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.8E-06
LOOP	6.7E-06
LOCA	8.0E-04
Total	8.1E-04
ATWS	
TRANS	0.0E+00
LOOP	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	7.4E-04	4.3E-01
72 loca -rt -afw HPI	CD	6.3E-05	3.6E-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	7.4E-04	4.3E-01
72 loca -rt -afw HPI	CD	6.3E-05	3.6E-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:\asp\1989\pwraseal.cmp
BRANCH MODEL: c:\asp\1989\millstn3.all
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

Event Identifier: 423/91-011

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	4.6E-04	1.0E+00	
loop	1.8E-05	3.3E-01	
loca	2.4E-06	4.3E-01	
t	2.8E-04	1.2E-01	
-t/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	2.0E-01	3.4E-01	
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	3.5E-01	1.0E+00	
ep.rec(sl)	7.6E-01	1.0E+00	
ep.rec	1.5E-01	1.0E+00	
HPI	1.0E-03 > 1.3E-02 **	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
HPI(F/B)	1.0E-03 > 1.3E-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		
porv.open	2.0E-02	1.0E+00	4.0E-04
HPR/-HPI	1.5E-04 > 1.5E-04	1.0E+00	1.0E-03 > 1.2E-01
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02		
car	9.3E-05	1.0E+00	

* branch model file
** forced

Minarick
08-31-1992
10:17:05

Event Identifier: 423/91-011

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 3	0 5 0 0 0 4 2 3	1 OF 0 3

TITLE (4): Both Trains of High Pressure Safety Injection System Inoperable Due to Relief Valve Leakage

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 NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
0 4	1 0	9 1	9 1	1 1	0 0	0 5	1 0	9 1		0 5 0 0 0

OPERATING MODE (9): 3

POWER LEVEL (10): 0 0 0

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

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Terry O. McNatt, Engineer, Ext. 5592	2 0 3 4 4 7 - 1 7 9 1

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)

(If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

On April 10, 1991, at 2225 hours with the plant at 0% power in Mode 3 (Hot Standby), 557 degrees Fahrenheit and 2250 psia, a safety injection system (SIH) relief valve lifted while performing a boundary valve leak test surveillance procedure. The valve did not reseat until the running "A" safety injection pump was stopped. The 79 gpm flowrate of the relief valve exceeded the 50 gpm assumed for passive failure of the safety injection system.

The root cause of the event is design deficiency. The setpoint for the relief valves was too close to the operating pressure of the system. The system has historically operated close to the relief valve setpoint. Pressure surges, valve manipulations, and surveillance testing have previously resulted in the lifting of system relief valves.

As immediate corrective action shift management declared the safety injection system inoperable. The "B" train relief valve, which was temporarily gagged to minimize failure during troubleshooting, were ungagged, and the "B" train was declared operable. The system design pressure was reanalyzed and the setpoint of the relief valves was increased to 2250 psia from 1750 psia. Both trains of the safety injection system were declared operable following the increase in setpoint for the "A" train and "B" train relief valves.

NRC Form 366 (6-89)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 3	0 5 0 0 0 4 2 3	9 1	— 0 1 1 —	0 0	0 2 OF 0 3

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

I. Description of Event

On April 10, 1991, at 2225 hours with the plant at 0% power in Mode 3 (Hot Standby), 557 degrees Fahrenheit and 2250 psia, the "A" train high pressure safety injection (SIH) relief valve (3SIH*RV8853A) lifted and did not reseat while performing leak testing of the SIH to RCS Loop 4 Hot Leg check valve (3SIH*V112) in accordance with the Reactor Coolant System (RCS) Pressure Isolation Valve Test surveillance procedure (SP 3601F.4). The relief valve lifted when the Test Line Isolation Valve (3SIH*AV8889C) was opened. This aligned the piping between check valves 3SIH*V112 and the RCS Loop 4 Hot Leg check valve (3RCS*V102) to the safety injection pump discharge piping which is protected from overpressurization by relief valve 3SIH*RV8853A. The 79 gpm flow rate of the relief valve exceeded the 50 gpm assumed for the passive failure of the safety injection system. Shift management declared both trains of the safety injection system inoperable and logged into Technical Specification 3.0.3. The "A" SIH pump was isolated from the "B" train. The temporary gagging device, previously installed on the "B" train relief valve (3SIH*RV8853B) to limit failures while investigating the lifting problems, were removed, and the "B" train was declared operable 2 hours and 15 minutes after invoking Technical Specification 3.0.3. At that time, Technical Specification 3.5.2.a was invoked with one train of SIH operable. Both trains were declared operable at 1208 hours on April 13, 1991, following the resetting and testing of the "A" train and "B" train relief valves.

II. Cause of Event

The root cause of the event is design deficiency. The setpoint for the relief valves was too close to the operating pressure of the system. The system has historically operated close to the relief valve setpoint. The pressure that the relief valve was subjected to during the performance of the surveillance procedure was in excess of the normal setpoint of 1765 psia. The gradual leakage through check valve 3RCS*V102, located in the safety injection line at the "C," reactor coolant loop, allowed the upstream pressure (between 3RCS*V102 and 3SIH*V112) to approach reactor coolant system pressure of 2250 psia. When valve 3SIH*AV8889C was opened per the procedure, the safety injection piping which included relief valve 3SIH*RV8853A was subjected to this higher pressure resulting in the lifting of the relief valve.

III. Analysis of Event

This event is being reported in accordance with 10CFR50.73(a)(2)(v), as an event or condition that alone could have prevented the fulfillment of the safety function of systems needed to mitigate the consequences of an accident, and, 10CFR50.73(a)(2)(vii), as an event where a single cause or condition caused two independent trains to become inoperable in a single system designed to mitigate the consequences of an accident. An immediate notification was made in accordance with 10CFR50.72(b)(2)(iii).

There were no significant safety consequences due to this event. The surveillance procedure was performed with the reactor shut down and the plant in Mode 3. Relief valve 3SIH*RV8853A shut when the "A" safety injection pump was stopped to lower the system pressure below the lift setpoint. For design basis accidents which require the safety injection pumps to operate, the relief valve would be subjected to pressures in the range of 1765 psia only at minimum flow conditions. At this pressure, the relief valve has been proven to relieve at approximately 40 gpm which is within the margin of the safety injection system.

NRC Form 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

IV. Corrective Action

When the event occurred, shift management declared the safety injection system inoperable and invoked Technical Specification action 3.0.3. The failed "A" train relief valve (3SIH*RV8853A) was gagged shut. The temporary gagging device, previously installed on the "B" train relief valve (3SIH*RV8853B) to limit failures while investigating the lifting problems, was removed, and the "B" train of the safety injection system was declared operable following the removal of the gagging devices and Technical Specification 3.5.2.a was invoked. The system design pressure was reanalyzed and the setpoint of the "A" train and "B" train relief valves was increased to 2250 psia from 1765 psia based on the conclusion of the analysis.

A test procedure was written, approved, and performed that utilized the appropriate steps of the surveillance procedure to duplicate the conditions that existed when the relief valve lifted. Instrumentation was installed on the safety injection system to provide a trace of the actual pressure seen by the relief valve. The testing verified that the pressure in the system exceeded the relief valve setpoint pressure. The test procedure verified that other combinations of valve and pump manipulations did not subject the relief valves to pressures higher than their new lift setpoint of 2250 psia.

V. Additional Information

The safety injection system relief valves have had a history of lifting during surveillance testing. Previous procedure changes to minimize valve manipulations while the system was in operation appeared to have minimized relief valve lifting problem. There have been no previous similar events with the same root cause and underlying concerns.

EIIS Codes

System

High Pressure Safety Injection System-BQ

Component

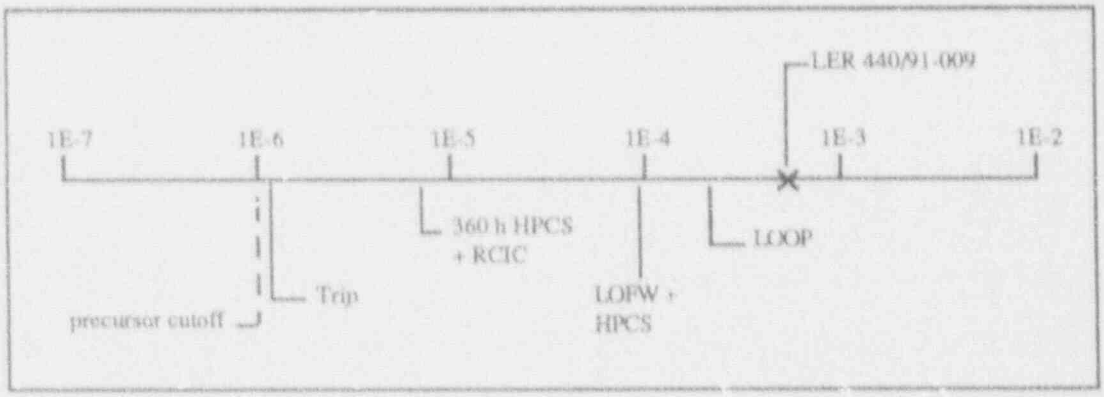
Relief Valve-RV

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 440/91-009
Event Description: Two EDGs inoperable
Date of Event: March 14, 1991
Plant: Perry

Summary

Perry was operating at 100% power on March 14, 1991, when the Division 2 emergency diesel generator (EDG) failed a surveillance test. Subsequently, the Division 1 EDG also failed its surveillance test. It took 11 h and 55 min to restore one EDG to operable status. It was later determined that one EDG had been inoperable for over 28 d, and the other EDG was potentially unavailable for 15 d. The conditional core damage probability estimated for this event (assuming both EDGs were unavailable for 15 d) is 5.3×10^{-4}. The relative significance of this event compared to other postulated events at Perry is shown below.



Event Description

Perry was operating at 100% of rated power at 0915 hours on March 14, 1991, when the Division 2 EDG failed its monthly surveillance test. The EDG reached rated speed but was unable to generate any output voltage because the field contactor failed to close. Subsequent investigations revealed that excessive play in the pivot point of the latch mechanism allowed the latch arm to twist sideways and weld the contacts in the trip position of the K1 close coil of the field contactor. It was concluded that this could only have occurred during shutdown of the EDG during the last surveillance test performed February 14, 1991. Thus, the EDG had been out of service for the entire 28-d period between tests.

When the Division 2 EDG failed its surveillance test, plant Technical Specifications required that the Division 1 EDG be demonstrated operable. During this demonstration run, the Division 1 EDG started and came up to rated speed, but the operators were unable either remotely or locally to synchronize the generator to the grid. The Division 1 EDG was also declared inoperable. In this situation, the plant Technical Specifications require either one EDG to be returned to operability within 2 h or for shutdown to begin. In spite of this, the plant remained at full power throughout the ~12 h time required to repair the Division 2 EDG.

The plant decided to repair the Division 2 EDG first, since the failed component was known. Field contactor repair parts for the Division 2 EDG were not available from warehouse stock and were instead obtained from the Division 1 EDG. The Division 2 EDG was repaired, tested, and placed back in service at 0220 hours on March 15, 1991. At this time, investigation and troubleshooting was begun on Division 1 EDG. The utility concluded that the lower limit switch on the motor-operated potentiometer was malfunctioning although no conclusive cause was ever identified. If this was the case, then the EDG would be expected to function in the event of a loss of offsite power (LOOP). However, after inspection, cleaning, exercising, and post-maintenance testing, the problems that prevented the governor speed control from functioning during the surveillance test could not be recreated. The utility believed that the conditions causing the event were corrected during the maintenance activities. Division 1 EDG was placed back in service at 2305 hours on March 15, 1991. Both EDGs were inoperable at the same time for repairs for 11 h and 55 min. If the cause of the Division 1 EDG failure would have prevented its operation following a LOOP, then both EDGs would have been inoperable for an expected 15 d.

Additional Event-Related Information

Offsite power is available to the Perry 1 345-kV switchyard from five 345-kV transmission circuits. Engineered safety features (ESF) loads are assigned to three independent load groups designated Divisions 1, 2, and 3. Divisions 1 and 2 are redundant, while Division 3 supplies power for the high-pressure core spray (HPCS) system. Each division consists of a 4.16-kV switchgear bus and assembly, diesel generator standby power supply, motor control centers, batteries, and battery chargers. The preferred power supply for the class 1E buses is the startup transformer. Alternate power is available through a manual normally-open disconnect from the unit 2 startup transformer. Emergency loads for Divisions 1 and 2 are supplied from EDGs rated at 7,000 kW.

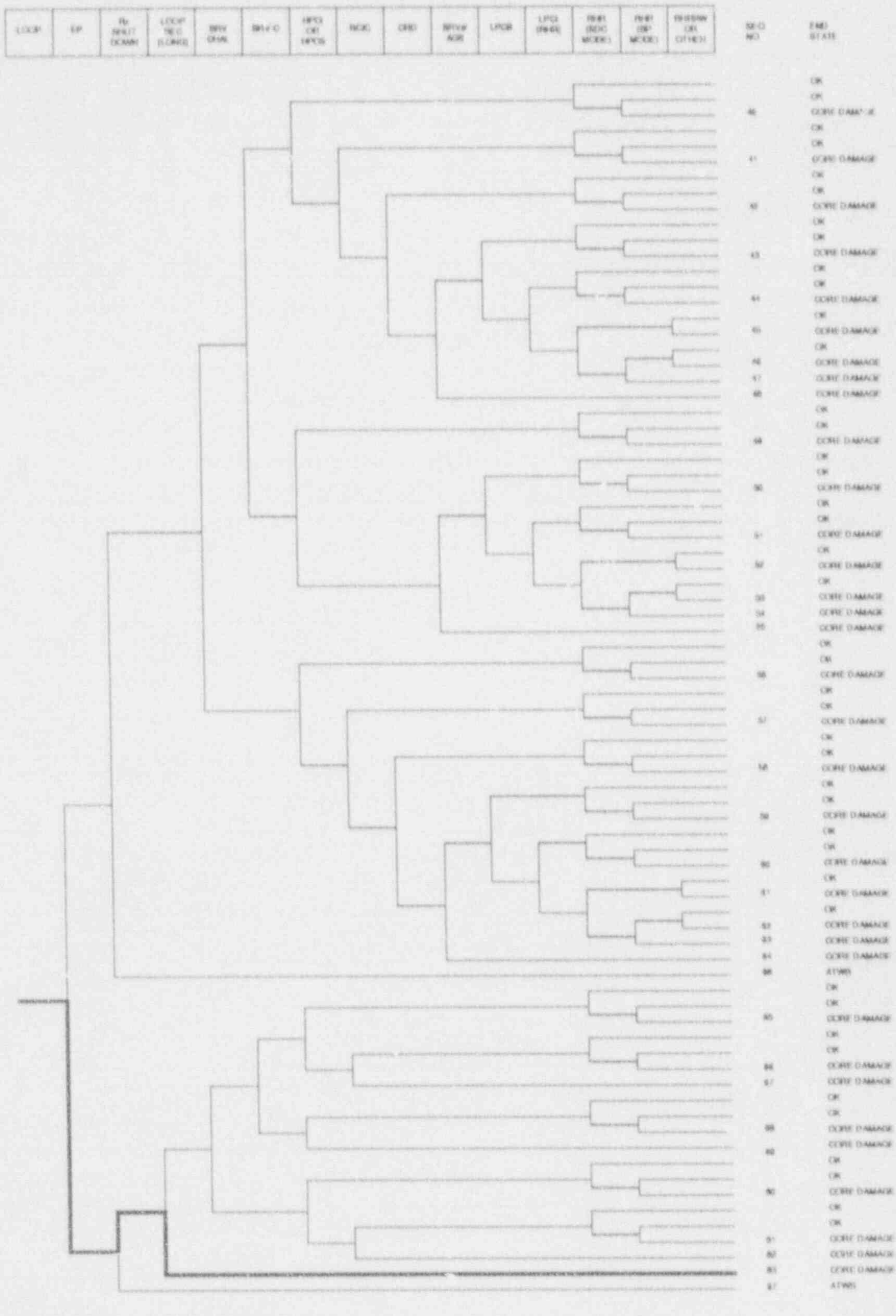
ASP Modeling Assumptions and Approach

Division 2 EDG was inoperable for more than 28 d, and Division 1 EDG was unable to synchronize to the grid when required. Since the cause for the latter unavailability was never positively identified, nor was it demonstrated that the EDG would have assumed loads following a postulated LOOP, it was assumed that the Division 1 EDG was unavailable for one half its surveillance period of 15 d. Therefore, this event has been modeled as a postulated LOOP with both the EDGs unavailable and nonrecoverable for 15 d.

Analysis Results

The conditional probability of subsequent core damage estimated for two EDGs unavailable for 15 d is 5.3×10^{-4}. A sensitivity analysis was performed to ascertain the effect of out of service time on the conditional probability. If it is assumed that the two EDGs were only unavailable for the 11.9 h repair time, the conditional probability of core damage decreases by more than an order of magnitude to 1.7×10^{-5}.

The dominant core damage sequence, highlighted on the following event tree, involves a postulated LOOP, a nonrecoverable emergency power system failure, and failure to restore AC power prior to battery depletion.



Dominant core damage sequence for LER 440/91-009

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 440/91-009
Event Description: Two emergency diesel generators inoperable
Event Date: 03/14/91
Plant: Perry 1

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.1E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	5.3E-04
Total	5.3E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
83	loop EMERG.POWER -rx.shutdown/ep ep.rec	CD	5.3E-04	5.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
83	loop EMERG.POWER -rx.shutdown/ep ep.rec	CD	5.3E-04	5.3E-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:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\perry.sll
PROBABILITY FILE: c:\asp\1989\bwr_csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.7E-04	1.0E+00	

Event Identifier: 440/91-009

loop	1.6E-05	5.3E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	6.3E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 1.0E+00	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Failed		
ep.rec	1.7E-01	1.0E+00	
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
hpci	2.0E-02	3.4E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	2.0E-02	3.4E-01	
lpci(rhr)/lpcs	6.0E-04	7.1E-01	
rhr(adc)	2.3E-02	3.4E-01	1.0E-03
rhr(adc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(adc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(adc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(adc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(adc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Mina:lck
03-14-1992
16:23:45

Event Identifier: 440/91-009

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: ... FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Perry Nuclear Power Plant, Unit 1	0 5 0 0 0 4 4 0	1 OF 0 [illegible]

TITLE (4): Violation of Technical Specifications and Inoperability of the Division 1 and 2 Diesel Generators Due to Equipment Malfunctions.

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 3	1 4	9 1	9 1	0 0 9	0 0	0 4	1 5	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	1 0 0

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

X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
TS 4.8.1.1.3 and 6.9.2

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Henry L. Hegrat, Compliance Engineer, Extension 5185	2 1 6 2 5 9 - 3 7 3 7

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	D G	C N T R	X 9 9 9	N					
X	D G	3 3	W 2 9 0	N					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO | EXPECTED SUBMISSION DATE (15) Month Day Year

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

On March 14, 1991 at 0915, a failure of the Division 2 Diesel Generator (DG) occurred when the field failed to flash during the monthly surveillance operability test. The Division 2 DG was declared inoperable and the other divisional DGs were run within 24 hours to verify operability. During the Division 1 DG test, the governor speed control failed to respond to manual operation in the lower direction, preventing synchronization to the grid. The Division 1 DG was declared inoperable on March 14, 1991 at 1425. Following repairs, the Division 2 DG was declared operable on March 15, 1991 at 0220 and the Division 1 DG was declared operable at 2305.

The root cause of both events was equipment malfunction. The Division 2 DG field contactor K1 failed to close due to a component failure, which occurred at completion of the last successful diesel surveillance run during engine shutdown on February 14, 1991. The Division 1 DG equipment malfunction was isolated to the governor control circuit, which was serviced and tested prior to declaring the DG operable.

To prevent recurrence, design and procedural changes were initiated to enhance the reliability of the field contactor and procedural changes will be made for servicing the governor control circuitry. In addition, the Division 2 DG failed component was returned to the vendor for failure analysis and a notification of the event was provided to the DG Owners Groups (DeLaval and General Motors EMD).

Submittal of this report satisfies the requirements of Technical Specifications 4.8.1.1.3 and 6.9.2.

NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. INTRODUCTION

From February 14, 1991 at 1124 to March 15, 1991 at 0220, the Division 2 Diesel Generator (DG) was rendered inoperable due to an undetectable equipment problem that occurred during shutdown after the previous monthly surveillance test. With the Division 2 DG inoperable, there was no diesel backup power available for Division 2 safety related equipment during this period, in violation of Technical Specification 3.8.1.1 action statement (b), which requires an inoperable DG to be restored to an OPERABLE condition within 72 hours. Otherwise, the reactor is required to be in Operational Condition 3 (HOT SHUTDOWN) within the next 12 hours and in Operational Condition 4 (COLD SHUTDOWN) within the following 24 hours. Additionally, from March 14, 1991 at 1425 to March 15, 1991 at 0220, the Division 1 and Division 2 DGs were both inoperable due to unrelated equipment problems. During the entire time of these events, the plant was in Operational Condition 1 (POWER OPERATION) at normal full power operations, with the Reactor Pressure Vessel [RPV] at saturated conditions at approximately 1040 psig.

II. DESCRIPTION OF EVENT

On March 14, 1991 at 0905, a monthly surveillance test instruction (SVI-R43-T1318) "Diesel Generator Start and Load Division 2" was initiated. The Division 2 Diesel Generator [DG] engine [ENG] started and accelerated to minimum speed (441 RPM) within the specified time; however, the field contactor (K1) failed to close, resulting in no generator output voltage. The Division 2 DG was declared inoperable at 0915 following this valid test and failure. The plant entered Technical Specification 3.8.1.1 action statements (b) and (e), which require among other things, the demonstration of operability of the remaining OPERABLE diesel generators by performing appropriate surveillance requirements separately for each diesel generator within 24 hours.

To accomplish the above mentioned requirements for the Division 1 DG, surveillance test instruction (SVI-R43-T1317) "Diesel Generator Start and Load Division 1" was initiated at 1425. During the operability test, the Division 1 DG engine started, accelerated and achieved rated speed and voltage, but the governor did not respond in the lower direction upon demand from the Control Room, prohibiting manual synchronization to the grid. The DG control was shifted from the Control Room to the local panel with the same result. As a result of the inability to satisfactorily complete the surveillance requirements, the Division 1 DG was declared inoperable at 1425. The plant entered Technical Specification 3.8.1.1 action statement (g), which requires restoration of either Division 1 or 2 DG to an OPERABLE condition within 2 hours or entry into Operational Condition 3 (HOT SHUTDOWN) within the next 12 hours and into Operational Condition 4 (COLD SHUTDOWN) within the following 24 hours. The NRC Operations Center was informed of the inoperability of both Division 1 and 2 DGs via the Emergency Notification System at 1614. The Division 3 DG surveillance test was satisfactorily completed at 2035.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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It was decided to restore the Division 2 DG first due to the known nature of the Division 2 DG failure and the need to restore at least one of the Standby Diesel Generators in an expedient manner. At the time no field contactor K1 parts were available from warehouse stock. Therefore, it was decided to obtain the required field contactor K1 parts (carrier assembly and tripping coil assembly) from the Division 1 DG and transfer these parts for installation in the Division 2 DG. The carrier assembly and tripping coil assembly were transferred from the Division 1 DG at 1800. Following inspection, installation, functional testing and one successful maintenance run to verify proper latching of field contactor K1, the Division 2 DG surveillance test for operability was successfully completed on March 14, 1991 at 2353. The Division 2 DG was declared operable on March 15, 1991 at 0220. Following extensive troubleshooting including visual inspection, cleaning and exercising all accessible contacts, verification of all terminations, replacement of transferred parts and appropriate maintenance testing, the Division 1 DG surveillance test for operability was successfully completed on March 15, 1991 at 1730. The Division 1 DG was declared operable at 2305.

III. CAUSE ANALYSIS

The root cause of the Division 2 DG failure was a failure of the field contactor K1 (ITE Telemechanique Cat. No. A143G) to close due to a failure of the switching contact to reset. The troubleshooting investigation identified the switching contacts for the K1 close coil on the tripping coil assembly open. Disassembly of the mechanism revealed the contacts lightly welded in the trip position preventing contact reset on contactor trip. This was attributed to excessive play in the pivot point of the latch mechanism allowing the latch arm to twist sideways. The latch arm slid along the tang of the tripping coil assembly preventing a normal smooth contact snap reset. This resulted in an extended (time unknown) energization of the trip coil with subsequent contact arcing (in comparison to normal clearing time). The failed closed trip contact and the resultant open contact in the closure control circuit prevented K1 from closing, thereby constituting a valid failure of the Division 2 DG. During this investigation, it was further determined that the malfunction could have only occurred during the shutdown from the February 14, 1991 surveillance test. Therefore, the Division 2 DG was inoperable from February 14, 1991 at 1124 until March 15, 1991 at 0220; however, there were no indications of the failure which could have led to that discovery until the next attempt to run the engine.

This is a valid test and failure in accordance with Regulatory Guide (R.G.) 1.108 C.2.e.5. This is the first valid failure in the last 100 total valid tests to occur on the Unit 1 Division 2 Diesel Generator. The Division 2 DG failed to achieve specified generator voltage during surveillance testing. The total repair time for the Division 2 DG was 17 hours and 5 minutes. The total out-of-service time for the Division 2 DG was 28 days, 14 hours, and 56 minutes

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because the failure was determined to have occurred during engine shutdown from the previous monthly surveillance test completed on February 14, 1991 at 1124. The Division 2 Diesel Generator Surveillance Test interval will remain at once every 31 days in accordance with Perry Technical Specification Table 4.8.1.1.2-1.

The root cause of the Division 1 DG surveillance test suspension was equipment malfunction. After the successful engine start, when operators attempted to synchronize the generator with the grid, the manual governor control failed to respond in the lower direction. Extensive troubleshooting was performed on the Division 1 DG governor controls after the engine was shutdown. The lower limit switch on the motor operated potentiometer appeared to be the malfunctioning component. Based on the performance of automatic reset and the lack of manual control in the lower direction from either local or remote locations, the malfunction was isolated to a small portion of the circuit that includes two relays, the governor lower limit switch and associated wiring. Troubleshooting included visual inspection, cleaning and exercising all accessible contacts and limit switches, verification of all terminations, and appropriate maintenance testing. However, the conditions that prevented the governor speed control from functioning during the surveillance test could not be recreated during subsequent troubleshooting. Although no conclusive cause of the Division 1 DG governor speed control malfunction could be identified, it is believed that the conditions causing the event were corrected during these maintenance activities. The tripping coil assembly from the Division 2 DG was serviced and reinstalled on the Division 1 DG along with a new carrier assembly obtained from the salvage warehouse.

Followup investigation determined that the problem with frequency control, which prohibited synchronizing the Division 1 DG with the preferred source and required the DG to be declared inoperable, would not have prevented the DG from assuming loads under accident conditions. Thus in accordance with R.G. 1.108 c.2.e.2, the Division 1 DG test was not considered a valid failure since the DG was fully capable of performing its intended safety function. The Division 1 DG could have provided power promptly to the engineered safety features in the unlikely event a loss of offsite power occurred.

IV. SAFETY ANALYSIS

The Standby Diesel Generator System provides an independent source of AC power to the Division 1, 2 and 3 Class 1E buses in the event of a loss of the redundant offsite power supplies. During the entire event, Class 1E power was available from two physically independent circuits from the transmission network to the onsite electrical distribution system. Additionally, the High Pressure Core Spray System [BG] (HPCS) and its associated diesel generator were verified operable during this event. Upon failure of the synchronizing mechanism, the Division 1 DG could not be determined to be OPERABLE, due to the inability to

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

demonstrate loading capabilities per the surveillance test. During this time, however, the Division 1 DG was capable of responding properly to a loss of bus voltage until it was further disabled by the removal of parts to expedite the repairs to the Division 2 DG. The total time was 11 hours and 55 minutes that both Division 1 and 2 DGs were incapable of responding to a loss of power to their respective busses. Therefore, the event is considered safety significant because the loss of Division 1 and 2 backup power supplies results in conditions outside Updated Safety Analysis Report assumptions under certain accident scenarios.

Previous similar events with two or more inoperable divisions of the DG system were identified in LERs 87-009, 89-001, and 90-005. None of these events were caused by failures of the field contactor K1 assembly or the diesel governor mechanisms. Two previous plant events documented in Condition Reports occurred involving the field contactor K1. The first occurrence was due to a sticky latching mechanism resulting from aged grease. This resulted in a valid test failure of the Division 1 DG (reference letter PY-CEI/NRR-1120L dated January 19, 1990). The second event in December, 1990 was due to performance of an inadequate Periodic Test Instruction, resulting in an open closing coil on the Division 1 contactor and the switching contact welded. As part of the corrective actions from this event, the Division 2 contactor was inspected by work order on February 12, 1991 for similar damage and found in satisfactory condition. Subsequent to this inspection activity, proper operation of the Division 2 contactor was verified by independent maintenance and surveillance runs of the diesel generator on February 14, 1991. The failure discovered on March 14, 1991 on the Division 2 DG is, therefore, considered to be an isolated instance due to the cause for malfunction.

VI. CORRECTIVE ACTIONS

Corrective actions previously identified and implemented would not be expected to have prevented this event from occurring.

The following corrective actions were or will be completed to prevent recurrence:

1. The Division 2 DG carrier assembly was sent to the vendor (Basler Electric) for failure analysis. Conclusions and recommendations as a result of the failure analysis will be evaluated by the responsible system engineer in conjunction with the DG engineering support group. Appropriate corrective action(s) will be implemented as necessary.

2. Notification of this event was provided to the DG Owners Groups (DeLaval and General Motors EMD) on April 4, 1991.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

3. Implement design changes (DCP 91-0086 and 91-0086A) to enhance the reliability of the field contactor (K1) by monitoring critical component position and addition of an electrical seal-in feature. This design change should prevent undetectable failures of the field breaker K1 causing the diesel generator to be inoperable. These design changes were already implemented on the Division 1 DG.

4. Revise Periodic Maintenance Instruction "Diesel Panel Maintenance" to incorporate specific inspection criteria and service requirements for both Division 1 and 2 field contactor K1.

5. Revise Instrument Maintenance Instruction "Diesel Generator General Maintenance" to incorporate specific inspection and service requirements for both Division 1 and 2 governor control circuitry.

This submittal satisfies the requirements of Technical Specifications 4.8.1.1.3 and 6.9.2.

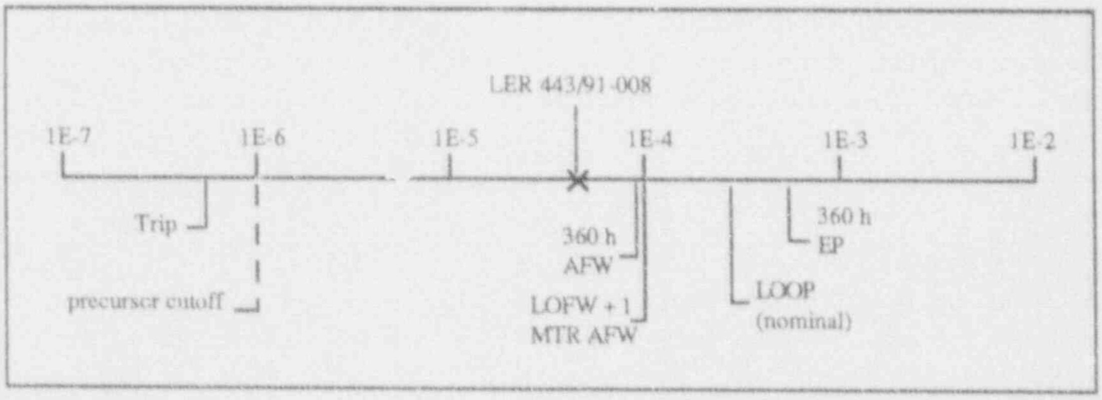
Energy Industry Information System Codes are identified in the text as [XX].

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 443/91-008
Event Description: Loss of offsite power
Date of Event: June 27, 1991
Plant: Seabrook

Summary

Seabrook underwent a loss of offsite power (LOOP) on June 27, 1991. Following the LOOP, the main turbine generator tripped, causing the reactor to scram from 100% power. Both emergency diesel generators (EDGs) started and energized their respective buses and loads. Normal power was restored to the plant's emergency buses 36 min after the LOOP. The plant was stabilized in Operational Mode 3, Hot Standby, within 1 h. The conditional core damage probability estimated for this event is 4.4×10^{-5}. The relative significance of this event compared to other postulated events at Seabrook is shown below.



Event Description

Seabrook was operating at 100% of rated power at 1334 hours on June 27, 1991, when two 345-kV switchyard circuit breakers tripped open while returning a relay to service following preventative maintenance. The relay had two break-before-make switches instead of one break-before-make and one make-before-break as required. Consequently, the two switchyard breakers opened without generating a signal to open the unit auxiliary transformer (UAT) supply breakers for onsite buses 1-4, E5, and E6. This prevented the automatic transfer to the reserve auxiliary transformer (RAT). Both EDGs automatically started and energized their respective buses and loads. The opening of the switchyard breakers caused a turbine trip followed by a reactor scram. When the turbine tripped, the turbine control valves fast-closed causing a steam line high-pressure spike. This, in turn, generated a high-high steam generator (SG) level signal, which isolated feedwater. The actual SG level never approached the high-high level setpoint, but the loss of feedwater (LOFW) caused an emergency feedwater (EFW) actuation. After the LOOP, the shift superintendent confirmed within 5 min with the load dispatcher that power was available to the RAT. Buses 1-4 were energized from offsite sources within 20 min of the LOOP. Following the trip, the atmospheric steam dump valves (ASDV) opened to limit steam line pressure. When the operators started reactor coolant pump (RCP) C to establish forced coolant flow, ASDV C did not modulate to control pressure; consequently, the SRV on SG C lifted. Vital buses E5 and E6 were energized from offsite sources within 36 min of the LOOP, and the EDGs were secured within 45 min. The plant was stabilized in Operational Mode 3, Hot Standby, within 1 h of the LOOP.

Additional Event-Related Information

Seabrook is supplied 345-kV from three offsite sources distributed between two buses that, in turn, supply the two RATs. The RATs are the alternate supply for the 4.16-kV emergency buses, E5 and E6. The normal supply for E5 and E6 comes from the UATs, which receive power from either a 345-kV offsite source or the unit main generator via a generator step-up transformer connection. Each UAT and RAT is a three-phase, three-winding transformer, with one wye-connected 13.8-kV output winding and one delta-connected 4.16-kV output winding. The 4.16-kV windings supply buses 3, 4, E5, and E6. Buses E5 and E6 supply vital, 4.16-kV safety-related loads and are backed up with emergency power from the EDGs. Buses 3 and 4 supply 4.16-kV nonsafety-related loads.

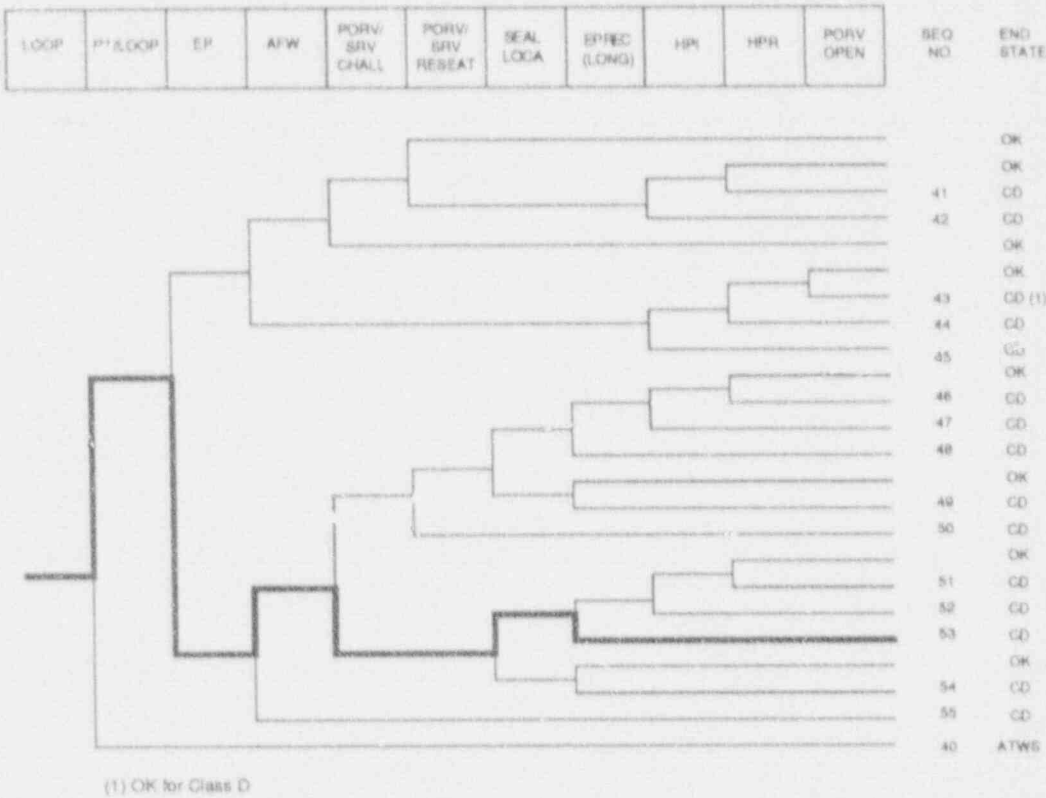
ASP Modeling Assumptions and Approach

The event has been modeled as a plant-centered LOOP. Probabilities for AC power nonrecovery following an RCP seal loss-of-coolant accident (LOCA) and prior to battery depletion, and for a seal LOCA, 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). Since power was available to the RAT, the LOOP nonrecovery probability used in the analysis was revised from that assumed for a nominal plant-centered LOOP at Seabrook to 0.12, to reflect burdened recovery in the control room had the EDGs failed.

Analysis Results

The conditional probability of core damage estimated for this event is 4.4×10^{-5}. The dominant core damage sequence, highlighted on the following event tree, involves a

LOOP, failure of emergency power, an RCP seal LOCA, and failure to recover AC power before core uncovery.



Dominant core damage sequence for LER 443/91-008

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 443/91-008
Event Description: Loss of offsite power
Event Date: 06/27/91
Plant: Seabrook 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	4.4E-05
Total	4.4E-05
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	2.9E-05	9.5E-02
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	8.5E-06	9.5E-02
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	4.7E-06	3.3E-02
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	1.2E-06	9.5E-02

** 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	1.2E-06	9.5E-02
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	2.9E-05	9.5E-02
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	8.5E-06	9.5E-02
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	4.7E-06	3.3E-02

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\seabrook.sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

Event Identifier: 443/91-008

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	5.3E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	5.3E-01 > 1.2E-01	
Branch Model: INITOR			
Initiator Freq:	1.6E-05		
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	8.0E-01	
afw	1.3E-03	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-02
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

Minarick
06-06-1992
14:34:37

Event Identifier: 443/91-008

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Seabrook Station	0 5 0 0 0 4 4 3	1 OF 0 4

TITLE (4) Turbine Trip with Reactor Trip Due to an Inadvertent Actuation of Switchyard Circuit Breakers

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 NAMES	DOCKET NUMBER(S)
0 6	2 7	9 1	9 1	– 0 0 8 –	0 0	0 7	2 6	9 1		0 5 0 0 0
										0 5 0 0 0

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

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

[ ]	20.402(b)	[ ]	20.405(c)	[X]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[ ]	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ]	20.405(a)(1)(iii)	[ ]	50.73(a)(2)(i)	[ ]	50.73(a)(2)(viii)(A)		
[ ]	20.405(a)(1)(iv)	[ ]	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Allen L. Legendre, Lead Engineer - Compliance, Extension 2373	6 0 3	4 7 4 - 9 5 2 1

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)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On June 27, 1991, at 1:34 p.m., a turbine generator trip with a subsequent reactor trip occurred while the plant was at 100% power. The turbine trip was initiated when two switchyard 345kV circuit breakers tripped open disconnecting the generator from the offsite distribution system.

The event occurred during the performance of a preventive maintenance activity on a breaker failure relay [50BF-2/11(H)] for 345kV circuit breaker 11. As the relay was being returned to service (closure of two knife blade switches), momentary arcing occurred across the contacts. The arcing caused a high speed tripping auxiliary relay to pick up without picking up an associated lock out relay. This partial relay actuation resulted in 345kV circuit breakers 11 and 163 opening without generating a signal to open the Unit Auxiliary Transformer (UAT) supply breakers to unit busses 1 through 6. Because of this, the automatic transfer to the Reserve Auxiliary Transformers (RAT) was prevented, resulting in the automatic starting of both emergency diesel generators. Offsite power remained available to the RATs at all times. A turbine trip occurred within one second of the opening of the 345kV circuit breakers. The turbine trip initiated a reactor trip. Following the reactor trip, natural circulation was established. A Main Feedwater Isolation and subsequent Emergency Feedwater Actuation also occurred. Additionally, a Containment Ventilation Isolation and an actuation of the Control Room Emergency Air Cleanup and Filtration System occurred due to the momentary deenergization of the Emergency Busses.

The root cause has been determined to be a manufacturing error in the relay housing contact block assembly for the breaker failure relay. This breaker failure relay was caution tagged to preclude any further maintenance until it is replaced during the first refueling outage. Other relays similar in design will be inspected to ensure that the correct switch assemblies are installed. In addition the automatic transfer scheme from the UATs to the RATs and the tripping scheme for the out of step relay will be reevaluated.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Seabrook Station	0 5 0 0 0 4 4 3	9 1	— 0 0 8	— 0 0	0 2 OF 0 4

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

On June 27, 1991, at 1:34 p.m., EDT, a turbine generator trip with a subsequent reactor trip occurred while the plant was at 100% reactor power. The turbine trip was initiated when two switchyard 345kV circuit breakers (11 and 163) tripped open disconnecting the generator from the offsite distribution system.

Description of Event

Prior to the event, the plant was at 100% power, with plant systems in a steady state condition. The event occurred during the performance of a preventive maintenance activity on a breaker failure relay [50BF-2/11(H)] for 345kV circuit breaker 11. When the two knife blade switches were closed to restore the relay to service, a momentary arcing occurred across the contacts. This caused a high speed tripping auxiliary relay (94-78/B3), part of the 78/B3 out of step relay, to actuate without, actuating an associated lock out relay (86-78/B3). This partial relay actuation resulted in the opening of 345kV circuit breakers 11 and 163 without generating a relay signal to open the Unit Auxiliary Transformer (UAT) supply breakers to unit busses 1 through 6. As a result of the UAT breaker not opening, the automatic transfer to the Reserve Auxiliary Transformers (RAT) was prevented, resulting in both emergency diesel generators starting automatically and energizing 4kV vital busses E5 and E6. It is important to note however, that offsite power remained available to the RATs at all times during the transient. Power was manually transferred to the RATs once operators ensured that the plant was in a stable condition.

The sudden loss of turbine load caused the early valve actuation (EVA) and the power load unbalance (PLU) protective features to actuate the rapid closure of the turbine control valves and intercept valves. A turbine trip occurred within one second of the opening of the 345kV circuit breakers. The rapid closure of the turbine control valves created pressure pulses which resulted in a Main Feedwater Isolation. These pressure pulses were transmitted through the steam flow transmitters water filled lines and sensed by the high pressure side of the steam generator narrow range level transmitter. This resulted in the steam generator high-high signal and subsequent feedwater isolation. Actual steam generator levels did not approach the high-high level setpoint (P-14) at any time. Due to the loss of feedwater to a steam generator, an Emergency Feedwater Actuation occurred as designed.

The turbine trip initiated a reactor trip. Natural circulation was established in the Reactor Coolant System (RCS) as expected. Due to the loss of power, condenser steam dumps were not available, except for a brief period (approximately one second) following the trip. The atmospheric steam dump valves in each of the four main steam headers opened to control steam pressure during the event. Plant buses were re-energized from the offsite power sources beginning at 1:54 p.m. EDT with all busses being reconnected by 2:20 p.m. EDT.

In addition, when 345kV circuit breakers 11 and 163 opened, vital instrument bus 1E momentarily deenergized resulting in a Train "A" Containment Ventilation Isolation and an actuation of the Control Room Emergency Air Cleanup and Filtration System.

Safety Consequences

There were no adverse safety consequences as a result of this event. Offsite power remained available to the RATs at all times during the transient. All the applicable trips and interlocks associated with the reactor trip functioned as designed. In addition, the emergency diesel

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Seabrook Station	0 5 0 0 0 4 4 3	9 1	— 0 0 8	— 0 0	0 3 OF 0 4

generators reached their rated speeds and voltage, and sequentially energized their respective loads as required.

All operator actions were determined to be appropriate to ensure the safety of the plant. At no time during this event was there any impact on the health and safety of plant employees or the public.

Root Cause

The root cause has been determined to be a manufacturing error in the relay housing contact block assembly on the 345kV breaker 11 breaker failure protection relay. The contact block is designed to have a make-before-break feature which allows the relay to be removed from service while other relay protection circuits remain in service. The contact assembly is comprised of a bank of knife blade style switches in the relay housing. The knife blade switches are in pairs with one of the paired switches being configured to make-before-break while the other is configured as a break-before-make switch. This configuration allows the device to be removed from a current transformer circuit without interrupting the circuit. Post-trip troubleshooting revealed that one of the pairs of knife blade switches was incorrectly assembled with two break-before-make switches.

Corrective Action

After the trip, the plant was placed in HOT STANDBY in accordance with operating procedure OS1000.11, "Post Trip to Hot Standby". An event evaluation and post trip review were immediately initiated. A Human Performance Enhancement System (HPES) analysis as well as a root cause analysis were also initiated.

The subject relay, 50BF-2/11(H), was caution tagged to preclude any further maintenance while the unit is operating at power. The out of step relay (78/B3) was tagged out of service until a thorough test is performed. Additional corrective actions include the following:

1) The relay housing for relay 50BF-2/11(H) will be replaced during the first refueling outage.

2) Other relay assemblies similar in design to relay 50BF-2/11(H) will be inspected to ensure that the correct switch assemblies are installed. These inspections will be performed before further preventative maintenance activities are conducted on the relays. These inspections are currently scheduled to be completed by December 31, 1991.

3) The tripping scheme for the out of step relay (78/B3) and the automatic transfer scheme from the UATs to the RATs will be reevaluated. This evaluation is currently scheduled to be completed by December 31, 1991.

4) An evaluation will be conducted to determine the cause for the momentary deenergization of the vital instrument bus IE. This evaluation is currently scheduled to be completed during the first refueling outage.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Seabrook Station	0 5 0 0 0 4 4 3	9 1	— 0 0 8	— 0 0	0 4 OF 0 4

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

Plant Conditions

At the time of this event, the plant was in Mode 1, Power Operation at 100%, with an RCS temperature of 587 degrees Fahrenheit and pressure of 2,235 psig.

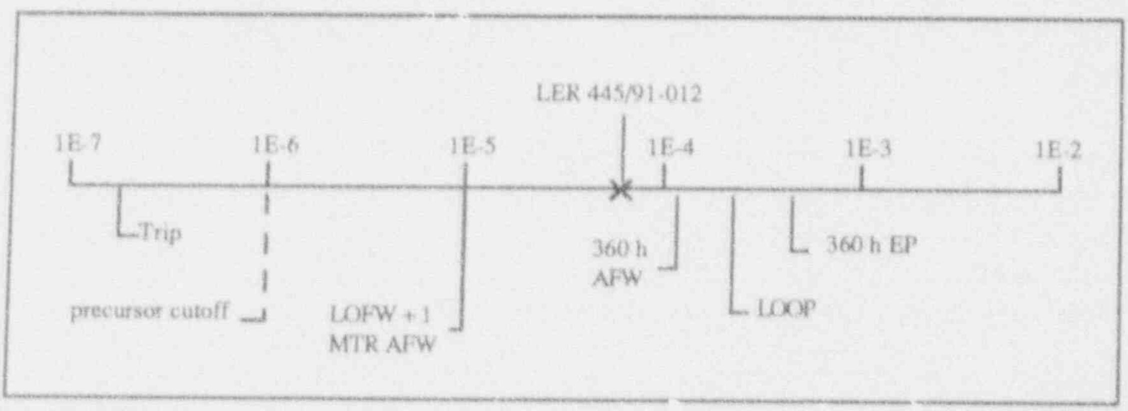
This is the first event of this type at Seabrook Station.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	445/91-012
Event Description:	Potential charging pump unavailability due to hydrogen void expansion
Date of Event:	March 26, 1991
Plant:	Comanche Peak 1

Summary

Two hydrogen gas voids were identified in chemical and volume control system (CVCS) piping. One of the voids, in the boric acid tank (BAT) gravity feed line, was large enough to impact charging pump operation following use of the line or during safety injection (SI) when lower charging pump suction header pressures could result in expansion of the hydrogen void into the suction line. The conditional core damage probability estimated for this event is 6.2×10^{-5}. The relative significance of this event compared to other postulated events at Comanche Peak 1 is shown below.



Event Description

On March 26, 1991, analyses of ultrasonic inspections of CVCS piping at Comanche Peak 1 indicated that hydrogen voids existed in two locations, the 2-in. diameter alternate boration line and the 3-in. diameter gravity feed line from the BAT. The utility stated that the size of the void in the alternate boration line was small and would not have resulted in degraded charging pump performance. However, the void in the BAT gravity feed line was large enough to potentially impact charging pump performance by directly damaging or gas-binding the pumps. This could have occurred if the BAT gravity feed line was used for boration or when charging pump suction pressure was reduced, which would cause the gas void to expand into the suction header. This later condition could exist following transfer of charging pump suction from the volume control tank (VCT) to the refueling water storage tank (RWST) during a safety actuation.

The utility performed the ultrasonic examinations of charging pump piping following a recommendation in an October 25, 1990, letter from Westinghouse regarding the formation and venting of hydrogen in charging system piping. This letter responded to NRC Information Notice 90-64, "Potential for Common-Mode Failure of High-Pressure Safety Injection Pumps or Release of Reactor Coolant Outside Containment During a Loss of Coolant Accident."

Additional Event-Related Information

The two centrifugal charging pumps, along with the two SI pumps and two residual heat removal (RHR) pumps, provide for SI at Comanche Peak. The SI and RHR pumps are normally aligned to the RWST. The charging pumps are normally aligned to the VCT. After an SI actuation signal occurs, the VCT is isolated from charging pump suctions by two series motor-operated valves, and two parallel, motor-operated isolation valves are opened to provide flow from the RWST to the charging pumps.

Following a small-break loss-of-coolant accident (LOCA) or during feed and bleed, and after the RWST inventory is depleted, the RHR pumps are used to take water from the containment sump and provide it, cooled by the RHR heat exchangers, to the suctions of the charging pumps and SI pumps. The piping arrangement is similar to many later Westinghouse plants — one RHR pump supplies flow to both charging pumps and (via the charging pump suction header) to one SI pump. The other RHR pump provides flow to the second SI pump.

A simplified diagram of the SI system is included as Fig. 1.

ASP Modeling Assumptions and Approach

The event has been modeled assuming both charging pumps would be unavailable because of expansion of hydrogen from the BAT gravity feed line into the charging pump suction header following a small-break LOCA or when required for feed and bleed. During the recirculation phase, one SI pump was also assumed unavailable because its suction supply is via the charging pump suction header. The unavailability may have existed since initial criticality, which occurred ~1 yr prior to the event. A 6132 h unavailability period was utilized, based on an assumption that the plant was at power or hot shutdown for 70% of the year.

Because the suction piping for the SI pumps is cross-connected upstream of valves 8923A and 8923B, it is possible that hydrogen gas in the charging pump suction piping could migrate to the second SI pump during recirculation. A sensitivity analysis was performed to assess the impact of this possibility on event significance.

Analysis Results

The conditional probability of core damage estimated for this event is 6.2×10^{-5}. The dominant core damage sequence, highlighted on the following event tree, involves a postulated small-break LOCA, auxiliary feedwater and high-pressure injection success, and failure of high-pressure recirculation.

If the second SI pump were to be damaged by hydrogen traveling through the cross-connect in the pump suctions, then the significance of the event is much higher — 6.3×10^{-3} based on the current Accident Sequence Precursor models and 2.1×10^{-3} using revised models currently under development. For this to occur, however, sufficient hydrogen would have to expand into the charging pump suction piping to damage both charging pumps and SI pump 1A, and also travel (via valves 8923A and 8923B) to the suction of SI pump 1B.

LER 445/90-035 (documented in Appendix C to the 1990 precursor report) describes another event at Comanche Peak involving potential charging pump damage caused by hydrogen. In that event, incorrect design and installation of vent valves between the pump suction piping and the VCT prevented venting of hydrogen in the suction lines back to the VCT, but did not prevent hydrogen from traveling from the VCT to the pumps.

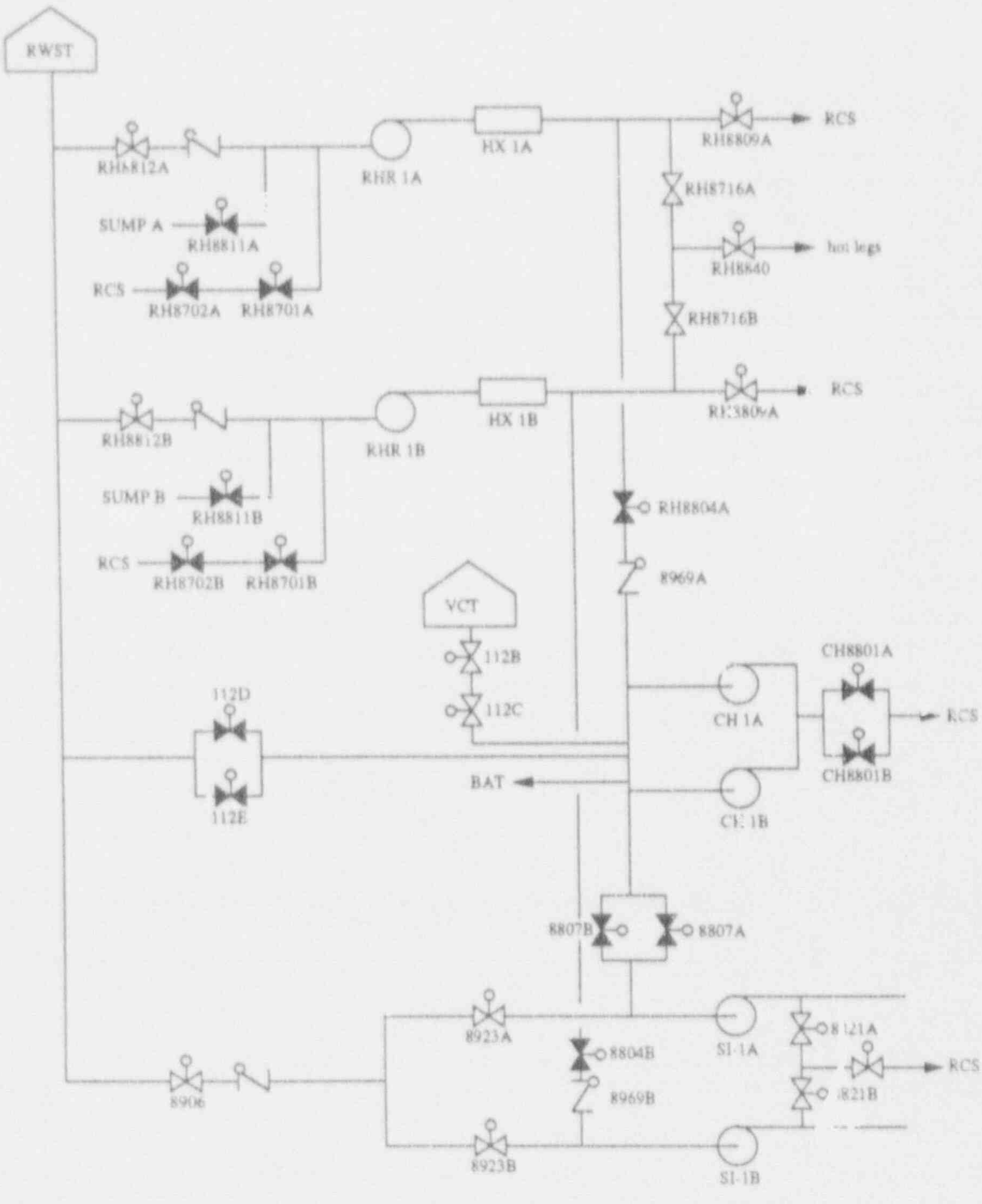
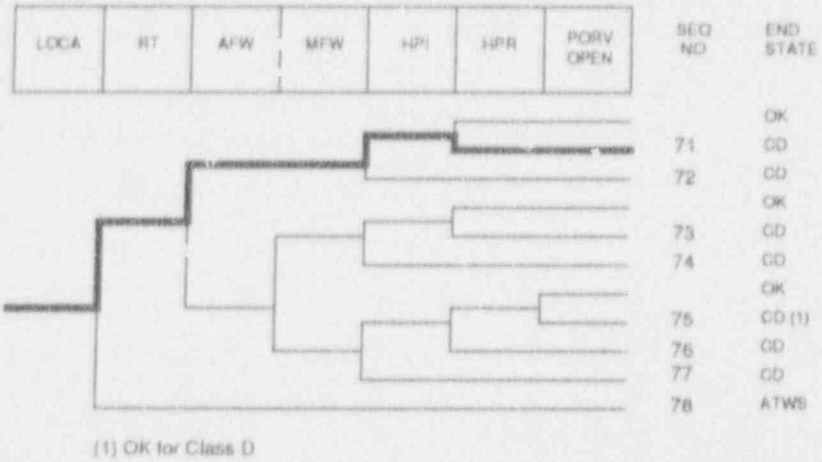


Fig. 1. Comanche Peak Safety Injection Systems



Dominant core damage sequence for LER 445/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 445/91-012
Event Description: Potential charging pump unavail due to hydrogen voids
Event Date: 03/26/91
Plant: Comanche Peak 1

UNAVAILABILITY, DURATION= 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	4.5E+00
LOOP	5.3E-02
LOCA	6.7E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	1.3E-07
LOOP	1.8E-07
LOCA	6.2E-05
Total	6.2E-05
ATWS	
TRANS	0.0E+00
LOOP	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	6.2E-05	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	6.2E-05	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:\asp\1989\pwrbaseal.cmp
BRANCH MODEL: c:\asp\1989\comanch1 sll
PROBABILITY FILE: c:\asp\1989\pwr_bsll.pro

No Recovery Limit

Event Identifier: 445/91-012

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.4E-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	8.0E-01	
afw	3.8E-0[illegible]	2.6E-01	
afw/emerg.power	5.0E-[illegible]	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)	5.8E-01	1.0E+00	
ep.rec	1.8E-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 > 1.0E-02	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

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07-27-1992
09:59:14

Event Identifier: 445/91-012

Enclosure to TXX-91145

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

Facility Name (1): COMANCHE PEAK - UNIT 1
Docket Number (2): 0 5 0 0 0 4 4 5
Page (3): 1 OF 0 6

Title (4): POTENTIAL GAS BINDING OF CENTRIFUGAL CHARGING PUMPS DUE TO VOIDS IN THE BORIC ACID GRAVITY FEED LINE

Event Date (5): Month 0 3 Day 2 6 Year 9 1
LER Number (6): Year 9 1 - Sequential Number 0 1 2 - Revision Number 0 0
Report Date (7): Month 0 4 [illegible]
Other Facilities Involved (8): Facility Names N/A; Docket Numbers 0 5 0 0 0 [illegible]; 0 5 0 0 0 [illegible]

Operating Mode (9): 5
Power Level (10): 0 0 0

This report is submitted pursuant to the requirements of [illegible]: 20.402(b); 20.405(a)(1)(i); 20.405(a)(1)(ii); 20.405(a)(1)(iii); 20.405(a)(1)(iv); 20.405(a)(1)(v); 20.405(c); 50.36(c)(1); 50.36(c)(2); 50.73(a)(2)(i); 50.73(a)(2)(ii); 50.73(a)(2)(iii); [X] 50.73(a)(2)(iv); 50.73(a)(2)(v); 50.73(a)(2)(vii); 50.73(a)(2)(viii)(A); 50.73(a)(2)(viii)(B); 50.73(a)(2)(x); 73.71(b); 73.71(c); Other (Specify in Abstract below and in Text, NRC Form 366A)

Licensee Contact For This LER (12)

Name: T. A. HOPE, COMPLIANCE SUPERVISOR
Telephone Number: Area Code 8 1 7 8 9 7 - 6 3 7 0

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)

[ ] Yes (If yes, complete Expected Submission Date) [X] No

Expected Submission Date (15): Month | Day | Year

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

Ultrasonic examination of the Chemical and Volume Control System (CVCS) suction piping was performed on March 4, through March 15, 1991. These examinations revealed voids in the alternate boration line and the gravity feed line from the Boric Acid Storage Tank (BAT). Engineering evaluation shows that voids in the alternate boration line would not affect operability of the Centrifugal Charging Pumps (CCPs). However, engineering evaluation indicates that the void in the gravity feed line from the BAT could cause damage to or gas binding of the CCPs.

The potential root cause was identified as hydrogen coming out of solution, in the lower pressure CCP suction header. Corrective actions include daily venting of the gravity feed line and further monitoring for hydrogen accumulation. Based on the results of this monitoring, venting requirements will be established.

Enclosure to TXX-91145

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

Facility Name (1)	Docket Number (2)	LER Number (6) Year	Sequential Number	Revision Number	Page (3)
COMANCHE PEAK - UNIT 1	0 5 0 0 0 4 4 5	9 1	- 0 1 2 -	0 0	0 2 OF 0 6

Text (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF THE REPORTABLE EVENT

A. REPORTABLE EVENT CLASSIFICATION

Any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to shutdown the reactor and maintain it in a safe condition, or mitigate the consequences of an accident.

B. PLANT OPERATING CONDITIONS PRIOR TO THE EVENT

On March 26, 1991, Comanche Peak Steam Electric Station (CPSES) Unit 1 was in Mode 5, Cold Shutdown, with the Reactor Coolant System (RCS) (EIIS:(AB)) at a temperature of 130 degrees Fahrenheit and pressure of approximately 300 pounds per square inch-gage.

C. STATUS OF STRUCTURES, SYSTEMS, OR COMPONENTS THAT WERE INOPERABLE AT THE START OF THE EVENT AND THAT CONTRIBUTED TO THE EVENT

There were no inoperable structures, systems or components that contributed directly to the event.

D. NARRATIVE SUMMARY OF THE EVENT, INCLUDING DATES AND APPROXIMATE TIMES

On October 29, 1990, Westinghouse sent a letter to CPSES regarding the formation and venting of hydrogen in the Chemical and Volume Control System (CVCS) (EIIS:(CB)) in response to Nuclear Regulatory Commission (NRC) Information Notice (IN) 90-64, "Potential for Common-Mode Failure of High Pressure Safety Injection Pumps or Release of Reactor Coolant Outside Containment During a Loss-of-Coolant Accident." In this letter Westinghouse, identified locations in the CVCS suction piping where gases would tend to accumulate. Westinghouse recommended ultrasonic examination to monitor the rate at which gas accumulates in these locations.

Enclosure to TXX-91145

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION		APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		

Facility Name (1)	Docket Number (2)	LER Number (6) Year	Sequential Number	Revision Number	Page (3)
COMANCHE PEAK - UNIT 1	0 5 0 0 0 4 4 5	9 1	- 0 1 2 -	0 0	0 3 OF 0 6

Text (If more space is required, use additional NRC Form 366A's) (17)

From March 4, 1991, through March 15, 1991, ultrasonic examination of various locations of the CVCS suction piping was performed. Locations examined included the 8 inch diameter suction header; the Positive Displacement Charging Pump (PDP) (EIIS:(P)(CB)) suction line; the Centrifugal Charging Pump (CCP)-02 (EIIS:(P)(CB)) miniflow line; and all of the vertical piping connected to the 8 inch diameter suction header, including alternate boration, boric acid filter, chemical feed, and the gravity feed line from the Boric Acid Storage Tank (BAT) (EIIS:(TK)(CB)).

The ultrasonic examinations revealed voids in two locations, the 2 inch diameter alternate boration line and the 3 inch diameter gravity feed line from the BAT. The size of the void identified in the alternate boration line was determined to be relatively small. Engineering evaluation shows that a void in this line would not cause any significant degradation in CCP or PDP performance, or affect operability of the Emergency Core Cooling System (ECCS) (EIIS:(BQ)). The size of the void found in the BAT gravity feed line was much larger. Engineering evaluation indicates that this void could potentially cause damage to or gas binding of the CCPs when the BAT gravity feed line is used for boration, forcing the gas bubble into the suction header, or when pressure conditions change causing expansion of the bubble into the suction header.

On March 26, 1991, this event was recorded via the appropriate administrative procedure. The reportability of this event was uncertain at first, however, after further evaluation it was determined to be reportable at 1645 on March 28, 1991. At 1840 on March 28, 1991, the NRC Operations Center was notified via the Event Notification System.

E. <u>THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE OR PROCEDURAL ERROR</u>

Ultrasonic examination of various locations of the CVCS suction piping was performed due to concerns expressed by Westinghouse in their October 29, 1990, letter. As a result of the examinations, conducted from March 4, 1991, through March 15, 1991, voids in two locations of CVCS suction piping were identified.

II. COMPONENT OR SYSTEM FAILURES

A. FAILURE MODE, MECHANISM, AND EFFECT OF EACH FAILED COMPONENT

Not applicable - there were no component failures associated with this event.

B. CAUSE OF EACH COMPONENT OR SYSTEM FAILURE

Not applicable - there were no component failures associated with this event.

C. SYSTEMS OR SECONDARY FUNCTIONS THAT WERE AFFECTED BY FAILURE OF COMPONENTS WITH MULTIPLE FUNCTIONS

Not applicable - there were no component failures associated with this event.

D. FAILED COMPONENT INFORMATION

Not applicable - there were no component failures associated with this event.

III. ANALYSIS OF THE EVENT

A. SAFETY SYSTEM RESPONSES THAT OCCURRED

Not applicable - there were no component failures associated with this event.

B. DURATION OF SAFETY SYSTEM TRAIN INOPERABILITY

Not applicable - there were no safety systems which were rendered inoperable due to a failure.

Enclosure to TXX-91145

NRC FORM 366A	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

Facility Name (1)	Docket Number (2)	LER Number (6) Year	Sequential Number	Revision Number	Page (3)
COMANCHE PEAK - UNIT 1	0 5 0 0 0 4 4 5	9 1 -	0 1 1 2 -	0 0	0 5 OF 0 6

Text (If more space is required, use additional NRC Form 366A's) (17)

C. SAFETY CONSEQUENCES AND IMPLICATIONS OF THE EVENT

The operability of two independent ECCS subsystems, as required by Technical Specifications 3/4.5.2, ensures that sufficient emergency core cooling capability will be available in the event of a Loss of Coolant Accident assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the accumulators (EIIS:(ACC)(BP)) is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits.

During this event the potential for gas binding of the CCPs existed due to void accumulation in the CVCS suction piping. This increased the probability of a common-mode failure of both independent ECCS subsystems.

IV. CAUSE OF THE EVENT

ROOT CAUSE

Evaluation of this event has identified the potential root cause to be hydrogen coming out of solution in the lower pressure CCP suction header and collecting in the vertical piping. This phenomenon is not present under current plant conditions (Mode 5), and therefore cannot be verified until normal RCS hydrogen concentration is re-established.

V. CORRECTIVE ACTIONS

A. IMMEDIATE

The gravity feed line from the BAT was vented. Administrative controls were established to vent this line daily.

Facility Name (1)	Docket Number (2)	LER Number (6) Year	Sequential Number	Revision Number	Page (3)
COMANCHE PEAK - UNIT 1	0 5 0 0 0 4 4 5	9 1	- 0 1 2	- 0 0	0 6 OF 0 6

Text (If more space is required, use additional NRC Form 366A's) (17)

B. CORRECTIVE ACTIONS TAKEN TO PREVENT RECURRENCE

ROOT CAUSE

Evaluation of this event has identified the potential root cause to be hydrogen coming out of solution in the lower pressure CCP suction header and collecting in the vertical piping.

CORRECTIVE ACTION

The gravity feed line from the BAT will be monitored for hydrogen accumulation upon return to normal hydrogen concentration in the RCS. Based on the results of this monitoring, venting requirements will be established.

VI. PREVIOUS SIMILAR EVENTS

On October 4, 1990, NRC IN 90-64 was issued. During evaluation of IN 90-64 it was concluded that a design error existed that could result in the common-mode failure of the CCPs due to gas binding (the CCP suction piping, high point, solenoid-operated isolation vent valves (SOIV) (EIIS:(FSV)(CB)) were oriented in the wrong direction). This condition was addressed in Licensee Event Report (LER) 90-035.

As a result of the October 29, 1990, letter from Westinghouse addressing the SOIV orientation, various locations in the CVCS suction piping were identified as having the potential for gas to accumulate. The subsequent ultrasonic examinations are the subject of this LER (91-012).

VII. ADDITIONAL INFORMATION

The times listed in the report are approximate and Central Standard Time.

Appendix C

CONTAINMENT-RELATED AND OTHER EVENT DOCUMENTATION

Appendix C

CONTAINMENT-RELATED AND OTHER EVENT DOCUMENTATION

This appendix contains documentation for 1991 operational events identified in the Accident Sequence Precursor (ASP) Program that involve

- unavailability of containment isolation, containment cooling, containment spray, or post-accident hydrogen control;
- other events that cannot currently be modeled in the ASP Program (primarily shutdown-related events).

For each event, a description is provided, along with the applicable LER. A table of contents, Table C.1, is also provided.

Note that copies of LERs used in the ASP Program are also used in other Oak Ridge National Laboratory programs and may contain markings made during abstracting and coding in those programs.

Table C.1. Index of containment-related and other events

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	255/91-017
Event Description:	Reactor coolant pump seal heat exchanger tube failure could result in loss of coolant outside containment
Date of Event:	August 5, 1991
Plant:	Palisades

Summary

An engineering analysis at Palisades determined that the failure of a reactor coolant pump seal cooler tube could fail the component cooling water (CCW) system and result in a nonisolable loss of reactor coolant outside containment.

Event Description

Reactor coolant pump (RCP) seals at Palisades are cooled by heat exchangers in which heat is transferred to the CCW system. Failure of a cooling water tube in an RCP seal heat exchanger would allow high-pressure reactor coolant system (RCS) inventory to flow into the low-pressure CCW system. There are isolation valves in the CCW system supply and return lines for the containment; however, the utility analysis does not indicate that these valves could be closed against RCS pressure. In addition, these containment isolation valves receive a signal to close on high containment pressure, which would not exist. Failure of an RCP seal heat exchanger tube thus could result in a uncontrolled release of up to 55 lbm/s (approximately 550 gpm) until primary pressure was reduced into the range of CCW pipe design pressure, 150 psig. As CCW system relief valve capacity is inadequate for this event, pressures of up to 1400 psig would be expected, and failures in the CCW piping system might occur. One likely point of failure would be the CCW surge tank, as surge tanks are typically rated for only a few psig. Similar analyses for Palo Verde (see LER 528/91-001) suggested that up to several hundred thousand gallons of reactor coolant could be released outside containment before pressure in the CCW piping dropped sufficiently to permit isolation.

In addition to the RCP seals, the CCW system provides cooling for the following: fuel pool heat exchangers, radwaste evaporator, charging pump seals, shutdown cooling heat exchangers, waste gas compressor and aftercooler, vacuum pump seal water cooler, low-pressure safety injection (LPSI) pump seal coolers, high-pressure safety injection (HPSI) pump seal coolers, containment spray (CS) pump seal coolers, reactor shield cooling system, letdown heat exchanger, and the control rod drive mechanisms.

An RCP seal heat exchanger tube failure could be expected to result in loss of CCW cooling to the above loads. An alternate service water supply exists for the LPSI, HPSI, and CS pump seal coolers. Notable among the other loads that would be lost are the shutdown cooling heat exchangers, which provide cooling for sump recirculation as well as for shutdown cooling, and the charging pumps. Loss of the charging pumps, in conjunction with the loss of CCW, would remove all cooling from the other three RCP seals. This could potentially cause additional seal failures. Substantial releases of RCS inventory are thus possible within the containment, as well as without. High-pressure and low-pressure injection capability would be unaffected; however, shutdown cooling and sump recirculation functions would be lost.

A preliminary evaluation of the radiological consequences of these failures by the utility indicates that offsite doses could exceed 10CFR100 limits within 90 min.

ASP Modeling Assumptions and Approach

This event was not modeled as an accident sequence precursor.

NRC Form 366

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Palisades Plant	0 5 0 0 0 2 5 5	1 OF 0 5

TITLE (4): POTENTIAL INTER-SYSTEM LOCA WITHIN THE PRIMARY COOLANT PUMP

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 NAMES	DOCKET NUMBER(S)
0 8	0 5	9 1	9 1	0 1 2	0 0	0 9	0 5	9 1	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9)	N
POWER LEVEL (10)	1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: X OTHER (Specify in Abstract below and in Text, NRC Form 366A) — Informational

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Cris T Hillman, Sr Licensing Engineer	6 1 6 7 6 4 - 8 9 1 3

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
NA									

SUPPLEMENTAL REPORT EXPECTED (14): YES (If yes, complete EXPECTED SUBMISSION DATE) / X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

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

ABSTRACT

At 1000 hours on August 5, 1991, the plant was operating at approximately 100% power. An evaluation by the Reactor and Safety Analysis engineering group determined that a postulated break in the primary coolant pump (PCP) integral heat exchanger could result in a primary coolant system leak outside the containment building. This determination was based on Palisades specific calculations developed as a result of the review of Information Notice No. 89-54, "Potential Overpressurization of the Component Cooling Water System." A preliminary evaluation of the radiological consequences resulting from an inter-system LOCA within the primary coolant pump indicates that, if the leak was not isolated, the site boundary thyroid dose limit, as specified in 10 CFR 100, would be exceeded in approximately 90 minutes.

The postulated failure leading to an inter-system LOCA within the primary coolant pump was not covered in the original design basis of the plant.

Corrective action for this event includes determining the appropriate modifications to address the issue and documenting the radiological consequences analysis of an inter-system LOCA within the primary coolant pump.

NRC Form 366

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 1	— 0 1 7 —	0 0	0 2 OF 0 5

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

EVENT DESCRIPTION

At 1000 hours on August 5, 1991, the plant was operating at approximately 100% power. An evaluation by the Reactor and Safety Analysis engineering group determined that a postulated break in the primary coolant pump (PCP) integral heat exchanger [AB;HX] could result in a primary coolant system leak outside the containment building [NH]. This determination was based on Palisades specific calculations developed as a result of the review of Information Notice No. 89-54, "Potential Overpressurization of the Component Cooling Water System."

Background

The NRC issued an Information Notice No. 89-54, "Potential Overpressurization of the Component Cooling Water System" on June 23, 1989. Its purpose was to alert licensees to potential problems resulting from failure of the component cooling water (CCW) tubing within the integral heat exchanger of the primary coolant pump (PCP). The notice also described design deficiencies of the CCW tubing at Surry Power Station reported by the licensee.

Discussion

Four identical Byron-Jackson primary coolant pumps [AB;P] are installed at Palisades. The primary coolant at the integral heat exchanger [AB;HX] is pressurized to about 2060 psia with a temperature of approximately 540°F. The CCW system [CC] has a design pressure of 150 psig and a design temperature of 140°F. In the event of a postulated inter-system LOCA, primary coolant would enter the CCW system and pressurize the CCW system beyond its design pressure. The possibility of a LOCA occurring within the PCP was not previously analyzed at Palisades.

Based on the information provided in IN 89-54, Palisades performed an analysis to evaluate overpressure protection requirements of the CCW system in the event of failure of the PCP integral heat exchanger tubing. The analysis identified a postulated scenario in which a double ended guillotine break of a tube in the PCP heat exchanger would result in overpressurization of the CCW system with potential for a leakage path outside the containment building.

A preliminary evaluation of the radiological consequences of the inter-system LOCA was performed. For this evaluation it was conservatively assumed that all the leaking primary coolant was released directly to the atmosphere with no holdup. Two cases were assumed in the evaluation; one being an event generated iodine spike and the other a pre-accident iodine spike. Similar results were produced for both cases and showed that, if the leak was not isolated, the site boundary thyroid dose limit, as specified in 10 CFR 100, would be exceeded in approximately 90 minutes.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 1	0 1 7	0 0	0 3 OF 0 5

This event is being reported to the NRC as an informational licensee event report.

CAUSE OF THE EVENT

This licensee event report did not involve the failure of any equipment important to safety.

The postulated failure leading to an inter-system LOCA within the primary coolant pump was not addressed in the original design basis of the plant. This is a low probability event that requires a complete break of the PCP integral heat exchanger tubing. A break of this tubing is unlikely considering the geometry of the PCP.

ANALYSIS OF THE EVENT

Various break locations were considered within the PCP integral heat exchanger. The worst location of such a break would be at the inlet weld area of the tube side of the heat exchanger which contains the primary coolant. A break at this area would result in maximum flow due to the least flow resistance in the direct path (see Figure 1). A parallel path is also available for the primary coolant. This is reverse flow via the flow path that cools the seal package from the heat exchanger (see Figure 1). In order to maximize the flow from the PCS, a double-ended guillotine break was assumed. A RETRAN (EPRI transient thermal-hydraulic code) model to simulate this break, with and without the parallel path, was developed. The model incorporates the specific geometry of the Palisades Byron-Jackson pumps and the inter-connected CCW system.

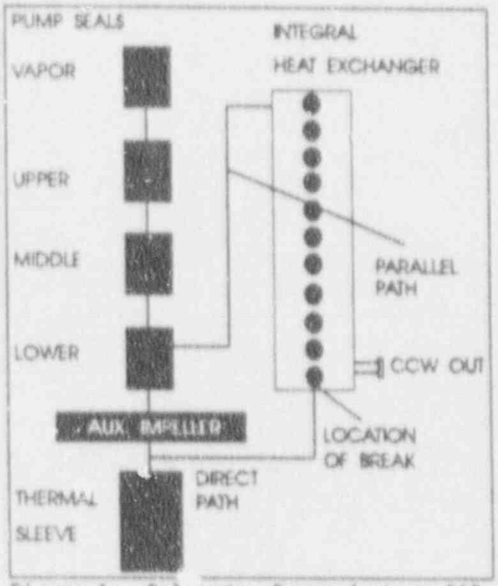

Figure 1: Palisades Byron-Jackson PCP Integral Heat Exchanger

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Palisades Plant	0 5 0 0 0 2 5 5	9 1	— 0 1 2	— 0 0	0 4 OF 0 5

ASSUMPTIONS

1. Various break locations that would cause an inter-system LOCA were considered. A break at the inlet tubing weld of the integral heat exchanger was considered most credible and is also the most conservative break for this analysis. The break was assumed to take place at the entrance weld to the heat exchanger tube side. Primary coolant system (PCS) fluid enters the CCW system at the break (shell side of PCP heat exchanger).

2. In order to simplify the model, the semicircular path to the CCW exit from the tube side break location is assumed to be an extension of the tube side up to the CCW exit location. This assumption adds to the conservatism in this analysis.

3. A third relief valve (RV-2108) is available on the CCW inlet line to the PCP integral heat exchanger. (The first two relief valves are RV-0956 and RV-0939). This is located in the reactor shield cooling system. Relief provided by this valve is in the order of 15 gpm at 150 psig, and was conservatively omitted for the analysis.

RESULTS

A postulated inter-system LOCA event caused by a failure of tubing within the primary coolant pump integral heat exchanger was simulated using RETRAN-02. Primary coolant enters the component cooling water system. Rapid pressurization of the CCW system is observed. The occurrence of this postulated accident under current conditions would produce a maximum pressure and temperature in the CCW system of approximately 1416 psia and 544°F, respectively, assuming no pipe failure.

A model using a relief valve designed to pass the flow required to maintain the CCW system pressure at 150 psig was developed. The results showed CCW pressures to be higher than expected. This was due to critical flow upstream of relief valves RV-0956 and RV-0939. The flow rate that should be relieved to keep the CCW system pressure below the permitted maximum of 150 psig is ≈55 lbm/sec. However, this relief capacity cannot be obtained purely by using larger safety relief valves because of critical flow conditions upstream of relief valves RV-0956 and RV-0939. When a significantly larger relief valve replacing RV-0939 only was modeled, it was observed that the CCW system pressure downstream of the relief valves was maintained at about 150 psig and 400°F. However, piping upstream of the relief valves developed pressures higher than the design pressure of 150 psig. Pressures of about 950 psig were observed in the PCP integral heat exchanger. Brief pressure spikes throughout the CCW system, following critical flow occurrences in the relief valves, were observed. These spikes lasted for a few seconds and reached about 200 psig. Further analysis is required to determine modifications to the system.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Palisades Plant	0 5 0 0 0 2 5 5	9 1	— 0 1 7	— 0 0	0 5 OF 0 5

Another factor that was considered was the PCP seal integrity issue. Due to the failure of the PCP integral heat exchanger and the resultant rapid invasion of the primary coolant, a nearly instantaneous temperature rise in the PCP seal area is observed. The high temperature of about 540°F could initiate degradation of the PCP seals. Any leakage through these seals would be confined to the containment building and would not worsen the radiological consequences.

CONCLUSIONS

The study conducted on the PCP inter-system LOCA for Palisades has determined the need for increased relief capacity. By providing increased relief capacity, the CCW system outside of the containment can be maintained at about 150 psig. Further increases in relief valve capacity (size) will not contribute to a further reduction in CCW pressure because of the critical flow phenomenon observed upstream of the relief valves.

CORRECTIVE ACTION

Prior to the development of the corrective action related to this event, operator training on the issue of an interfacing system LOCA and an inter-system LOCA was in progress. The event described in IN 89-54 is being used as an example of an inter-system LOCA.

Proposed corrective action that was developed as a result of the evaluation of this event includes:

1. Determine the appropriate modifications or alternatives to address the issue. Include in the evaluation of proposed modifications or alternatives a cost/benefit analysis, PRA analysis and radiological consequences analysis.

2. Document the radiological consequences analysis for an inter-system LOCA within the PCP under current plant conditions.

ADDITIONAL INFORMATION

No previous similar events have been reported in accordance with 10 CFR 50.73.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	260/91-013
Event Description:	Both containment airlock doors open at same time
Date of Event:	June 5, 1991
Plant:	Browns Ferry 2

Summary

Unauthorized personnel action resulted in disarming of the drywell airlock interlock and simultaneous opening of both the inner and outer airlock doors, resulting in loss of primary containment integrity.

Event Description

During the power ascension test program at Browns Ferry 2 with the reactor critical at <1% power and 150 psig, three mechanical maintenance craftsmen were supporting in-containment thermal expansion testing through operation of the drywell airlock doors. Based on a brief discussion with a radiological controls technician, one of the craftsmen violated procedures by disarming the airlock interlock and opening both the inner and outer airlock doors simultaneously, thereby allowing direct access to the drywell.

The craftman informed his foreman and general foreman of this action, who failed to notify the shift operations supervisor (SOS). The drywell doors remained open for approximately 4 h before the airlock status was questioned and reported to the SOS. Primary containment integrity was reestablished 45 min after the report to the SOS. At the time of this event, the reactor was in startup mode with the vessel pressure at 150 psig.

Additional Event-Related Information

Browns Ferry 2 is a boiling-water reactor (BWR) with a Mark I pressure suppression containment. Loss of integrity of the primary containment shell provides a direct pathway to the reactor building, bypassing the suppression pool, for postulated radiological releases from the reactor vessel or in-containment piping.

ASP Modeling Assumptions and Approach

Since this is a containment-related event, it has not been modeled for potential core damage significance.

NRC Form 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

Approved OMB No. 3150-0104
Expires 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Browns Ferry Unit 2

DOCKET NUMBER (2): 0|5|0|0|0| 2| 6| 0

PAGE (3): 1 OF 1 2

TITLE (4): Technical Specification Violation Following Loss of Primary Containment Caused by Personnel Error

EVENT DAY (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 6	0 5	9 1	9 1	0 1 3	0 1	0 7	1 9	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

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

__ 20.402(b)	__ 20.405(c)	__ 50.73(a)(2)(iv)	__ 73.71(b)
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	__ 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ OTHER (Specify in Abstract below and in Text, NRC Form 366A)
__ 20.405(a)(1)(iii)	X 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	
__ 20.405(a)(1)(iv)	__ 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: Stewart A. Wetzel, Compliance Licensing Engineer

TELEPHONE NUMBER: AREA CODE 2 0 5 | 7 2 9 - 2 0 4 8

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)

__ YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On June 5, 1991 at approximately 0245 hours a loss of primary containment integrity occurred when both drywell personnel airlock doors were opened. This condition occurred after the interlock which prevents both doors from being simultaneously open was disarmed. Upon notification the Shift Operations Supervisor re-established primary containment integrity at approximately 0645 hours.

The root cause of this event was an unauthorized personnel action. The individual involved (utility, non-licensed) performed unauthorized work by disarming the interlock on the drywell airlock. A contributing cause of this event was the lack of action taken by those in the direct area during the event.

The corrective actions to address the specifics of this event included general and specialized training for plant personnel, procedure enhancements to ensure Operations personnel are responsible for the operation of the drywell doors, and personnel corrective action in accordance with TVA policy. In addition, TVA performed an independent review to identify areas in which improvements were prudent to further enhance maintenance-related activities and to reinforce requisite operational attitudes. This review resulted in additional procedure improvements, guidelines to enhance pre-test briefings, and identification of future training upgrades.

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DESCRIPTION OF EVENT

On June 5, 1991 at approximately 02[illegible] hours a loss of primary containment integrity occurred when both drywell personnel airlock doors were opened. This condition occurred after the interlock which prevents both doors from being simultaneously open was disarmed.

During the power ascension test program, entries were required to verify proper thermal expansion of primary system piping. This testing was being performed in accordance with Test Instruction (TI) 190, System Thermal Expansion, with reactor coolant system pressure at approximately 150 psig. Mechanical Maintenance craftsmen were designated to operate the drywell airlock doors. These individuals were the assigned and qualified personnel to perform this task.

At approximately 0040 hours on June 5, 1991 three Mechanical Maintenance craftsmen were dispatched to perform the task of operating the airlock doors to support the thermal expansion testing. After supporting three entries into the drywell to determine the radiological conditions, a brief discussion took place between one of the three Maintenance craftsmen and a Radiological Controls technician. Based on this discussion the craftsman understood it was acceptable to defeat the airlock interlock and open both inner and outer doors, providing an unobstructed pathway into the drywell. After defeating the airlock interlock, the craftsman reported his action to his foreman and general foreman. These individuals did not question this action and failed to notify the Shift Operations Supervisor (SOS).

At approximately 0600 hours on June 5, 1991 the status of the airlock was questioned and the condition reported to the SOS. (The method utilized to defeat the airlock interlock had caused the door position indication in the control room to be erroneous.) Following this notification the SOS took appropriate actions and reestablished primary containment integrity at approximately 0645 hours.

At the time of this event Unit 2 was in the startup mode with a reactor moderator temperature of 365 degrees Fahrenheit and a reactor vessel pressure of 150 psig. No fuel handling or operations over spent fuel were in progress. The loss of primary containment is a violation of Technical Specification 3.7.A.2, which is reportable in accordance with 10 CFR 50.73(a)(2)(i).

ANALYSIS OF EVENT

A. Introduction

The safety significance of this event was evaluated assuming the primary containment airlock doors were both open for approximately

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four hours on June 5, 1991. The plant conditions existing at the time of this event are listed in Table 1 below.

Table 1

Plant Operating Conditions Prior to the Primary Containment Breach Event

Reactor Status: Critical <1% Full Power
SCRAM Setpoint: 15% Full Power
Primary System Pressure: 150 PSIG
Primary System Temperature: 365°F
Decay Heat Load: <0.04% Full Power
Fuel Fission Product Inventory: <1% of the Safety Analysis Assumption
Reactor Coolant Fission Product Inventory: 0.0001% of the Safety Analysis Assumption for Failed Fuel

The plant design philosophy provides multiple barriers to fission product release: 1) the fuel cladding, 2) the primary system boundary, and 3) the primary containment. In addition, a secondary containment ensures filtered release of any leakage from the primary barriers. During this event the primary containment was functionally disabled such that the remaining two barriers and the secondary containment were relied upon to protect the public health and safety. This constituted a decreased overall capability to mitigate a postulated accident and thus increased the probability that an accident, had it occurred during that time frame, would result in the release of fission products and radiological dose consequences to the public. However, the plant operating conditions that existed at the time of the event presented a greatly reduced source term, a reduced challenge to safety systems and a reduced challenge to the primary system boundary such that there was no significant impact on public health and safety.

B. Analysis of Postulated Events

Design basis accidents and transients which could occur in the startup/hot shutdown condition and which challenge the fuel cladding and primary system barriers are a stuck open relief valve, control rod drop accident, small break loss of coolant accident, and large break loss of coolant accident. Each is discussed below.

1. Stuck Open Relief Valve

In the event that a single relief valve inadvertently opened, the reactor would have depressurized by exhausting steam to the suppression pool via the relief valve tail pipe. The energy stored in the coolant and reactor assembly would have been transferred to the suppression pool. Fuel cladding integrity would have been maintained by keeping the core submerged with water injected by low pressure pumps. Non safety-related condensate and condensate booster pumps were running and capable of injecting makeup water, and safety-related RHR and core spray pumps were available to automatically start and restore level. Fission products would have remained within the fuel cladding and radiological release from the open primary containment would have been well below 10 CFR 100 limits after being filtered by standby gas treatment prior to release from the plant stack. The probability of this event occurring during a four hour period is 5.3 x 10^{-5} based on full power rated conditions.

2. Control Rod Drop Accident

   In the unlikely event of a control rod drop accident, energy deposition in the affected fuel elements may result in localized fuel cladding failure and fission product release into the reactor coolant. Had this occurred, the fission products would have been retained within the reactor coolant system and the lack of primary containment integrity would not have been a factor. The very low decay heat combined with the low initial system pressure would have allowed the primary system to contain the heat produced and would not have required steam release to maintain system pressure below rated. The main steam isolation valves were closed throughout the event and thus there would have been no release via the main condenser. Reactor coolant and fission products would have been contained within the reactor coolant system and would not have been released to the primary containment unless an unrelated passive equipment failure such as a pipe break, seal failure, or inadvertent relief valve actuation is assumed, and the probability of these events is extremely low. Thus the lack of containment integrity would not have a significant impact on the consequences of a control rod drop accident initiated with the plant conditions existing at the time if the event. The probability of occurrence of a control rod drop accident is much less than 1.0 x 10^{-6}.

3. Loss of Coolant Accident - Small Break

   In the event of a small pipe break (approximately 0.01 ft^2) or a recirculation pump seal failure, reactor coolant would be released to the primary containment at a rate within the makeup capability of the high pressure systems to maintain water level above the top of the core. If normal makeup systems did not maintain water level, the reactor would scram and ECCS systems would automatically start to maintain water level over the core. The liquid portion would accumulate in the lower levels of the drywell, and a significant amount would be released through the breach to the secondary containment as steam. The

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reactor would gradually depressurize as the lost reactor coolant is replaced with cooler makeup water. The steam released would not be sufficient to pressurize secondary containment and thus secondary containment would stay intact. Fuel cladding integrity would have been maintained since the core would remain covered. Radiological dose offsite would be well below 10 CFR 100 limits due to the lack of fuel damage, the low fission product inventory in the reactor coolant, and the design function of the secondary containment.

A small break LOCA or recirculation pump seal failure with primary containment open would expose equipment located within the reactor building to more severe environmental conditions. Because fuel damage would not occur, radiation dose to equipment would be less than that assumed for environmental qualification. Temperatures in some areas of the reactor building would exceed those assumed for environmental qualification for 10 CFR 50.49 although to a much lesser extent than in a large break. For 10 CFR 50.49 equipment needed to safely shut down the reactor, documentation is available to demonstrate that it will perform its safety function. Further, if a loss of offsite power is not assumed to occur, the condensate and control rod drive systems would have been available and capable of maintaining water level.

The probability of a small break LOCA occurring during a four hour period is 1.95×10^{-5}.

4. Loss of Coolant Accident - Large Break

In the unlikely event of a design basis pipe rupture inside primary containment, primary coolant would be discharged from the break in the form of liquid and steam. The reactor would rapidly depressurize and the water level would rapidly decrease. Low water level signals would automatically initiate a reactor scram and low pressure ECCS systems would automatically initiate to provide core cooling. The liquid portion would accumulate in the lower levels of the drywell and spill into the torus while with the primary containment doors open a significant amount of steam would be released into the secondary containment. Secondary containment would become pressurized and relief panels within the building and on the refueling floor would actuate. Fuel cladding integrity would have been maintained due to the design response of the ECCS systems. Radiological release, had it occurred, would be limited to the activity in the reactor coolant which was small due to the low power and lack of recent core power history.

Because fuel damage would not occur, the radiation dose to equipment would be less than that assumed for environmental qualification. Energy discharged from the break and out of the primary containment doors would

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create temperatures in excess of environmental qualification temperatures utilized for 10 CFR 50.49 analyses for some areas of the reactor building. Although this reduces the reliability of the affected equipment, there is a high probability that a minimum complement of ECCS equipment would remain capable of providing adequate core cooling. The core cooling requirements were greatly reduced during the event due to the low decay heat thus reducing the challenge to core cooling systems. Therefore, there was excess margin in available ECCS equipment. ECCS systems and associated electrical equipment and instrumentation are generally distributed throughout the reactor building such that all ECCS functions would not be affected to the same degree by a localized energy release. Equipment located remotely from the containment door opening would have continued to perform its function and the event would not have resulted in a common mode failure of ECCS due to harsh environment.

The dose at the site boundary from release of the existing reactor coolant fission product inventory directly to the environment, and very conservatively taking no credit for primary or secondary containment, was calculated to be 0.96 REM whole body and 65.2 REM thyroid. This is well within the 10 CFR 100 limits of 25 REM and 300 REM respectively.

The probability of a large break LOCA occuring during a four hour period is 1.8×10^{-7}.

5. Risk Assessment

The risk to public health and safety is a function of the probability of occurrence of postulated accidents and the consequences in terms of offsite radiation dose. Some accidents and transients postulated in the FSAR are not possible with the operating conditions that existed during the event, such as turbine trip without bypass. Others as discussed above have insignificant consequences due to the reduced decay heat load and fission product inventory. Accidents such as pipe breaks have a reduced probability of occurrence due to the reduced primary system pressure. As a result of the reduced temperature and pressure conditions at the time of the event, the maximum piping stress (primary and secondary) was less than 17 ksi which is less than 40 percent of the normal allowable stress. Maximum pipe stresses at other locations range down to 25 percent of allowable. These lower stresses provide an important additional margin of safety. Primary plus secondary stress being less than 40 percent of normal allowable stress is a generally recognized point below which critical cracks in intermediate (between terminal end points) pipe locations need not be postulated[1]. Seismologically induced stresses which are a significant part of the total stress for which the primary system piping is designed were not

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present during the event, and the probability of a design basis earthquake occurring in that four-hour timeframe was calculated to be 1.6×10^{-8}. This supports the conclusion that a critical crack was not credible during the event.

Plant conditions were also not sufficient to cause catastrophic failure such as a double ended pipe rupture or a critical pipe crack that is assumed to occur in the design basis accident analysis considering that the system is designed for at least 1146 psig. In NUREG 1061, Volume 3, the NRC Piping Review Committee recognized the leak-before-break (LBB) approach as a valid methodology to justify mechanistically that breaks in high energy fluid system piping need not be postulated. The LBB concept is based on the fact that piping fabricated from tough, ductile materials can tolerate large through-wall cracks without complete failure under service loading.

The LBB approach in conjunction with conservative leak rate monitoring limits used at BFN provide justification that a pipe break was not a credible event under the existing conditions. Drywell leakage monitoring equipment was operable and leakage monitoring was being conducted in accordance with the technical specifications.

The probabilities of occurrence for the events considered in this analysis are based on rated conditions. These probabilities would be further reduced if they had been determined utilizing the actual event conditions. The actual probability of a pipe break would also be substantially less due to the reduced primary pipe stresses associated with reduced system pressure as discussed above.

C. Summary

A review has been made of limiting design basis accidents and transients which could challenge the primary containment during startup and hot shutdown conditions. These included a stuck open relief valve, control rod drop, and small and large break loss of coolant events.

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[1]NRC Branch Technical Position MEB 3-1, Revision 2, June 1987, provides criteria for determining pipe rupture locations in fluid systems. 0.4 times the sum of the stress limits given in NC/ND-3653 of ASME Section III is specified for Class 2 and 3 piping for postulation of critical cracks. This was selected as the most conservative for this evaluation.

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The postulated effects on the environment are greatly limited by the low decay heat, the low actual pressure and temperature, and the availability of necessary safety systems.

TVA's assessment of the safety significance of this event has demonstrated that: (1) the postulation of a double-ended guillotine break is not required, (2) the evaluated events have a low probability of occurrence, (3) the postulation of critical cracks is not required due to low stress levels, and (4) the calculated offsite dose as the result of a worst limiting large break LOCA is well below 10 CFR 100 limits. Thus, the low accident probability in conjunction with plant conditions during the event lead to the conclusion that this event had no actual or potential adverse impact on the health and safety of the public.

CAUSE OF EVENT

The root cause of this event was an unauthorized personnel action. The Mechanical Maintenance craftsman (utility, non-licensed) performed unauthorized work by disarming the interlock on the drywell airlock. Prior to this act the craftsman had received no direction from his supervisor or the SOS to perform this task. In addition, the craftsman did not have written authorization allowing him to perform this work. A contributing cause of this event was the lack of action taken by those in the direct area during the event.

PREVIOUS SIMILAR EVENTS

There have been no previous occurrences of loss of primary containment integrity.

CORRECTIVE ACTIONS

Upon notification immediate corrective action was taken by the SOS to re-establish primary containment integrity.

Corrective actions have been implemented in several areas to address the specifics of this event. The areas and their respective corrective action(s) are provided below.

1. Verbal Communication - Without proper authorization, the Maintenance craftsman modified the assigned scope of work. The foreman and general foreman failed to react to the unauthorized personnel action after becoming aware of it.

   Corrective Actions - Plant management developed an operating plant philosophy training package and conducted employee training sessions for plant personnel from June 7 through June 12, 1991. These sessions provided final event description, plant personnel responsibilities, SOS responsibility/authority, and attitude and response to issues. In addition, the training sessions addressed specific examples of previous events involving poor foreign material control, failures to perform adequate self-verification and problems associated with configuration control and equipment manipulation.

2. Work Practices - The craftsman defeated the interlocks without proper authorization and work documentation as required by plant procedures.

   Corrective Action - In addition to the training described in item 1 above, TVA has trained Maintenance craft and craft supervision on the requirements for the performance and documentation of assigned work. TVA will also provide more in-depth training and will include this type of training in the craft annual training program.

3. Procedure Change Evaluation - Risks and consequences associated with changing the method of defeating interlocks were not adequately reviewed or assessed for applicability during a 1987 revision of the procedure for defeating the interlocks.

   Corrective Actions - Operating instructions have been enhanced to ensure Operations personnel are responsible for operation of the drywell doors. Maintenance instructions for defeating drywell interlocks have been improved to ensure correct drywell airlock door status is indicated in the control room with the interlocks defeated, and to remove responsibility and authority of operation of the drywell airlock from the Maintenance craft. A review of over 2000 plant procedures to ensure that interlock mechanisms are properly controlled has been completed. Based on the results of this review plant procedures are being enhanced as necessary to improve communications.

4. Managerial Methods - Prior to this event, plant management had met with plant personnel on several occasions to emphasize the importance of recognizing that BFN is becoming an operating plant, including the increased technical specification and operating requirements which would be in effect. Discussions included emphasis on correct job performance (e.g., ensure adequate time is taken; ensure each activity is clearly understood, if not, stop; if equipment failures occur, ensure proper actions are taken to determine root cause; self-checking). Several in-house assessments, including independent reviews (e.g., Operational Readiness Review, Senior Management Assessment) were conducted to assess the readiness of personnel to resume operations. While significant improvements were noted, management recognized that continuous, sustained emphasis and actual operating performance would be necessary to obtain desired levels of excellence. Frequent management assessments of operational performance were included in the Power Ascension Program.

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Corrective Actions - Training as discussed in item 1 above was given to plant personnel. Site Quality Assurance (QA) performed surveys to determine the effectiveness of this training. Based on these surveys, additional training was provided in the Maintenance area. In addition, the site Training department has enhanced its program on the requirements of the plant's safety barriers and the responsibility to maintain their effectiveness.

5. Unauthorized Personnel Action - The personnel involved performed unauthorized work in violation of plant procedures.

   Corrective Action - The personnel involved have received personnel corrective action in accordance with TVA policy.

In addition, TVA management performed an independent review of the event to identify areas in which improvements may be prudent to further enhance maintenance-related activities and to reinforce requisite operational attitudes. This review resulted in the development of the comprehensive set of improvements listed below.

1. Procedure Enhancements - The plant instruction governing work request control, Site Director Standard Practice (SDSP) 7.6, Maintenance Management System, contained adequate controls to ensure Operations notifications and authorization prior to commencing work. The procedure has, however, been enhanced to improve the process for notifying Operations of the status of in-progress work. Specifically, it has been enhanced to ensure that if during performance of a work order (WO) any significant delays (over four hours) and scope changes occur, the SOS and unit operator are notified. The work planner's guide has also been improved to reflect this enhancement. In addition, for work that affects certain critical systems, a "red sheet" must be filled out and inserted in the front of the work package as a flag to alert craftsmen of potential adverse impacts on plant operations.

2. Shift Turnovers - To ensure proper attendance and information exchange during SOS turnover meetings, General Operating Instruction 300-1, Attachment A, SOS Turnover Checklist, was enhanced to clearly identify the individuals scheduled to attend the shift turnover. The turnover checklist was also enhanced to include a listing of power ascension tests that would be carried over into the oncoming shift. In addition, the checklist now requires the listing of prejob briefings to ensure the oncoming shift receives a briefing on the work activities/test activities in progress.

3. QA Review - The site QA organization performed a review of open WOs. No WOs were identified where Operations notifications were not being made. The review revealed that 12 of the WOs required minor changes or improvements in the way Operations notifications were being provided, and 14 WOs were

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unnecessary and needed to be closed or canceled. TVA determined that no problems would have resulted from execution of these WOs. The remaining WOs were found to have adequate scope and work controls. QA also independently reviewed over 700 of the procedures discussed previously in Item 3 above, Procedure Change Evaluation.

4. Pretest Briefings - To enhance the conduct of job briefings, guidelines have been issued to test directors to reemphasize compliance with procedural requirements for conducting briefings for power ascension testing. These guidelines require that pretest briefings be held on the shift during which the test is performed; that personnel directly or indirectly involved in performance of the test be present at the briefings; and that the test director conduct two pretest briefings: one prior to the test crew assuming shift duties (a general test overview, usually at the Operations shift turnover meeting) and a second prior to commencing the test (a detailed briefing). Briefings will ensure the test crew understand the test criteria, expected plant responses, and required actions.

5. Task Qualification Training - To ensure that required job performance criteria have been addressed, TVA reviewed the task qualification process and found it to be satisfactory. In addition, QA is monitoring the implementation of this program on an ongoing basis to evaluate the adequacy and effectiveness of the program.

6. Craft Qualification Training - TVA is also evaluating the applicability of a Peach Bottom type screening and evaluation program for craft personnel. This includes the possibility of using craft screening services provided by Edison Electric Institute (Power Plant Maintenance Positions Selection System).

7. Power Ascension Test Review - To ensure that support activities are completely specified and documented, TVA reviewed the power ascension tests. Nineteen tests were reviewed; seven of which were improved.

8. Shift Technical Advisor (STA) Training - TVA reviewed the current STA training program, which includes senior reactor operator qualification, and found it adequately covers primary containment requirements. Interviews with individual STAs found them knowledgeable of these requirements.

9. Foreman Qualification Evaluation - TVA will develop a screening and evaluation program to assess the job performance of Maintenance foremen. The program will include screening and evaluation of both current foremen and future selection candidates to ensure they possess adequate skills to perform their supervisory roles. A similar program has been successfully implemented at the Peach Bottom plant. TVA will review the Peach Bottom program and consider its key elements for incorporation into the TVA program. Additionally, TVA is developing a continuing supervisory training program which foremen will attend.

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10. Access Levels - To ensure that only individuals requiring access to plant areas obtain the applicable access level, TVA reviewed access levels of site personnel and changed the level of 108 individuals.

11. Review of Critical Activities - To ensure proper control by Operations, TVA reviewed other critical activities, such as those related to fire protection, radiation monitors, and high radiation doors. No deficiencies were identified.

12. Secondary Containment Interlocks - To preclude a similar event from occurring on BFN's secondary containment airlocks, TVA checked secondary containment interlocks and verified proper functionality.

13. Maintenance Management Structure - To ensure that BFN has an optimum Maintenance management organization, TVA will evaluate the existing two-level Maintenance supervisory structure.

TVA's June 13, 1991 letter from D. A. Nauman to S. D. Ebneter previously committed to perform these corrective actions.

COMMITMENTS

None.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

AIT No.:	269/91-028
Event Description:	Decay heat removal system operational problems
Date of Event:	September 7 and September 19, 1991
Plant:	Oconee 1

Summary

On September 7, 1991, approximately one month into a refueling outage, low-pressure injection (LPI) / decay heat removal (DHR) system train A was removed from service and train B was placed in operation. Service water to the B train was either not aligned or became isolated, and the LPI pump suction temperature rose over a 4-h period from 110°F to 187°F, without the operators being aware of the temperature rise. The problem was identified and the system was realigned correctly when operations personnel in the reactor building reported that water in the reactor vessel was "roiling".

On September 19, 1991, as preparations for startup were being made, reactor coolant system (RCS) pressure was increased from 90 to 245 psig, with the intention of increasing RCS pressure to 300 psig. Operation at the higher pressure necessitated that the DHR system be realigned in the "switchover" mode; however, this was not done. Consequently, a DHR pump suction relief valve lifted and relieved approximately 12,000 gal of reactor coolant to the high activity waste tank before the problem was identified and corrected.

Event Description

On day 37 of a refueling outage, LPI pump 1A was in service to provide decay heat removal. To facilitate testing of an LPI injection valve in the A train, plant operators removed the A train from service and placed B train DHR in service. Service water for cooling of the B DHR heat exchanger was either not aligned at that time, or it was isolated soon after, and RCS temperature began to rise.

RCS temperature was about 110°F at 1007 hours, when the B train was placed in service. At about 1420 hours, a nonlicensed operator in the reactor building informed the control room that the water in the reactor vessel was "roiling" and that significant amounts of steam were coming from the vessel. Control room operators then noted that the LPI pump suction temperature was 187°F and that no service water was flowing through the B DHR heat exchanger. DHR train A was placed back in service, B was shut down, and RCS temperature was observed to decrease. The utility subsequently calculated that a temperature of 212°F existed in the core region.

Unaware of what had transpired, maintenance personnel closed the A train LPI injection valve about 30 min later, isolating DHR. Operators then placed B train back in service, this time ensuring proper service water flow. By 2200 hours, RCS temperature was reduced to normal (110°F).

Subsequent investigation found that multiple control room indications of DHR temperature, service water flow, and valve position were available throughout the event and that six operations personnel were assigned responsibilities in the control room during the inadvertent heatup.

Late on day 50 of the planned 55-d refueling outage, the plant was in a cold shutdown condition with RCS temperature at 100°F and pressure at 60 psig. RCS pressure was increased to 90 psig at 2200 hours and, around 2300 hours, operators energized pressurizer heaters to initiate a pressure increase to 300 psig. At the time, the LPI system was in DHR mode.

When the LPI system is operated in DHR mode, reactor coolant is drawn from a hot leg to the LPI pump suctions and then is pumped through the DHR heat exchangers back to the reactor vessel. The LPI pumps are capable of developing about 200 psid, and portions of the LPI/DHR system are rated for only 420 psig. To protect the system from overpressures, pump suction relief valves are provided that operate at 125 psig. This precludes operation of LPI in DHR mode at RCS pressures above 125 psig. LPI operation for decay heat removal can be accomplished at pressures somewhat higher by realigning to a configuration referred to as "switchover" mode. In this configuration, water from the RCS is drawn first through a DHR heat exchanger and then pumped directly back to the reactor vessel. This reduces somewhat the pump suction pressure and permits removal of decay heat at higher RCS pressures. In this event, the necessity to convert to switchover mode was overlooked.

As RCS pressure began to rise, increases in the high activity waste tank level and in makeup flow were noted. Decreasing pressurizer level was also observed, and an investigation was begun to determine if and where a leakage of reactor coolant might be occurring. At around 0030 hours the next day, a nonlicensed operator reported that the LPI suction relief valve was leaking. At that point, control room personnel realized that the plant should have been placed in switchover mode before the pressure increase was attempted. Using auxiliary spray, RCS pressure was reduced below 110 psig by around 0400 hours and the LPI suction relief valves reseated. Approximately 12,400 gal were transferred to the high activity waste tank during the event.

A subsequent investigation noted that six operations personnel were assigned responsibility in the Unit 1 control room during the event.

Additional Event-Related Information

Contributing causes to these events included inattention by operations personnel, improper use of and inadequate procedures, schedule and workload pressures, inadequate training, poor communications, and management failures.

ASP Modeling Assumptions and Approach

This event was not modeled as an accident sequence precursor.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No.: 50-269/91-28

Licensee: Duke Power Company

Docket No.: 50-269

License No.: DPR-38

Facility Name: Oconee Nuclear Station Unit 1

Inspection Conducted: September 9-13 and 20-25, 1991

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Executive Summary

The AIT investigated the Oconee unit 1 events of September 7, 1991, Reactor Coolant System heat-up/loss of decay heat removal, and September 19-20, 1991, LPI system overpressurization. The inspections covered the periods of September 9-13 and 20-25, 1991. The AIT concluded that neither event posed a significant threat to the plant or the public. However, after completing an in-depth review of the events, several significant weaknesses were identified.

For the Reactor Coolant System heat-up/loss of decay heat removal event, the AIT concluded that inadequate procedures, lapses in operator responsibilities/watchstanding principles, and informal schedule changes for testing were major contributors to the initiation and progress of the event. Procedures associated with operating the LPI system while in a shutdown condition did not address specifics of the LPI system alignment for decay heat removal, including establishing Low Pressure Service Water flow through the LPI (decay heat) coolers. Operator responsibilities were found to be lacking pertaining to monitoring critical plant parameters and maintaining a safety perspective.

For the LPI overpressurization event, the AIT concluded that failure to follow procedures, weaknesses in operator responsibilities/watchstanding principles, and lack of management oversight were major causes of the event. In addition, corrective actions taken in response to the September 7, 1991, Reactor Coolant System heat-up/loss of decay heat removal event were ineffective in correcting weaknesses previously identified in operator responsibilities and watchstanding principles. Procedures were not followed when the control room operators suspended use of the controlling procedure for unit start-up on the step prior to the step requiring alignment of the LPI system to the switchover mode. Most significant of the weaknesses identified pertains to inadequacies in Senior Reactor Operator supervisory responsibilities and management oversight in general. The unit supervisor did not maintain an appropriate overview of control room operations. His lack of awareness of the conduct of shutdown operations, including plant status and impact of outage activities on his shift was a direct contributor to the event. Facility management oversight was also deficient in that apparent weaknesses identified after the Reactor Coolant System heat-up/loss of decay heat removal event were not detected or corrected.

Although not directly related to the events discussed above, a serious weakness was identified in the "control" of valve testing. Because of a lack of testing controls, the recovery from the Reactor Coolant System heat-up/loss of decay heat removal event was unnecessarily interrupted when a valve undergoing testing was cycled shut. The licensee has taken corrective actions to ensure that operators maintain "control" over systems which are not actually operating but may be called into service.

Pertaining to both events, the AIT identified a lack of or weaknesses in abnormal operating procedures covering shutdown plant casualties. The recovery from both events would have benefited by having procedures which were more specific to shutdown plant conditions.

In conclusion, one common significant weakness contributed to both events. Management inadequate oversight and deficiencies in watchstanding principles were considered to be root causes of these events. Along with this, the AIT concluded that the lack of a sense of responsibility exhibited by unit supervisors and control room operators in regard to these events are faults that utility management should have detected through routine oversight of plant operations.

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1. September 7, 1991, Loss of Decay Heat Removal

I. INTRODUCTION - AUGMENTED INSPECTION TEAM (AIT) FORMATION AND INITIATION

A. Background

Oconee units 1, 2, and 3 are B&W pressurized water reactors with steel lined prestressed post tensioned concrete cylinders with hemispherical dome containments. The units are located 8 miles north of Seneca, South Carolina in Oconee County. Unit 1 went critical in April 1973 and was commercially operational in July 1973. Units 2 and 3 went critical in November 1973 and September 1974 and were commercially operational in September 1974 and December 1974 respectively.

On Saturday September 7, 1991, at approximately 1730, the licensee notified the Resident Inspector of a unit 1 Reactor Coolant System heat-up from a temperature of approximately 110 to 187 degrees Fahrenheit. Unit 1 was in a refueling outage, core recently reloaded, and the LPI system was aligned in the decay heat removal mode of operation. On the following day, at 1452 the licensee notified the NRC Headquarters duty officer of the event that had occurred on September 7. The notification stated:

"The purpose of this call is to inform you of a situation that occurred here at Oconee unit 1 at 1425 yesterday, September 7, 1991. An improper adjustment was made to low pressure service water flow which allowed the reactor coolant system water to increase in temperature from about 110 to 187 degrees Fahrenheit. When alerted by an operator in the reactor building that the temperature appeared to be increasing, action was taken to increase the flow of service water. Reactor coolant temperature began to decrease immediately. At no time was LPI (reactor coolant water) flow lost or even decreased. The NRC resident inspector was notified. We are informing you of this due to the high level of attention to residual heat removal events that take place during shutdown."

B. AIT Formation

On the morning of Monday, September 9, 1991, the Regional Administrator, after further briefing by the regional and resident staff and consultation with senior NRC management, directed the formation of an AIT from Region II and NRR personnel. The AIT was to be headed by a Region II Reactor Safety Section Chief. The basis for the formation of the AIT was to gain a clearer understanding of an event related to the generic concern of shutdown risk management.

C. AIT Charter - Inspection Initiation

Refer to Appendix C

II. Event Description

A. Event Overview

At approximately 1424 on September 7, 1991, a non-licensed operator reported from the reactor building to the control room that he observed a significant amount of steam coming from the reactor vessel area and that the water in the reactor vessel was roiling. The operators in the control room then noted that the LPI pump suction temperature was indicating abnormally high at 187 degrees Fahrenheit. They also noted that the Low Pressure Service Water flow to the decay heat cooler was indicating zero flow. The other LPI train was immediately aligned and decay heat cooling was restored on unit 1. Apparently, the "A" flow control valve controller on the Low Pressure Service Water system had been improperly set earlier. This resulted in decay heat not being removed (Reactor Coolant System heat-up) over a period of approximately four hours.

B. Detailed Sequence of Events as Verified By the AIT

DATE/TIME	EVENT
09/07/91	
- 0700	1A LPI pump is in service in the decay heat removal mode. Low Pressure Service Water flow through the 1A decay heat cooler is approximately 300 gpm. The control room logs indicated the 1A LPI pump suction temperature to be about 100 degrees Fahrenheit at shift turnover.
- 0930	The unit 1 operations coordinator and maintenance engineering discuss the problem with the VOTES sensor on 1LP-18. Based on the 12 hour epoxy curing time, the unit operations coordinator recommends to the unit 1 supervisor to place the 1B LPI train in service and remove the 1A LPI train from operation (decay heat removal mode) to support VOTES testing on valves 1LP-12 and 1LP-17.
- 1007	1B LPI train is placed in service for decay heat removal - 1LP-8, 13 and 18 are verified open - Low LPI flow and low pump differential pressure limits are discuss.

- 1B LPI pump is started and valve 1LP-14 is throttled open to attain 2700 to 2800 gpm flow.

- 1B Low Pressure Service Water flow indicates ~400 gpm (no 1LPSW-252 position changes are made at this time).

- 1A LPI train is secured by throttling 1LP-12 and stopping 1A LPI pump.

- 1LPSW-252 controller is adjusted by the reactor operator to decrease flow from ~400 gpm down to ~250 gpm to match the A Low Pressure Service Water flow. (The reactor operator claimed that the controller was left in auto.)

The lineup was performed based on the operators knowledge of the system. There are no requirements to switch LPI trains using approved procedures. Clearance was also given to perform VOTES testing on valves 1LP-12 and 1LP-17.

~ 1045 Unit 3 supervisor visiting unit 1 control room noted an LPI pump suction temperature of approximately 123 degrees Fahrenheit. He did not note this as abnormally high and did not alert the unit 1 operators.

During interviews following the event, this reactor operator has stated that following aligning 1B LPI train in the decay heat removal mode, he had verified the LPI suction and discharge temperatures and did not notice any changes. The LPI temperatures were not observed by either of the four reactor operators assigned to unit 1 or the unit 1 senior reactor operator or the unit 1 and 2 control room senior reactor operator.

~ 1415 The reactor building equipment hatch is closed in preparation for placing the reactor vessel upper plenum assembly.

~ 1420 Non-licensed operators enter the reactor building to do work on the main bridge in preparation for reactor vessel head movement. The reactor operator announces to the personnel that the reactor vessel was "steaming". The control room was notified by phone.

- LPI suction temperature indicated about 187 degrees Fahrenheit and the controller for valve 1LPSW-252 indicates zero flow.

- The control room senior reactor operator, shift manager, and reactor operators check the valve alignment.

- The reactor operator places 1LPSW-252 controller in manual and begins opening the valve.

~ 1424 The unit 1 supervisor enters the control room from the operations center (located inside the control room doors).

- The reactor operator aligns 1A LPI header, starts 1A LPI pump, and establishes 800 gpm flow through valve 1LPSW-251. At this time 1LP-17 and 1LP-12 are still released to the VOTES crew for testing. The breaker for 1LP-17 was open. Valve 1LP-17 was open and approximately 3000 gpm flow was established through the A header.

- Radiation protection personnel set up air sample, take dose rates, and surveys around canal. **They note that the vessel water was bubbling with a lot of steam coming from the vessel.** 5 to 10 millirem per hour (normal) dose noted. The non-licensed operator tells the radiation protection personnel to get out.

- **The VOTES crew was not notified that 1A LPI train was now in service and that A train valve manipulation are prohibited.** Abnormal procedure AP/1/A/1700/07 was referred to but the procedure was not specific for this event.

~ 1426 Decreasing trend on A cooler outlet temperature is observed and 1B LPI pump is secured.

~ 1440 Radiation protection notes that half the stud holes are full of water. Radiation survey and air samples are taken with no changes noted.

~ 1445 1A LPI decay heat cooler outlet temperature is noted at approximately 145 degrees Fahrenheit. The control room senior reactor operator orders the reactor operator to stop cooldown by throttling valve 1LPSW-251 to prevent exceeding the 45 degree F/hr cooldown rate limit. A manual cooldown rate trend was started.

~ 1458 1A LPI train flow statalarm "1SA-3 A-8" is received in the control room. The VOTES personnel, not aware of the change in status of 1A LPI train, cycle closed valve 1LP-17 from the breaker. The unit 1 operators realize the mistake. 1B LPI train is placed back in service and Low Pressure Service Water cooling flow through valve 1LPSW-252 is established at 600 gpm.

- ~ 1459 1A LPI train is secured and VOTES personnel are paged. 1LP-17 is re-opened following discussions with the VOTES personnel.

- ~ 1504 LPI flow is established in both trains using 1B LPI pump (1400 gpm/header). LPI cooldown is continued at 20 degrees Fahrenheit/hr.

- ~ 1530 The operations superintendent and integrated scheduling superintendent decide to initiate a detailed investigation, the Oconee Site Review Group is notified.

- ~ 1730 NRC resident inspector is notified.

- ~ 1900 Shift turnover occurs and LPI suction temperature is 122 degrees Fahrenheit and progressing toward 110 degrees Fahrenheit.

- ~ 2200 LPI pump suction temperature reaches 110 degrees Fahrenheit.

C. Initial Conditions

On September 6, 1991, the unit was in **day 37** of End of Cycle 13 **refueling outage. Fuel, composed of 1/3 new and 2/3 burned, had been reloaded in the vessel earlier on September 6, 1991**, and the fuel transfer canal had been drained. Source range nuclear instrumentation NI-1 and NI-2 were in service. Reactor **vessel level was approximately level with the vessel flange** (78 inches on LT-5). The **vessel head was not installed**; the indexing fixture was in place in the vessel in preparation for plenum installation. Nozzle dams were still installed on the four cold legs; having been positioned earlier in the outage for steam generator work. The 1C LPI pump was in operation in the decay heat removal mode with discharge into the vessel through both LPI headers. The LPI pump suction temperature was 100 degrees Fahrenheit and LPI cooler outlet temperature was approximately 10 degrees Fahrenheit lower than LPI pump suction temperature. The 1A and 1B LPI pumps were also available. Both trains of the Low Pressure Service Water System were in service with flow through both decay heat coolers. VOTES (motor operated valve actuator diagnostic testing) testing was scheduled to be performed on valves 1LP-12, 17, 14 and 18.

The equipment hatch was open and the reactor building purge was in service. Radiation Instrument Alarm 3, located on the auxiliary bridge, and Radiation Instrument Alarm 4, located at the reactor building entrance, were in service. In addition, portable monitors located at various locations in the building were also available. The reactor building particulate, Iodine, gas, and the high range containment monitors were out of service. Both main feeder buses and the start-up transformer were energized. Both Keowee units as well as the emergency transformer were also available. Keowee hydro unit 2 had failed to start at 2054 on September 6, following a request by the dispatcher. A failed relay was identified and replaced. At 0055 on September 7, the unit was returned to service, prior to the heat-up event. At 0700 on the morning of September 7, 1991, the 1A LPI train was in service in the decay heat removal mode. 1B LPI train was not in service due to scheduled VOTES testing of 1LP-18.

D. Event Initiation

The AIT interviewed the operators involved in the event. The purpose of these interviews was to identify what happened in the control room and to evaluate operator actions during the event and subsequent recovery. The following is an annotated list of operator actions as presented to the AIT during the interviews. This list is not meant to represent the chronology of the event; the intent is only to present relevant operator actions.

At the beginning of the shift (0700) on September 7, 1991, plans were to perform a VOTES test on the 1B train isolation valve (1LP-18) using temporary test procedure TT/1/A/251/11, VOTES Testing of LPI Header Motor Operating Valves. The 1B LPI train was aligned per the instructions in TT/1/A/251/11 to accommodate testing on 1LP-18. **For reasons not specified, the test procedure also required that 1LPSW-252, 1B LPI cooler Low Pressure Service Water outlet control valve, be shut. The shutting of this valve stopped all cooling water flow through this idled cooler.**

VOTES testing commenced on valve 1LP-18. The plans for VOTES testing of 1LP-18 were changed, however, when testing revealed a faulty VOTES strain gage. Installation and cure time for the new VOTES sensor, which is epoxied on the valve yoke, was approximately 12 hours. Based upon this, the unit 1 operations coordinator and maintenance engineering (the group performing VOTES testing) requested that the unit supervisor place 1B LPI train in service (decay heat removal mode) and remove train 1A from service such that VOTES testing could be performed on 1A LPI train valve 1LP-17. The unit supervisor in turn instructed a reactor operator to perform the realignment.

At 1007 the operator realigned the LPI system per step 12.1.2 of TT/1/A/251/11 which instructed that the 1B LPI pump be aligned to the 1B LPI header to control Reactor Coolant System temperature per the LPI system procedure OP/1/A/1104/04. Independent verification of this step was also required.

There are several factors in this step which contributed to the initiation of the Reactor Coolant System heatup. Step 12.1.2

references OP/1/A/1104/04 for aligning the 1B LPI header. However, OP/1/A/1104/04 does not contain guidance for shifting LPI trains while in the decay heat removal mode. Because of this, the operators performed the shift in alignment from memory without a step-by-step instruction. The task of shifting trains is relatively simple requiring manipulation of only a few valves. The valves on the LPI train were indeed aligned and verified properly. **However, 1B Low Pressure Service Water, valve 1LPSW-252, which was shut earlier, is not addressed in step 12.1.2 of TT/1/A/252/11, nor is it addressed in OP/1/A/1104/04. Because of operator error, valve 1LPSW-252 apparently remained shut preventing cooling water flow through the B decay heat cooler.** After the realignment of the LPI trains the control room operators were involved in tasks for supporting outage work. Then, at approximately 1424, on September 7, 1991, a non-licensed operator reported from the reactor building to the control room that he observed a significant amount of steam coming from the vessel area and that the water in the vessel was roiling.

E. Operator Response (Recovery)

Although the control room operators responded properly to the unexpected heat-up, the recovery was not entirely without complications.

Following the call, at 1424, from the non-licensed operator in the reactor building notifying the control room of the vapor coming from the reactor vessel, the control room operators immediately noted that LPI pump suction temperature was indicating 187 degrees Fahrenheit and Low Pressure Service Water flow indicated zero. Based on this, the control room operators started the 1A LPI pump to establish cooling through the 1A LPI train. The control room operators verified 1A LPI pump current draw (amperes) to be normal and LPI flow to be at 3000 gpm. The LPI suction and cooler discharge temperatures were noted to be decreasing with a Low Pressure Service Water flow of 800 gpm through valve 1LPSW-251. At 1426 the 1B LPI train was secured based on confirmation that decay removal function was restored. The control room operators initiated the Reactor Coolant System cool-down in a controlled fashion and were diligent in maintaining cool-down rates to within administrative and Technical Specification limits.

While establishing decay heat removal, the control room operators failed to recognize/recall that VOTES testing was continuing on the 1A LPI train. During the start-up of the 1A LPI train, in response to the high Reactor Coolant System temperature condition, the operators failed to recognize or realize the significance of there being no control room position indication for valve 1LP-17. The breaker for the 1A LPI train discharge valve (1LP-17) was open for VOTES testing.

This resulted in a loss of remote control of this valve from the control room panel as well as a loss of position indication on the panel. At the time that the control room operators started the 1A LPI train, the valve, 1LP-17, was open. The valve could very well have been closed.

At 1458 the 1A LPI train low flow statalarm was received as the VOTES personnel, because of the continued testing described above, started to cycle close valve 1LP-17. After establishing flow through the 1A LPI train, the control room operators had failed to notify the VOTES personnel to suspend VOTES testing on the 1A LPI train. The control room operators recognized the cause of the statalarm and placed 1B LPI train in service and established Low Pressure Service Water cooling flow through the decay heat cooler by opening valve 1LPSW 252. The 1A LPI train was secured and VOTES personnel were notified of plant conditions and ordered to suspend testing. At 1504, both LPI trains were placed in the decay heat removal mode and a cool-down rate of 20 degrees Fahrenheit/hr was established. By 1900, during shift turnover, the LPI suction temperature had decreased to 120 degrees Fahrenheit.

As described above, on the morning of September 7, 1A LPI train was removed from service and aligned for testing using procedures TT/1/A/251/11 and OP/1/A/1104/04. The operator stated that after he placed the 1B train in service he verified that Low Pressure Service Water had been established to the 1B LPI decay heat cooler by observing flow indication on the newly installed controllers for valves 1LPSW-251 and 252 (flow control valves that regulate cooling water flow to the 1A and 1B train decay heat coolers respectively). This is a significant point in that neither TT/1/A/251/11 or OP/1/A/1104/04 contain guidance relative to establishing Low Pressure Service Water flow to the decay heat coolers when in the LPI decay heat mode of operation. It should also be noted that, as described above, valve 1LPSW-252 had been closed and independently verified at 0226 that morning when the 1B LPI train had been aligned for testing of 1LP-18 per TT/1/A/251/11. Based on subsequent licensee analysis of the rate and extent of the Reactor Coolant System temperature increase, Low Pressure Service Water flow was either not established or was immediately secured (speculation) to the 1B LPI train decay heat cooler when the 1B LPI train was placed in service. The operator also stated that he monitored reactor coolant temperature for a period of thirty to sixty minutes and noted no change (increase). This is inconsistent with the licensee's analysis which indicated that the Reactor Coolant System temperature increase began coincident with the realignment. It is also inconsistent with an observation made by the unit 3 supervisor, who when passing through the unit 1 control room at 1045, observed reactor coolant temperature to be 123 degrees Fahrenheit. He later stated in an AIT interview that although the temperature was slightly higher than expected, he did not consider the temperature to be extraordinary and therefore did not alert the unit 1 control room operators. Normal reactor coolant temperature in this condition is 110 degrees Fahrenheit.

From 1007 when 1B LPI train was placed in service, until 1424 when the elevated reactor coolant temperature was detected, no member of the unit 1 operating staff monitored reactor coolant temperature. It is significant to note that the control room Senior Reactor Operator was present in the control room for virtually the entire period of the event. Although he was responsible for "...ensure(ing) the safe operation of the unit(s)..." per OPM 2-1, for the period in question, he did not monitor reactor coolant temperature on unit 1.

F. Radiation Protection Response

When notified, the radiation protection technicians providing coverage for reactor building activities on the third and fourth floor reacted quickly in setting up portable air samplers and surveying dose rate around the canal. All personnel working on the third and fourth floor were instructed to evacuate the area. In addition, a body burden analysis was performed on each of seven individuals working in the reactor building on the third floor because of the potential for radioactive intake. The body burden analysis of these individuals did not indicate any internal activity.

G. Licensee Response (Short Term)

1. Event Notification

The NRC resident inspector was notified of the event by the licensee at approximately 1730 on the day of the event, September 7, 1991. The headquarters duty officer was not notified until the following day. The notification of the NRC headquarters duty officer, made at 1452 following discussions with the resident inspector staff, was classified by the licensee as a voluntary call. The AIT reviewed the facility's Emergency Plan Implementing Procedures (Volume C, Rev 91-8), Emergency Classification Procedure RP/0/B/1000/01, in particular, the classification of events, Loss of Shutdown Functions (Enclosure 4.1.5), and entry into emergency action levels. A requirement to declare an Unusual Event if decay heat cooling were lost for greater that ten minutes was noted. However, the licensee did not consider this event to be a loss of decay heat removal because primary coolant flow through the LPI system was never lost; only service water (cooling water) through the decay heat cooler was lost.

2. Immediate Corrective Actions

As described previously, upon discovery of the elevated Reactor Coolant System temperature, within several minutes the decay heat removal function was established by the control room operators. Additionally, within approximately 24 hours of the event, licensee management initiated several other actions. These included:

- Investigations

  The licensee initiated a detailed team investigation by members of the Oconee Site Review Group. Interviews of the involved operators were commenced within a few hours of the event. Based on the potential safety significance and the sensitivity to shutdown cooling events, after consulting with the Vice President for Nuclear Production, the decision was made to bring in a Corporate guided Significant Event Investigation Team to review the event.

- Shift Briefings

  The on-coming shifts were briefed by plant management as to the significance of the event and the need for attention to detail at all times including shutdown. Clear identification of the operator at the controls (OATC) was discussed. The operators' responsibility for monitoring of plant critical safety parameters was reinforced.

- Log Readings/Parameter Monitoring

  LPI pump suction temperature loggings were commenced every two hours by the reactor operator. LPI pump suction temperature was placed on a video trend in the control room. Later, reactor vessel water level, pressurizer leve and source range counts were added to the two hour logging requirement. Prior to this, loggings were required only at the begining of the shift, every 12 hours.

- Equipment Checks

  Because of the concern that the control valve (1LPSW-252) may have failed shut isolating Low Pressure Service Water flow to the decay heat cooler and because the flow controllers were newly installed during this outage the licensee again performed stri..g and calibration checks on these controllers. No problems were identified.

- Notifications

  As discussed previously, the NRC resident inspector and the NRC Operations Center were notified. These were made as information calls only.

The AIT concluded that because of the plant status (outage) and the extended period of time over which the event (heat-up) occurred, two additional areas should have been addressed as part of the licensee's initial actions. These included reviewing whether the work load in the control room may have contributed to the event and whether inappropriate execution of operator responsibilities may have contributed to initiation and lack of detection of the event.

III. REVIEW OF CONTRIBUTING FACTORS

A. Procedures

The AIT reviewed procedures related to the maintenance being performed on the LPI system valves, procedures available to the control room staff related to plant condition at the time of the event, and procedures available to the control room for responding to the abnormal conditions specific to the event.

1. Abnormal Procedures

The abnormal procedures available, AP/1/A/1700/07 Loss of LPI system, and AP/1/A/1700/24, Loss of Low Pressure Service Water, did not provide guidance to the control room operators for reacting to the event. Neither of these procedures were immediately utilized by the control operators to recover from the event. The procedures were referred to by the operators later for guidance. Both procedures address a total loss of the system flow related to a loss of the system pump. The actual event was a mis-positioning of a valve, and neither procedure referred to the affected flow control valves (1LPSW-251 and 252). In summary, the licensee does not have abnormal procedures which specifically address loss of decay heat removal capabilities due to loss of service water flow. However, as noted later in this report the licensee had addressed loss of decay heat removal during classroom and simulator training.

2. Surveillance Procedures

For a shutdown plant with reactor coolant temperature less than 200 degrees Fahrenheit, the facility's procedure governing the routine logging of plant parameters, PT/1/A/600/01 "Periodic Instrument Surveillance", did not require frequent recording of reactor coolant temperature. Temperatures were recorded approximately every 12 hours, at shift change.

3. Test Control Procedures

There are two administrative control mechanisms at Oconee designed to control the removal and restoration of station equipment; the block tag-out and the Removal and Restoration. The block tag-out is normally used to isolate whole systems or parts of systems for maintenance.

The philosophy of a block tag-out is that boundary valves are tagged and are not to be moved. Valves within the boundary have their breakers tagged out and such valves can be moved manually provided movement does not result in movement of water. Movement by such means as electric power and air require control room involvement. Valves not within the boundary can only be moved with permission from the control room.

The Removal and Restoration is normally used for smaller scope jobs, such as to remove a single component from service. The normal process previously used for performing the static VOTES tests, is for operations to issue an Removal and Restoration isolating the valve(s) to be tested, allowing the static test(s) to be completed, and then returning the valve(s) to service.

It should be noted that although the operations procedure which describes the Removal and Restoration process, OP/0/A/1101/06, Removal and Restoration of Station Equipment, should be used to "... remove from service equipment which ... affects the operability of the unit ...(or) affects safety related equipment ..." (step 2.3), the procedure does not require that Removal and Restoration be generated during refueling or extended outages. Specifically, step 2.6 of the Limits and Precautions states that "This procedure is to be used during normal plant operations. ...(but) may be used during refueling or extended outages at the discretion of the unit coordinator."

The AIT concluded that in this case, the conventional administrative process was not used to remove and/or restore the LPI system to/from service; but the failure to use the process was not a contributor to the event. However, the specific procedures employed to control the testing associated with this event were inadequate. Two procedures were used in realigning the LPI system for VOTES testing. The two procedures were TT/1/[illegible]/251/11, VOTES Test of LPI Header Motor Operating Valves, and

OP/1/A/1104/04, LPI System. The TT, 12.1.2 (I.V. step), required the operators to..." align the 1B LPI pump to the 1B LPI header to control Reactor Coolant System temperature per OP/1/A/1104/04, LPI System." As covered previously, the AIT review of the procedure coupled with interviews with the operators revealed that the procedure contained no information pertaining to realigning flow from one operating train of LPI to another when in the normal decay heat removal mode of operation or instructions relative to aligning Low Pressure Service Water to the decay heat coolers.

It should also be noted that the licensee elected to not use a block tagout or Removal and Restoration while conducting testing on the LPI trains. Instead, the licensee decided to maintain the train undergoing testing in a condition from which it could easily be called into service. This reasoning was based on the risk associated with a plant that is shutdown on decay heat removal cooling and the desire to have a readily available backup means of decay heat cooling. The AIT concluded that the licensee's reasoning for the plant conditions described was sound and their decision was proper. However, this same reasoning would lead to the conclusion that proper controls must be adhered to when conducting testing on systems important to safety. Because of the inadequate test controls, 1A LPI train flow was lost soon after being called to service in response to the elevated reactor coolant system temperature.

B. Operator Responsibilities

The responsibilities of the reactor operators and the senior reactor operator in the control room, are delineated in Operations Management Procedure 2-1, Duties and Responsibilities of Reactor Operators, Non-Licensed Operators, and the Senior Reactor Operator in the Control Room.

These positions were focused upon primarily because these personnel were in the control room for virtually the entire period in question. The reactor operator's duties include providing "... surveillance of operations and instrumentation (in) the control room to ensure the safe operation of the unit. During shutdown periods, he/she shall ensure that continuous safe shut-down conditions exist". Further, "The reactor operator shall ensure that his/her... instruments... are responding as expected for the existing condition."

Additionally, procedure TT/1/A/251/11, VOTES Test of LPI Header, required specifically in Limit and Precaution 6.3, that the operators were not to allow the LPI pump suction temperature to exceed 140 degrees Fahrenheit.

Per Management Procedure 2-1 the control room Senior Reactor Operator is required to be "in the control room" during all modes of plant operation from cold shutdown conditions to 100 percent power operations. The Senior Reactor Operator is responsible for reviewing with unit supervisor(s) their unit status and activities planned during the shift. The Senior Reactor Operator's primary concern is to ensure the safe operation of the unit(s). The Senior Reactor Operator is required to make rounds in the control room to review control room status. The Senior Reactor Operator is required to oversee the activities in the control room.

It is apparent that with several reactor and senior reactor operators in the control room for the duration of the Reactor Coolant System heat-up (over approximately 4 hours) the duties and responsibilities of the licensed control room operators were not met.

C. Communications

On the morning of September 7, 1991, at approximately 1000 the unit 1 supervisor gave the VOTES test technicians permission to begin work on valve 1LP-17, a valve in the discharge flow path of the 1A LPI pump. It was understood that 1LP-17 would be closed intermittently as part of the testing.

At 1458 that afternoon, after the loss of decay heat removal event had been identified and 1A LPI train had been placed in service, the control room received an alarm indicating a low flow condition in that train. The low flow condition was caused by the VOTES test personnel closing valve 1LP-17.

One example of ineffective communications associated with this specific event was identified. In response to the heat-up event when the control room operators elected to place 1A LPI train in service, at approximately 1424, they did not notify the VOTES test personnel that the train had been placed in service and that testing should be discontinued.

D. Independent Verification

When the control room operators realigned the LPI system on the morning of September 7, 1991, to perform VOTES testing on valves in the 1A LPI train, they used procedure TT/1/1/251/11. Step 12.1.2 requires the control room operators to align the 1B LPI pump to the B LPI header to control Reactor Coolant System temperature per OP/1/A/1104/04, LPI System. This procedure step (12.1.2) requires independent verification. Both control room operators signed the step, certifying to the fact that they had aligned 1B train to control Reactor Coolant System temperature. As is delineated elsewhere in this report, OP/1/A/1104/04 was inadequate to facilitate realigning from one operating LPI train to another when the plant is in the normal decay heat removal mode of operation. More specifically, neither procedure contained guidance relative to establishing Low Pressure Service Water to the decay heat coolers, a necessary function if one is to control Reactor Coolant System temperature. Notwithstanding these administrative deficiencies, both operators independently verified that they had aligned LPI to control Reactor Coolant System temperature.

The AIT concluded that because of the inadequacy of the procedures available to the control room operators to realign the LPI trains in the decay heat removal mode, the operators apparently did not realize the significance of the I.V. step requiring verification of the ability to remove decay heat. The operators apparently verified that the LPI system specific valves were aligned to provide an LPI flow-path.

E. Low Pressure Service Water Modification

Nuclear Station Modification ON-12526 replaced the pneumatic control system for several valves at Oconee unit 1, including 1LPSW-251 and 1LPSW-252. These two valves control the service water supplied to the two decay heat removal coolers by throttling the service water discharge from the coolers. The modification corrected a Human Engineering Discrepancy which identified a problem with some valve controllers and manual loaders in the control room which operate such that the controlled valves are shut at 100% controller demand. In addition, the previous controllers had become obsolete, making replacement parts difficult to obtain.

The previous pneumatic controllers were replaced by electro-pneumatic controllers manufactured by Moore Products Company, Model MYCRO 352. The same modification had been installed in unit 3 during that unit's previous outage. The same type of controller is also used on other unit 1 systems. Features of the new controllers included both auto and manual control functions, ability to select digital display of either service water flow, control valve position or service water flow set-point and a continuous analog display of set-point and flow-rate. The modification was installed for both trains of decay heat removal while all fuel was removed from the reactor vessel, when decay heat removal was not needed. Post-modification testing was performed on both valve controllers on September 2, 1991. Testing of 1LPSW-252 (Low Pressure Service Water return from 1B train Decay Heat Removal cooler) was satisfactory completed; however, the stroke test of 1LPSW-251 (Low Pressure Service Water return from 1A train Deacy Heat Removal cooler) was unsatisfactory, requiring adjustment of the valve operator. This valve was satisfactorily retested on September 3, 1991. When 1LPSW-251 failed the stroke test, the Removal and Restoration form under which the work had been done was cleared, and rework was done under the control of the modification work procedure. As described previously, OP/0/A/1102/06, Removal and Restoration of Station Equipment, specifies "Removal and Restorations should be generated to remove from service equipment which, ...affects safety related equipment," the same procedure states that Removal and Restorations need only be used during refueling outages at the discretion of the unit coordinator. The unit 1 coordinator had concurred in the process used to rework 1LPSW-251. However, with the Removal and Restoration form cleared, there was no formal documentation available in the control of the operational status of this valve. This rework was completed on one shift, and the on-shift operators were aware of the status; therefore, the lack of formal control had no impact on this particular event. In addition, although all post-modification testing was completed on 1LPSW-252 on September 2, the Removal and Restoration was not signed off until 1726 on September 7 (after the event). The unit 1 operations coordinator, who was present during the testing, confirmed that all testing had been completed on September 2.

The quality of work associated with this modification and the material condition of the plant was evaluated by direct observation and walk-down of the modification, tours of the plant and interviews with plant personnel and NRC resident inspectors. No deficiencies were noted in the actual modification installation. Post-event testing of both LPSW-251 and LPSW-252 revealed no deficiencies with either controller or valve. The material condition of the plant was considered average for a plant of this age, with significant efforts in housekeeping and general area maintenance noted in the turbine building. No deficiencies were noted in either area which would have contributed to the initiation or progress of this event.

Although the controller installation had been completed as discussed above, two flow indicators showing service water flow to each of the decay heat removal coolers were not installed because the instruments had not yet been received. However, it was not felt that the lack of these instruments contributed significantly to the event, because flow indication was available on the controller and other indications of system performance were available to the operators.

The AIT evaluated the operation of the controller and concluded that the operation was straight-forward and user-friendly. The controller appears to have corrected the deficiencies present in the previous controller, which is still installed in unit 2. The orientation of the new controllers is opposite of the old installation, with the new orientation being 1A train components on the left and 1B train components to the right, which is consistent with most control room equipment. However, an operator who had been used to the previous orientation may have a greater probability of operating the wrong train as a result of this change.

The AIT concluded that the modifications, installation of the two new Low Pressure Service Water flow controllers, were an improvement over the previous design. The controller layout is not complex and was found to be easy to understand and operate, and was appropriately labelled. In summary, the controller design did not significantly contribute to the initiation or progress of the event. However, the possibility remains that the operator could have inadvertently operated the idled (train A) low pressure service water flow controller.

F. System Engineer Involvement

The Low Pressure Service Water system had been modified by the installation of new controllers for the service water discharge valves (1LPSW-251 and 252) for both Decay Heat Removal coolers. The duties of the system engineer (designated the system manager at Oconee) are documented in Oconee Nuclear Station Directive 4.4.5, Mgr., System Engineering Program. This directive was comprehensive and specifically addressed requirements to perform system modification reviews. In practice, an accountable engineer will normally be assigned to coordinate and review a specific modification, with the system manager maintaining an overall status of the system. This modification had such an accountable engineer assigned. Through interviews with station personnel and in reviews of modification documentation, the AIT determined that the system manager and system accountable engineer had been actively involved in the planning and implementation of this modification. The actions of the system manager and accountable engineer were in accordance with the station directive and were determined to have no significant impact on this event.

G. Training

The AIT investigated training and procedures related to operations during decay heat removal mode of cooling and the work being performed to support VOTES testing of the LPI system valves.

The AIT interviewed licensee personnel regarding training activities concerning maintaining plant conditions during Decay Heat Removal operations. Licensee discussions were corroborated by the contents of training lesson plans. In addition, the AIT reviewed the facility's implementation of training related to Reactor Operator and Senior Reactor Operation watch-standing responsibilities.

The licensee has both classroom and simulator raining which address a loss of cooling during the Decay Heat removal mode of operation. The facility's training emphasizes the need to maintain cooling to the reactor while in the plant conditions in effect during the event. The facility's training emphasizes the responsibilities for tracking plant conditions to maintain plant safety. However, this may not have been incorporated into the requalification program.

The AIT reviewed the training program used to train operators and senior operators in the day-to-day operations of the plant. Guidelines for this training are developed by the training department. Responsibility for the proper execution of this program lies with the Operations Support Group. The Operations Support Group develops a training book for each operator and senior operator, who must then demonstrate his/her knowledge and abilities related to the various subjects of day-to-day operation of the plant. Qualified reactor operators and senior reactor operators test the knowledge of the student operators assigned. When the candidate has demonstrated sufficient knowledge and on-the-job performance he/she will be referred to a management representative to receive credit.

Based on the above, the AIT concluded that the initial licensed operator training program provided sufficient knowledge so that the operators could competently operate the LPI and Low Pressure Service Water plant systems in a shutdown decay heat removal condition. However, based on licensed operator interviews, the AIT concluded that the requalification program does not cover in detail system training for shutdown plant operations.

H. Outage Management/Planning

The licensee has a clear definition of an outage and the philosophy as covered by Duke Power Company procedure 3.0, Outage Management Philosophy. The nuclear operations manager is responsible for establishing a team that determines how outages are to be planned and conducted, and ensures continuity between the three Duke Power nuclear stations.

The AIT reviewed the licensee's management and planning of the outage. The intent was to determine to what degree unreasonable pressures may have been placed upon the operating staff to meet the schedule. Also considered was whether outage work not completed within the original schedule window, which is subsequently moved to another period in the outage, contributed to the event.

AIT interviews with control room operators revealed that the operators use, as a self-imposed measure for excellence, the ability to complete a job on time or ahead of schedule. This could result in a "self-generated" stress to improve on the schedule. Through interviews, the AIT noted that the general feeling among the operators is that management seldom pushes them excessively. However, interviews also revealed that "engineering" does press, sometimes unreasonably, to move onward with the schedule. No operator interviewed thought that the event was caused by being too busy to properly monitor the plant. It should be noted that facility management was aware of the outage work load during this period of time, and compensated by augmenting the required number of two reactor operators with two additional operators to manage the outage work load for the period in question. However, the AIT did conclude that the personnel in the control room were so actively engaged in support of outage work that they overlooked the monitoring of critical plant parameters. This is not to indicate that the work load was excessive but instead that the management of the control room workload was inadequate. The Reactor Operator responsible for monitoring/maintaining plant conditions should not have been permitted to become so involved in outage activities that his primary responsibilities were overlooked. In summary, the problem was with the supervision of the control room, specifically the unit 1 supervisor and the control room Senior Reactor Operator, and their failure to control/limit Reactor Operator involvement in tasks other that their primary responsibilities.

On the subject of valve testing, it was noted that the schedule is frequently adjusted. This requires the control room operators to make unexpected adjustments to the control room routine. These adjustments include changing systems lineups and plant conditions. Additionally, these changes, which could be termed as minor operational evolutions are not necessarily reflected on the schedule of activities and usually do not involve pre-briefings.

For the specific case associated with this event, VOTES testing of valves 1LP-17 and 18, the licensee originally did not schedule the testing early in the outage due to the high decay heat load and Technical Specifications restricted the testing during fuel movement. The core barrel was removed this outage and reactor vessel inspections were conducted with the reactor de-fueled. The refueling cavity had to be filled for the reactor vessel work, and VOTES testing was scheduled for this de-fueled window.

However, packing nut problems were encountered with the valves in question. These problems could not be corrected while the refueling cavity was full because valves 1LP-17 and 18 are considered by the licensee as boundary valves in addition to the system check valves. Consequently, the test was rescheduled for later in the outage, when the licensee intended to perform VOTES testing on one train at a time. These outage schedule changes were appropriate considering the circumstances.

The AIT concluded that the licensee made several informal changes to the outage schedule to accommodate VOTES testing. These changes, affecting control room routine, initially appear to have a relatively minor impact on control room operations. However, when combined with the expected outage work load for a particular shift, these unplanned schedule adjustments apparently perturbed the control room routine to an extent that a loss of safety system configuration control resulted.

Specifically, the Reactor Coolant System heat-up event was initiated with the unplanned (for the involved operating shift) shifting from 1A LPI train to 1B train to accommodate VOTES testing. Later, VOTES testing complicated the event recovery when continued testing resulted in a loss of the LPI train after it was placed in service to remove decay heat. There are other significant contributing factors, discussed elsewhere in this report; however, the above discussion illustrates that significant results can be prompted by seemingly minor unplanned configuration changes made during outage conditions.

I. Control Room Instrumentation

The AIT reviewed the availability of control room instruments and indicators and how they may have impacted the event. Important parameters involving this event were Low Pressure Service Water flow and Reactor Coolant System temperature (LPI pump suction). LPI pump suction temperature was available on the front of the control room panel in two locations. These included an analog (wide range) instrument and a CRT display which included along with Reactor Coolant System temperature, several other parameters not directly related to this event. A digital temperature indicator was also available and functional on the forward side of the back control panel. This indicator is visible to the operators from the normal watch-standing position in the control room. Decay heat cooler Low Pressure Service Water flow indication was also available and functional on the same back control panel. This indicator was part of the flow control modules for flow control valves 1LPSW-251 and 252. Valve position indication can also be selected as an indication on these modules. In addition to the indicators described above, low LPI flow and high Reactor Coolant System temperature (190 degrees Fahrenheit) alarms were functional in the control room. The LPI pump suction temperature reached a maximum of 187 degrees Fahrenheit during the event so the alarm did not actuate. The low LPI flow alarm sounded when LPI A train flow was lost temporarily when the VOTES test personnel shut 1LP-17.

The AIT concluded that sufficient indication of Reactor Coolant System temperature was available, providing the necessary information to alert the control room operators of the increasing Reactor Coolant System temperature and the lack of Low Pressure Service Water flow through the on-line decay heat cooler. There was discussion on whether the flow controllers for the Low Pressure Service Water may have failed causing the flow control valves to shut. Also, there was a potential that the control room operator may have adjusted the wrong controller, A verses B, or was otherwise confused when he made the flow adjustment. The AIT considers flow controller failure unlikely. However, had a failure/error occurred and had the control room operators been attentive to the monitoring of these critical safety parameters the problem would have been easily identified much earlier than was the actual case.

IV. SAFETY CONSEQUENCES/SIGNIFICANCE

A. Radiation Protection

The radiological consequences of the heat-up event were minimal. There was no significant change in dose rates nor was there any significant increase in airborne activity in the reactor building during the event. The general area dose rates around the fuel transfer canal remained at 8 - 10 millirem per hour. Air samples taken following the discovery of the event revealed that airborne activity remained at approximately .25 maximum permissible concentration. In addition, no increase in amount of activity releases through the equipment hatch, while the hatch was open, was noted.

When the event occurred Radiation Instrument Alarms 3 and 4 were operable. Radiation Instrument Alarm 3 was set to alarm in the control room at 22.5 millirem per hour and Radiation Instrument Alarm 4 was set to alarm at 2.5 millirem per hour. These alarms did not actuate at any time during the event. Continuous air monitors located at the equipment hatch and on the third floor of the reactor building did not show any change. Radiation Instrument Alarm 47, reactor building particulate, Radiation Instrument Alarm 48, reactor building Iodine, Radiation Instrument Alarm 49, reactor building gas, were out of service for a performance tests, and Radiation Instrument Alarm 2, reactor building Main Bridge, Radiation Instrument Alarm 5, In-core Tank, Radiation Instrument Alarm 57 and 58, Hi Range Containment Monitors, were out of service as they were being replaced during the outage.

Expansion of reactor coolant during the heat-up caused water to be displaced into approximately one third to one half of the reactor vessel stud holes. These had to be decontaminated and approximately 100 millirem total dose was received on this effort.

B. Fuel Integrity

Fuel integrity was not jeopardized during this event. Generally, fuel damage during shutdown conditions will not occur unless the water level is below the point that fuel uncovery occurs. Water covering the fuel is sufficient to prevent fuel or fuel clad damage due to the low heat fluxes (in comparison to power operation) and the resulting fuel temperature, which for practical purposes remains at the water temperature regardless of whether or not boiling occurs.

The licensee reported that there was no loss of inventory, which is substantiated by the report that water level swell due to heat-up during the event caused water to be displaced into some of the reactor vessel bolt holes. A substantial loss of inventory would have resulted in an ultrasonic level indicator alarm. The alarm set-point is of the order of five or six feet above the top of the core. Level indicator LT-5 was also available. The reported temperature of 187 degrees Fahrenheit at the LPI pump suction, an alarm set-point of 190 degrees Fahrenheit (which the licensee confirmed to be operating and in calibration), and a licensee calculated temperature of 212 degrees Fahrenheit in the core provide further substantiation that no temperatures were attained that could cause fuel damage.

C. Safety System Performance

All safety systems performed as designed. The loss of flow through 1LPSW-252 and the problems encountered while the 1A LPI train was aligned in the decay heat removal mode were personnel errors and not considered to be safety system failures.

As discussed earlier in this report, the specific failures associated with the lack of Low Pressure Service Water flow through the B decay heat cooler was apparently due to operator error in performing the initial system realignment conducted on the morning of September 7, 1991. The loss of flow to the A LPI system minutes after it was placed in-service in response to the elevated Reactor Coolant System temperature (187 degrees Fahrenheit) was due to a lack of test controls on valves undergoing VOTES testing.

D. Plant Proximity to Safety Limits as Defined in Technical Specifications/Technical Specification Adequacy

The AIT reviewed Oconee Technical Specifications to determine whether a "mode" change was made as a result of this heat-up event and also if any Technical Specification safety limits/requirements were exceeded.

Technical Specifications 1.2.6 defines Refueling Shutdown as:

"The reactor is in the refueling shutdown condition when, even with all rods removed, the reactor would be sub-critical by at least 1 percent delta k/k and the coolant temperature at the LPI pump suction is no more than 140 degrees Fahrenheit. Pressure is defined by Specification 3.1.2. A refueling shutdown refers to a shutdown to replace or rearrange all or a portion of the fuel assemblies and/or controls rods."

Technical Specification 1.2.7 defines Refueling Operation as:

"An operation involving a change in core geometry by manipulation of fuel or control rods when the reactor vessel head is removed."

Technical Specification 1.2.1 defines Cold Shutdown as:

"The reactor is in the cold shutdown condition when it is sub-critical by at least 1 percent delta k/k and Tavg is no more than 200 degrees Fahrenheit. Pressure is defined by Specification 3.1.2."

The licensee's position regarding their Technical Specifications and this event is that unit 1 was in cold shutdown prior to, during, and at the discovery of this event since the indicated reactor coolant temperature at the LPI pump suction did not exceed 200 degrees Fahrenheit. The licensee's interpretation of Technical Specification 1.2.6 and 1.2.7 is that the unit was not in a refueling shutdown condition as there was no fuel movement in progress, and because of this, the requirement to be below 140 degrees Fahrenheit was not applicable.

The AIT compared the Oconee Technical Specifications with the Standard Technical Specification for pressurized water reactors. The Standard Technical Specification defines Refueling as fuel in the vessel with the vessel head closure bolts less than fully tensioned or with the head removed and average coolant temperature at less than or equal to 140 degrees Fahrenheit.

Related to Technical Specifications the AIT also reviewed the following:

Technical Specification 3.8, Fuel Loading and Refueling, applicable during fuel loading and refueling operations as defined by Technical Specifications 1.2.6 and 1.2.7 (listed above). For the plant conditions at the time of the event this Technical Specification was not applicable.

Technical Specification table 3.1-2 which specifies a maximum allowable cool-down rate with the Reactor Coolant System depressurized as equal to or less than 50 degrees Fahrenheit in any one hour period.

The AIT reviewed cool-down rate information covering the period after the elevated Reactor Coolant System temperature of 187 degrees Fahrenheit was identified. Based on this review the allowable rate was not exceeded. It should be noted that the rates were calculated using the LPI pump suction temperature; the only indications available as Reactor Coolant System temperature.

Technical Specification 3.6.1 which requires that containment integrity shall be maintained whenever all three of the following conditions exist:

a. Reactor coolant pressure is 300 psig or greater.
b. Reactor coolant temperature is 200 degrees Fahrenheit or greater.
c. Nuclear fuel is in the core.

The reactor vessel head was removed which assured that the Technical Specification limit could not be reached because of Reactor Coolant System venting. For the plant conditions at the time of the event this Technical Specification was not applicable.

The AIT reviewed the Technical Specifications applicable to shutdown plant conditions to determine whether the specifications or lack of specifications contributed to the event. The following is a summary of this review. The assurance that a facility will be maintained in a configuration (depending on plant conditions) that ensures protection of public health and safety, operating personnel, and the facility can be accomplished through various specifications including: licensee commitments, administrative controls and procedures, and operating procedures, etc. The facility Technical Specifications are also included in this group which, as part of the operating license, specify minimum equipment which must be operable depending on plant conditions/modes. All of these standards are combined to provide guidelines to ensure the facility is operated safely. Technical Specifications for Oconee vintage plants tend to focus on power operational modes and are less specific for shutdown and refueling conditions/modes. This strong reliance on Technical Specifications for power operations is a typical philosophy to achieve safe power operation. However, for facilities that are less specific in non-operational modes, it is not prudent to rely solely on Technical Specifications for shutdown/refueling operations due to the sparse coverage provided by these Technical Specifications for shutdown/refueling conditions.

The AIT considers it reasonable that adequate administrative controls be in place to provide an appropriate "mix" between Technical Specification and administrative controls to provide specifications for shutdown plant operations.

E. Conclusions/Safety Significance

1. Conclusions

With regard to the heat-up event of September 7, 1991, the AIT reached the following conclusions:

Technical Specifications for Oconee tend to focus on power operational modes and are less specific for shutdown and refueling conditions/modes. This lack of specificity was not covered by facility administrative controls.

Adequate procedures did not exist for operating the LPI and Low Pressure Service Water system while in shutdown plant conditions.

Abnormal operating procedures were not adequate to address shutdown casualties such as loss of decay heat removal due to loss of heat sink/Low Pressure Service Water.

The licensed operators in the control room during the event (four reactor operators and two senior reactor operators) were inattentive to their duties and responsibilities.

Control room supervisors, unit 1 supervisor (Senior Reactor Operator) and unit 1/2 control room Senior Reactor Operator did not appropriately carry out their duties to ensure critical safety parameters were monitored and controlled. In summary, they did not maintain a proper safety perspective for a shutdown unit nor did they instill this perspective in their subordinate reactor operators. This is an indication of inadequate supervisory oversight and failure to properly assign and implement responsibilities in the control room.

Facility management oversight was not at a level necessary to ensure that control room activities were meeting management's expectations.

Valve testing schedule changes were informally modified without appropriate briefings of the control room staff, disrupting the normally heavy control room outage work load.

Controls governing VOTES testing were not provided to ensure that control room operators maintained "control" over testing being conducted on safety systems expected to be maintained in an operational state.

Existing control room instrumentation was adequate to provide the necessary information to the control room operators to determine that an increasing Reactor Coolant System temperature and a Low Pressure Service Water no flow condition to the decay heat cooler existed.

Operators possessed knowledge sufficient to ensure competent operation of systems required for shutdown plant operations, including the recently replaced Low Pressure Service Water controllers.

The heavy control room work load was inadequately managed by the control room supervisors such that the operators became so involved that they were distracted from monitoring plant parameters. The pre-occupation with control room activities should not have precluded the operators from fulfilling their responsibilities for monitoring critical safety parameters. This is considered to be a fundamental watch-standing principle on which safe nuclear power plant operations are based.

2. Safety Significance

The AIT investigated the event and reviewed the licensee's preliminary analysis of core conditions during and after the event and concluded that the event did not result in a significant threat to the public health and safety. As discussed previously in this report, fuel integrity was not jeopardized during the event.

The AIT also examined the potential of plant/core damage had the event continued without operator intervention. The AIT concluded there was little possibility of damage for the following reasons:

- Continuation of the event would have caused the LPI temperature to have reached 190 degrees Fahrenheit, which would have initiated an audible alarm.

- Continuation of the event would have eventually led to loss of LPI flow due to flashing in the high point of the LPI suction line or air entrainment from the hot leg. The licensee's analysis indicated that LPI flow loss would occur at 15 hours with no operator action due to air entrainment. Pump flow loss would cause an audible alarm, and an operator response would be likely.

- The licensee's analysis indicated core uncovery at 21 hours with core damage calculated to occur at 25 hours, all presuming no operator action. The AIT considers it unlikely that the event would have continued much longer than it did without detection because of the number of people working in containment and the obvious generation of copious quantities of steam. It is noted that the discovery of the loss of cooling occurred as the steam release started, not after prolonged boiling which would have caused LPI temperature to approach the boiling temperature. In addition, the on coming shift would have detected the elevated Reactor Coolant System temperature during log readings required at the beginning of shift.

- The equipment hatch was closed prior to discovery of the heat-up condition, the personnel hatch was operated with the requirement that one door be closed at all times, and a manifold arrangement was being used via the escape hatch for electrical and other outage support wires and tubes to provide for containment closure.

- The operators had other options for stopping the heat-up, including:

  a. Re-initiation of Low Pressure Service Water flow.

  b. Gravity feed of water into the reactor coolant system.

  c. Initiating flow from the Reactor Coolant System into the LPI system via the connection between the LPI hot leg suction line and the containment emergency sump, effectively bypassing a vapor bound elevated section of LPI piping.

  d. Use of other pumps to transfer water from the borated water storage tank to the Reactor Coolant System.

  e. Re-initiation of LPI flow if lost following appropriate correction of conditions as identified in items 5a and 5d.

  Interviews with personnel who were in the control room during the event indicated that they were aware of these potential actions, although detailed abnormal procedures addressing some of these potential shutdown plant conditions were not available.

- Little release of radioactive material would occur due to steaming as long as the fuel remained undamaged.

V. ROOT CAUSES

A. Inadequate Procedures

Procedures used in realigning the LPI and Low Pressure Service Water systems while shut-down from train 1A to train 1B were inadequate. The procedures did not provide guidance for operation of the LPI and Low Pressure Service Water systems while in the decay heat removal mode of operation. This resulted in Low Pressure Service Water not being lined up to the appropriate decay heat cooler when the systems were realigned and the subsequent unmonitored reactor coolant system heat-up.

B. Inappropriate Execution of Operator Responsibilities

The licensed operators were inattentive to their duties and responsibilities in that critical plant safety parameters were not monitored for a period of approximately four hours. This resulted in reactor coolant temperature unexpectedly increasing from 110 to 187 degrees Fahrenheit. This is indicative of a weakness in the training and/or understanding of the fundamentals of watch-standing principles.

C. Inadequate Facility Management Oversight

Management oversight was not sufficient to ensure that control room activities were meeting management's expectations, i.e., that the control room staff were executing their duties per established guidelines and management directives.

D. Schedule Changes to Accommodate VOTES Testing

The control room operators, in addition to the normal outage work load, had to adjust to several informal changes to the outage schedule to accomplish valve testing. These changes, made soon after shift change on the morning of September 7, 1991, caused the operators to realign the LPI trains which eventually resulted in the unmonitored reactor coolant system heat-up. Although these changes did not cause the event, the disruption in control room activities to accomplish these tasks played a significant role in the initiation and progress of the event.

2. September 19-20, 1991, Over-pressurization of the LPI System.

I. INTRODUCTION - AIT FORMATION AND INITIATION

A. AIT Continuation

On the morning of Friday, September 20, 1991, the Regional Administrator, after further briefing by the regional and resident staff and consultation with senior NRC management, directed that the AIT made up of Region II and NRR personnel for the reactor coolant system heat-up event of September 7, 1991, be extended to include this event. The basis for the continuation of the AIT was to gain a clearer understanding of an event related to the over-pressurization of the LPI system and the subsequent loss of approximately 12,400 gallons of reactor coolant.

B. AIT Charter

Refer to Appendix C

II. EVENT DESCRIPTION

A. Event Overview

Late on the evening of September 19, 1991, the licensee failed to follow their start-up procedure. This failure to follow procedure resulted in the over-pressurization of portions of the LPI system and the subsequent loss of approximately 12,400 gallons of reactor coolant.

B. Detailed Sequence of Events

TIME		EVENT
9/19/91	2151	1B High Pressure Injection pump started for testing.
	2200	Reactor Coolant System pressure increase to 90 psig to stabilize letdown.
	2300	Unit 1 supervisor called the control room and notified the Reactor Operator that unit 1 was "cleared" to increase Reactor Coolant System pressure to 300 psig.
	2300	The Reactor Operator receiving the communication tells the Reactor Operator at the Controls that the unit 1 supervisor wanted to increase pressure to 300 psig. The Reactor Operator

energizes pressurizer heaters to increase pressure to 300 psig.

	2352	1B letdown filter is placed in service.
09/20/91	0000	One Reactor Operator, while operating High Pressure Injection pumps, notices an increase in High Activity Waste Tank level, and makeup flow rate. The Reactor Operator also notes decreasing pressurizer level and informs the other Reactor Operator.
	0013	Letdown filter is bypassed, suspecting a gasket leak.
	0014	The Reactor Operator sends non-licensed operators to check for LPI and High Pressure Injection leakage.
	~0016	The Reactor Operator informs the operations engineer and shift supervisor of increased leakage. The operations engineer and shift supervisor review prints.
	~0020	Unit 1 supervisor refers to abnormal procedure for excessive Reactor Coolant System leakage.
	~0020	Non-licensed operator finds drains in High Pressure Injection pump room overflowing.
	0025	Control room receives a call from a performance technician that 1LP-26 (LPI Pump Suction Relief Valve) is leaking.
	0027	Shift supervisor and operations engineer review Reactor Coolant System pressure and the LPI lineup. They realize that the plant should have been in switchover mode.
	0027	Shift supervisor directs the Reactor Operator to deenergize the pressurizer heaters.
	~0100	Shift supervisor confers with all reactor operators and unit supervisors in unit 1 control room to determine what had happened. He decides not to enter switchover mode, but to depressurize Reactor Coolant System using auxiliary spray.
	0100-0200	Control room sends non-licensed operators to lineup auxiliary spray. (Valves are located in the Penetration Room)

0130-0200 There are problems with the auxiliary spray lineup: One of valves (stop check) was completely lagged over with no observable label. The downstream valve was closed.

0200 NRC resident notified of event by licensee.

0234 The operators began using auxiliary spray (pressurizer temperature was 391 degrees Fahrenheit, Letdown Storage Tank Temperature was 93 degrees Fahrenheit, Reactor Coolant System Pressure was 207 psig).

0243 Reactor Coolant System pressure decreases below 200 psig.

0300 Radiation protection shift supervisor is notified of leakage in LPI pump room. Air samples and contamination surveys are initiated.

0320 Reactor Coolant System Pressure lowered to less than 125 psig.

0410-0415 Relief valves reseat (High Activity Waste Tank level increase stabilized).

0615 Licensee makes information only call to NRC duty officer in operations center.

C. Initial Conditions

On September 19, 1991, unit 1 was in day 50 of a scheduled 55 day refueling outage. The reactor was completely refueled and start-up activities were in progress per the start-up procedure. During shift turnover at 1830, the unit was in cold shutdown with the Reactor Coolant System intact and temperature at 100 degrees Fahrenheit. A pressurizer steam bubble had been established and Reactor Coolant System pressure was being controlled at 60 psig. The LPI system was in the decay heat removal mode of operation with both LPI headers in service. At 1335 the High Pressure Injection system had been placed in service per the unit start-up procedure covering cold shutdown to Reactor Coolant System temperature of 250 degrees Fahrenheit and pressure of 3?0 psig. This was performed earlier by the day shift with the 1A High Pressure Injection pump operating, maintaining pressurizer level. The 1B High Pressure Injection pump was scheduled for a performance test and the test was started shortly after shift turnover. The Reactor Coolant System pressure was increased to 90 psig, with the control room Senior Reactor Operator aware of the increase, to stabilize letdown flow to maintain the 1B High Pressure Injection pump bearing temperature during the pump performance run.

D. Event Initiation

The AIT interviewed the operators involved in the event. The purpose of these interviews was to identify what happened in the control room and to evaluate operator actions during the event and subsequent recovery. The following is an annotated list of operator actions as presented to the AIT during the interviews. This list is not meant to represent the chronology of the event; the intent is only to present relevant operator actions.

On the evening of September 19, 1991, pending completion of the 1B High Pressure Injection pump test, the unit was in route to placing the reactor coolant pumps in service. The prerequisites for placing the reactor coolant pumps in service were the availability of the 1B High Pressure Injection pump for seal injection backup and an Reactor Coolant System pressure of approximately 300 psig for reactor coolant pump net positive suction head requirements. Plans were to start pressurization of the Reactor Coolant System following completion of the post-maintenance test on the High Pressure Injection pump. In addition, because of the design of the LPI system, the LPI system would have to be realigned in the switchover mode of decay heat removal prior to increasing Reactor Coolant System pressure above 125 psig. The procedure for unit start-up outlined the requirements to conduct this alignment change.

The need to align the LPI system in the switchover mode of operation prior to Reactor Coolant System pressure of 125 psig arises from the fact that, portions of the LPI system are not designed for the combined Reactor Coolant System and LPI pump pressure. Therefore, the coolant is first directed through the LPI coolers and then routed to the suction of the LPI pumps and into the reactor vessel.

At about 2300 on September 19, 1991, the 1B High Pressure Injection pump test was completed, the B High Pressure Injection pump was now available and the operations engineer notified the unit 1 supervisor that the requirements to pressurize were met. The unit supervisor, following notification from the operations engineer, called the control room and notified them that they were now "cleared" to increase pressure. The Reactor Operator controlling plant pressure energized the pressurizer heaters, initiating the pressure increase. The operations engineer was not aware that the requirement to place the LPI system in the switchover mode of operation had not been met. The unit supervisor, the control room Senior Reactor Operator, as well as the operators in the control room failed to refer to the next step in the start-up procedure which required the LPI system to be put in the switchover mode. Instead, Reactor Coolant System pressurization was initiated with the LPI system in the normal decay heat alignment.

At approximately midnight a control room operator noted a rapidly increasing High Activity Waste Tank level combined with a decreasing pressurizer level. The makeup flow was limited due to a flow restrictor placed on the pressurizer level control valve for low temperature over-pressure protection.

E. Operator Response (Recovery)

When the operators noticed that the High Activity Waste Tank level was off scale high, both the letdown storage tank level and pressurizer level were decreasing. Based upon this, the operators concluded that there was a leak in the auxiliary building. The operators initiated the operations procedure for indications of primary leakage. Based upon the observed conditions, Non-licensed Operators were dispatched to search the auxiliary building for leakage. A maintenance technician called the control room to report leakage from the LPI relief valve. After the leak was detected the operators concentrated on the letdown system as the most likely source of the leakage because it was the last system manipulated. The operators bypassed the letdown filter which had just been placed in service. This appeared to stop the leak because pressurizer level began to recover. However, the operators noticed that letdown storage tank level was continuing to drop. At this point it was clear that system leakage was continuing. After it was apparent that there was still leakage, the control room operator was informed that there was a leak in the LPI pump room. At this point the operators discovered that the plant was not in the switchover mode which was required to be in service above 125 psig; the plant was at approximately 250 psig.

The control room operators then turned off the pressurizer heaters and reactor pressure stabilized and subsequently began to slowly decrease. After the operators noted the slow response of reactor pressure, the shift supervisor directed the control room operators to manually align the auxiliary spray system. The manual alignment of the auxiliary spray system took about two hours. The manual alignment was exacerbated by lagging covering some of the valves in the warm-up line. During this time, the leakage from the reactor coolant system continued. The auxiliary spray system was turned on and the rate of depressurization increased. The relief valves reseated at 110 - 115 psig. When the relief valves reseated the leakage stopped and the level stabilized in the High Activity Waste Tank.

F. Licensee Response (Short Term)

Event Notifications

The NRC resident inspector was notified of the event by the licensee at approximately 0200 on September 20, 1991. The headquarters duty officer was notified at 0615 the same day. Notification of the NRC headquarters duty officer, was classified by the licensee as a voluntary call. The AIT reviewed the facility's Emergency Plant Implementing Procedures (Volume C, Rev 91-8), Emergency Classification Procedure RP/0/B/100/01, in particular, the classification of events, Reactor Coolant System leakage (Enclosure 4.1.1), and entries into emergency action levels. For Reactor Coolant System leakage exceeding the specified limits, entry into emergency action levels is required only with the unit in Hot Shutdown through power operations. For this event the unit was in Cold Shutdown.

Investigations

The licensee initiated a detailed investigation of the event. Interviews of the involved operators were commenced within a few hours of the event. Based on the potential safety significance and after consulting with the Vice President for Nuclear Production, the licensee made the decision to bring in a corporate guided Significant Event Investigation Team to review the event.

Manager on Shift

Plant Management elected to place a manager on shift until the outage was completed. This manager had written instructions to ensure the following:

- Operators have procedures and the procedures are being followed.
- Senior Reactor Operators are maintaining a "big picture" with regard to plant status; ensuring plant safety is maintained.
- Senior Reactor Operators are maintaining proper command and control over plant operations.
- Communications standards are being met.

Shift Briefings

The on-coming shifts were briefed by plant management as to the significance of the event and the need to follow procedures.

Plant Start-up

Suspended plant recovery from the outage until event was understood and measures in place to prevent recurrence.

III. REVIEW OF CONTRIBUTING FACTORS

A. Procedures

Controlling Procedure for Unit Start-up

The AIT reviewed procedure OP/1/A/1102/01, Controlling Procedure for Unit Start-up. The procedure covered performance of the unit start-up, in a step-by-step format. The procedure could be performed in a step sequence that differed from the written procedure only if it was changed in accordance with the licensee's Operations Management Procedure OMP 1-9. This procedure contained instructions for performance of steps out of sequence provided an adequate approved justification was written on the working copy of the procedure.

The AIT reviewed the administrative procedure for performing procedure steps out of sequence which is covered in Operations Management Procedure OMP 1-9, Use of Procedures, section 6.3, Deviation from an Approved Procedure. Sub-steps 6.3.A.1 a, b, and c provided the instructions for deviation from the sequence of steps in an approved procedure. With two exceptions the procedure for deviation from approved procedures was followed for the changes in step sequence for OP/1/A/1102/01, Controlling Procedure for Unit Start-up. The two exceptions were, steps 2.1 and 2.2 were not performed in sequence. Step 6.3.A.1.b of OMP 1-9 required that an evaluation of the consequences of a sequence change should be documented on the working copy of the procedure by the individual performing the procedure and by the initials of the Senior Reactor Operator approving the change in sequence. This was not done; however, it did not have an effect on this event.

Step 2.3.1 was signed by an operations engineer that was not performing duties as an operator on shift. Additionally, the operations engineer wrote the justification for performing the step out of sequence. The appropriate approval was not given for this justification.

An additional observation of inconsistencies in OP/1/A/1102/01 was that not all of the completed steps were dated when they were initialed and timed. This provided misinformation on the actual date that steps were performed. Skipped steps were left blank and the dates and times were filled in later. Operators stated that undated steps were performed on the date of the preceding step. When the dates for skipped steps were filled in, it gave the appearance that steps had been performed on the wrong date.

Other procedural weaknesses noted by the AIT are discussed below. In general procedures covering LPI operation did not provide a straightforward, "up front" warning to conduct switchover prior to exceeding 125 psig. Part of the problem was the number of procedures involved in making the switchover operation. The problem is exacerbated by the apparent failure to address these areas of operation in periodic operator retraining.

Procedure OP/1/A/1102/01, enclosure 4.1, states that "Enclosure 4.1A (Flowchart) should be used as a guide by the Senior Reactor Operator/Reactor Operator to aid in maintaining the big picture." Step 2.4 is followed by a "bullet" block that identifies "LPI IN SWITCHOVER" but does not identify a pressure. This is step 2.5 in the procedure, but this step designation is missing from the flowchart. This is an important omission since the instructions for following the procedure state: "All number steps are critical path steps. All steps that follow a bullet are parallel steps that need to be done along with the critical path step but not in any sequence. Prior to going to the next critical step, all parallel steps should be completed unless otherwise stated."

Step 2.6 includes, "PRIOR TO 150# (psi)....", thus the flowchart allows switchover above the procedure requirement of 125 psig (as discussed below). The AIT concluded that all steps with such pressure and/or temperature restrictions should have the restrictions clearly identified prior to the step. The flowchart did not consistently include this information.

Step 2.4 of the above procedure states: "Prior to reaching 100 psig in the Reactor Coolant System...." and step 2.5 is "Align LPI system to Switchover Mode per OP/1/A/1104/04 ...."; no pressure is identified. A note following step 2.5 mentions 350 degrees Fahrenheit, a caution prior to step 2.6 mentions 310 psig, and a note prior to step 2.6 mentions > 295 psig. There is no mention of a pressure associated with switchover.

Procedure OP/1/A/1104/04, LPI System, "Limitations and Precautions" section at the front of the procedure does not mention switchover nor does it provide an applicable pressure limitation. This information is covered later in enclosure 3.2, "Reactor Coolant System Heat-up", where step 2.1

states: "Place system in SWITCHOVER MODE as follows prior to exceeding 125 psig."

As discussed above, several procedural weaknesses were identified; however, the AIT concluded that adequate start-up procedures were available. Had the procedures been utilized they would have provided appropriate guidance for aligning the LPI system to the switchover mode without overpressurizing the system.

Abnormal Operating Procedures

During this evolution the operators had the abnormal operating procedure AP/1/A/1700/02 "Excessive Reactor Coolant System Leakage" available. The procedure was opened, but was not used in the mitigation of the event. There were no Abnormal Operating Procedures or Emergency Operating Procedures that address Reactor Coolant System leakage specific to shutdown conditions. The operators used procedure OP/0/B/1106/33 "Primary System Leakage Identification" to determine the potential leakage path into the High Activity Waste Tank.

After realizing that the LPI system was in an improper lineup, the operators considered aligning the LPI system to switchover. However, they chose not to because of radiological concerns associated with the relief valve leakage in the LPI room. The alignment to switchover would have required an operator to enter the LPI room. The operators also considered using the Power Operated Relief Valves to reduce pressure. The decision was made not to use the Power Operated Relief Valves due to the potential of the Power Operated Relief Valve sticking open or the potential rupture of the rupture disc in the quench tank. The operators chose to use auxiliary spray to reduce pressure. This required a time consuming manual alignment of auxiliary spray. Had an Abnormal Operating Procedure been available addressing Reactor Coolant System leakage when shutdown, the decisions on how and by what method to reduce pressure would likely have been straight forward and more efficiently executed.

B. Operator Responsibilities

The team reviewed Operations Management Procedure 2-1, "Duties and Responsibilities of Reactor Operators, Non-Licensed Operators, and the Senior Reactor Operator in the Control Room". This procedure in part defined the responsibilities of the licensed reactor operators on the control board, Senior Reactor Operator in the control room, and the non-licensed operators.

Again, as in the September 7, 1991, heat-up event,the unit 1 supervisor and the control room operators were deficient in meeting their watch-standing responsibilities. The control room Senior Reactor Operator was distracted, by the heavy on going workload, from fulfilling his responsibilities pertaining to monitoring overall plant operations and ensuring that procedures are followed. The unit 1 supervisor's overview of unit 1 operations was inadequate; this was considered by the AIT to be a major weakness associated with the event. The unit 1 supervisor was not sufficiently involved in the control room routine on the day of the event so as to have a feel for the impact of outage work on plant operations. Additionally, the unit 1 supervisor notified one of the Reactor Operators, without first verifying plant conditions/status, that the Reactor Coolant System could be pressurized. This communication was made by telephone and bypassed the control room Senior Reactor Operator. The Reactor Operator receiving the notification to increase pressure passed the word to the Reactor Operator who was controlling Reactor Coolant System pressure. This Reactor Operator then commenced the pressurization without referring to the appropriate procedures. Subsequently, the LPI system was over-pressurized due to an incorrect system line-up for the planned evolutions.

C. Control Room Activities

The AIT reviewed the activities in which the unit 1 licensed operators were involved on the night of September 19, 1991. The team noted that there was a significant amount of work on-going throughout the early part of the shift. The activities included: post maintenance test run on the 1B high pressure injection pump, completion of the containment isolation valve checklist, performance test run on the motor driven emergency feedwater pump, returning to service the 1A and 1B feedwater heaters, restoration of 1LPSW-18, return to service of the reactor building cooling units, and seal supply filter replacement. Of these activities, the 1B High Pressure Injection pump performance test required by far the most effort, keeping the unit supervisor, the control room Senior Reactor Operator, and two reactor operators preoccupied. The control room Senior Reactor Operator, who was responsible for monitoring plant parameters and maintaining the overall picture, was heavily involved in coordinating the High Pressure Injection pump test. He also was involved in the details of the containment valve verification process. The completion of this test was a prerequisite for pressurization of the Reactor Coolant System to meet reactor coolant pump net positive suction head requirements.

Considering that four reactor operators were assigned to the shift, the AIT concluded that the overall work load for the operators was not excessive. The amount of work going on at the time was substantial; however, it was not atypical for plant start-up following a refueling outage. Additionally, the

AIT concluded that preoccupation with activities should not have precluded the operators from referring to the start-up procedures. With one exception, based on a review of activities, as well as conversations with the involved licensed operators, the AIT concluded that the workload, although not well organized, was not a major contributing factor to the initiation of this event. However, it is likely that the recently qualified unit 1 control room Senior Reactor Operator, considering his inexperience in this position, was overloaded with the details of outage activities. Licensee management, as a corrective action for the prior week's Reactor Coolant System heat-up event, had assigned a control room Senior Reactor Operator exclusively to the unit 1 control area to monitor overall plant operations, concentrating on the safety of the plant and critical safety parameters while shut-down. Clearly, this function was not executed by the control room Senior Reactor Operator due to his involvement in outage activities.

Considering the above, the AIT concluded the unit supervisor did not tour the control room and was not involved in the control room routine in sufficient detail so as to assess the level of distractions which may have been impacting operator performance on the day of the event. Specifically, the workload of the control room Senior Reactor Operator should have been redirected by the unit 1 supervisor such that management expectations (monitoring overall plant safety and maintaining the "big picture") for the existing outage conditions were met. The AIT concluded that these unit 1 supervisor duties were not performed.

D. Training

The inspectors reviewed portions of selected guides that were provided to the licensed operator instructors. The lesson on the LPI system identified all switchover mode requirements. Although the maximum pressure prior to switchover was not specifically identified in a lesson plan, start-up procedures were identified. Operator training did address the system fundamentals, and if operators followed procedures as they had been trained, this event would not have occurred. Training deficiencies did not directly influence this event.

In interviews conducted by the AIT, operations personnel noted that little refresher training is provided with respect to such areas as systems, new procedures, and shutdown (outage) operations. Also noted was that Oconee's training is focused on the NRC exams, and in this regard the training has been successful as evidenced by the facility's record in passing these exams. However, the operators expressed the need for more training in the areas of plant evolutions and plant/system operations. The AIT concluded that emphasis should be placed on training in the areas of shutdown plant operation, including emergency response and shutdown system lineups/functions.

E. Communications

The AIT reviewed Operations Management Procedure 2-1, "Duties and Responsibilities of Reactor Operators, Non-Licensed Operators, and the Senior Reactor Operator in the Control Room". This procedure in part defined the responsibilities of the Licensed Reactor Operators on the Control Board, Senior Reactor Operator in the Control Room, and the non-licensed operators. The procedure delineates the lines of communication for instructions from shift management to plant operators. The lines of communication in the procedure did not reflect the pathway for information during this event.

In general, the AIT concluded that poor communications existed within the control room between the Senior Reactor Operator and Reactor Operator. Specifically, the unit 1 supervisor, without verifying plant status ordered/notified one of the four control room Reactor Operators that the plant was "cleared" to be pressurized. This communication was conducted by telephone. The Reactor Operator receiving the notification then informed another Reactor Operator (operator controlling plant pressure) to increase Reactor Coolant System pressure. The control room Senior Reactor Operator was not involved in the communication. This effectively by-passed the control room Senior Reactor Operator's responsibility for maintaining the plant "big picture."

IV. SAFETY CONSEQUENCES/SIGNIFICANCE

A. LPI Over-Pressure Analysis

A brief evaluation of the event and examination of the LPI and High Pressure Injection pump areas did not identify any significant complications. Overall, the AIT concluded that LPI system integrity was not affected. The following is a summary of the LPI system pressurization including a review of system performance had the pressurization continued.

The Reactor Operator was planning to raise system pressure to 300 psi and actually reached 245 psi on the LPI pump suction piping. LPI pump discharge pressure reached about 450 psi. If 300 psi had been reached, the discharge pressure would have been approximately 500 psi. This would have over-stressed some 10 inch piping (maximum code allowable of 420 psi) but it is unlikely that this could have caused a pipe failure. The heat exchanger is hydrostatically tested to 600 psi and is not a concern, nor is the suction piping with a maximum code allowable pressure of 489 psi. Other leaks could be conceived, such as in instrumentation, that would increase the leak rate, but not by the magnitude needed to exceed High Pressure Injection capacity. Such leaks are isolable from the Reactor Coolant System and most could be isolated locally. Some local valve operations may have been difficult unless LPI operation was temporarily stopped to allow depressurization of the LPI system.

The licensee's post-event LPI system engineering analysis identified two instruments that required replacement because they were over-ranged and two others that required recalibration. The licensee reported that no over-pressurization of major system components occurred with respect to such criteria as allowable hydrostatic test pressure (heat exchangers), maximum code allowable pressure (piping), and design capability (valves). The licensee concluded that the LPI system is safe for continued operation.

B. Radiation Protection

The over-pressurization of the LPI system resulted in approximately 12,000 gallons of reactor coolant leaking out of the Reactor Coolant System/LPI system. The leak was contained within the auxiliary building. There was no change in activity levels noted by radiation monitoring instruments located in the High Pressure Injection room as well at "discharge to environment" locations. Personnel doses received from the leak were minimal and body burden analysis performed on personnel, who had entered the LPI and the High Pressure Injection rooms while the leak was in progress, did not identify any presence of radioactive intake. The leak did cause the unit 1 "A" LPI pump room and the unit 1 and 2 HPI room to become contaminated.

At midnight, after noticing an increase in the High Activity Waste Tank level and decreasing pressurizer level, control room personnel suspected a leak in the High Pressure Injection or the LPI system and dispatched non-licensed operators to check for leakage. At this point radiation protection was not notified of the suspected leakage. The non-licensed operators entered the High Pressure Injection pump room and observed that the floor drains were overflowing. The non-licensed operators did not take into consideration the potential for airborne activity. A performance technician who entered the LPI room, observed leakage on valve 1LP-26 and notified the control room. This performance technician received a total dose of 10 millirem from approximately 2000 on September 19, 1991, to 0200 on September 20, 1991. At approximately 0300 radiation protection personnel were notified by control room personnel of the leaking valve (1LP-26) in the A LPI pump room and requested radiation protection coverage for entry into the LPI pump room. Air samples taken prior to the entry into the LPI pump room indicated less than .01 Maximum Permissible Concentration. However, personnel entering the room were required to wear a particulate respirator to reduce the potential for uptake. Additionally, a body burden analysis was performed on the personnel, including radiation protection, who had entered the LPI room. No presence of activity was identified.

The normal relief path for the fluid past 1LP-26 is to the High Activity Waste Tank, located in the High Pressure Injection pump room, through a hard pipe connection. However, due to a leak in the valve itself, there was some coolant being sprayed into the LPI pump room causing the LPI pump room to become contaminated. The hard pipe connecting valve 1LP-26 and the High Activity Waste Tank also has among other connections, a line from the High Pressure Injection pump base drains. With a 30-40 gpm flow through the pipe, some coolant backflowed through the High Pressure Injection pump base drain and into the High Pressure Injection pump room causing the High Pressure Injection pump room to become contaminated. Surveys taken by radiation protection indicated contamination levels of up to 200,000 dpm/100cm2 in the "A" LPI pump room and up to 250,000 dpm/100CM2 in the High Pressure Injection pump room.

The High Activity Waste Tank has a capacity of approximately 1800 gallons. To prevent overflowing of the tank, the contents of High Activity Waste Tank were pumped to the miscellaneous waste holdup tank throughout the course of the event. Contents of the miscellaneous waste tank were then pumped to the radioactive waste feed tanks located in the radioactive waste facility from where the liquid was released following treatment.

During the event, no change in dose rates as well as activity levels were noted on Radiation Instrument Alarm 32, auxiliary building gas monitor, Radiation Instrument Alarm 43, unit 1 vent particulate monitor, Radiation Instrument Alarm 44, unit 1 vent monitor, Radiation Instrument Alarm 45, unit 1 vent gas monitor, and Radiation Instrument Alarm 15, High Pressure Injection room area monitor. In addition, no activity was detected in the Low Pressure Service Water system which is the heat sink for the LPI coolers. The Low Pressure Service Water discharges into Lake Keowee through the condenser circulating water system.

The AIT concluded that the radiological consequences of the event were minor resulting in no environmental releases or personnel overexposure. However, the AIT concluded that the notification of radiation protection should have been made earlier so as to give sufficient time for radiation protection to assess the situation and thus minimize the potential for exposure.

C. Conclusions

With regard to the LPI system over-pressurization of September 19-20, 1991, the AIT reached the following conclusions:

Procedures for plant pressurization and start-up were available but not followed by the control room operators.

Abnormal operating procedures were not adequate to address shutdown plant casualties such as high Reactor Coolant System leak-rate.

A combination of inexperience and the heavy control room outage workload distracted the control room Senior Reactor Operator from his primary responsibility of ensuring the safety of the plant and maintaining a proper safety perspective or "big picture".

Shutdown plant system alignment and operation training was weak.

Control room communications between the unit supervisor, control room Senior Reactor Operator, and the Reactor Operators were inadequate.

Command and control of activities in the control room were inadequate. Administrative procedures covering the command chain were inadequate.

No operator in the unit 1 control chain of command exhibited ownership for the plant startup procedure. As a result, the step requiring LPI alignment to switchover was not performed.

Corrective actions in response to the September 7, 1991, heat-up event were inadequate. Although management attempted to make changes to improve the conduct of control room operations after the first event, business remained effectively unchanged. The following conclusions apply and were also made in reference to the prior event:

Unit 1 supervisor and the unit 1 control room Senior Reactor Operator, did not appropriately carry out their duties to ensure that the safety of the shutdown plant was maintained and procedures were followed.

Facility management oversight was not at a level necessary to ensure that control room activities were meeting management's expectations.

V. ROOT CAUSES

A. Failure to Follow Procedures

Procedures for start-up of the plant from refueling conditions were not followed. Steps requiring alignment of the LPI system to the switchover mode of operation were not completed. Additionally, precautions that Reactor Coolant System pressure not be raised above 125 psig until the LPI system was aligned in the switchover mode were not followed.

B. Inadequate Corrective Actions

Corrective actions in response to the September 7, 1991, heat-up event which required a control room Senior Reactor Operator be assigned exclusively to the outage unit to ensure that the "big picture" was maintained were inadequate. The control room Senior Reactor Operator was not involved in the decision and subsequent order to pressurize the Reactor Coolant System.

C. Inadequate Control Room Communications

Control room communications were inadequate. The unit 1 supervisor by-passed the control room Senior Reactor Operator when ordering the Reactor Operator to raise Reactor Coolant System pressure. Additionally, the unit 1 supervisor made the communication by telephone without reviewing plant status.

D. Inadequate Management/Supervisor Oversight

Management/supervisor oversight was not sufficient to ensure that control room activities were meeting management's expectations. Facility management was not aware that corrective actions taken because of the prior heat-up event were not being adequately implemented. The unit 1 supervisor was not sufficiently aware of plant status when communicating to the Reactor Operator to increase plant pressure. Additionally, oversight of control room operations by the unit 1 supervisor was weak due to his lack of control room tours during the subject shift.

3. Confirmation of Action Letter/Management Meeting

A Confirmation of Action Letter (CAL) documenting the licensee's commitments made as result of the two shutdown events on unit 1 was issued by NRC Region II on September 20, 1991. The letter required the licensee to take the following actions:

a. Immediately provide 24-hour operational oversight using management personnel on-shift until the NRC agrees this coverage is no longer necessary.

b. Investigate the facts and circumstances associated with the September 19-20, 1991, overpressurization event and report the results of this investigation and the corrective actions taken for this and the September 7, 1991, loss of shutdown cooling event to the NRC staff.

c. Perform and complete an engineering evaluation of the overpressurization of the low pressure injection piping to determine the effect this had on the low pressure piping.

d. Do not restart the unit (i.e., achieve criticality) prior to meeting with the NRC to discuss these issues.

The circumstances associated with the events were discussed with the NRC during a meeting conducted in the Region II office on September 25, 1991. As discussed previously, the engineering preliminary evaluation performed by the licensee did not indicate any adverse effect on the LPI piping. On September 27, 1991, the NRC granted permission to the licensee to achieve criticality on unit 1. On October 18, 1991, the NRC released the licensee from the requirement to have 24-hour management oversight in the unit 1 control room.

4. Exit Interviews With Licensee Management

Inspection scope and findings were summarized during two exit interviews, one on September 13, 1991, and the other on September 23, 1991, with those persons indicated in Appendix A. The NRC described the areas inspected and discussed in detail the inspection results covering the Reactor Coolant System heat-up event on September 7, 1991, and the LPI over-pressure event on September 19-20, 1991. No proprietary material is contained in this report. No dissenting comments were received from the licensee.

5. Licensee Long Term Corrective Actions

In addressing the causes of the two events covered in this report and other significant weaknesses identified in the investigation, the licensee had taken or has plans to initiate the following corrective actions:

a. Implement enhanced controls of testing activities effecting valve positioning.

b. Add a dedicated control room SRO for shutdown units.

c. Develop a set of duties and responsibilities for the unit supervisor which support and reinforce the expectations of the control room SRO.

d. Differentiate the duties and responsibilities of the operator at the controls (OATC) with respect to the other control room reactor operators, such that expectations for oversight of the primary plant are reinforced.

e. Revise management procedures to reflect c. and d., and train reactor and senior reactor operators on the changes.

f. Evaluate command and control, and watchstanding practices to develop and implement standards which assure lines of communication and authority support duties and responsibilities of the control room personnel.

g. Perform a review of all procedures associated with shutdown operations and provide training on these procedures to all operating personnel.

h. Perform a review and implement enhancements to integrate the planning, scheduling, and coordination of valve positioning activities during shutdown conditions.

i. Perform a review and implement enhancements to procedures and processes for the conduct of system hydrostatic testing.

j. Analyze and take corrective actions to address the impact of control room outage burden on the safe conduct of operations.

Several of the above actions have been completed as interim measures following the events reviewed in this report. The remaining actions will be completed prior to the licensee commencing the next refueling outage (unit 2) currently scheduled for January 1, 1992.

Appendix A

Persons Contacted

S. Alexander, Shift RP Supervisor
H. Barron, Station Manager, Oconee Nuclear Station
J. Collier, Nuclear Production Engineer
T. Coutu, Unit 1 Operations Manager
D. Coyle, Projects Manager
D. Craig, Nuclear Operations Coordinator, nuclear Support
T. Curtis, Compliance Manager
J. Davis, Superintendent, Technical Services
D. Deatherage, Operations Support Manager
C. Eflin, Nuclear Instructor
W. Foster, Superintendent, Maintenance
R. Futrell, Nuclear Safety Assurance Manager
A. German, Design Engineer, Oconee Nuclear Station
P. Gillespie, Reactor Engineer
B. Holcombe, Oconee Safety Review Group, Member
W. Horton, Operations Coordinator
D. Hunter, General Supervisor, Instrument and Electrical
G. Jones, Operations Coordinator, Unit 1
W. Knight, Shift Supervisor
O. Kohler, Licensing
E. Kyle, Nuclear Assistant Shift Supervisor
T. Lackey, Nuclear Control Operator
C. Little, Instrument and Electrical Manager
H. Lowery, Oconee Safety Review Group, Chairman
J. Mangum, Jr., Nuclear Control Operators, Unit 1 RO
D. Melton, Instrument and Electrical Specialist
H. Morgan, Operations Coordinator, Unit 1
L. Nowell, Nuclear Control Operator
D. Nuckolls, Nuclear Assistant Shift Supervisor
M. Patrick, Test Engineering Supervisor
L. Payseur, Shift Manager
S. Perry, Assistant Licensing Coordinator
D. Powell, Superintendent, Station Services
J. Preston, Nuclear Assistant Shift Supervisor, Unit 1 SRO
G. Ridgeway, Shift Operations Manager
G. Robinson, Nuclear Control Operator, Unit 1 RO
W. Rostron, Production Specialist, Maintenance Engineering
G. Rothenberger, Superintendent, Integrated Scheduling
J. Rowell, Senior Engineer, Projects
E. Shaw, Nuclear Assistant Shift Supervisor, Control Room 1 SRO
S. Spear, General Supervisor, Station Sciences
T. Stevens, Shift Supervisor
P. Stovall, Director of Operator Training
J. Strictland, Nuclear Control Operator
R. Sweigart, Superintendent, Operations
M. Tuckman, Vice President, Nuclear Operations
J. Ward, Control Room Operators
T. Wehrman, Oconee Safety Review Group, Member
R. White, Technical Systems Manager, Oconee Nuclear Safety Assurance

J. Whitener, Nuclear Instructor
M. Williams, Nuclear Assistant Shift Supervisor
C. Yongue, Radiation Protection Manager

Appendix B

Procedures Reviewed

AP/1/A/1700/02	Excessive RCS Leakage
AP/1/A/1700/07	Loss of Low Pressure Injection
AP/1/A/1700/24	Loss of Low Pressure Service Water
OP/0/A/1102/06	Removal and Restoration of Station Equipment
PT/1/A/600/01	Periodic Instrument Surveillance
OP/1/A/1102/01	Controlling Procedure for Unit Startup
OP/0/A/1102/11	Controlling Procedure for Cold Shutdown
OP/1/A/1104/04	Low Pressure Injection System
OP/0/B/1106/33	Primary System Leak Identification
OP/1&2/1104/10	Low Pressure Service Water
IP/0/A/3001/011B	Testing Motor Operated Valves Using VOTES
TT/1/A/251/11	VOTES Testing of LPI Header MOVS
OP/0/A/1102/20	Shift Turnover
OMP 2-1	Duties and Responsibilities of Reactor Operators, Non-licensed Operators, and the Senior Reactor Operator in the Control Room

Nuclear Station Modification Manual
Oconee Nuclear Station Directives
Oconee Nuclear Station Operations Manual
ONS Emergency Plan Implementing Procedures
ONS Technical Specifications
ONS Final Safety Analysis Report
ONS Integrated Scheduling Group Directives

Other References Reviewed

1. Duke Power Company, "Outage Management Philosophy," Procedure 3.0, Rev 4, May 2, 1990.

2. Crutchfield, Dennis M., "Loss of Decay Heat Removal," generic letter sent to all holders of operating licenses or construction permits for pressurized water reactors, GL 88-17, NRC, October 17, 1988.

3. "Duke Power Company, Oconee Nuclear Station, Integrated Scheduling Group," Section 1.0, "Introduction/Responsibilities," ISG Directive 1.0, Rev 9, February 18, 1991.

4. "Duke Power Company, Oconee Nuclear Station, Integrated Scheduling Group," Section 3.0, "Refueling Outages," ISG Directive 3.0, Rev 7, May 22, 1989.

5. Tucker, Hal B., "Oconee Nuclear Station, Docket Nos. 50-269, 270, and 287, Generic Letter 88-17, Loss of Decay Heat Removal," Letter from Duke Power to USNRC, January 3, 1989.

6. Tucker, Hal B., "Oconee Nuclear Station, Docket Nos. 50-269, 270, and 287, Generic Letter 88-17, Loss of Decay Heat Removal," Letter from Duke Power to USNRC, February 2, 1989.

7. Ebneter, Stewart D., "NRC Inspection Report Nos. :50-269/91-08, 50-270/91-08, and 50-287/91-08," Letter from NRC Regional Administrator to Duke Power Company, April 15, 1991.

8. "Duke Power Company, Oconee Nuclear Station, Selected Licensee Commitments, Manual," Oconee FSAR, Chapter 16, Section 16.5.3, "Loss of Decay Heat Removal, Commitment," February 1991.

9. Hood, Darl S., "Comments on Expeditious Actions and Notice of Audit on Oconee Nuclear Station, Units 1, 2, and 3 (TACS 69758, 69759, and 69760)," Letter from USNRC to H. B. Tucker of Duke Power Company, May 17, 1989.

10. "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990," USNRC, NUREG-1410, June 1990.

Training Documents Reviewed

1. "Design Engineering Department Operability Evaluation," Oconee Unit 1, PIR Number 1-091-0101, September 20, 1991.

2. "Low Pressure Injection System," a lesson in the operations training program, OP-OC-PNS-LPI, Rev 5, October 1, 1990.

3. "Controlling Procedure for Unit Startup," a lesson in the operations training program, OP-OC-CP-011, Rev 5, June 19, 1990.

4. "Controlling Procedure for Unit Shutdown," a lesson in the operations training program, OP-OC-CP-014, Rev 5, August 18, 1989.

Appendix C

AIT Charter

The Charter for the AIT was prepared on September 9, 1991 and updated on September 20, 1991. The special inspection commenced with an Entrance Meeting and licensee management briefing September 9, 1991 for the first event and September 20, 1991 for the second event. The Charter for the AIT specified that the following tasks be completed:

1. Develop and validate the sequence of events associated with the September 7, 1991, degradation of decay heat removal and the September 20, 1991, overpressurization of the low pressure injection piping at Oconee. This sequence should begin with plant conditions immediately prior to these events, including known significant deficiencies in safety-related and balance of plant equipment, and extend until the plant was stable.

2. Evaluate the significance of these events with regard to radiological consequences, safety system performance, and plant proximity to safety limits as defined in the Technical Specifications.

3. Identify any human factors, training, or procedural deficiencies related to these events. Evaluate operator action during the Unit 1 events of September 7 and 20, 1991, and subsequent equipment recovery. Specifically, evaluate the effectiveness of the procedures for recovery from loss of decay heat removal and low pressure injection overpressurization which were used during these events, and the requirements for monitoring primary plant parameters such as reactor coolant temperature and pressure while shutdown and during changes to the shutdown cooling lineup.

4. Evaluate the degree to which prior work planning for the outage could have precluded these events. Include the following aspects: (a) Independent Verifications, (b) Verbal Communications, (c) Outage Control, and (d) System Engineer Involvement.

5. Evaluate the accuracy, timeliness, and effectiveness with which information on these events were reported to the NRC. Also, evaluate the adequacy of both of the events classification.

6. Determine if any of the following played a significant role in these events: service water modifications; plant material condition; the quality of maintenance; or the responsiveness of engineering to identified problems.

7. Evaluate management involvement during the Unit 1 event, the post event reviews, and the subsequent recovery.

8. For each equipment malfunction or personnel error to the extent practical, determine:

    a. Root cause.

    b. If the equipment was known to be deficient prior to the event.

    c. If equipment history would indicate that the equipment had either been historically unreliable or if maintenance or modifications had been recently performed.

    d. Pre-event status of surveillance, testing (e.g., Section XI), and/or preventive maintenance.

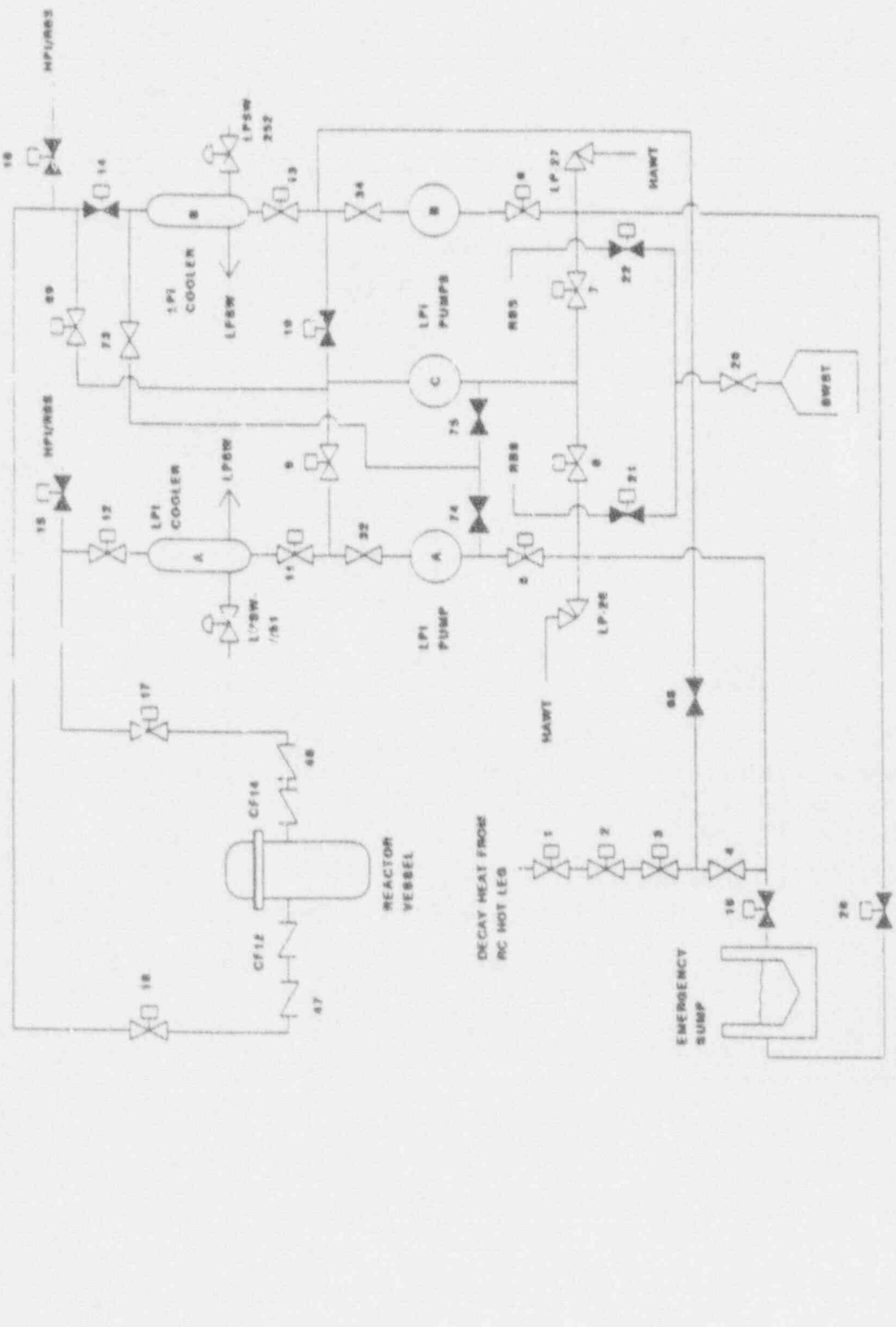
9. Prepare a special inspection report documenting the results of the above activities within 30 days of inspection completion.

Appendix D

Acronyms

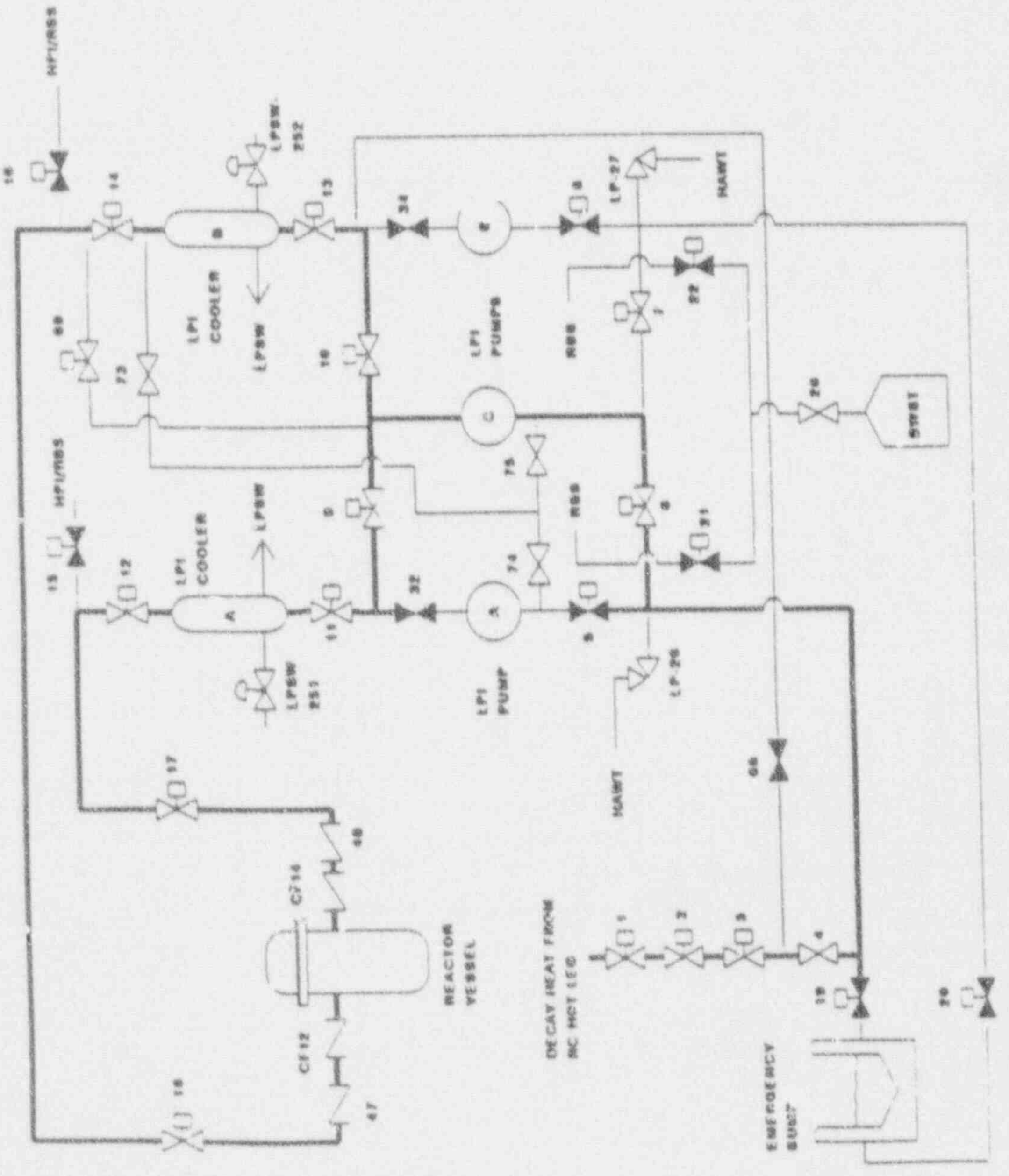
AIT	Augmented Inspection Team
DPM	Disintegrations per Minute
IV	Independent Verification
LPI	Low Pressure Injection
NRC	Nuclear Regulatory Commission
TT	Temporary Test (Procedure)

Figure 1



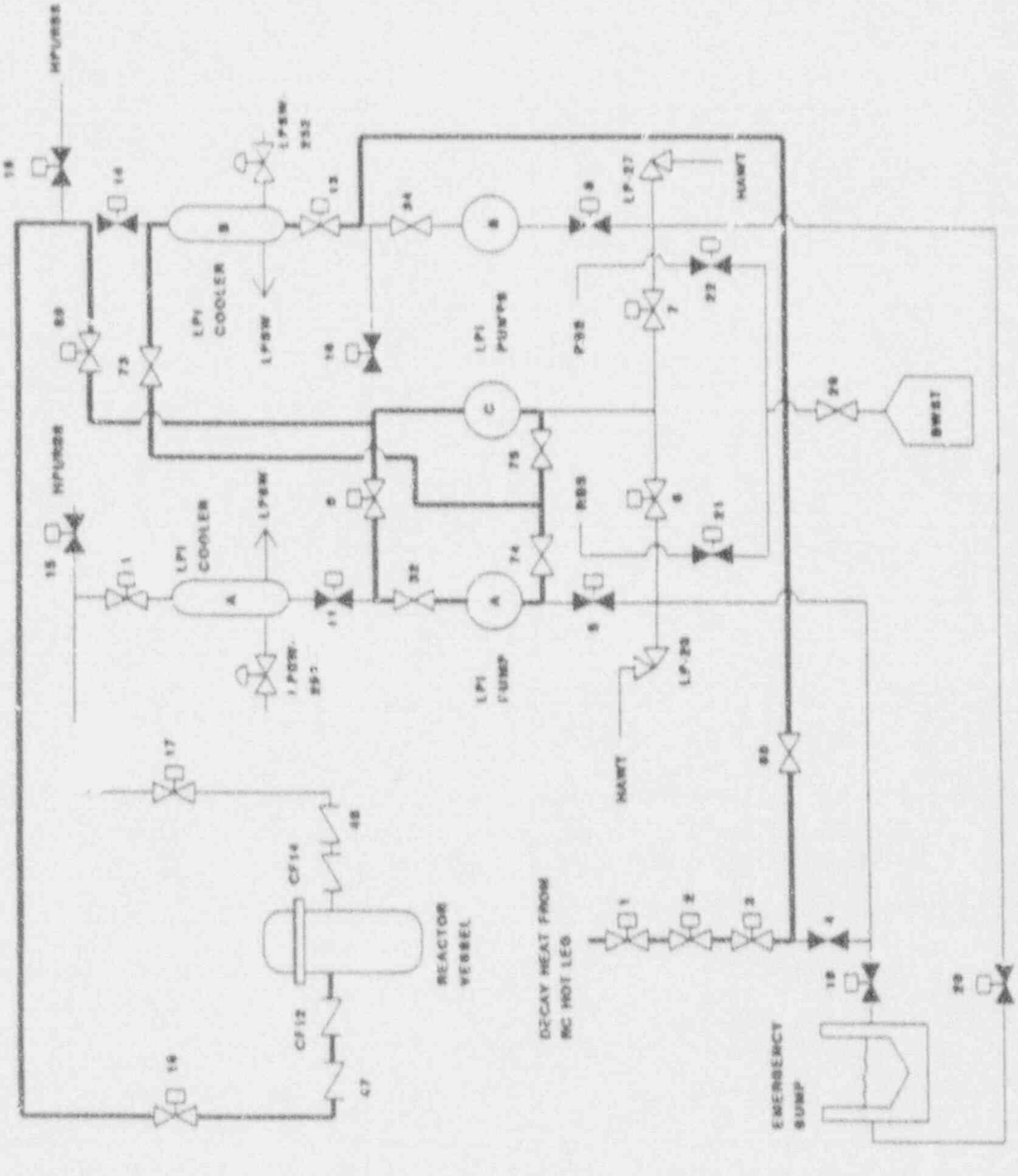
LOW PRESSURE INJECTION SYSTEM

Figure 2



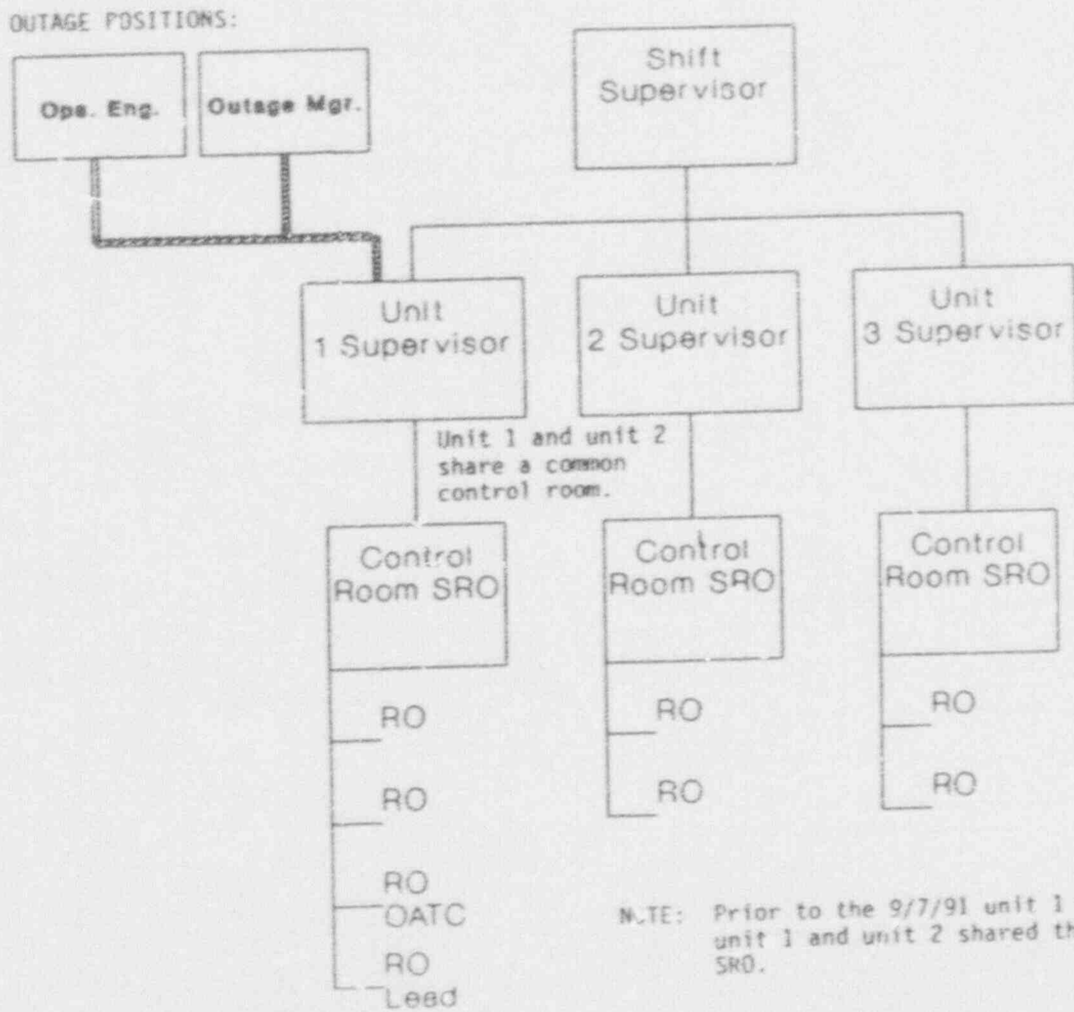
LOW PRESSURE INJECTION SYSTEM
ALIGNMENT ON SEPTEMBER 19, 1991

Figure 3



LOW PRESSURE INJECTION SYSTEM
SWITCHOVER MODE

Operations Shift Organization Chart
(after 9/7/91 heat-up event)



NOTE: Prior to the 9/7/91 unit 1 heat-up event unit 1 and unit 2 shared the control room SRO.

Figure 4

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No:	287/91-002
Event Description:	Reactor coolant inventory loss at cold shutdown
Date of Event:	March 8, 1991
Plant:	Oconee 3

Summary

There are two reactor building emergency sump (RBES) suction lines at Oconee 3. During leak rate testing, a flange was installed on the wrong suction pipe. When the valve undergoing leak rate testing was cycled, 14,000 gal of water flowed from . reactor coolant system (RCS) to the emergency sump. Reactor vessel level dropped to the bottom of the reactor coolant nozzles, interrupting decay heat removal for ~19 min. The open sump valve was subsequently closed, gravity feed was used to refill the RCS, and decay heat removal was restored.

Event Description

While shutdown during a refueling outage, 14,000 gal of wat leaked from the RCS and borated water storage tank (BWST) to the reactor building at Oconee 3. Reactor vessel level dropped from ~12 ft above the top of the core to the bottom of the reactor coolant loops (the location of the RHR suction line) ~4 ft above the top of the core, in a short period of time. This loss interrupted decay heat removal for ~19 min. Core temperature increased from 94°F to a maximum temperature of 117°F. The utility estimated the time to core boiling was 55 min, and the time to uncover the core was 3 h after decay heat removal was lost. The reactor core had been refueled.

The cause of this event was a blank flange installed in the wrong train. The blank flange was being installed to perform a required leak check of a section of the LPI system. The blank flange was supposed to be installed on the pipe that connects the RBES train "A" to low-pressure injection (LPI) isolation valve 3LP-19. The technicians performing the leak test installed the flange based on a handwritten label on the wall above the pipe. The flange was actually installed on the RBES train "B" pipe, which connects to LPI isolation valve 3LP-20.

After performance of the leak test (on the wrong train), valve 3LP-19 was repacked. Due to the location of the valve and its surrounding enclosure, this required the motor operator to be removed and then reinstalled. This was accomplished between February 23, 1991, and March 5 1991, while the reactor was defueled and the LPI system was shut down.

At approximately 0730 hours on March 8, 1991, technicians asked the control room for permission to stroke valve 3LP-19. At approximately 0848 hours, a technician began manually opening the valve. The utility stated that, although the operators had granted permission to stroke-test 3LP-19, a requested control room notification prior to the actual valve stroking had not been received. At 0848 hours, the control room received a reactor building normal sump high alarm. At 0852 hours, the 3A LPI pump was stopped due to fluctuations in pump amperage, and procedure AP/3/A/1700/07 "Loss of LPI" was entered. At 0854 hours, technicians completed manually opening valve 3LP-19.

At 0856 hours, valves 3LP-21 and 3LP-22 (BWST supply to LPI) were opened as required by the loss of LPI procedure, but were reclosed when it was realized that water from the BWST was not refilling the RCS.

At 0857 hours, technicians closed the valve 3LP-19 electrically. Between 0859 and 0901 hours, technicians cycled the valve again — the technicians were still unaware of the effects of opening 3LP-19. The control room had attempted to page the technicians without success and had sent an operator to 3LP-19 to have the valve closed. The operator reached the technicians just as the technician had closed the valve for the second time electrically. The operator informed the technicians to stop work and leave the valve in the closed position.

At 0903 hours, operators reopened valves 3LP-21 and 3LP-22. Reactor vessel level increased and these valves were reclosed at 0905 hours when reactor level reached 76 in. (just below the head flange). Operators vented the 3A LPI pump and returned it to service at 0911 hours. BWST level had decreased from 43.4 ft to 41.7 ft.

Although containment closure did not exist during this event, the utility stated that containment closure could have been established within 1 h. Air samples taken during and after the event indicate that no significant airborne contamination above 0.25 times the maximum permissible concentration was generated during the spill. The loss of RCS inventory also increased the dose rate for workers in the reactor building. The highest whole-body dose to anyone inside the reactor building at the time of the accident was 40 mrem.

Additional Event-Related Information

The reduction in reactor vessel water level was observed by personnel in the reactor building. Dose rates above the fuel transfer canal increased to 8 rem/h. The third and fourth floors of the reactor building were evacuated.

ASP Modeling Assumptions and Approach

During this event, the reactor head was removed. Successful core cooling required sufficient makeup flow to compensate for boil-off, which could have been provided by gravity feed from the BWST once 3LP-19 was manually closed. If 3LP-19 failed to close, makeup could have been provided by two of the LPI pumps once 3LP-6 (an LPI suction cross-connect valve) was closed, or by another high- or low-pressure source of borated water. Because of the time period available, all valve operations could be performed manually, which significantly increases the likelihood that reactor vessel makeup could be provided before core uncovery. The core damage probability estimated for this event is $<10^{-6}$, and therefore the event was not identified as an accident sequence precursor.

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 3	0 5 0 0 0 2 8 7	1 OF 1 1

TITLE (4): Loss of Reactor Coolant Inventory, Due to Inadequate Procedure and Labeling Policy, Results in Loss of Decay Heat Removal Ability While Shutdown

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 NAMES	DOCKET NUMBER(S)
0 3	0 8	9 1	9 1	— 0 0 2 —	0 0	0 4	0 8	9 1		0 5 0 0 0
										0 5 0 0 0

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

OPERATING MODE (9): N

POWER LEVEL (10): - 0 -

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	50.73(a)(2)(v)(B)
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	50.72(b)(2)(iii)(B)
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Henry R. Lowery, Chairman Oconee Safety Review Group	8 0 3	8 8 5 - 3 0 3 4

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
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On March 8, 1991, at 0848 hours, Oconee Unit 3, while shut down during a refueling outage, spilled 14,000 gallons of water from the Reactor Coolant System (RCS) and Borated Water Storage Tank to the Reactor Building during a valve test. A Reactor Building Emergency Sump (RBES) isolation valve had been cycled without installing a blank flange to prevent flow to the RBES. The blank flange had been incorrectly installed on the other suction train. Reactor vessel level dropped from approximately 12 feet above the top of the core to 4 feet above the top of the core. This loss interrupted decay heat removal for 18.5 minutes. Remote reactor building radiation monitors were unavailable due to system upgrade. Operator action isolated the leak, reestablished reactor vessel level and core decay heat removal. The maximum RCS temperature in the core reached approximately 117 degrees Fahrenheit. Radiation dose rates above the reactor vessel increased significantly. A local evacuation of areas in the reactor building prevented excessive radiation exposure. Two root causes of the event were identified: deficient procedure, incomplete information and management deficiency, inadequate labeling policy. Contributing causes were inappropriate actions, improper action and poor communication. Corrective actions include upgraded procedures and labeling to identify flanges and review of work activities affecting decay heat removal ability.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

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

BACKGROUND

The Low Pressure Injection (LPI) (EIIS:BP) system at Oconee is used to remove core decay heat during shutdown conditions. Three LPI pumps are available to take suction from the decay heat drop line which originates at the bottom of a Reactor Coolant System (RCS) (EIIS:AB) reactor vessel discharge leg (hot leg). The point at which the decay heat drop line joins the hot leg is approximately four feet above the top of the reactor core. Alternate suction sources for the LPI pumps are the Borated Water Storage Tank (BWST) and the Reactor Building Emergency Sump (RBES). The LPI pumps discharge through either of two coolers to the reactor vessel.

Two sumps exist in the Reactor Building (RB) basement. The Reactor Building Normal Sump (RBNS) is used to process normal drainage to the RB floor. The Reactor Building Emergency Sump (RBES) is designed to provide suction to the LPI pumps when BWST inventory is depleted during accident conditions. There are two pipes which exit the RBES, penetrate the Reactor Building wall, and join the LPI suction header. Each pipe is isolated from the LPI suction source by valves 3LP-19 and 3LP-20, located in the Auxiliary Building. A blank flange is installed on the RBES side of the suction pipes when it is necessary to test the isolation valves during decay heat removal operation. Procedures specify that only one inlet pipe may be blanked at a time to allow the open pipe to serve as a backup LPI suction source.

During shutdown, with RCS level established at or below the reactor vessel head flange, there are three reactor vessel level instruments available to the control room. LT-5 (Reactor Vessel Wide Range Level) is calibrated on a scale of 0 to 100 inches where zero inches is at the centerline of the hot legs. Two ultrasonic detectors monitor the level in the B hot leg and the B1 Reactor Coolant Pump discharge (cold leg).

EVENT DESCRIPTION

On February 13, 1991, Oconee Unit 3 was shut down for refueling. On February 22, 1991, Maintenance Supervisor A assigned Maintenance Technicians A and B the task of installing a blank flange on the suction pipe from the Unit 3 Reactor Building Emergency Sump (RBES) to 3LP-19 (RBES Train A to Low Pressure Injection Isolation Valve). The technicians questioned Maintenance Supervisor A concerning the location of this pipe. Maintenance Supervisor A consulted a schematic diagram (Oconee Flow Diagram 102A.3-1) which he assumed gave the correct physical layout of the emergency sump. He gave directions to install the blank flange on the left suction pipe as viewed when facing the RBES. This corresponds to the west suction pipe. Maintenance Technicians A and B used these directions to independently verify the location of the pipe. The technicians were using Maintenance procedure MP/0/A/1800/105, "Reactor Building Emergency Sump LPI Suction Line Flange Installation, Removal and Screen Inspection." The technicians also observed a handwritten label reading "3LP-19", with an arrow pointing to the west pipe, had been written on the wall above the pipe. They installed the flange on the west suction pipe which is actually connected to 3LP-20 (RBES Train B to LPI Isolation Valve).

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NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 3	0 5 0 0 0 2 8 7	9 1	— 0 0 2	— 0 0	0 3 OF 1 1

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

At 0401 on February 23, 1991, Operations initiated PT/3/A/203/04, "LPI System Leakage", Enclosure 13.2. This procedure is designed to leak check the suction pipe from the RBES to 3LP-19 and valve 3LP-19 itself and is required by Technical Specification 4.5.4, Low Pressure Injection System Leakage. The initial conditions section of the procedure requires a verification that the blank flange is installed on the 3LP-19 suction pipe and not installed on the 3LP-20 suction pipe. Reactor Operator A (RO A) used the maintenance flange installation procedure (MP/0/A/1800/105) to verify that 3LP-19 had been blanked. A Non-licensed operator (NLO A) verified that a blank flange did not exist on 3LP-20 using the handwritten markings on the wall. The leak check portion of the procedure was performed. Although the required pressure was maintained, a small leak was noticed on the flange itself. It was not realized that the test was invalid since the flange was incorrectly installed.

After performance of the leak test portion of PT/3/A/203/04 on the 3LP-19 suction pipe, valve 3LP-19 was repacked under Work Request 57933D. Due to the location of the valve and its surrounding enclosure, this job required that the motor operator be removed during the task and then reinstalled. This was accomplished between February 23, 1991 and March 5, 1991 while the reactor was defueled and the LPI system was shut down.

On March 8, 1991, the Oconee Unit 3 plant status was as follows: The reactor vessel had been refueled. The reactor vessel had its closure head and upper internals removed. Water level in the Reactor Coolant System (RCS) was between 76 and 80 inches on LT-5, RCS Wide Range Level Transmitter. This places the level at slightly below the reactor vessel head flange level. This is above the reduced inventory action level addressed by Generic Letter 88-17, Loss of Decay Heat Removal, which corresponds to 14 inches on LT-5. The LPI system was operating in the decay heat removal mode with the 3A LPI pump discharging through the 3B LPI header. The 3C LPI pump was available as was the 3A LPI header. The 3B LPI pump breaker was removed from service but could have been used if the breaker was first "racked in". Core exit thermocouples had not yet been inserted into the core during the core reassembly process following refueling. The Unit 3 Reactor Building Radiation Indicating Alarms (RIAs) (EIIS:IL), Reactor Building Purge radiation monitors, and unit ventilation monitors were being replaced with a new system and were out of service. The Reactor Building equipment and personnel hatches were closed. The Reactor Building Purge system (ventilation) was not operating but a flow path through the purge filters was provided to prevent the Reactor Building from pressurizing due to the use of compressed air during outage activities.

At approximately 0730 on March 8, 1991, Instrument and Electrical (I&E) Technicians A, B and C asked the Control Room Supervisor for permission to stroke valve 3LP-19. They were using Work Request 57933D and procedure IP/0/A/3001/10, "Maintenance of Limitorque Valve Operators" to check the valve operator limits. The Control Room Supervisor was reluctant to stroke the valve. He was aware of the small leak on the installed flange that had been detected during the leakage test. The Control Room Supervisor discussed the job with Unit Operations Engineer A in the presence of I&E Technicians A and B. Unit Operations Engineer

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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

A was concerned that the suction piping may contain air and that cycling the valve might lead to air binding of the operating Low Pressure Injection (LPI) pump. The Control Room Supervisor and Unit Operations Engineer A jointly concluded that valve 3LP-19 could be stroked, that leakage to the RBES would be negligible, and that the operating LPI pump would be secured prior to the valve stroke. The Control Room Supervisor gave permission to stroke the valve.

The Control Room Super-isor has stated that at this point he requested that the I&E Technicians contact the control room prior to stroking the valve. I&E Technicians A and B do not remember bein, t'ld 'o contact the control room. After Operations removed the saf-' red .gs associated with valve 3LP-19, I&E Technician C was stationed at the breaker to 3LP-19 and established communication with I&E Technicians A and B who were at the valve itself. At approximately 08:48, I&E Technician A began manually opening valve 3LP-19.

At 0848, the control room received a Reactor Building Normal Sump (RBNS) high alarm. Reactor Operator B (RO B) noticed that LT-5 had decreased to 20 inches. At 0848:37 an Emergency Sump Level High alarm was received in the control room followed by a Reactor Vessel Ultrasonic Level alarm. Control room personnel began investigating the cause and verifying the LPI valve lineup.

Radiation Protection Specialist A (RPS A), assigned to the RB personnel hatch, received a call from personnel in the Reactor Building stating that reactor vessel water level was decreasing. Radiation Protection Technician A (RPT A), assigned to the third floor of the Reactor Building (level of the top of the fuel transfer canal), found with a portable dose rate meter that dose rates above the fuel transfer canal had increased to approximately 8 Rem/hour. RPT A evacuated th d floor of the Reactor Building and came to the personnel hatc S A sent him back to evacuate the fourth floor and direct any t on the fourth floor down the stairwells and away from the fuel tra...er canal. RPS A contacted personnel on the RB polar crane and determined from their dosimetry and personal ratemeters that they were not in an abnormally high radiation field. The workers in the polar crane were not directly over the fuel transfer canal and were not evacuated.

At approximately 0852 Operations entered AP/3/A/1700/07, "Loss of LPI" procedure. RO B called RPS A at the RB personnel hatch to investigate possible leakage in the Reactor Building and was told that although Radiation Protection had not heard of any leakage, they were aware of a loss of reactor vessel level. At 0852:32 RO C stopped the 3A LPI pump due to a fluctuation in pump amperage. At 0853:58 pumping began from the Reactor Building Normal Sump to waste hold up tanks.

At 0854:51 I&E Technicians A and B completed manually opening valve 3LP-19.

At 0856:30, valves 3LP-21 and 3LP-22 (Borated Water Storage Tank Supply to LPI) were opened per the Loss of LPI procedure after closing the valve breakers. The breakers had been opened to prevent inadvertent operation as a step in the fuel transfer canal drain procedure. At 0857:21, valves 3LP-21 and 3LP-22 were reclosed when it was realized

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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that water from the Borated Water Storage Tank (BWST) was not refilling the RCS.

I&E Technician C, after conferring with I&E Technician B, closed valve 3LP-19 from the breaker at 0857:32. Between 0859 and 0901 valve 3LP-19 was cycled again electrically from the breaker. The I&E Technicians were still unaware of the effects of opening 3LP-19 since the valves are located in the Auxiliary Building. The control room had attempted to page the I&E Technicians without success and had sent Non-licensed Operator B (NLO B) to 3LP-19 to have the valve closed. NLO B reached the valve just as I&E Technician C had closed the valve for the second time from the breaker. NLO B informed I&E Technicians to stop work on valve 3LP-19 and leave it in the closed position.

RPS A had received a call from a worker exiting the Reactor Building basement that water was flooding the floor and had reached six to twelve inches near the RBES. At 0901 RPS A called the control room and spoke to RO A. He informed RO A of the leakage in the Reactor Building and the increased dose rates above the fuel transfer canal. At 0902:52 Operations reopened 3LP-21 and 3LP-22. Reactor Vessel level increased and 3LP-21 and 3LP-22 were reclosed at 0905:32 when LT-5 reached approximately 76 inches.

Operations vented the 3A LPIP and returned it to service at 0911:02. BWST level had decreased from 43.4 feet to 41.7 feet. LPI Pump suction temperature had risen from 94 degrees Fahrenheit to 99 degrees Fahrenheit.

Radiation Protection personnel collected the five ongoing samples from the continuous air samplers in the Reactor Building between 0912 and 0940. Five additional collections were taken from these same samplers approximately two hours later. Compensatory samples which were being collected on the Reactor Building Purge system and the Unit Ventilation system were also analyzed. Results showed less than 25 percent of the maximum permissible concentration of airborne contamination existed in the Reactor Building at the time of this event. Six of the sixty people who were in the Reactor Building during the event had body burden analyses performed and results were all less than 0.03 percent of the maximum permissible organ burden. The highest radiation exposure of any personnel in the Reactor Building at the time of the spill was 40 millirem. Spilled water was pumped to the Liquid Waste Disposal (EIIS:WD) system where it was processed and released. Decontamination of the Reactor Building basement was performed after it was drained. Follow up investigation on the day of the event showed that the RBES sump blank flange had been installed on the suction pipe to 3LP-20 and not 3LP-19.

The On-site Safety Review Group was notified to begin an investigation of the incident. An Emergency Notification of the Nuclear Regulatory Commission (NRC) was completed per 10CFR50.72. The resident NRC inspector was also notified.

Duke Design Engineering was asked to analyze the event with respect to core temperature increase. Their analysis, using conservative assumptions of decay heat load and core conditions, concluded that core

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temperatures could not have increased more than 23 degrees Fahrenheit. Graphs contained in the Loss of LPI procedure which plot time to core boiling after a loss of decay heat removal versus time after shutdown indicate that the time to core boiling under the conditions of this event was 40 minutes.

CONCLUSIONS

Approximately 14,000 gallons of water were spilled to the Unit 3 Reactor Building basement. Approximately 9700 gallons originated from the Reactor Coolant System (RCS) and the remainder from the Borated Water Storage Tank (BWST). Reactor vessel level dropped to the bottom of the hot leg where Low Pressure Injection (LPI) suction is taken, leaving four feet of water above the top of the core. Concurrent with the loss of RCS inventory was an 18.5 minute loss of decay heat removal ability. The LPI pump used for forced cooling of the RCS was secured to prevent cavitation. Furthermore, the loss of inventory lead to increased dose rates above the fuel transfer canal. RCS water temperature in the core increased to 117 degrees Fahrenheit but stayed well below the 212 degrees required to reach core RCS boiling.

The loss of RCS inventory occurred because the blank flange used to prevent RCS drainage had not been installed on the correct suction line and verification of the proper installation was not performed adequately. A root cause of this event is deficient procedure, incomplete information. Section 4.2.3.4, Procedure Requirements, of Duke Power Company's Administrative Policy Manual for Nuclear Stations states that the nomenclature used within a procedure to describe equipment "should agree with that on the equipment actually installed in the field" and that the procedure should be written in adequate detail to ensure accurate results from users. Contrary to these requirements, the procedure that is used to install blank flanges on the Reactor Building Emergency Sump (RBES) suction lines, did not adequately describe the RBES suction pipe flanges. The correct result could have been accomplished as follows: 1) by referring to the containment penetration number which is labeled in the Reactor Building and is present on the flow diagram of the system, 2) by referring to the physical arrangement of the RBES suction lines (i.e. west or east), 3) by labeling the suction lines as "3LP-19 suction line" or "3LP-20 suction line" and referring to them as such in the procedure, or 4) by incorporating a sketch of the RBES in the procedure. The Operations procedure for performing the leak test on 3LP-19 and 3LP-20, PT/3/A/203/04, LPI System Leakage, and a Performance procedure for stroking these valves, PT/3/A/0150/22R, Refueling Valve Stroke Tests, also do not adequately describe the suction piping.

Another root cause of this event is assigned management deficiency, inadequate program (labeling). No approved labeling existed on this piping at the flange location. Conversation with Operations Unit Engineers and Operations Shift Supervisors indicate that the identification of 3LP-19 and 3LP-20 suction pipes have had to be researched during other outages. Operations Management Procedure 4-5, Station Labeling and Control Board Conventions, describes in detail the responsibilities and requirements for station labeling. It lists

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components such as valves, pumps and breakers that must meet these requirements. Flanges are not addressed in this procedure. The fact that a handwritten sign was used at the suction pipe indicates that a need for proper labeling existed.

A contributing cause to this event is inappropriate action, action taken was not the best alternative, on the part of Maintenance Supervisor A and Non-licensed Operator A (NLO A). The blank flange would have been installed correctly if Maintenance Supervisor A had correctly used the schematic flow diagram. The flow diagram uses a rough sketch of a sump but it is schematic only and is not meant to show the actual physical layout of the sump. The penetration number was present both on the flow diagram and in the Reactor Building and would have properly identified the component. Piping layout diagrams exist that could have been consulted which give the correct physical locations of the suction pipes.

An opportunity to identify that the blank flange was installed on the wrong pipe was present when NLO A was sent to verify that the flange was not installed on 3LP-20 suction pipe. However, NLO A used handwritten labeling to incorrectly verify the location of the flange.

Another contributing cause is inappropriate action on the part of the Control Room Supervisor and I&E Technicians A and B because deficient communication and misunderstood verbal instructions occurred. Station training in the proper methods of communication had been performed in 1990. However, directions to contact the control room were not repeated back to the originator nor was a repeat back requested. Once the decision to stroke 3LP-19 was made, some loss of RCS inventory was inevitable. However, the magnitude of the loss may have been significantly lower if proper communication existed between the Control Room Supervisor and I&E Technicians A and B. Knowledge that valve 3LP-19 was being stroked manually would have allowed control room personnel to more quickly diagnose and mitigate the loss of RCS inventory.

The response to the event by Operations and Radiation Protection personnel was proper. Operations quickly secured the operating LPI pump when indications of cavitation were observed. The appropriate actions were taken to isolate the leak and restore reactor vessel level. Radiation Protection personnel quickly detected the areas with elevated dose rates, evacuated those areas, and routed traffic appropriately. No external radiation exposure greater than 40 millirem occurred as a result of this event. Internal exposure was less than 0.03 per cent of maximum permissible organ burden.

Several lessons were learned from this event. They involve the procedural mechanism for initiating a Reactor Building evacuation, the special precautions necessary for fuel transfer canal work, and the scheduling of work activities which may impact decay heat removal abilities.

Due to the Radiation Indicating Alarm (RIA) system upgrade modification, the control room did not have direct indication of dose rates in the Reactor Building. Control room and Radiation Protection personnel did not communicate concerning the higher dose rates until late in the

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event. Both groups were occupied with other matters: Operations with reestablishing core decay heat removal and Radiation Protection with the local evacuation in the Reactor Building. Radiation Protection personnel have stated that they expec[illegible] Operations to evacuate the Reactor Building. On the other hand [illegible]erations was following AP/3/A/1700/07, "Loss of LPI". Pers[illegible]nel evacuation is required as a step in a section of this procedure which establishes containment closure. The nature of this event did not require entry into the containment closure section of the procedure. Therefore t[illegible] Reactor Building evacuation was not performed. More precise communication between Operations and Radiation Protection and better procedural guidance is required.

Although the areas with high dose rates were quickly evacuated, it is possible that significant personnel exposure could have occurred if work had been in progress in the fuel transfer canal at the time of this event. However, alarming dosimeters utilized by crews assigned to fuel transfer canal work would have alerted personnel to the rising dose rates and initiated an evacuation from the area.

The scheduling of the activity involving valves 3LP-19 and 3LP-20 also needs review. There are more opportune times in a refueling outage schedule to perform this task. Specifically, the outage schedule refers to a low point maintenance window, which occurs when the reactor is defueled. A review of the previous six refueling outages at Oconee Nuclear Station indicate that valve strokes of the RBES suction valves occurred six times during low point maintenance, five times with fuel in the core and the fuel transfer canal filled , and once with fuel in the core and vessel level [illegible]t 80 inches.

Previous events leading to a loss of decay heat removal due to cycling of the RBES suction valves has not occurred. There [illegible]ve been several incidents involving mislabeled or unlabeled components in the last two years. However, they all involve components (valves, breakers) which are listed in the labeling directive (Operations Management Procedure 4-5, Station Labeling). None of the incidents involve components not listed in this directive. This event is not considered to be recurring. It is not NPRDS reportable.

<u>CORRECTIVE ACTIONS</u>

Immediate

1) Loss of Reactor Coolant System (RCS) Inventory was stopped by closing valve 3LP-19.

2) Decay heat removal was reestablished by filling the reactor vessel to 80 inches on LT-5 (Wide Range Reactor Vessel Level), venting and restarting the 3A Low Pressure Injection (LPI) pump.

3) The third and fourth floor of the Reactor Building were evacuated and personnel traffic routed away from areas of high dose rates.

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Subsequent

1) Stenciled labels were painted on the Reactor Building wall above the 3LP-19 and 3LP-20 suction pipes indicating the upstream isolation valve for each line.

2) PT/3/A/203/04, LPI System Leakage, was performed correctly on the suction lines to 3LP-19 and 3LP-20.

Planned

1) Stenciled labels will be painted on the Reactor Building at the Reactor Building Emergency Sump (RBES) suction pipes of the other two Oconee Units.

2) Procedures used to install the Reactor Building Emergency Sump suction flanges and procedures which require the verification of correctly installed flanges will be enhanced to agree with labeling.

3) Flanged connections on safety systems routinely manipulated during shutdown conditions will be identified. Associated procedures and work processes will be reviewed to assure that location, description and labeling are properly described.

4) The RCS and LPI systems and associated connections will be analyzed to identify potential flow paths which could lead to a rapid loss of inventory. Appropriate barriers will be implemented (including restrictions on configuration changes) in order to protect against a single error resulting in a loss of decay heat cooling.

5) Procedures will be implemented to assure that radiation monitoring equipment with local alarm is installed in the transfer canal area anytime the Reactor Coolant System (RCS) is in a reduced inventory condition.

6) A training package describing the limitation on the use of flow diagrams and electrical elementaries will be issued to all supervisors with the potential to use these drawings.

7) A communication will be issued to all station personnel with directions on the proper actions to be taken in response to missing or informal labeling found in the plant. This direction will be incorporated into administrative procedures.

8) This event will be reviewed with all Control Room and Instrument and Electrical (I&E) crews with emphasis on the communication [illegible] and the responsibility of the individual [illegible] a repeat back of information from the individual [illegible] he is communicating.

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9) AP/A/1700/07, Loss of LPI, will be revised on all three Oconee units to provide better guidance to ensure that a Reactor Building evacuation occurs during loss of decay heat removal events.

10) A training package will be issued to all shift Radiation Protection (RP) personnel stressing the importance of communication with the control room if RP feels that an area evacuation is warranted but has not occurred.

SAFETY ANALYSIS

The rapid loss of Reactor Coolant System (RCS) inventory presented two challenges to nuclear safety: 1) a loss of core decay heat removal ability and 2) an increase in dose rates in the Reactor Building.

The ability to remove core decay heat using forced cooling was lost for 18.5 minutes. Core temperatures increased an estimated 23 degrees Fahrenheit to approximately 117 degrees Fahrenheit in this time. This is well below the amount required to begin RCS boiling in the core. Core boiling would lead to further loss of RCS inventory and eventual core uncovery and damage. Duke Design Engineering has estimated that the time to core boiling was at least 55 minutes from the initial loss of decay heat removal and the time to core uncovery was approximately three hours . The loss of decay heat removal was mitigated by prompt and appropriate operator action using the Loss of Low Pressure Injection (LPI) procedure. The leak was isolated by closing valve 3LP-19. Borated water from the Borated Water Storage Tank (BWST) was used to reestablish reactor vessel level. The LPI pump was vented and returned to service.

If 3LP-19 could not have been closed, the BWST could still have been able to flood the core. Operation of valves on the LPI suction header (3LP-6 or 3LP-7) could have isolated the BWST supply from the leak and allowed flooding of the RCS. Flow from the reactor vessel would have been to the Reactor Building basement via the open 3LP-19 or, by isolating the decay heat drop line using isolation valves 3LP-1 or 3LP-2, the water would have been allowed to fill the fuel transfer canal. Once BWST inventory was depleted, forced cooling could have been established by allowing the LPI pumps to take suction from the Reactor Building Emergency Sump (RBES).

Although containment closure did not exist during this event, Operations Engineering staff has stated that containment closure could have been established within one hour. Maintenance on Reactor Building penetration valves were scheduled in such a manner that only one side of a penetration had work scheduled at a time. The Reactor Building Purge flow path could have been isolated by either of two remotely operated valves. Both the personnel hatch and equipment hatch were in place. Air samples taken during and after the event indicate that no significant airborne contamination above 0.25 times the maximum permissible concentration was generated during the spill.

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The loss of RCS inventory also presented a threat to the health and safety of the workers in the Reactor Building. Dose rates increased in and above the fuel transfer canal. The dose rate on the third floor of the Reactor Building at the fuel transfer canal adjacent to the reactor vessel increased from less than 80 millirem per hour to 8 Rem/hr. The action of Radiation Protection personnel in performing a local evacuation of the third and fourth floor of the Reactor Building adequately protected personnel from these increased dose rates. The highest whole body dose to anyone inside the Reactor Building at the time of the accident was 40 millirem.

Worker protection from the increased dose rates was complicated by the fact that radiation monitoring which gave indication to the control room of Reactor Building dose rates was out of service. The entire Radiation Indicating Alarm (RIA) system was being upgraded and it was not possible to remove the alarms from service individually. Radiation Protection issued an alarming dosimeter to at least one worker in each work group in the Reactor Building if that group did not have constant dose rate monitoring by a Radiation Protection (RP) Technician. These dosimeters give an audible alarm when a cumulative dose or a dose rate setpoint is reached. If a work crew had been performing a task in the fuel transfer canal at the time of this accident, they would have been alerted by either an alarming dosimeter, an RP Technician, or visual evidence of decreasing water level.

The combination of prompt operator action, sufficient BWST inventory, and the ability to establish containment closure provided adequate protection against threats to the health and safety of the public present from the loss of decay heat removal ability.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	287/91-008
Event Description:	87,000 gal reactor cooling system leak
Event Date:	November 23, 1991
Plant:	Oconee 3

Summary

A 3/4-in. compression fitting on an instrument line failed, resulting in a 70 gpm reactor coolant system (RCS) leak, and a shutdown was begun. At 33% power, feedwater oscillations caused a reactor scram. No engineered safeguards (ES) or emergency feedwater (EFW) actuations occurred.

Event Description

At 0141 hours on November 23, 1991, with Oconee 3 at 100% power, alarms were received that indicated failure of "ICCM Train A". This instrumentation system includes the reactor vessel level indication system (RVLIS) and an RCS wide-range pressure transmitter. At approximately the same time, a fire alarm was received that was located inside the reactor containment building. An operator attempted to visually inspect the reactor building using a video camera; however, the image was so foggy that the operator assumed that the camera was either not working properly or was badly out of adjustment.

At 0143 hours, it was noted that the letdown storage tank (LDST) and pressurizer levels were decreasing and that high-pressure injection (HPI) make-up flow had increased significantly. The reactor building normal sump also showed an increase in level. Operators concluded that the problem was an RCS leak rather than a fire.

At 0203 hours, the leakage was estimated to be 70 gpm, and a rapid controlled shutdown was ordered. RCS letdown was isolated at 0211 hours to eliminate that loss.

At 0217 hours, an integrated control system (ICS) asymmetric rod signal generated a rapid load limit runback from 77% to 55% full power. The control rod drive indication was diagnosed as spurious, and the ICS feedwater and reactor control stations were put in manual to stop the automatic runback at 60% full power.

At 0320 hours, the leak was still estimated to be approximately 60 to 70 gpm. Power reduction was stopped at approximately 33% full power to shut down one of two main feedwater pumps and the ICS feedwater control station was returned to automatic. Oscillations in feedwater flow eventually caused a reactor scram. At the time of the scram these oscillations raised the power level to approximately 37% full power. The main feedwater pumps do not trip due to low discharge pressure, so both pumps continued to run until the operator manually tripped MFWP "A".

At 0348 hours, the unit was considered to be stable in hot shutdown, and the leak was estimated to be approximately 130 gpm. Reactor building sample results indicated that the reactor building atmosphere contained radioactive iodine at twice the maximum permissible concentration (MPC) and noble gases at 407 MPC.

At about 0400 hours, the video camera in containment was used to examine the area and showed a significant amount of steam rising from the A steam generator (SG) cavity. No indications of steam leakage were observed in the vicinity of the reactor vessel head or SG B.

At 0520 hours, the ES system was bypassed and RCS pressure was reduced below 1750 psig (the ES high-pressure actuation setpoint).

At 1717 hours, the RCS reached 200°F and 293 psig (cold shutdown).

Throughout the event, additions were made to the letdown storage tank from the bleed holdup tanks and concentrated boric acid tank to maintain adequate inventory to compensate for the leak. No ES system or EFW actuations occurred.

At 0800 hours on November 24, 1991, it was estimated that approximately 5 to 10 gpm was still leaking out of the RCS due to the fact that the pressurizer was still at saturation temperature and was maintaining a 30-psig system pressure.

By 1700 hours on November 24, 1991, the unit was completely depressurized and the leak stopped.

At 1300 hours, on November 25, 1991, an inspection team entered the reactor building and located the source of the leak. A 3/4-in. diameter instrument line had pulled out of a compression fitting downstream of a root valve. The line was located at the top of the RCS hot leg pipe where it entered the "A" SG. The tubing configuration is shown in Fig. 1. The same configuration was used on both SGs and the reactor vessel head on all three Oconee units when RVLIS was installed. A series of tubing reducers were used to transition from a 3/4-in. root valve to 3/8-in. tubing. This configuration resulted in a total of six compression joints per line. The compression fitting that failed had not been fully crimped onto the instrument line during initial installation in 1987. Subsequent inspection of 455 compression fittings found 28% outside the nominal makeup gap range. One of these showed indication of leakage, and another had a loose nut.

Additional Event-Related Information

A projected dose was calculated using an assumed carbon filter efficiency of 90%. An estimated dose was calculated using actual filter efficiencies from the latest surveillance tests. Both methods use annualized average meteorological data rather than actual conditions at the time of the release. Monitoring prior to the leak estimated that eight fuel pins were leaking. Dose to the public was calculated to be 0.00139 mrem whole body (0.0122 mrem thyroid) due to liquid release, 0.00218 mrad whole-body for noble gas, and 0.0513 mrem (projected iodine) thyroid doses.

Modeling Approach and Assumptions

During this event, reactor plant makeup flow was sufficient to make up reactor coolant lost from the failed tube. Mitigation of the event, including the reactor trip, required a normal post-trip response plus continued makeup from the running HPI pump. If this pump were to fail, two other pumps were available for makeup. The leak rate was limited by the size of the failed instrument line. The conditional probability of subsequent core damage estimated for this event is $<10^{-6}$. The event was not identified as an accident sequence precursor.

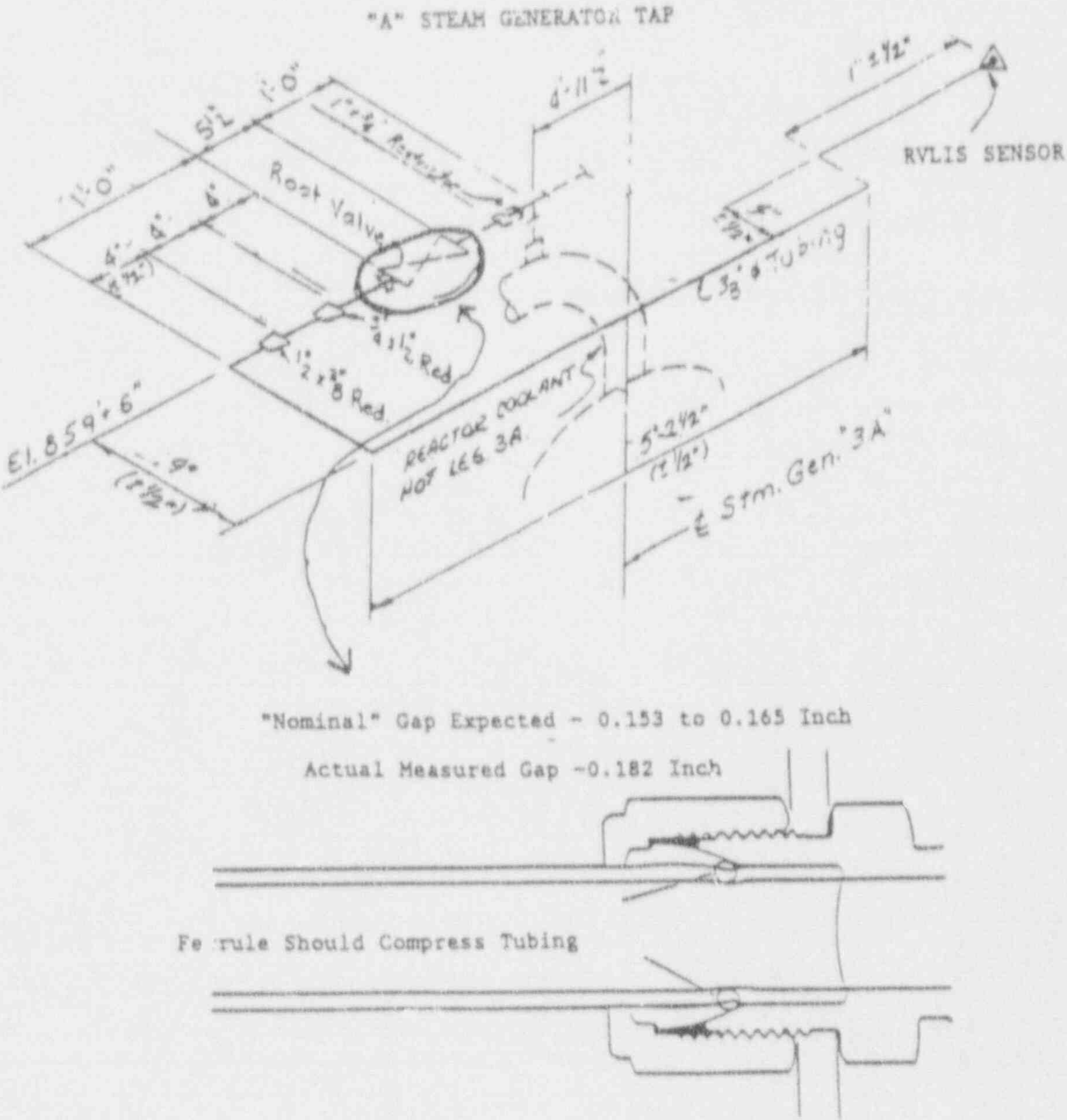

Fig. 1. Failed tubing configuration

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TITLE (4) Excessive Reactor Coolant Leak, Reactor Trip, And Inadvertent Protective System Actuation Result From Management Deficiencies and Equipment Failure

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 NAMES	DOCKET NUMBER(S)
1 1	2 3	9 1	9 1	— 0 0 8 —	0 0	1 2	2 3	9 1		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N
POWER LEVEL (10)	1 0 0

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

- X [illegible] (A)
- X [illegible]
- X OTHER (Specify in Abstract below and in Text, NRC Form 366A) 50.72 (A)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Steve Bunesoie, Safety Review Group	8 0 3	8 8 5 - 3 5 1 8

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	A B	P S P	P 0 7 0	Yes					

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

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

On November 23, 1991, Oconee Unit 3 was operating at 100% Full Power (FP) when the Control Room Operators (CROs) received several alarms at 0141 hours which indicated failed instruments inside the reactor building (RB). At 0143 hours, the CROs observed symptoms of excessive Reactor Coolant System (RCS) leakage and began assessing the leak rate. At 0203 hours, they started a rapid controlled shutdown. At 0214 hours, the Shift Supervisor concluded that leakage was approximately 60 to 70 gpm, and declared an ALERT. At 0327 hours, the unit tripped from 33% FP due to a control oscillation while the CROs were attempting to secure a feedwater pump. At 0641 hours, an additional unanticipated Reactor Protective System actuation occurred due to operator error. At 1720 hours the unit reached cold shutdown and the ALERT was terminated. The leak was determined to be a failed fitting on an instrument line at the top of a steam generator. A total of approximately 87,000 gallons of RCS leakage was confined within the RB. The instrument line was replaced, and additional fittings inspected. The root causes are Management Deficiency and Equipment Failure.

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BACKGROUND

The Reactor Protective System (RPS) [EIIS:JC] is a safety related system which monitors parameters related to the safe operation of the plant. The RPS provides a two-out-of-four logic for tripping the reactor when a predetermined setpoint is exceeded. One parameter which will cause an RPS actuation is low Feedwater [EIIS:SJ] Pump discharge pressure. The RPS logic requires that pressure switches for both pumps must actuate in at least two-of-four channels to initiate a trip. Another parameter which will cause a trip is RCS pressure being either too high or too low. During cooldown and depressurization to cold shutdown, the RPS normal RCS pressure trips can be can be bypassed and a lower high pressure trip setpoint imposed to limit pressure excursions.

The Integrated Control System (ICS) [EIIS:JA] provides automatic control of both primary and secondary system components. Reactor control rod positions, feedwater flow rates, and throttle valve positions are adjusted by the ICS as needed to maintain the principal control parameters: average reactor coolant temperature (Tave), feedwater throttle valve pressure drop, and main turbine [EIIS:TA] header pressure.

The Control Rod Drive (CRD) [EIIS:AA] system receives a reactor power demand signal from the ICS through a hand/automatic selector station known as the "Reactor/Bailey" station. The power demand signal is further processed and is input to the CRD control station, known as the "Diamond" panel. The control rods are divided into safety, regulating, and power shaping groups. Groups one through four are safety rods, used to provide shutdown capacity, and must be fully withdrawn from the core before the reactor is permitted to go critical. Groups five through seven are regulating rods, used to regulate power level. Group eight is a special group of partial length rods, and is used to control power distribution along the core axis.

Control Rod [EIIS:ROD] position indication is provided by a series of position indication switches located along the length of the drive mechanism. A faulty switch can result in an inaccurate indication. Also, the group out limit is activated when the first rod in a group reaches its out limit switch.

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Pumps [EIIS:P], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control. The HPI System is also a part of the Emergency Core Cooling System (ECCS) which mitigates the consequences of loss of coolant accidents (LOCA).

The Reactor Coolant System (RCS) has two steam generators [EIIS:HX] with associated pumps, piping, and instrumentation. These are designated Loop A and Loop B. The flow indications for each loop are provided by one flow element with one pair of impulse lines which act as headers and are

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connected to several differential pressure transmitters. Four of these transmitters are connected to the four redundant channels of the RPS. A fifth transmitter provides the normal input to the ICS.

The Reactor Vessel Level Indicating System (RVLIS) [EIIS:XT] was installed on Unit 3 during an outage that concluded in March, 1987. This modification ad ...n level instruments and associated instrument impulse lines to ......ing taps on the reactor vessel head, both A and B steam generators, and two taps on the decay heat drop line.

EVENT DESCRIPTION

On November 23, 1991, Oconee Unit 3 was operating at 100 % Full Power (FP). All safety systems were operable. The unit was known to have a higher than normal level of Reactor Coolant System (RCS) activity due to an estimated 8 fuel cladding pinhole leaks.

At 0120 hours, the Control Room Operators (CROs) completed an RCS leakage periodic test which indicated 0.18 gpm total system leakage.

A. RCS Leak

At 0141 hours, the CROs received alarms which indicated failure of "ICCM Train A", which includes the Reactor Vessel Level Indication System (RVLIS) and an RCS wide range pressure transmitter. At approximately the same time, they received a fire alarm from a detector [EIIS:IC] located inside the reactor containment building (RB) [EIIS:NH]. CRO A checked for a spurious alarm by resetting the fire alarm and observed that it alarmed again. The CROs notified the Unit Supervisor and Control Room Senior Reactor Operator (CRSRO) that a problem existed. CRO A also attempted to visually inspect the RB using a video camera installed inside the RB at one end of the refueling canal and a monitor adjacent to the control room. However, the image was so foggy that CRO A assumed that the camera was either not working properly or was badly out of adjustment.

At 0143 hours, CRO B noted that the Letdown Storage Tank (LDST) and Pressurizer levels were decreasing and that High Pressure Injection (HPI) make-up flow had increased significantly. The RB normal sump also showed an increase in level. The operators concluded that the problem was an RCS leak rather than a fire and entered AP/3/A/1700/02, "Excessive RCS Leakage."

The Shift Supervisor and the Shift Manager, who performs the Shift Technical Advisor function, were notified at this time. They both reached the Unit 3 control room shortly after notification.

At 0155 hours, an RB particulate radiation monitor [EIIS:IL] alarmed momentarily.

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At 0203 hours, the leakage was estimated to be 70 gpm and the Shift Supervisor ordered a rapid controlled shutdown. The CROs set the Integrated Control System (ICS) for a load reduction at 15 MW/min. They isolated RCS letdown at 0211 hours to eliminate that loss from the system.

At 0214 hours, the Shift Supervisor officially declared the unit to be in an ALERT Emergency Classification and began making the necessary notifications to establish the Technical Support Center (TSC), and Operational Support Center (OSC) as required by the Site Emergency Plan.

At 0217 hours, during the power reduction, an ICS Asymmetric Rod signal generated a rapid load limit runback of the ICS from 77% to 55% FP. The operators diagnosed the CRD indication as spurious and, at the Unit Supervisor's direction, placed the ICS Feedwater and Reactor control stations in manual to stop the automatic runback at 60% FP.

Throughout the event, the CROs made additions to the LDST from the Bleed Holdup Tanks and Concentrated Boric Acid Storage Tank (CBAST) to maintain adequate inventory to compensate for the leak.

At 0305 hours, the TSC, adjacent to the Unit 1&2 control room, and OSC, adjacent to the Unit 3 control room, were manned and the Station Manager assumed the position of Emergency Coordinator. One of the first TSC actions was to have the operators re-establish letdown flow at 20 gpm to facilitate collection of RCS liquid samples to be analyzed for boron concentration and for indications of failed fuel. Other immediate actions included initiation of Radiation Protection surveys of areas outside the Reactor Building, and outside the Site Protected area to assure that no radioactive materials were being released from the RB as a result of the event. The Crisis Management Center (CMC) was activated in accordance with the emergency plan.

At 0320 hours, the leak was still estimated to be approximately 60 to 70 gpm.

B. Reactor Trip

The power reduction was stopped at approximately 33% FP in order to shutdown one of the two main feedwater pumps from a stable power level. At 0320 hours, the ICS Feedwater control station was returned to Automatic. This resulted in a slight increase in the magnitude of the normal oscillation of the control system. At 0324 hours, CRO A placed the "B" Main Feedwater Pump (MFWP B) in manual and began to reduce its demand. Apparently, FDWP B discharge pressure reached the Reactor Protective System (RPS) trip setpoint for two or more pressure switches and the contact buffers for that portion of the logic sealed in. As MFWP B output was reduced, FDWP A output momentarily increased but a divergent oscillation began. When the magnitude of the oscillation became apparent to CRO A, he increased the output of MFWP B. As he brought the demand for MFWP B up,

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the control system reacted to match total feedwater flow to total feedwater demand by reducing MFWP A demand and output. The oscillation also resulted in feedwater header low pressure alarms, low Main Steam pressure alarms, and opening of turbine by-pass valves (TBVs) due to high Main Steam pressure. MFWP A suction flow went to zero and the MFWP A minimum flow valve cycled open. Other system parameters such as reactor power, generated power, RCS pressure and RCS temperature were also oscillating.

The low discharge pressure on MFWP A apparently reached the trip setpoint and the second pump's contact buffers actuated. This satisfied the RPS logic and, at 0327:55 hours, RPS channels A and D tripped on low Main Feedwater Pump discharge pressure, which requires detection of low discharge pressure (800 psi) on both pumps. At the time of the trip, the oscillation had raised power to approximately 37% FP.

The immediate post trip response of the plant was normal. All CRD breakers opened and all control rod groups were inserted into the core. The turbine generator tripped, and both 4kv and 7kv electrical power supplies [EIIS:EA] transferred to the start-up source. Unit 3 stabilized at hot shutdown conditions with the operators safely controlling the reactor after the trip. No Engineered Safeguards System or pressurizer relief valve actuations occurred.

The RCS system response was normal. RCS pressure ranged between a low of 1988 psig and a high of 2141 psig. RCS average temperature dropped from 578 F, at the time of the trip to 551 F. Pressurizer level dropped from approximately 220 inches to between 135 and 144 inches. Letdown was isolated by the CROs in accordance with the trip procedure.

On the secondary side, the post trip reduction in feedwater demand proceeded as normal, and the steam generator level was maintained between 20 and 28 inches. The turbine stop valves closed and the TBVs opened. At least some of the main steam relief valve setpoints were reached and some of the valves opened. Main steam pressure varied between 973 psig and 1044 psig, according to the Transient Monitor [EIIS:IQ]. The operators momentarily reduced turbine header pressure to 970 psig in order to reseat one of the main steam relief valves, then returned to the normal post-trip pressure of 1010 psig. The Main Feedwater pumps do not trip due to low discharge pressure, so both pumps continued to run until CRO A manually tripped MFWP A. The emergency feedwater system [EIIS:BA] was not actuated after the trip.

At 0340 hours, letdown was re-established at 20 gpm.

By 0348 hours, the unit was considered to be at stable hot shutdown. The leak was then estimated to be approximately 130 gpm. RB sample results indicated that the RB atmosphere contained radioactive Iodine at 2 times maximum permissible concentration (MPC) and Noble gases at 407 MPC.

At about 0400 hours, the video camera in containment was used to examine the area. It showed a significant amount of steam rising from the "A" Steam Generator cavity. The steam was condensing on virtually all visible walls, hand rails, and equipment. The camera was panned to view the reactor vessel head, which showed significant amounts of water, but no steam leak, on the head. The top of the "B" Steam Generator cavity was also checked, but showed no steam source.

At 0406 hours, Chemistry samples showed an RCS boron concentration of 579 ppm. At 0445 hours, the operators began to cool the RCS down to 532 F. Plans were made to initiate boron addition to raise boron concentration for long term shutdown margin considerations.

At 0520 hours, the Engineered Safeguards (ES) [EIIS:JE] system was bypassed, per procedure, before lowering RCS pressure below the ES high pressure setpoint of 1750 psig.

At 0530 hours, the RCS pressure had been reduced to 1735 psig and temperature was 535 F. Permission was given by the TSC to begin cooling down to 450 F, at a rate of 45 degrees per 30 minutes. However, the operators had several procedures in progress and took some time to assure that all appropriate requirements were met and steps documented prior to continuing the cooldown.

C. Inadvertent RPS Actuation

Step 2.3 of Enclosure 4.2 in the shutdown procedure specified that the turbine bypass valves (TBVs) [EIIS:SO] were to be placed in Manual. The TBVs are used to control main steam pressure and, therefore, the saturation temperature in the steam generator, which, in turn, controls the RCS temperature. However, CRO A had been controlling pressure by using the ICS turbine header pressure setpoint control. He wished to continue in that mode to minimize the number of ICS stations in Manual and, therefore, limit operator burden. This was discussed with CRSRO A, who gave verbal approval for CRO A to keep the TBVs in Automatic and to perform the transfer to Manual out of sequence at a later time. The exact point in the procedure where this would be accomplished was not discussed.

At 0606 hours, the AMSAC/DSS (ATWS mitigation system) was bypassed. At 0613 hours, the Emergency Feedwater pumps were placed in Manual.

At 0622 hours, RCS pressure was 1660 psig and temperature was 526 F. At 0633 hours, the RPS was placed in "Shutdown Bypass", which allows the system to be reset below the normal low pressure trip setpoint. This also instates an over-pressure trip setpoint of 1710 psig to prevent inadvertent re-pressurization. CRO B announced to the other Operations personnel in the control room that he was about to "reset the reactor" and, at 0638 hours, the control rod drive breakers were reset. This was done in preparation for partially withdrawing one group of control rods as a standby source of negative reactivity.

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However, when the breakers were reset, the ICS removed an automatic bias which is applied to the turbine header pressure setpoint after a trip. (This bias automatically increases the setpoint by 125 psig to raise the saturation temperature after a trip to limit the RCS cooldown and control RCS temperature at 555 F.) As a result of removing the bias, the ICS sensed a 125 psi pressure error and opened the bypass valves in an attempt to achieve the new setpoint. This created a cooling transient on the RCS and RCS pressure dropped to approximately 1620 psig.

CRO A responded by placing the TBVs into Manual at 0638 hours and driving them closed. This response resulted in RCS temperature and pressure increasing again. CRO A stated that he concentrated on RCS temperature and turbine header pressure while trying to match the setpoint to demand in order to smoothly return to automatic. At approximately 0640 hours, CRO A returned the TBVs to Auto but RCS pressure was still increasing rapidly. At 0641 hours, RCS pressure reached the overpressure set point and tripped the RPS. The CRD breakers opened but, since all control rods were already fully inserted, no other consequences occurred. RCS pressure continued to increase to approximately 1720 psig until CRO A took the TBVs back into manual at 0642 hours and reopened them to stabilize pressure.

D. Subsequent Actions

The operators subsequently reset the control rod drive breakers and withdrew one group of control rods to 50% withdrawn in accordance with procedure. The cooldown continued.

At 1717 hours, the RCS reached 200 F, and 293 psig (cold shutdown). At this point the event emergency classification was terminated.

At 2115 hours, samples of RB atmosphere indicated that airborne iodine activity was 1382 MPC.

Between 0002 and 0450 hours on the morning of November 24, 1991, Operations pumped part of the water from the RB normal sump into waste tanks for processing.

At 0800 hours, it was estimated that approximately 5 to 10 gpm was still leaking out of the RCS due to the fact that the pressurizer was still at saturation temperature and was maintaining a 30 psig system pressure. The normal cooldown process requires that personnel enter the RB to align manual valves to establish a flow through the pressurizer to cool it. However, due to the level of airborne contamination this was not possible and a less effective flow path had to be used. Additionally, a special method of venting the pressurizer and steam generators was incorporated into the shutdown procedure to reduce level in Steam Generator A hot leg below the leak. By 1700 hours on November 24, 1991, the unit was completely de-pressurized and the leak stopped.

At 2200 hours, airborne iodine activity inside the RB was 731 MPC.

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On November 25, at 0100 hours, the Reactor Building Purge System [EIIS:VA] was started to clean up the RB atmosphere for building entry.

At 1300 hours, airborne iodine activity was 27 MPC. An inspection team entered the RB and located the source of the leak. It was found to be due to a 3/4 inch diameter instrument line which had pulled out of a compression fitting downstream of a root valve. The line was located at the top of the RCS hot leg pipe where it entered the "A" Steam Generator (SG A).

The tubing configuration is shown as Attachment A. The same configuration was used on both steam generators and the reactor vessel head on all three Oconee units when RVLIS was installed. Note that a series of tubing reducers were used to transition from a 3/4 inch root valve to 3/8 inch tubing. This configuration resulted in a total of six compression joints per instrument line.

The root valve, fittings, and affected tubing from SG A were subsequently removed from the system for inspection and analysis. The equivalent impulse lines on the "B" Steam Generator and the reactor vessel head were inspected and found to be intact. It was subsequently decided to replace these lines with a new configuration which used welded fittings to reduce to 3/8 inch tubing. The new configuration has only two compression joints per line.

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Parker Hannifin Company (Parker), manufacturer of the fitting, was contacted and provided a range of "nominal" values for the makeup gap between the hex on the fitting and the end of the nut. The Parker spokesperson stated that these nominal values did not constitute acceptance tolerances or specifications. The inspections showed that the gap was 0.182 inch versus a nominal 0.153 inch. The degree of crimping of the tube was determined by comparing the internal diameter (ID) reduction of the failed fitting to the reduction due to the fitting at the other end of the tube, which did not fail. The ID reduction at the failed end was only 0.002 inch compared to 0.007 inch at the "good" end.

Both Oconee Engineering personnel and the Babcock and Wilcox Lynchburg Research Center (B&W) concluded that the inspections indicated that the fitting had not been fully crimped onto the instrument line during initial fitup and installation in 1987.

It was decided to inspect a sample of compression fittings located in the RB, which included both Parker and Swagelock fittings. Vernier calipers were used to measure the gap on Parker fittings for comparison against the nominal values supplied by Parker. Swagelock fittings were checked with Swagelock go/no go gauges.

This initial sample found approximately 10% of the fittings to be out of the nominal range, although all of the fittings checked had been in service with no signs of leakage. The decision was made to perform a full

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inspection of fittings attached to the Reactor Coolant System and primary support systems such as the High Pressure Injection Systems. This inspection included 455 fittings (264 Parker and 191 Swagelock) of which 126 (27.7%) were found out of the nominal range. Of these, one had boron on it, indicating that it had leaked, and another had a loose nut. The technicians attempted to tighten all of these fittings into the nominal range. However, 27 Parker fittings (5.7%) could not be tightened into the nominal range without use of excessive force in the opinion of the technicians. Maintenance Engineering selected one of these Parker fittings, which had been the most out of the nominal range after re-tightening, to be replaced and inspected. Maintenance Engineering concluded from their inspection that the ferrule was installed properly and was adequately crimped on the tube despite being out of the nominal range provided by Parker. Three more fittings were subsequently tightened into the nominal range. The remaining 23 fittings, of which 16 are 1/2 inch and 7 are 1/4 inch, were left out of range after an engineering evaluation concluded that it was acceptable to do so. Portions of that evaluation are addressed in the Safety Evaluation section of this report.

Other equipment inside the RB was inspected due to exposure to the extremely humid atmosphere during the event. These components and the results are listed on Attachment B.

Because a divergent control oscillation developed in the Integrated Control System and appeared to cause the unit trip, a team of consultants was brought in to analyze available data in accordance with the B&W Owners Group Transient Assessment Program. The results of that assessment are included in the Conclusions section below.

E. Radiological Consequences

The RCS water that leaked into the RB overflowed the Normal and Emergency Sumps and covered the RB basement floor. It was contained there until it was transferred to waste storage tanks for treatment. A total of 87,183 gallons was treated and released.

The Reactor Building Purge System was used to lower airborne activity inside the RB. The Purge System is a once through ventilation system which filters RB air through High Efficiency Particulate Air and Carbon Adsorber filters prior to release through the Unit vent. Radiation Protection personnel calculated the dose to the public due to releases via the Purge using two different filter efficiencies. The Projected Dose was calculated using an assumed carbon filter efficiency of 90%. An Estimated Dose was calculated using actual filter efficiencies from the latest surveillance tests. Both methods use annualized average meteorological data rather than actual conditions at the time of the release.

The release data is summarized on Attachment C. Final calculations will be included in the Semi-annual Effluent Report.

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Monitoring in accordance with the Fuel Reliability Program indicated that, prior to the leak, there was an estimated 8 leaking fuel pins. Unit 3 activity levels shortly before the leak were approximately 0.15 microcuries/milliliter dose equivalent Iodine, compared to Unit 1 levels of approximately 0.01 microcuries/milliliter dose equivalent Iodine.

As a result, the leak produced high contamination levels throughout the RB. Some of the results of smear surveys are shown on Attachment D. The decision was made early in the outage to perform minimum decontamination at this time. The intent was to allow the contamination to decay until the next scheduled refueling outage and minimize the amount of dose due to decontamination activities. However, additional items were found which required maintenance and extended the outage beyond the initial scope. The total dose to personnel performing outage activities through 0600 hours, December 17, 1991, was 30.70 person-rem. No personnel have received doses in excess of Duke Power administrative limits.

CONCLUSIONS

A. RCS Leak

It is concluded, based on the investigation performed by Oconee Engineering and Babcock and Wilcox, that the initiating cause of the leak in this event was improper installation of the fitting. Specifically, the fitting nut was not fully tightened. Therefore, a contributing cause of Inappropriate Action, (Improper Action, Action chosen was proper but execution failed because an action was performed with insufficient precision), is assigned. However, the root cause of this event is determined to be Management Deficiency, for less than adequate policy, directive, or task specific procedure, as explained below.

A review of procedures, Quality Control (QC) manuals, and personnel interviews indicated that procedures provided less than adequate guidance and/or documentation of installation or inspection of tubing fittings. The procedure for installation of the RVLIS instruments included one signoff step for each impulse line being installed which covered installation of all associated fittings and instrument tubing. It did not contain specific instructions on how to makeup fittings. Each step had provision for the initials of one craft person as installer, one person as independent verifier, and one QC inspector. The reference section of the procedure refers to a design specification on installation standards for instruments which specifies that tubing fittings be installed in accordance with the manufacturer's instructions.

Both Swagelok and Parker provide installation instructions which specify that their fittings should be installed "finger tight," then tightened 1 and 1/4 turns (3/4 turns on tubing 3/16 inch or less). This process has been considered "skill of the craft" and has been included in technician

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training. Both vendors recommend that one face of the nut be marked while finger tight to facilitate counting the turns, but training documents do not include this recommendation. The technicians were aware of the recommendation to mark the nut, but they did not interpret it as a requirement, and they did not, as a general practice, mark the nut. Swagelock manufactures go/no go gauges for inspecting their fittings, but, prior to this event, no program or procedure required that they be used and they were not in general use at Oconee. No similar device or inspection criteria was referenced in Parker installation instructions.

According to the craft technician who signed the step for the "A" Steam Generator line, the valve, 3/4 inch and 1/2 inch tubing, and associated fittings had been made up in the shop area and transported as an assembly into the Reactor Building. No one signed for the individual fitting connections and it is unknown who performed the fitup and tightening on them. The independent verification sign off was based on the fact that the line was installed, rather than that the individual fittings were properly tightened. The QC inspector stated that the line was inspected in accordance with the QC manual which specified a general inspection of the tubing. It did include a requirement to "verify that all fittings are tight," but no method to check fitting tightness was included. The inspector stated that he typically checks to see that fittings cannot be loosened by hand and that the tubing cannot be pulled out of the fitting.

The impulse line was subjected to a pressure test of the entire RCS at 2200 psig as required by Technical Specifications during startup following refueling outages (or any other opening of the RCS). This test includes walk down of the system and any leakage at the fitting should have been detected prior to operation after it was installed. The fitting subsequently held for 4 and 1/2 years and the line has been subject to inspection during three subsequent refueling outages without any indication of leakage. It is apparent that the fitting, if not tightened exactly in accordance with the manufacturer's instructions, was tightened to an extent that the deficiency could not be discovered by routine observation without some specific inspection criteria (such as a go/no go gauge or disassembly to visually verify proper compression of the tubing).

No system transient was detected immediately prior to or simultaneously with the initiation of the leak which might have explained why the fitting failed at this particular time.

The inspection performed on existing fittings on Unit 3 after the event found that approximately 28 % of the fittings inspected did not meet the manufacturer's guidelines. This indicates that "skill of the craft" was not adequate to assure that the manufacturer's guidelines were met.

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B. Reactor Trip

The root cause for the reactor trip was found to be an unanticipated interaction of control signals with plant parameters steam pressure and feedwater flow at low power conditions after placing a Main Feedwater pump (MFWP B) in manual to shutdown the pump. This root cause is classed as a Equipment Failure, due to ICS components being slightly out of tune.

The resolution of the problem is to "tune" the turbine header pressure control to make it more stable in this configuration. The Oconee philosophy on tuning the ICS is to calibrate individual components periodically (typically during refueling outages), review operating data to evaluate system performance, and perform system tuning only when necessary to resolve a problem. This is based on the fact that tuning activities require that small transients be intentionally imposed on the system, which increases the possibility of a unit trip.

The investigation of plant and ICS performance data recorded immediately prior to the trip revealed that steam pressure and feedwater demand were out of phase and limit cycling before MFWP B was placed in manual. After switching the pump to manual, the amplitude of the steam pressure and feedwater flow oscillations increased exponentially in a classic unstable manner.

Specifically, one component of the oscillation was caused by the response of the turbine header pressure control portion of the system. This portion of the system has been recognized by assigned ICS technical support personnel as being marginally stable when the reactor is in manual. With the ICS SG/Reactor Master station in Automatic, the feedwater demand was modified by the turbine header pressure error signal, which was oscillating within stable limits due to the response time of the various components. A second contribution to the oscillation was the response of the feedwater pump control portion of the system. With both feedwater pumps in automatic, the response time of the feedwater pumps to the changes in demand was fast enough to keep the oscillations stable. However, when the operator took one pump to manual, only one pump could respond. Therefore, that pump speed had to change more to produce the same flow change. That meant that the pump turbine throttle valve had to move further, and, due to proportional control, the error signals had to be larger to cause the change. This shifted the response time of the pump control system such that the oscillations became divergent.

One difference between this event and other shutdowns was that the reactor was in manual control at the time. This caused the Tave control to modify the feedwater control signal, and prevented the reactor from contributing to the overall response to the control signals. Therefore, the feedwater pump control system response time was affected by the Tave control and the turbine header pressure response time was affected by the lack of reactor response, thus neither sub-system was experiencing the response times seen in a normal shutdown.

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The period of oscillations (approx. 36 seconds) and time from initiating event to reactor trip was too short for the operators to adequately evaluate and react to the situation.

Given sufficient time for diagnosis, the operator could have stabilized the oscillation by taking other stations to Manual. The first preference would be for him to have taken turbine control to manual. The second preference would be for the SG/Reactor master control station to have been left in, or returned, to manual, as this would have blocked the steam pressure affect on feedwater control.

It is noted that the Oconee training simulator does not model the ICS and response of individual secondary components in sufficient detail to exhibit this type of control oscillation during training.

An initial question was raised after the trip as to why the Emergency Feedwater pumps were not started if the unit tripped on low MFWP discharge pressure, as indicated by the Unit 3 Events Recorder, because the initiating pressure switches have the same nominal setpoint as the RPS switches. This was subsequently explained as follows:

First, the RPS logic contact buffers require manual reset. The contact buffers on MFWP B were apparently actuated when CRO A manually ran back the demand for that pump which caused discharge pressure to drop. A control room alarm should have alerted the operator to the actuated buffer, but it was apparently overlooked due to the large number of alarms resulting from the leak and the sudden appearance of the divergent oscillation. When CRO A reacted by increasing manual demand on MFWP B, the system responded by reducing demand for MFWP A, which was still in Automatic. When MFWP A discharge pressure reached the setpoint, the associated contact buffers actuated and satisfied the logic in the RPS. The Emergency Feedwater pumps are also actuated by indicated low discharge pressure on both MFWPs, but that logic does not seal in if only one pump discharge pressure is low. The system will only actuate if both MFWPs are low simultaneously.

Second, the pressure switch calibrations were verified after the trip. These checks found that one switch in each actuation channel of the Emergency Feedwater actuation logic was slightly out of the procedure calibration tolerance on the low side. Therefore, MFWP discharge pressure could fall low enough to actuate the RPS switches, which were all within tolerance, and still be above the actual setpoint of the Emergency Feedwater pump logic.

Because of the continuing divergent secondary plant oscillation, it is believed that the reactor would have tripped even if the operator had not increased MFWP B speed.

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C. Inadvertent RPS Actuation

It is concluded that the root cause of the inadvertent actuation of the Reactor Protective System (RPS) is Management Deficiency, Deficient Supervision, by CRSRO A.

CRO A was operating with the ICS turbine header pressure control in Automatic after the procedure directed the operator to manually control header pressure by placing the Turbine Bypass Valves in Manual. However, both CRSRO A and CRO A state that they had discussed this deviation from the procedure and reviewed portions of the procedure in an attempt to identify any adverse affects. Neither CRSRO A nor CRO A either recalled from training or reviewed the procedure adequately to identify the reason for the requirement that Turbine Bypass Valves be in manual. This inappropriate action of less than adequate attention to detail contributed to the event.

CRSRO A granted verbal approval for CRO A to stay in Automatic control for the time being. Station directives allow performance of steps out of sequence with the supervisor's approval but require that the approval be documented in the procedure. Additionally, Operations management has a more restrictive Operations Management Procedure which directs that the Shift Supervisor's approval, rather than the CRSRO's, is required prior to performing steps out of sequence. Although the existing operating conditions were unusual, this deviation could not be justified as being necessary to mitigate an emergency situation. Therefore, it was inappropriate for CRSRO A to grant such approval. CRSRO A did so in his role as supervisor, therefore this act is classified as deficient supervision.

It is noted that the procedures in use, OP/3/A/1102/10, "Unit Shutdown" Enclosure 4.2, and OP/0/A/1105/09, "Control Rod Drive System", did not provide any Note, Caution, or verification step immediately prior to resetting the CRD breakers to indicate that the turbine bypass valves should be in Manual or that resetting the CRD breakers would result in a change in pressure if the bypass valves were in automatic.

Recurrence and Other Conclusions

The RCS leak is not considered to be a recurring event. Oconee has not had a history of leaks due to leaking compression fittings. The reactor trip is considered recurring. On April 26, 1990, Oconee Unit 1 tripped due to an unexpected control interaction when an operator stopped the second of four reactor coolant pumps during shutdown. Following a Technical Specification change which prohibited operation with only two running pumps, the RPS had been calibrated to trip the unit if only two pumps were running and power was greater than zero. It was not anticipated that, during the shutdown, the power level indicated by the neutron detectors was small but greater than zero. That event was reported as LER 269/90-06.

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The unplanned actuation of the RPS is also considered recurring. On April 1, 1991, Unit 3 had two inadvertent actuations of the Diversified Scram System (an ATWS mitigation system which provides a back up to the RPS) which resulted in an reactor trip and a subsequent scram of a partially withdrawn group of control rods. The subsequent scram occurred during troubleshooting when involved personnel failed to anticipate that the control rods would be affected by their actions. That event was reported as LER 287/91-05. In the RPS actuation portion of this event, CRSRO A and CRO A failed to anticipate the effect of leaving header pressure control in automatic.

There were no personnel injuries or excessive personnel exposures associated with this event. Releases of radioactive materials were controlled and within normal limits. The failure of the fitting, a Parker Hannifin Company model 12-3/4 ZHBW2-SS, has been determined to be NPRDS reportable.

CORRECTIVE ACTIONS

Immediate

1. Operators began a controlled unit shutdown.

2. An Emergency Classification of "Alert" was declared and notifications made to initiate activation of the Technical Support Center and Operational Support Center in accordance with the Site Emergency Plan.

3. Following the Unit trip, Operations stabilized the unit and continued shutting down to cold shutdown.

Subsequent

1. The root valve, tubing, and associated fittings on both the "A" and "B" Steam Generator RVLIS impulse lines were replaced with new components.

2. All compression fittings on tubing connected to the Reactor Coolant System and related high pressure systems (High Pressure Injection and Core Flood) were inspected, and tightened if necessary.

3. An operability evaluation was performed to document the engineering justification for returning Unit 3 to service with the gap on several fittings remaining outside the manufacturer's nominal range. This also documented the justification for continuing operation of Units 1 and 2 without shutting down to inspect for similar defects.

4. Appropriate calibration procedures were revised to change the tuning of the Integrated Control System with the intent to minimize the control oscillation which caused the unit trip.

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5. The calibration of the Main Feedwater Pump low discharge pressure RPS and Emergency Feedwater pressure switches were checked. Two Emergency Feedwater pressure switches were slightly out of tolerance low (785 versus 793 psig) and were recalibrated.

Planned

1. The RVLIS instrument line on the Unit 3 reactor vessel head will be replaced prior to startup.

2. The equivalent RVLIS instrument lines on Units 1 and 2 will be replaced with a configuration using fewer compression fittings during the next outage of sufficient duration.

3. All compression fittings on tubing connected to the Reactor Coolant System and related high pressure systems on Units 1 and 2 will be performed during the next outage of sufficient duration.

4. Policy, directive and/or procedure enhancements shall be implemented to assure proper installation and inspection of compression fittings.

5. All personnel who inspect, install, makeup or remake tubing fittings will receive additional training to assure that the manufacturer's instructions are understood and complied with.

6. During unit startup following this outage, a pressure test and walkdown inspection of the RCS will be performed as required by Technical Specifications.

7. During unit startup following this outage, the ICS shall be operated in manual with one Feedwater pump in service long enough to verify that the control oscillation which caused the unit trip is more stable after the tuning adjustment.

8. Operators involved in the inappropriate action and less than adequate supervision will be counselled.

9. Operations procedures will be evaluated for enhancements. Specifically, additional "condition oriented" guidance on ICS controls will be reviewed and implemented as deemed appropriate.

SAFETY ANALYSIS

FSAR Section 15.14.4.3, "Small Break LOCA", defines the minimum area for a small break LOCA to be 0.007 sq. ft. This corresponds to a circular opening approximately 1.13 inches in diameter. The tubing/fitting which failed resulted in an opening of approximately 0.75 inch diameter, or 0.003 sq. ft. area. Therefore, by definition, this event was not a LOCA. All identified consequences were bounded by FSAR analyses for a Small Break LOCA. The leak rate was calculated to average approximately 80 gpm while the Reactor Coolant System (RCS) was at operating pressure. One High Pressure Injection (HPI) pump was capable of maintaining RCS pressure and inventory at this leak rate. No Engineered Safeguards actuations were necessary as a result of the leak. The unit trip which occurred was not caused by the leak.

As shown in Attachment C, radiological releases made as a result of this event were very small percentages of NRC annual limits. All releases were made in a controlled manner after processing the effluent appropriately to minimize the release. The total releases were increased due to the relatively high amount of failed fuel (estimated at 8 rods) which existed in the core prior to the event. Since there are 177 fuel assemblies and each assembly has 208 rods, eight leaks represents only 0.022 %, well less than the FSAR LOCA analysis, which assumes failure of 1% of the fuel rods. The FSAR Maximum Hypothetical Accident analysis further assumes failure of all fuel rods, and shows that 10CFR100 limits would still be met.

As discussed previously, the unit trip response was well within normal post trip response guidelines. No Engineered Safeguards or Emergency Feedwater actuations were required due to the trip. The trip was caused by an Integrated Control System (ICS) oscillation while in an infrequent but normal activity, i.e. taking one feedwater pump out of service at low power level while shutting down. The principle difference in this event from routine shutdowns was the combination of power level and control configuration, i.e. which ICS stations were in manual. The ICS will be tuned to minimize the probability of recurrence, but the worst case scenario would be for the ICS to fail in a similar divergent oscillation while at full power. Should such a failure occur, the Reactor Protective System (RPS) is designed to trip the unit prior to any safety limits being exceeded. In this case the RPS functioned as designed.

The inadvertent actuation of the RPS after resetting the Control Rod Drive (CRD) breakers had minor safety significance. Again, the RPS functioned as designed to assure that safety limits were not exceeded. If a similar event occurred at a higher RCS pressure and temperature (CRD breakers are normally reset at hot shutdown conditions in preparation for restarting the reactor after a trip), the sudden removal of the Turbine Header Pressure post-trip bias of 125 psig would result in a quick cooldown of the RCS from approximately 555 F to 532 F. Such a cooldown could affect RCS apparent inventory due to contraction of the RCS water. This would reduce system pressure and the RPS would trip on low pressure. The HPI system would provide additional makeup flow, but, if the pressurizer was at or near minimum post-trip levels, the pressurizer level could go off scale low momentarily. If the operator reacted similarly to CRO A and closed the Turbine Bypass Valves, RCS pressure would increase. If the operator failed

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to control pressure properly, the operator could possibly challenge the Pressure Operated Relief Valve (PORV), but the PORV should still assure that no safety limits were exceeded.

Oconee Engineering performed an evaluation of the 23 Parker fittings left out of the manufacturer's nominal range for fitting makeup. This evaluation concluded that Unit 3 could safely restart with these fittings in place. This conclusion was based on the facts that:

1) Parker does not consider the gap dimension to be a critical parameter,

2) the fittings were all tightened as much as appeared feasible to highly experienced instrument technicians,

3) these fittings have been in place for years without leaking, and

4) one of the fittings most out of the nominal range was removed from service, inspected, and verified to have adequate swaging of the ferrule on the tubing.

Because tubing failure has always been considered a possible failure mode, all of the affected instrument lines have been previously analyzed and evaluated, particularly with consideration of single failure criteria. However, the affect of failure of these 23 "problem" fittings was re-analyzed, including the affect on the connected instrumentation. A summary of the results of this analysis follows:

1. Problem fittings were found associated with three RPS Loop A RCS flow instruments and the ICS Loop A RCS Flow instrument. These all share common impulse lines and are always subject to being affected by any single failure of the impulse lines. Failure on the high pressure side would cause a low flow signal on all the RPS channels and would cause a reactor trip on Flux/Flow/Imbalance. A failure on the low pressure side would cause the flow indications to fail high, which would result in computer alarms to alert the operator. The low side failure would prevent an RPS Flux/Flow/Imbalance trip, but would not cause a trip condition to exist. If a real low flow condition occurred simultaneously with the tubing failure, the decreased heat transfer would result in a high RCS pressure condition which would trip the reactor using separate instruments.

2. Problem fittings were found which could affect pressure indication to Engineered Safeguards Channel B RCS pressure and RPS Channel B RCS pressure. A failure on this line could result in actuation of ES and

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RPS Channels B. Neither system would actuate solely due to actuation of only one channel.

3. Problem fittings were found on one of two level control transmitters which control Emergency Feedwater flow into the "B" Steam Generator (SG B). The affected transmitter shares an impulse line with transmitters for Startup, Operate, and Full Range level indications on SG B. Redundant transmitters exist on all of these except Full Range, which provides indication only. The redundant Startup and Operate transmitters would be selected by the Smart Automatic Signal Selector system so that the failure would have no affect on normal operation.

   These instruments are located inside containment. If one of these fittings failed, one result would be a main steam leak inside containment. This would have no affect on the RCS, but, if a LOCA occurred after the instrument failure, the open tubing would provide a leak path out of containment.

4. Problem fittings were found associated with the Pressurizer (PZR) level transmitters. Several fittings are on impulse lines associated with one normal PZR level transmitter, a second level transmitter which provides indication in the Standby Shutdown Facility, and a PZR pressure transmitter. Other fittings are on a line connected to only one of the other two transmitters.

   A failure of a fitting on the high pressure leg could cause low PZR level and pressure indications which could result in the PZR heaters being turned off and increased makeup. The operator would receive low level and low pressure alarms to alert him of the failure. He would have to properly diagnose the failure and select an alternate PZR level transmitter. If the operator delayed this action too long, the increased makeup flow could fill the PZR and challenge the PORV. A failure on the low pressure leg would result in a high level indication, which would cause an alarm and stop RCS makeup flow. The operator would have to diagnose the failure and select an alternate transmitter. If the operator delayed this action too long, the loss of makeup would allow real PZR level and pressure to drop. This could lead to uncovering the PZR heaters while they were energized which could result in damage to the heaters. However, in each failure mode, the other two level instruments would be reading properly and the affected instrument would be off scale either low or high, making diagnosis easy. Also, PZR instrument failure scenarios are frequently used in Operator training, and the Operators are trained to recognize these failure modes.

5. One problem fitting was found on a transmitter for HPI Nozzle Warming Flow, which provides indication only.

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The instruments connected to the RCS would result in system leakage, but, due to the size of the tubing, the leakage would remain within the capability of a single HPI pump to provide makeup. The HPI Nozzle Warming Flow instrument is located outside the Reactor Building (RB), but the makeup water is at low temperature and the associated instrument root valves would be accessible so that the leak could be isolated. The other instruments are located inside the RB and any leakage would be confined to the RB.

The evaluation also considered the possibility of similar fitting problems on Oconee Units 1 and 2. The conclusion reached was that the type and degree of problems found on Unit 3 do not warrant shutting down Units 1 or 2. Both Unit 1 and 2 will undergo similar tubing inspections during the next outage of sufficient duration. Unit 2 is currently scheduled to begin a refueling outage in January, 1992. There has been no history of tubing failures at Oconee prior to this event. Of the fittings found out of nominal range on Unit 3, only one showed any evidence of a slight leak. It was concluded that the probability of a fitting failure on either Unit 1 or 2 prior to the next outage is acceptably small. Furthermore, the tubing fittings on those units are of similar size to those on Unit 3, such that no fitting failure should be any worse than that on Unit 3.

In summary, the leak which occurred did not pose an immediate hazard to the public. The leakage was contained and all resulting effluents were treated prior to release to minimize dose to the public. All releases were within limits for normal operation. It is concluded that the health and safety of the public was not affected by this event.

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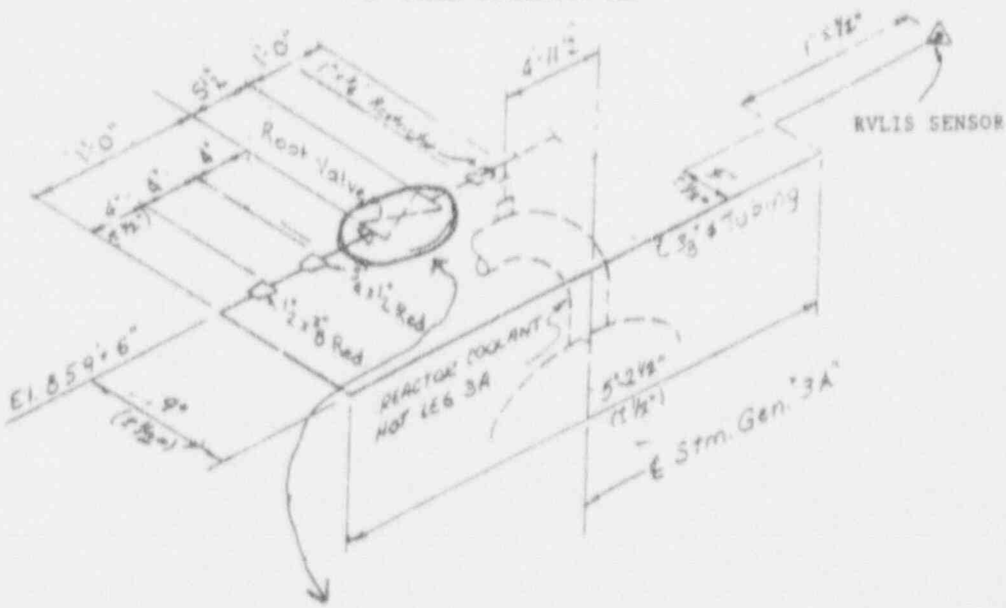
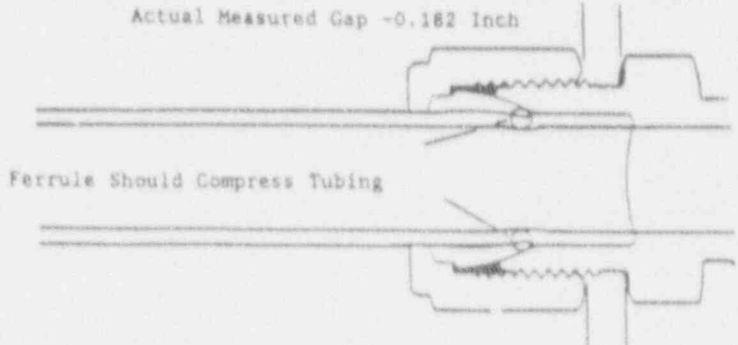
Attachment A

"A" STEAM GENERATOR TAP



"Nominal" Gap Expected - 0.153 to 0.165 Inch

Actual Measured Gap -0.182 Inch



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Attachment B

List of Equipment Inspected

Environmentally Qualified Transmitters- 4 of 11 opened and visually inspected. No evidence of water intrusion was found.

Environmentally Qualified Valves- 8 of 8 Target Rock solenoid valves were cycle tested successfully.

Valve Operators- Inspected 26 Limitorque limit switch housings for water.

Fire Detectors- 21 of 22 checked out good. Replaced bad one.

Electrical Penetrations- Opened 5 junction boxes, found no signs of moisture.

Control Rod Drives: Initially Megger tested 20 of 69, all good. Subsequently had one control rod stator fail during an attempted start-up. Later testing showed 29 of 69 to have some problems attributed to moisture. Four were replaced and the others were dried out.

Disconnected 2 control rod position indication tube cables, found no sign of moisture intrusion.

Pressurizer heaters- inspected two junction boxes and meggered 3 cables. No defects found.

Incore instruments- Performed TDR check on one of 7 detectors in each of 52 strings.

Resistance Temperature Detectors (RTDs)- Checked 5 RTDs on RCS.

Pressure Operated Relief Valve acoustic leak monitor- visual inspection

Reactor Coolant Pump Motors- performed High Pot Test on 2 of 4 pumps. Visually inspected instrument terminals on 2 of 4 pumps. Changed oil on 1A2 pump (both oil pots) after water found in upper oil pot.

Cranes- Visually inspected polar crane, Control Rod Drive crane, and fuel handling bridges.

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Attachment C

<u>DOSE to Public Due To Releases</u>

SOURCE	CURIES	WHOLE BODY	THYROID
Liquid	0.0305 Gross 0.0165 Tritium 0.293 Noble Gas	0.00139 mrem (0.0154 %)	0.0122 mrem (0.0407 %)
Noble Gas	672	0.00218 mrad (0.007[illegible] %)	N/A
Iodine Gas	0.000126		0.0004 mrem (Estimated) 0.0513 mrem (Projected) (0.114 %)

NOTE: All % values above are % of maximum allowed dose per calendar year.
Projected dose used 90 % carbon filter efficiency. Estimated dose used actual filter efficiency.

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Attachment D

Contamination Survey Results

AREA	CONTAMINATION		ISOTOPIC
A Steam Generator Cavity	24 K cpm	127 mrad	Co-58 71% Cr-51 11%
B Steam Generator Cavity	44 K cpm	42 mrad	Co-58 58% I-131 13% Cs-137 6% Cs-134 5%
Basement		(10,000 mrad)	
West Side		873 mrad	Co-58 36% I-131 36% Cr-51 8% Cs 6%
East Side		590 mrad	Co-58 47% I-131 20% Cr-51 11% Nb-95 4% Zr-95 2% Nb-97 2%
1st Floor	36 K cpm	10 mrad	Co-58 52% Cr-51 10% I-131 10% Cs 9%
2nd Floor	22 K cpm	68 mrad	Co-58 34% Cs-137 26% Cs-134 13% I-131 9%
3rd Floor	18 K cpm	156 mrad (1487 mrad)	Co-58 50% Cr-51 11% Nb-95 9% I-131 4% Cs-134 2% Cs-137 3%
4th Floor	20 K cpm	46 mrad	Co-58 48% I-131 13% Cs-137 9% Cs-134 8% Cr-51 8%
Polar Crane		90 mrad (182 mrad)	

NOTE: Readings indicate high "typical" readings in general area. Parentheses indicate readings at localized hot spots within general area.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	293/91-005
Event Description:	Loss of one division of class 1E loads
Date of Event:	March 15, 1991
Plant:	Pilgrim

Summary

On March 25, 1991, Pilgrim was operating at 100% power and performing a Technical Specification (TS) surveillance run of the B emergency diesel generator (EDG) because the shutdown transformer (SDT) was inoperable. The automatic voltage regulator (AVR) for the generator failed, which caused all the preferred and alternate power supplies to essential service bus A-6 to trip off on a sensed overcurrent condition on the bus. Subsequently, the EDG was also lost when it oversped on the loss of load. The loss of the EDG caused the loss of all AC power to train B of the vital loads distribution. The plant remained at full power for over 15 h with only one vital bus, the main generator, one source of offsite power, and one EDG available for all house and safety loads. Also, the plant operated in the Single Recirculation Loop mode during this time since power was also unavailable for one of the two reactor recirculation pumps.

Event Description

On March 24, 1991, the SDT was declared inoperable due to solar-induced disturbances causing perturbations on the 23-kV distribution system. Essential loads were being supplied by the unit auxiliary transformer (UAT). EDG B was undergoing a TS-required surveillance run because of the unavailability of the SDT. The EDG was fully loaded, synchronized to essential bus A-6, and paralleled with the UAT. The AVR on the EDG failed and caused an overcurrent condition to be sensed by the lockout relay 186-A6 on phase B of the feeder breaker A605.

The lockout relay actuated and opened breakers A605, A604, and A601, effectively stripping the load off essential bus A-6. This large load reduction caused EDG B to overspeed and trip, followed by breaker A609 tripping open. Thus, essential bus A-6 had no power supply, and all of its supplied loads were lost. Among the loads lost were control rod drive (CRD) pump B, residual heat removal (RHR) pumps B and D, core spray pump B, standby liquid control (SBLC) system pump B, reactor water cleanup (RWCU) system pump B, turbine plant closed cooling water (TBCCW) pump B, reactor building closed cooling water (RBCCW) pump B, high-pressure coolant injection (HPCI) pump room cooler and turbine exhaust containment isolation valve, reactor core isolation cooling (RCIC) turbine steam supply isolation valve, and reactor recirculation system motor-generator (MG) set B. This last item placed the plant in single recirculation loop operation.

The plant continued to operate at 100% power until power was restored to bus A-6 ~15 h later. After power was restored, the recirculation pump was restarted. Starting this large load caused the HPCI and RCIC inverters to trip. This event is addressed in LERs 293/91-006 and 293/91-024.

The Nuclear Regulatory Commission granted a waiver of compliance for operation beyond the 24-h limit required by numerous Limiting Conditions for Operation and a License Condition. However, this waiver was not required since power was restored in less than 24 h.

Additional Event-Related Information

The auxiliary power distribution system (APDS) at Pilgrim has six 4.16-kV buses. Four of these buses, A1, A2, A3, and A4, are designated as normal service buses, while the other two, A5 and A6, are emergency service buses. The emergency service buses supply power to essential loads required during normal operations, abnormal transients, and accidents. The other four buses supply power to station auxiliaries during planned operations. Power to all six buses is normally supplied by the UAT or the preferred offsite source, the startup transformer (SUT). The SUT is used to supply power during normal startup and shutdown. Power to the buses is then transferred to the unit source after the main generator is on line. Backup power to buses A-5 and A-6 is supplied from EDGs A and B or the SDT.

ASP Modeling Assumptions and Approach

This event was not modeled as an accident sequence precursor since it only involved a loss of redundancy for vital plant loads. However, it was an interesting event in that the plant remained at full power for over 15 h with only one vital bus, the main generator (which would be unavailable following a scram), one source of offsite power, and one EDG to power all house and safety loads. The utility noted that the probabilistic risk model for Pilgrim indicated that the risk associated with remaining at power was less than initiating a plant shutdown for a period of up to 48 h. (The current Accident Sequence Precursor model for Pilgrim indicates this time period is ~116 h.)

LICENSEE EVENT REPORT (LER)

U.S. NUCLEAR REGULATORY COMMISSION

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TITLE (4): Loss of AC Power to 'B' Trains of Safety Systems due to Diesel Generator 'B' Voltage Regulator Failure During Surveillance

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 NAMES	DOCKET NUMBER(S)
03	25	91	91	005	01	05	16	91	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: X 50.73(a)(2)(iv); X 50.73(a)(2)(v) D

LICENSEE CONTACT FOR THIS LER (12)

NAME: Douglas W. Ellis - Senior Compliance Engineer

TELEPHONE NUMBER: AREA CODE 508 747-8160

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
X	EK	RG	B093	Y					
X	EK	AMP	B093	Y					

SUPPLEMENTAL REPORT EXPECTED (14): X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

On March 25, 1991 at 0610 hours, the Emergency Diesel Generator (EDG) 'B' became inoperable, a loss of AC power to Train 'B' components of safety systems, and actuations of portions of the Primary Containment and Secondary Containment Isolation Control Systems occurred during a Technical Specification required surveillance test of the EDG 'B'.

The cause for the event was a failure of the automatic voltage regulator (AVR) of the EDG 'B' that was fully loaded on its safety bus at the time of the event. The voltage regulator was manufactured by the Basler Electric Company, model number SVR01AD_92B1B, serial number 9047500105. The affected safety system components were re-energized and returned to normal service by March 25, 1991 at 1100 hours. The EDG 'B' voltage regulator was replaced and the EDG 'B' was surveillance tested with satisfactory results. The surveillance was completed on March 28, 1991 at approximately 0915 hours. The failure of the AVR was caused by the failure of the AVR magnetic amplifier due to low insulation resistance. A manufacturer search of its production failure and returned materials data indicated the failure was an isolated occurrence.

This event occurred during power operation while at 100 percent reactor power. The reactor mode selector switch was in the RUN position. The Reactor Vessel (RV) pressure was 1035 psig with the RV water temperature at 548 degrees Fahrenheit. This report is submitted in accordance with 10 CFR 50.73 subparts (a)(2)(iv) and (a)(2)(v)(D), and this event posed no threat to the public health and safety.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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REASON FOR SUPPLEMENT

This report is being submitted to meet our commitment to supplement the original report. At the time the original report was submitted, the cause for the failure of the automatic voltage regulator had not been determined. The manufacturer's failure analysis report has since been issued and the results are included in the CAUSE section of this report.

BACKGROUND

The Auxiliary Power Distribution System (APDS) consists of six 4160 VAC buses. The APDS is divided into emergency service (Buses A5 and A6) and normal service (Buses A1, A2, A3, A4). Buses A5 and A6 supply power to essential loads required during normal operations and abnormal operational transients and accidents. Buses A1, A2, A3, A4 supply power to other station auxiliaries during planned operations. Power is distributed to the six 4160 VAC buses during normal operation from either the unit source (Unit Auxiliary Transformer) or the preferred offsite source (Startup Transformer). The preferred power source is used to supply the 4160 VAC buses during normal startup and shutdown. After the main generator has been synchronized to the 345 KV transmission system, the 4160 VAC buses are transferred from the preferred power source to the unit power source. The 4160 VAC emergency service Buses A5 and A6 can also be supplied from the standby power source (EDG 'A' and 'B') or the secondary power source (Shutdown Transformer).

Power from the 4160 VAC buses is fed to 4160 VAC powered loads and, through load center transformers, to 480 VAC load center buses. Bus A5 feeds 4160 VAC power to the motors of the Control Rod Drive (CRD) System pump 'A', Residual Heat Removal (RHR) System Loop 'A' pumps (P-203A/C), Core Spray (CS) System Loop 'A' pump (P-215A), and via transformer X-21 feeds 480 VAC power to Bus B1. Similarly, Bus A6 feeds 4160 VAC power to the motors of the CRD pump 'B', RHR Loop 'B' pumps (P-203B/D), Core Spray Loop 'B' pump (P-215B), and via transformer X-22 feeds 480 VAC power to Bus B2. Bus B6 is a swing type bus that can be powered by either B1 or B2, and is normally aligned to Bus B1. Bus B6 was aligned to Bus B1 at the time of the event. Power from the 480 buses is fed to motors and to motor control centers (MCCs). Power from the MCCs is fed to other motors, motor operators, and power panels.

Located at the end of this report is a Figure that depicts a simplified single line diagram of a portion of the APDS including Buses A5 and A6. The diagram does not depict feeder breakers A801 (152-801) and A802 (152-802) that are located on the Blackout Diesel Generator and Shutdown Transformer side of breaker 152-600.

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The EDG 'B' was being surveillance tested as required by Technical Specification 3.9.B.1 because the Shutdown Transformer (SDT) became inoperable on March 24, 1991 at 2300 hours. This was the result of the actuation of lockout relay 186-5 that occurred due to a solar induced disturbance on the offsite 23 KV distribution system. When the SDT became de-energized, the offsite 345 KV transmission system lines 342 and 355 were energized, the 345 KV switchyard air circuit breakers were closed, the Startup Transformer (SUT) was operable, the EDGs 'A' and 'B' were operable, and the 4160 VAC Auxiliary Power Distribution System (including emergency Buses A5 and A6) was energized via the Unit Auxiliary Transformer (UAT). The EDG 'B' was being tested per procedure 8.9.1 (Rev. 28), "Emergency Diesel Generator Surveillance", section 8.2. The event occurred while the EDG 'B' was fully loaded at approximately 2600 KW and synchronized to bus A6 in parallel with the Unit Auxiliary Transformer, after being loaded for approximately 15 minutes.

EVENT DESCRIPTION

On March 25, 1991 at 0610 hours, an automatic actuation of lockout relay 186-A6 followed by a trip of the Emergency Diesel Generator (EDG) 'B' output breaker A609 (152-609) occurred during an unscheduled Technical Specification required surveillance test of the EDG 'B'. The EDG 'B' became inoperable, a loss of AC power to Bus A6 and related sources of AC power to Train 'B' components of safety systems occurred, a trip of the Recirculation System motor-generator (MG) set/pump 'B' occurred, and actuations of portions of the Primary Containment and Reactor Building Isolation Control Systems occurred. These occurrences were the result of the actuation of lockout relay 186-A6.

The loss of power to 4160 VAC Bus A6 resulted in a loss of power to the following:

- The 4160 VAC motors of CRD pump 'B', RHR pumps 'B' and 'D', Core Spray pump 'B'.

  480 VAC load center Bus B2 and its related loads:

  - Turbine Building Closed Cooling Water (TBCCW) System Loop 'B' pump (P-110B)
  - 480 VAC MCC-B14 including:
    - 125 VDC Battery charger 'B'. The 125 VDC Battery 'B' was subsequently aligned to the backup battery charger (powered from Bus B6) at 0641 hours.
    - 250 VDC normal battery charger. The 250 VDC Battery was subsequently aligned to the backup battery charger (powered from Bus B6) at 0641 hours.

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- Standby Gas Treatment System (SGTS) Train 'B' heater (VGTF-201B) and exhaust fan (VEX-210B). This caused the SGTS Train 'B' to be inoperable.

- Control Room High Efficiency Air Filtration System (CRHEAFS) Train 'B' air inlet filter heater (VCRF-101B). This caused the CRHEAFS Train 'B' to be inoperable.

- High Pressure Coolant Injection (HPCI) turbine exhaust vacuum containment isolation valve MO-2301-34.

- Reactor Building Closed Cooling Water (RBCCW) System loop 'B' pumps (P-202D/E/F). This caused the Containment Cooling System Loop 'B' to be inoperable. The RBCCW Loops 'A' and 'B' were then cross-tied at 0611 hours.

- RBCCW System Loop 'B' heat exchanger discharge valve (MO-3806)

- Salt Service Water (SSW) System Loop 'B' pumps (P-208D/E). This also caused the Containment Cooling System Loop 'B' to be inoperable.

- Diesel Fuel Oil Transfer System 'B' pump (P-141B)

- Reactor Feedpump 'B' auxiliary oil pump (P-152B)

- Battery Room 'B' exhaust fan (VEX-103B)

- TBCCW System Loop 'B' heat exchanger discharge valve (MO-3805)

* 480 VAC MCC-B18 including:

  - EDG 'B' auxiliary panel (C-104A)

  - EDG 'B' compartment supply fan (VSF-208B) and exhaust fan (VEX-214B)

  - Drywell Train 'B' unit coolers (VAC-205A2/B2/C2/D2/E2/F2 and VAC-206A2/B2)

  - HPCI compartment unit coolers (VAC-201A/B). This caused the HPCI System to be administratively inoperable but was maintained in standby service.

  - RHR/Core Spray compartment 'B' unit coolers (VAC-204C/D)

  - CRD compartment Train 'B' unit cooler (VAC-203B)

  - Core Spray Loop 'B' valves (MO-1400-3B,-4B,-24B,-25B). This caused the Core Spray Loop 'B' to be inoperable.

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

- RHR Loop 'B' Suppression Pool suction valves (MO-1001-7B/D), Drywell Spray valves (MO-1001-23B and -26B), Heat Exchanger bypass valve (MO-1001-16B), pumps minimum flow valve (MO-1001-18B). This caused the RHR Loop 'B' to be inoperable for the Suppression Pool Cooling and Drywell Spray modes.

- RCIC turbine steam supply isolation valve (MO-1301-16)

- RHR Loop 'B' Suppression Pool Cooling/Suppression Chamber Spray block valve (MO-1001-34B), Suppression Pool Cooling valve (MO-1001-36B), Suppression Chamber Spray valve (MO-1001-37B). This also caused the RHR Loop 'B' to be inoperable for the Suppression Pool Cooling and Drywell Spray modes.

- RHR Loop 'B' Shutdown Cooling suction valves (MO-1001-43B/D). This caused the RHR Loop 'B' to be inoperable for the nonsafety related Shutdown Cooling mode.

- Standby Liquid Control (SBLC) System pump 'B' (P-207B)

- RBCCW valves:

    - MO-4010A/B (RHR Loop 'B' heat exchanger isolation)

    - MO-4009A/B (RBCCW Loops 'A'/'B' non-essential loads isolation)

    - MO-4002 (Drywell Trains 'A'/'B' and Recirculation System Loops 'A'/'B' coolers return line isolation)

    - MO-4083 (RBCCW Loop 'B' heat exchanger bypass)

- Power supply (Y7) for the following:

    - Suppression Pool water level and temperature monitoring (Panel C-165)

    - MCC-B18 air conditioning units (VRC-203A/B) and condenser units (VCC-203A/B)

    - MCC-B18 fan/damper control (Panel C-249)

- Recirculation System MG set 'B' auxiliary oil pumps (P-225A/B). This resulted in a lockout and trip of the recirculation MG set/pump 'B'. The speed of the MG set/pump 'A' was then gradually decreased manually to approximately 30 percent.

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- Suppression Chamber Train 'B' circulating fan (VEX-207B)
- Reactor Water Cleanup (RWCU) System recirculation pump 'B' (P-204B)
- CRHEAFS Train 'B' supply fan (VSF-103B). This also caused the CRHEAFS Train 'B' to be inoperable.
- Safeguard 120 VAC Train 'B' (Control Power Supply-Panels Y4 and Y41)

- 480 VAC MCC-B2B including:
  - Main Stack Dilution Fan 'A' (VSF-206A)
  - Main Stack Dilution Air Heaters 'A' and 'B'
  - Main Stack Exhaust Fan (VEX-209)
  - Electric Unit Heaters (VEUH-201A/B/C)

The loss of safeguard 120 VAC Train 'B' power from Panel Y4 to 120 VAC powered relays located in Panel C-942 resulted in actuations of portions of the Primary Containment Isolation Control System (PCIS) and Reactor Building Isolation Control System (RBIS).

The PCIS actuation resulted in the following responses:

- The Train 'B' Primary Containment System (PCS) Group 2/Sampling System isolation valves that were open closed automatically.
- The inboard and outboard PCS Group 3/RHR System isolation valves, in the closed position, remained closed.
- The outboard PCS Group 6/RWCU System isolation valves MO-1201-5 and -80, in the open position, closed automatically.

The RBIS actuation resulted in the following responses:

- The Train 'B' Secondary Containment System (SCS)/Reactor Building supply and exhaust ventilation dampers, in the open position, closed automatically.
- The SCS/SGTS Train 'B' exhaust fan (VEX-201B) did not start because it was de-energized. The SCS/SGTS Train 'A' exhaust fan was started manually by a utility licensed operator to maintain a negative pressure within the Reactor Building.

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LICENSEE EVENT REPORT (LER)
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APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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

Failure and Malfunction Report 91-97 was written to document the event. The NRC Operations Center was notified in accordance with 10 CFR 50.72 subparts (b)(2)(ii) and (b)(2)(iii) on March 25, 1991 at 0840 hours. Nine 24 hour Technical Specification Limiting Conditions for Operation (LCOs) and a 24 hour LCO for Facility Operating License condition 3.E were entered as a result of the event.

This event occurred during power operation while at 100 percent reactor power. The reactor mode selector switch was in the RUN position. The Reactor Vessel (RV) pressure was 1035 psig with the RV water temperature at 548 degrees Fahrenheit.

Verbal and written requests for a waiver of compliance of Facility Operating License condition 3.E (single recirculation loop operation) and the 24 hour Technical Specification LCOs were made to the NRC to permit restoration of electrical power to Bus A6 and related loads. The written requests were documented in Boston Edison Company Letters 91-041 (March 25, 1991) and 91-051 (March 26, 1991). The NRC granted a one-time waiver of compliance that conditionally extended the 24 hour limit of license condition 3.E and the 24 hour Technical Specification LCOs. The waiver of compliance was documented in an NRC Letter dated March 27, 1991. The waiver for Facility Operating License condition 3.E and the 24 hour Technical Specification LCOs was not invoked because the LCOs were terminated by 2300 hours on March 25, 1991 and the Recirculation System MG set/pump 'B' was returned to service on March 26, 1991 at 0043 hours.

CAUSE

The cause for the actuation of lockout relay 186-A6 was an overcurrent condition sensed by protective devices for phase 'B' of feeder breaker A605. The overcurrent condition was the result of a failure of the EDG 'B' automatic voltage regulator (AVR) that occurred during the surveillance test (8.9.1) while EDG 'B' was loaded on Bus A6. The voltage regulator was manufactured by the Basler Electric Company, model number SV..13C382B1B, serial number 9047500105. The cause for the failure of the AVR was the failure of the AVR magnetic amplifier (L1) that was due to low insulation resistance. A manufacturer search of its production failure data and returned materials data indicated the failure was an isolated occurrence. A possible contributor to the failure was the range of EDG 'B' room temperatures that have been greater than the range of EDG 'A' room temperatures. A comparison of EDG 'A' and 'B' room temperatures during 1990 revealed EDG 'B' room temperatures approximately 10 degrees Fahrenheit higher during the Summer months and approximately 15 degrees lower during the Winter months. The EDG 'B' AVR, like the EDG 'A' AVR, is within a panel located in the respective EDG room. The components of the normal ventilation system for the EDG 'A' and 'B' rooms are included in the preventive maintenance program. However, a calibration frequency has not been established and calibration procedures have not been developed for those components.

The cause for the loss of power to Bus A6 and related loads was the actuation of lockout relay 186-A6. Actuation of lockout relay 186-A6 results in a trip signal to feeder breakers A601/A604/A605 to Bus A6. For this actuation of lockout relay 186-A6, the EDG 'B' output breaker A609 (152-609) to Bus A6 was in the closed position for surveillance testing at the time of the actuation and remained closed as designed.

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The cause for the trip of EDG 'B' output breaker A609 was an overspeed condition of the diesel engine of EDG 'B'. The overspeed trip occurred at approximately 1090 k... igned and was the result of the actuation of lockout relay 186-A6. When the lockout relay actuated and tripped feeder breaker A605 to Bus A6, the EDG 'B' oversped due to the sudden load reduction and the automatic voltage regulator failure that affected the EDG 'B' engine governor control. The overspeed condition caused the EDG 'B' overspeed relay (OSR) to actuate the EDG 'B' shutdown relay (SDR) that resulted in the trip of breaker A609 (152-609) as designed.

CORRECTIVE ACTION

The CRHEAFS Train 'A' was surveillance tested in accordance with procedure 8.7.2.7 and was completed with satisfactory results on March 25, 1991 at 1215 hours.

The SBLC System pump 'A' was surveillance tested in accordance with procedure 8.4.1 and was completed with satisfactory results on March 25, 1991 at 1356 hours.

The following actions were taken prior to re-energizing Bus A6:

* The cause for the actuation of lockout relay 186-A6 was identified.

* Bus A6 was meggered in accordance with procedure 3.M.3-4, "Insulation Test", with satisfactory as-found results.

* Lockout relay 186-A6 was reset in accordance with Procedure 1.3.11 (Rev. 9), "Reset of Lock-Out Relays and Protective Relay Targets", on March 25, 1991 at approximately 1400 hours.

* Bus A6 was re-energized on March 25, 1991 at 1413 hours.

* Feeder Breaker A608 (152-608) to transformer X-22 was opened and the primary and secondary sides (4160 VAC/480 VAC) of transformer X-22 were meggered in accordance with procedure 3.M.3-4 with satisfactory as-found results.

* Feeder breaker A608 (152-608) was closed and Buses B2, B14, B18, B28 and related loads were re-energized by approximately 1900 hours on March 25, 1990.

The following actions were taken after Buses A6 and B2 (and related loads) were re-energized:

* The safeguards 120 VAC Train 'B' power was restored at 1918 hours.

* The PCIS and RBIS were reset on March 25, 1991 at approximately 1930 hours and the affected systems were returned to normal service.

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

- The Recirculation System MG set/pump 'B' was restarted on March 26, 1990 at 0043 hours and the 24 hour LCO for license condition 3.E was terminated. The start resulted in a trip of the 125 VDC/120 VAC inverters of the RCIC System and HPCI System. LER 50-293/91-006 was written regarding the trip of the inverters. The inverters were reset at 0052 hours. The 125 VDC Battery 'B' and 250 VDC Battery were subsequently aligned to their normal battery chargers at approximately 1840 hours.

The 24 hour Technical Specification LCOs were terminated by 2300 hours on March 25, 1991.

The SDT lockout relay (186-5) was reset in accordance with procedure 1.3.11 and the SDT was re-energized on March 27, 1991 at 2100 hours.

EDG 'A' was surveillance tested in accordance with procedure 8.9.1 and was completed with satisfactory results on March 25, 1991 at 0502 hours (just prior to the event), March 26, 1991 at 0703 hours, and March 27, 1991 at 0558 hours.

The following actions were taken prior to operability testing of the EDG 'B':

- The automatic voltage regulator was replaced.
- The generator windings were meggered with satisfactory as-found results.
- The EDG 'B' and automatic voltage regulator was post work tested in accordance with procedure TP 91-030 (Rev. 0), Post Maintenance Testing of 'B' Diesel Generator to A6". Essentially, TP 91-030 duplicates EDG 'B' surveillance testing that is performed per procedure 8.9.1 (Rev. 28) section 8.2. The test (TP 91-030) included additional administrative controls to preclude a loss of power to Bus A6 if a malfunction were to occur during the test. The test began on March 28, 1991 at 0413 hours and was completed with satisfactory results at 0539 hours. The review of test data was completed at approximately 0615 hours.

The EDG 'B' was tested in accordance with procedure 8.9.1 (Rev. 28) with satisfactory results. The test began on March 28, 1991 at approximately 0615 hours. The LCO for EDG 'B' was terminated on March 28, 1991 at approximately 0915 hours.

Temporary Modification 91-22 (Rev. 0) was prepared and approved on March 25, 1991. Essentially, the modification provided for energizing the circuit that controls the RHR/Shutdown Cooling suction line isolation valves while Panels Y4 and C-942 were de-energized. This action was taken as a contingency measure and its implementation was not necessary because 120 VAC power was restored to Panel C-942 (via Panel Y4) on March 25, 1991 at 1918 hours.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1	— 0 0 5 —	0 1	1 0 OF 1 2

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

PREVENTIVE ACTION

Procedures 2.4.25 (Rev. 13), "Loss of Shutdown Cooling", 5.3.18 (Rev. 5), "Loss of 120 VAC Safeguard Bus Y3", and 5.3.19 (Rev. 5), "Loss of 120 VAC Safeguard Bus Y4", have been revised. Procedure 2.4.25 (now Rev. 14) directs operator actions to procedures 5.3.18 or 5.3.19 if a loss of shutdown cooling occurs because of a loss of the supply power to Panel Y3 or Y4. Attachments 1 and 2 were added to Procedures 5.3.18 (now Rev. 6) and 5.3.19 (now Rev. 6). Essentially, these attachments reflect the actions that would have been taken if Temporary Modification 91-22 had been implemented.

A calibration frequency will be established and calibration procedures will be developed for applicable components of the normal ventilation system for the EDG 'A' and 'B' rooms.

Procedure 2.1.12.1 (currently Rev. 8), "Emergency Diesel Generator Daily Surveillance", is performed to record critical EDG 'A' and 'B' parameters including room temperature. The procedure will be reviewed for possible improvement. The focus of the review will be to ensure appropriate EDG 'A' and 'B' room temperatures and initiate applicable corrective action if necessary.

SAFETY CONSEQUENCES

This event posed no threat to the public health and safety.

The Core Standby Cooling System (CSCS) consists of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and RHR System (LPCI mode). Although not a CSCS system, the RCIC System is capable of providing high pressure water to the Reactor Vessel for core cooling. In the event the HPCI System had received an initiation signal while Bus A6 and its related loads were de-energized, the system was capable of starting to provide high pressure water for core cooling. If the HPCI compartment temperatures had subsequently increased sufficiently to initiate an automatic trip of the HPCI turbine/pump, the RCIC System was operable and capable of providing high pressure water for core cooling. In the unlikely event the RCIC System became inoperable while the HPCI System was not available, an automatic (or manual) actuation of the ADS would reduce Reactor Vessel pressure for low pressure core cooling provided independently by the Core Spray System (Loop 'A') and RHR/LPCI mode (Loop 'A').

Bus A6 and related loads were de-energized on March 25, 1991 at 0610 hours. During the period Bus A6 and related loads were de-energized, the redundant Bus A5 and its related loads were energized and operable. Bus A6 and related loads were de-energized for a period of approximately 15 hours. Based on the Pilgrim Station probabilistic model, an assessment for continued plant operation versus a plant shutdown concluded the margin of safety for plant operation up to 48 hours in this mode would not be significantly less than that for a plant shutdown.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1 — 0 0 5 — 0 1	1 1 OF 1 2

This report is submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the PCIS and RBIS actuations, although a designed response to a loss of power to the relays of the affected circuitry, were not planned.

This report is also submitted in accordance with 10 CFR 50.73(a)(2)(v)(D) because the HPCI compartment unit coolers were de-energized and inoperable for their cooling function in the event of an actuation of the HPCI System.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station LERs submitted since January 1984. The review focused on LERs involving a failure of EDG 'A' or 'B', or their voltage regulators. The review revealed no previous failure of EDG 'A' or 'B', or their voltage regulators. Review of Failure and Malfunction Reports for similarity revealed that voltage oscillations had occurred during previous EDG 'B' surveillance testing (Procedure 8.9.1). The root cause was a dirty motor operated potentiometer that was due to its enclosure cover not being installed for an unidentifiable period of time. The potentiometer was cleaned and the cover was installed. The potentiometer is physically separate from the voltage regulator.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

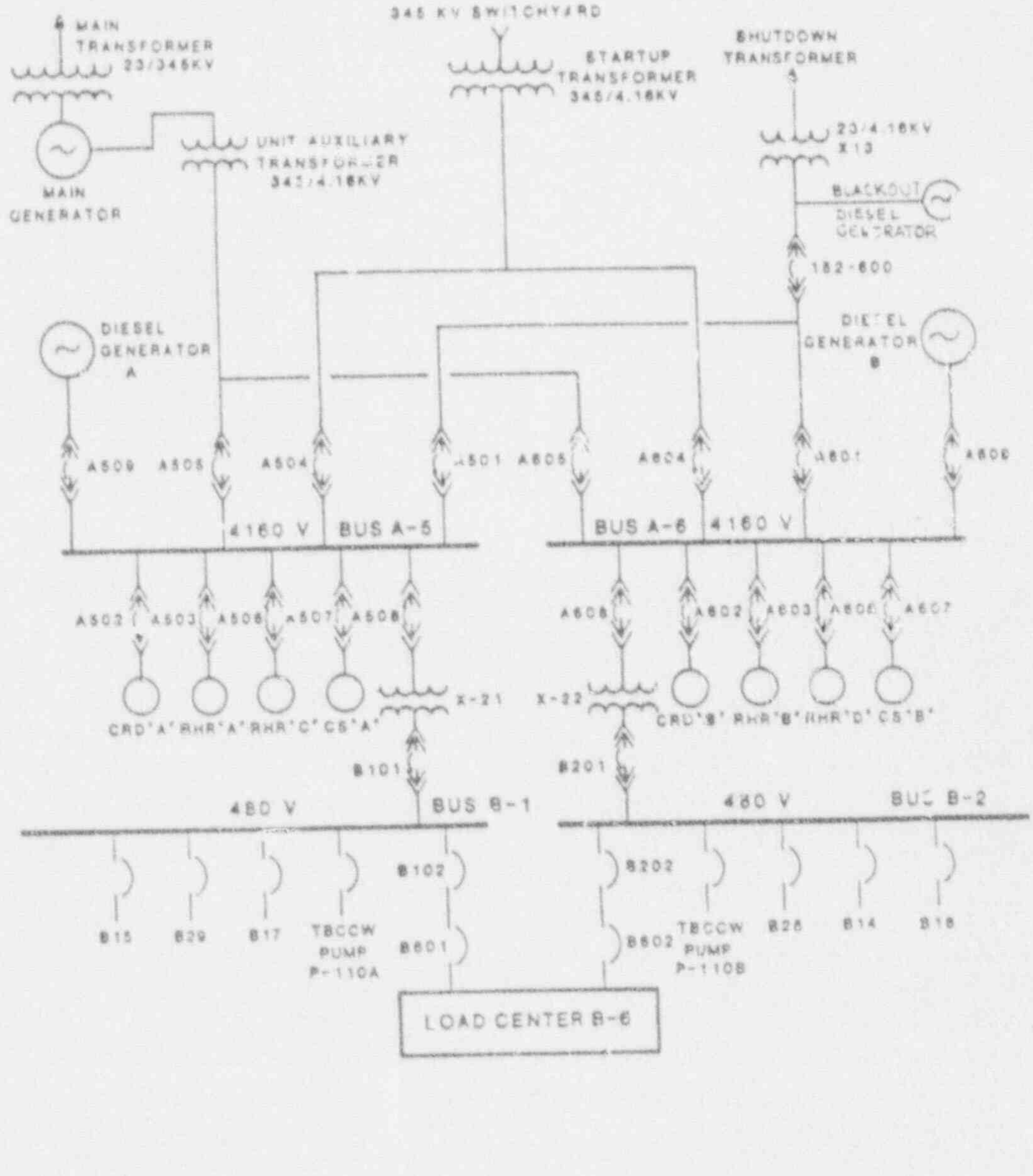
The EIIS codes for this report are as follows:

COMPONENTS	CODES
Amplifier (L1)	AMP
Breaker (152-605)	BKR
Bus (A6)	BU
Regulator (Voltage Regulator)	RG
Relay, Locking Out (186-5, 186-A6)	86
Transformer	XFMR

SYSTEMS	
Component Cooling System (RBCCW/TBCCW)	CC
Control Complex Environmental Control System (CRHEAFS)	VI
Control Rod Drive (CRD) System	AA
Core Spray System	BM
Emergency Onsite Power Supply System (EDG)	EK
Engineered Safety Features Actuation System (PCIS/RBIS)	JE
Essential Service Water System (SSW)	BI
High Pressure Coolant Injection (HPCI) System	BJ
Low Voltage Power System - Class 1E	ED
Medium Power System - Class 1E	EB
Reactor Core Isolation Cooling (RCIC) System	BN
Reactor Recirculation System	AD
Reactor Water Cleanup (RWCU) System	CE
Residual Heat Removal (RHR) System	BO
Standby Gas Treatment System (SGTS)	BH
Standby Liquid Control (SBLC) System	BR

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	9 1 — 0 0 5 — 0 1	1 2 OF 1 2



EMERGENCY AC DISTRIBUTION

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	302/91-018
Event Description:	Engineered safeguards actuation inappropriately bypassed
Date of Event:	December 8, 1991
Plant:	Crystal River 3

Summary

During a plant startup and while at ~15% power, the pressurizer spray valve opened but did not close after pressurizer pressure was reduced. Reactor coolant system (RCS) pressure decreased, and a reactor scram occurred. Prior to reaching the engineered safeguards (ES) setpoint, ES was bypassed. This action was inappropriate, since the cause of the RCS depressurization had not been determined.

Event Description

On December 8, 1991, Crystal River 3 was being returned to power following a reactor trip and maintenance outage. With the plant at ~15% power, the pressurizer spray valve, RCV-14, failed to close and resulted in a decrease in RCS pressure over the next 19 min. Valve position indicated "closed" when the valve opened and remained "closed" when it failed to reseat. Manual closure of RCV-14 was attempted without success. A variety of reasons for the RCS pressure decrease were discussed by the operators (pressurizer heater failure, secondary-side induced overcooling, and loss-of-coolant accident) but the cause of the pressure decrease remained indeterminate.

At the end of the 19 min period, RCS pressure decreased to the 1800 psi low RCS pressure trip setpoint, resulting in a reactor trip. Following the reactor trip, RCS pressure still did not stabilize. Three minutes later, RCS pressure had decreased another 100 psi to 1700 psi. Prior to the RCS reaching 1500 psi, both trains of high-pressure injection (HPI) were bypassed. This action was inappropriate since the cause of the RCS pressure decrease had not been diagnosed.

Two of the three ES low RCS pressure bistables tripped at 1500 psi, and the Senior Reactor Operator ordered the bypass removed. Once this was done, full HPI actuation occurred automatically.

HPI flow occurred for ~2 min before it was terminated. RCS pressure again began to decrease, and makeup flow was increased to recover RCS pressure. Forty-six minutes after the trip, the reason had still not been determined for the continuing loss of RCS pressure. A decision was made to close the pressurizer spray block valve. RCS pressure recovered. Stable RCS and pressurizer conditions were achieved, terminating the event.

ASP Modeling Approach and Assumptions

This event has not been modeled as an accident sequence precursor.

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

JAN 24 1992 BW

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	1 OF 0 5

TITLE (4): Reduction in Reactor Coolant System Pressure Due to Failure of Pressurizer Spray Valve and Associated Position Indication Results in Actuation of Reactor Protection System and Engineered Safeguards

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
1 2	0 8	9 1	9 1	— 0 2 8	— 0 0	0 1	0 7	9 2	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 1 5

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

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE	
W. A. Stephenson, Nuclear Safety Supervisor	9 0 4	7 9 5 - 6 4 8 6

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	A B	A B V	W 0 3 0	Yes					
D	A B	A B V	W 0 8 8	No					

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 2	0 17	9 2

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

On December 8, 1991, Crystal River Unit 3 was being returned to power operation. As reactor power was being increased from 11% RATED THERMAL POWER (RTP) to 15% RTP, Reactor Coolant System (RCS) pressure increased to the open setpoint for the Pressurizer Spray Valve, RCV-14. RCV-14 opened; however, the "closed" indicating lamp did not extinguish. On decreasing RCS pressure, RCV-14 did not close, resulting in a continued slow decrease in RCS pressure. Prior to RCS pressure reaching the Engineered Safeguards (ES) actuation setpoint, an operator inappropriately bypassed ES. Shift supervision directed ES out of bypass and ES actuation was initiated. After ES was reset, a plan was implemented which bypassed ES and used High Pressure Injection to raise RCS pressure. RCV-14 was manually isolated, terminating the event. The plant was placed in MODE 5 (COLD SHUTDOWN) and RCV-14 was repaired and tested satisfactorily. Plant Maintenance Procedures are being revised to preclude recurrence of this type of Motor Operated Valve failure. Administrative guidance has been developed on the bypassing of ES actuation signals.

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NRC Form 366 (6-89)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 1	— 0 1 8 —	0 0	0 2 OF 0 5

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

EVENT DESCRIPTION

On December 8 1991, Crystal River Unit 3 was being returned to power operation following a reactor trip on December 3 and a short maintenance outage to repair excore Nuclear Instrumentation (NI)[IG]. The plant was operating in MODE 1 (POWER OPERATION) at 11% RATED THERMAL POWER (RTP) and power was being slowly raised. At 0247, power was increased from 11% RTP to approximately 12% RTP. At 0249, power was again increased, this time from approximately 12% RTP to approximately 14% RTP. During each of these power increases, Reactor Coolant System (RCS) [AB] pressure increased to the 2205 psig setpoint for opening of the Pressurizer Spray Valve, RCV-14 [AB,V]. The "closed" indicating lamp [IL] did not extinguish in either instance. RCV-14 [AB,V] failed to close, resulting in a steady decrease in RCS [AB] pressure over the next 19 minutes. Troubleshooting strategies in the control room during this time period included taking manual control of RCV-14 [AB,V] and selecting it to the "closed" position. This was done despite the fact that the spray valve indication never changed from indicating full closure of the valve which had led the operators to believe it had not opened. Control room operators also looked for symptoms of a Loss of Coolant Accident (LOCA) and pressurizer heater failures. The operators concluded that a LOCA was not in progress, however they still suspected that the pressurizer heaters were not functioning normally. They also evaluated the possibility that the continuing RCS [AB] depressurization might be the result of a secondary plant induced overcooling of the RCS [AB]. This was based on secondary plant anomalies which existed just prior to the onset of the transient. At 0308, RCS pressure decreased to the Reactor Protection System (RPS) [JC] low RCS pressure setpoint of 1800 psig, resulting in a reactor trip.

Following the reactor trip, RCS [AB] pressure did not recover as expected. By 0311, RCS [AB] pressure had decreased below 1700 psig and the permissive to manually bypass automatic High Pressure Injection (HPI) [BQ] actuation had been met. Prior to reaching 1500 psig, one of the control room operators announced and bypassed both trains of HPI [BQ] but did not receive permission nor was his announcement acknowledged although operator interviews indicated that the Senior Reactor Operator (SRO) on duty was aware of the bypass. This action, taken at approximately 0313, was inappropriate since the reason for the ongoing RCS depressurization had not yet been diagnosed and management concurrence with the ES bypass had not been obtained. The acting Operations Superintendent, after completing phone notification of the Plant Manager, recognized that the operator had bypassed ES and recommended, to the SRO on duty, removal of the bypass. While this action was being discussed, two of three ES low RCS pressure (1500 psig) bistables tripped and the SRO on duty immediately ordered the bypass removed, at which time full HPI actuation occurred automatically. The Emergency Feedwater Initiation and Control (EFIC) [JG] System was also actuated by the HPI signals, resulting in the automatic start of both Emergency Feedwater (EFW) pumps [BA,P]. Both pumps were subsequently shutdown when Main Feedwater (MFW) flow was verified to be acceptable.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 1	0 1 8	0 0	0 3 OF 0 5

Full HPI [BQ] flow to the RCS occurred for approximately one minute, after which the system was once again placed in ES bypass, per the procedure, so that equipment could be manually controlled. HPI [BQ] flow continued for approximately another minute and was then terminated due to the rapid recovery in RCS pressure. The ES bistables were then reset to arm the HPI System [BQ] for reactuation. Following the termination of HPI, RCS pressure again began to decrease due to RCV-14 [AB,V] still being open. At approximately 0335, one of the three ES 1500# bistables tripped. As RCS pressure decreased to a minimum value of 1503 psig on the Loop "A" Wide Range indication, considerable discussion by the control room crew led to a plan to bypass ES, since a full actuation was not necessary based on observed indications, and to increase makeup flow into the RCS [AB] by opening HPI Valve MUV-24 [BQ,ISV]. This action was taken at approximately 0343. Over the next 10 minutes, RCS pressure gradually recovered as the increased makeup flow filled the pressurizer and compressed the pressurizer steam bubble.

After RCS pressure had increased to approximately 1700 psig, MUV-24 was closed. It had been anticipated that pressurizer temperature would eventually stabilize as the event progressed, however, pressurizer temperature continued to slowly decrease. At 0354, it was decided to close the Pressurizer Spray Block Valve [AB,ISV]. RCS pressure began to quickly recover. Stable RCS conditions were achieved (RCS pressure at 2155 psig, RCS temperature at 537°F, and pressurizer level at 100 inches), terminating the event.

An Unusual Event (UE) was declared based on a valid ES actuation and the Emergency Plan was entered at approximately 0455. Appropriate notifications of the state and the NRC were made within 15 minutes pursuant to 10CFR50.72(a)(3). The UE declaration was untimely since the automatic ES actuation occurred at 0319 and the emergency was not declared until 0455. Once the emergency was declared, all notifications were made within required times.

This event constitutes an ES actuation and is, therefore, being reported in accordance with 10CFR50.73(a)(2)(iv).

CAUSE OF EVENT

The cause of this event was the failure of RCV-14. The failure was compounded by the concurrent failure of the position indication for the valve. RCV-14 is a Walworth 2.5-inch, vertical body, vertical stem, stainless steel pressure seal globe valve. The motor operator for RCV-14 is a Limitorque Actuator Type SMB-00, rated at 15 ft-lb, with a 1 horsepower 460VAC motor.

RCV-14 failed to close in both the manual and automatic modes of operation because the middle ring of braided packing had become wedged between the valve stem and both the carbon spacer ring and the lantern ring located directly below the packing. The wedging action created an extremely high running load such that when the valve was required to close, the close contacts on the torque switch opened,

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (8) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 1	— 0 1 8 —	0 0	0 4 OF 0 5

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

effectively removing power to the valve's motor operator. The root cause for the damage experienced by the middle braided ring of packing has not been determined. The false RCV-14 position indication can be directly attributed to a missing valve stem anti-rotation key and retaining bolt. The function of the anti-rotation key was to prevent stem rotation during valve actuation. Once the stem was free to rotate during valve actuation, the initial timing established during Motor-Operated Valve (MOV) testing between the stem's position and the geared limit switch was lost. Each successive operation of the valve served to increase the error in position indication. Inspection of RCV-14 after disassembly showed the valve stem to be within 1/32 inch from the back seat (near fully open) despite the fact that the Main Control Board "closed" indicating light was illuminated.

The administrative guidance for initiating a manual bypass of ES was inadequate, thus resulting in the inappropriate bypassing of HPI prior to automatic initiation.

EVENT ANALYSIS

All emergency systems actuated appropriately and functioned as designed: RPS actuated due to a low RCS pressure signal of 1800 psig and all full length rods inserted; ES actuated at 1500 psig RCS pressure, initiating full HPI on both ES trains; and the ES block loading sequence proceeded as appropriate with no abnormalities. The HPI actuation also initiated EFW flow via EFIC actuation. With MFW available and adequate subcooling margin maintained throughout the event, EFW was not needed and was secured.

Although this event is not specifically addressed or analyzed in the Final Safety Analysis Report (FSAR), the relevant analyses (Chapter 6 - "Engineered Safeguards" and Chapter 14 - "Safety Analysis") indicate that as long as adequate Subcooling Margin (SCM) is maintained during an RCS depressurization event, the integrity of the core is not compromised from a lack of adequate core cooling. Since adequate SCM was maintained throughout this event, there was never any threat of inadequate core cooling.

No steam was released to the environment through the Main Steam Safety Valves or Atmospheric Dump Valves due to the low core power level at the onset of the event and the associated low decay heat load. There was never any threat to the general public or site personnel during this event.

CORRECTIVE ACTION

The plant was placed in MODE 5 (COLD SHUTDOWN) and RCV-14 was repaired and tested satisfactorily. A comprehensive failure analysis of RCV-14 was performed, addressing all mechanical and electrical aspects of the valve failure. As a result of the failure analysis, the appropriate maintenance procedure has been revised to ensure proper installation of the valve stem anti-rotation key. Additionally, all MOVs are being reviewed for anti-rotation device applicability. This includes an

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 1	— 0 1 8 —	0 0	0 5 OF 0 5

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

in depth review of testing and/or maintenance history files for indications of anti-rotation devices not being installed. Other applicable Maintenance Procedures will be revised as necessary to address the installation of anti-rotation devices as required by the specific valve design.

Training is being developed to provide direction regarding identifying and distinguishing between RCS overcooling and depressurization events, the steps to be taken to stabilize the plant in each instance, and the appropriate bypassing of ES. This training will be presented in the next cycle of Licensed Operator Requalification Training. Administrative guidance has been developed to provide direction for the appropriate bypassing of ES actuation signals.

PREVIOUS SIMILAR EVENTS

There has been no previous instance where a malfunction of RCV-14 resulted in automatic actuation of either the RPS or ES system. However, there have been three similar failures of RCV-14.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	327/91-020
Event Description:	Loss of fire protection system
Date of Event:	July 22, 1[illegible]
Plant:	Sequoyah 1

Summary

All fire protection spray and sprinkler systems and hose stations were unavailable for ~7.5 h, when the high-pressure fire protection (HPFP) system was inappropriately aligned for testing without knowledge of the control room operators.

Event Description

While Sequoyah 1 was operating at 100% reactor power, the fire protection spray and sprinkler systems and the fire hose stations were declared inoperable when pressure was lost in the fire suppression water system headers. Failure of assistant unit operators to follow approved plant procedures following surveillance activities had resulted in a system configuration in which an open flowpath existed from the fire suppression water system headers to a test drain. This configuration resulted from failure to close valve 2-26-575, the auxiliary building HPFP system supply valve. Failure to comply with procedures demanding main control room notification of the fire pump 2B-B performance test was a factor in nondiscovery of the misconfiguration. In combination with an open fire pump test header isolation valve, a direct path from the 2B-B fire pump to the 10-in. test discharge valve had been established. This resulted in loss of header pressure, with the consequent inoperability of the spray and sprinkler systems, and of the fire hose stations.

The incorrect valve configuration of the HPFP was undetected for approximately 5.5 h. About 3.5 h elapsed during which the system was discovered to be degraded (through gradual loss of system pressure) but without knowledge of the cause. System pressure was restored approximately 2 h following discovery of the open valve.

Additional Event-Related Information

Additional fire protection capacity is provided by offsite contractor pumpers.

Loss of HPFP also impacted the system's ability to provide emergency feedwater to the RCS steam generators as would be required under flood conditions.

ASP Modeling Approach and Assumptions

This event has not been modeled as an accident sequence precursor.

NRC Form 366
(6-89)

U.S. NUCLEAR REGULATORY COMMISSION

Approved OMB No. 3150-0104
Expires 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Sequoyah Nuclear Plant, Unit 1

DOCKET NUMBER (2): 0|5|0|0|0|3|2|7

PAGE (3): 1 OF 0 [illegible]

TITLE (4): Action Provisions of LCOs 3.7.11.2 and 3.7.11.4 Could Not Be Complied with Following the Loss of Fire Suppression Water System Pressure

EVENT DAY (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	2 2	9 1	9 1	0 2 0	0 0	0 [illegible]	2 1	9 1	Sequoyah, Unit 2	0|5|0|0|0|3|2|8
										0|5|0|0|0| |

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

___ 20.402(b)	___ 20.405(c)	___ 50.73(a)(2)(iv)	___ 73.71(b)
___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	XX OTHER (Specify in Abstract below and in Text, NRC Form 366A)
___ 20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: Russell R. Thompson, Compliance Licensing

TELEPHONE NUMBER: AREA CODE 6 1 5 | 8 4 3 - 7 4 7 0

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)

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

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On July 22, 1991, at 2115 Eastern daylight time (EDT), with Units 1 and 2 operating in Mode 1, Limiting Conditions for Operation (LCOs) 3.7.11.2 and 3.7.11.4 were entered when all fire protection spray and sprinkler systems and hose stations were declared inoperable. The required action provisions to establish fire watches and route backup fire hoses within one hour could not be complied with because all plant areas were affected, constituting operations prohibited by technical specifications. These systems were declared inoperable as the result of a loss of pressure in all fire suppression water system headers. The loss of header pressure was the result of incorrectly positioned valves that were manipulated during fire pump testing on the afternoon of July 22. Upon discovery of the incorrectly positioned valves, actions were promptly implemented to restore system pressure in a controlled manner. System pressure was restored, system valve alignment was verified, and LCOs 3.7.11.2 and 3.7.11.4 were exited at 0129 EDT on July 23. The Operations personnel responsible for incorrectly positioning the valves were appropriately disciplined. This LER also supplements information provided in Special Report 91-12, dated August 5, 1991.

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

DESCRIPTION OF EVENT

On July 22, 1991, at 2115 Eastern daylight time (EDT), with Units 1 and 2 operating in Mode 1 (100 percent reactor power, reactor coolant system [RCS] pressure at 2,235 pounds per square inch gauge [psig], and RCS average temperature at 578 degrees Fahrenheit, the fire protection spray and sprinkler systems [EIIS Code KP] and fire hose stations [EIIS Code KP] were declared inoperable when pressure was lost in the fire suppression water system [EIIS Code KP] headers. Although significant firewatch coverage was in effect, the action provisions of Limiting Conditions for Operation (LCOs) 3.7.11.2 and 3.7.11.4 could not be complied with because of the scope and cause of the inoperable systems. This constituted an operation prohibited by technical specifications (TSs).

During the performance of Surveillance Instruction (SI) 73.2, "Fire Pump 1B-B Performance Test," and SI-73.4, "Fire Pump 2B-B Performance Test," on July 22, 1991, inappropriate personnel actions resulted in an incorrect valve alignment that created an open flow path from the fire suppression water system headers to a test drain, which discharges into the intake forebay. Consequently, header pressure for the fire suppression water system was subsequently lost, and the system was declared inoperable at 2115 EDT on July 22. At the time of this event, the system was being considered the backup system required by Action b.1 of LCO 3.7.11.1 because of the inability to fully meet flow rate and pressure requirements. This condition was previously reported to NRC in Special Report 91-04, dated May 20, 1991, and LER 50-327/91009, dated June 5, 1991. Because of the lack of system pressure, the spray and sprinkler systems required by LCO 3.7.11.2, and the fire hose stations required by LCO 3.7.11.4 were also declared inoperable at 2115 EDT on July 22.

At approximately 0800 EDT on July 22, a dayshift assistant unit operator (AUO) responsible for American Society of Mechanical Engineers (ASME) Section XI, testing ('AUO A') was assigned to perform SI-73.2. AUO A was also assigned to be the SI-73.2 test director. Unrelated problems were encountered with the ultrasonic flow instrument used for this test, and the test completion was delayed.

At approximately 1500 EDT, an evening shift AUO responsible for ASME, Section XI, testing ('AUO B') was assigned to assist in the completion of SI-73.2 and to perform SI-73.4. AUO B was also assigned as the SI-73.4 test director. A pretest briefing was logged in the SI-73.4 test log at 1500 EDT. However, SI-73.4 had not been approved for performance by the assistant shift operations supervisor (ASOS).

At approximately 1530 EDT, the data collecting portion of SI-73.2 was completed and AUO A and AUO B restored the system to its normal lineup. AUO A served as the first person on this valve alignment, and AUO B served as the second person and independent verifier. Before taking the SI-73.2 package to the main control room (MCR) for review, the two AUOs conducted a turnover of the test and system status.

Without notifying the MCR, AUO A and AUO B began aligning the high pressure fire protection (HPFP) system to perform SI-73.4. The AUOs completed selected portions of SI-73.4, which bypassed steps that might have alerted the MCR to the changes being made to the HPFP system configuration.

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

SI-73.4 involves the positioni-- of eight valves. The purpose of these valve manipulations is to isolatc *.e pump being tested from the rest of the syrtum and to provide a test flow path. The AUOs placed seven of the eight valves in the required positioc One valve, 2-26-575, "Auxiliary Building HPFP Supply Valve," was left open. SI-73.4 requires 2-26-575 to be shut. AUO A and AUO B did s'ut valves 1-26-550, "FP Strainer 'nlet Isolation Valve," and 1-26-553, "FP strainer out et Isolation Valve," isolating the No. 1 HPFP strainer. Additionally, the fire mp test header isolation valve, 0-26-859, was opened. With the HPFP system i s i.d up, a direct path from the 2B-B fire pump to the 10 inch test discharge valve was established.

The AUOs intentionally did not follow the steps of SI-73.4. They were trying to save time by lining up for SI-73.4 before the results of SI-73.2 were reviewed and approved. However, they realized that the 1B-B fire pump was technically inoperable until SI-73.2 was complete. They believed that by leaving 2-26-575 open, a flow path for the Unit 2 fire pumps would be available until SI-73.4 was actually started. This deviation was not authorized. This alignment was not documented in the configuration log or in the SI-73.4 package.

The two AUOs took the SI-73.2 and SI-73.4 packages to the MCR. The AUOs delivered the SI-73.2 package to the Unit 1 ASOS and informed him that they were "set up" for SI-73.4. The ASOS interpreted this to mean that the test equipment was installed. The ASOS wanted Technical Support personnel to verify that the test results were satisfactory and directed the AUOs "not to start SI-73.4." The ASOS meant that no valve li -ups were to be performed.

At approximately 1730 EDT, the No. 2 HPFP strainer high differential pressure alarm was received in the MCR. AUO B was sent to the pumping station to i estigate. AUO B reported back to the MCR that the No. 1 strainer was isolated. .O B did not report that he had earlier isolated the No. 1 HPFP strainer with AUO A as part of the SI-73.4 valve alignment. The unit operator directed AUO B to unisolate the No. 1 HPFP strainer.

The ASOS checked the configuration log and the SI-73.2 and SI-73.4 packages to determine if the abnormal alignment of the No. 1 strainer was a result of the.. tests. The abnormal alignment was not documented. The ASOS questioned the AUO about the alignment and the AUO indicated that he did not know the cause of it, but it might have been done as part of SI-73.4.

The gradual loss of system pressure was first noted at approximately 1800 EDT on July 22 At the direction of the MCR, the turbine building AUO began monitoring the turbi building HPFP header pressure. Efforts were initiated to locate and isolate the cause the depressurization. The shift operations supervisor contacted the Fire Operations unit and the fire protection system engineer to evaluate compensatory measures and to develop a recovery plan. The status of the fire pump test header isolation valve was checked. The valve was found to be in the open position at 2140 EDT and was subsequently closed as part of the recovery actions.

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

Isolation of the turbine building and transformer yard open head sprinkler systems was completed at 2225 EDT to prevent the inadvertent spraying down of plant equipment as the system was being returned to normal. At 2302 EDT a pumper fire truck was used to begin system repressurization. System pressure was returned to approximately 145 psig at 2334 EDT. Safety-related areas of the plant had fire protection coverage available at this time. At 0129 EDT on July 23, system pressure was being maintained normal, and the fire suppression water system was aligned for normal service. LCOs 3.7.11.2 and 3.7.11.4 were exited at this time.

CAUSE OF EVENT

The flow path from the fire suppression water system to the intake forebay was the result of Valves 2-26-575 and 0-26-[illegible] (refer to Updated Final Safety Analysis Report [UFSAR], Figure 9.5.1-12) being incorrectly aligned in the open position at the same time. The cause of the incorrect valve alignment is attributed to inappropriate personnel actions.

The root cause of this event was the failure of AUOs A and B to follow approved plant procedures. The failure of the AUOs to follow Site Standard Practice (SSP) 8.1, "Conduct of Testing," directly led to this event. The AUOs were the designated test directors for these test evaluations. They violated the requirements of SSP-8.1, which deal with safety issues, precautions and limitations, the chronological test log, pretest briefings, operations notification, configuration control, test deficiencies, and out of sequence test performance. If these sections had been followed, the unauthorized valve alignment would not have been made and/or the MCR could have better mitigated the consequences.

An additional example of failing to follow procedures was the AUOs' noncompliance with SI-73.4. Specifically, valve 2-26-575 was not closed as required by Step 16 of Section 6.2 of SI-73.4. Several other steps in SI-73.4 were not performed that might have alerted the operators in the MCR to the changes being made to the HPFP system alignment. The AUOs did not document the plant configuration in the SI package, impeding the ability of the MCR operators to determine actual plant status.

Discussions with other AUOs, and an evaluation of their performance has led to the conclusion that the performance problems described above are isolated to the two AUOs specifically involved, and are not a reflection of deficiencies with AUO performance in general.

Poor communications used by personnel also contributed to this event. The use of informal terminology associated with the status of the surveillance testing inhibited the MCR's ability to determine actual plant configuration. If the AUOs and the MCR personnel had used precise terminology when discussing the status of SI-73.4, the event might have been prevented and/or better mitigated.

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

ANALYSIS OF EVENT

This event is being reported in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation prohibited by TSs.

The open flow path from the HPFP system headers to the forebay impacted the ability to provide design fire suppression water flowrates to the HPFP system. This impaired the plant's sprinkler systems and hose stations in both safety- and nonsafety-related areas of the plant. Additionally, some 10 CFR 50, Appendix R, cable interactions were dispositioned based on assumed water suppression and water curtains.

After the test header isolation valve was discovered open, a methodical plan of action was developed to isolate the valve and return system pressure to normal. These actions included the isolation of the turbine building and transformer yard open head systems to prevent the inadvertent spray down of plant equipment, and resultant diversion of flow, while system pressure was reestablished. The test header isolation valve was closed at approximately 2300 EDT, and system pressure was restored at 2334 EDT. The system alignment was restored and verified, and the system returned to normal service at 0129 EDT, July 23.

The overall duration of this event was approximately 9.5 hours. The system performance was degraded for approximately 5 hours and 35 minutes of this time. The incorrect valve configuration on the HPFP system was not recognized for approximately 5 hours and 40 minutes (approximately 1600 EDT to 2140 EDT). Approximately 3 hours and 40 minutes elapsed while the HPFP system pressure was degraded without knowing the cause. TS 3.7.11.1 action b.1 allows 24 hours to reestablish fire water suppression capabilities if the system becomes inoperable. As detailed above, corrective actions were pursued and the system restored within this timeframe.

The scope and cause of the inoperable fire protection systems precluded full compliance with the action provisions of LCOs 3.7.11.2 and 3.7.11.4; however, extensive firewatch coverage was in effect at the time of the event as compensatory measures for unrelated fire barrier or detection requirements. (Roving hourly watches were in effect, which provided coverage for all accessible areas of the control and auxiliary buildings, and a continuous watch was posted at the diesel generator building.) Additionally, a pumper truck was connected to the HPFP system yard piping as a compensatory measure. This compensatory measure was in place because of concerns of potential degradation of the HPFP fire pump power leads. If a fire had occurred during this period, in-service detection and/or firewatches would have alerted Operations, and a fire brigade would have been dispatched accordingly. The reduced HPFP system pressure and flow would have been detected by any of several indications; including start signals to the other fire pumps on low system pressure, observed low pressure and flow from sprinklers or hoses, and observations by members of the fire brigade. Operations could have then isolated sections of the system to divert flow to the area of the fire. In parallel to these actions, personnel would have pursued the identification and correction of the cause of the loss of pressure, as was done. Additional capacity would have been available through the use of contracted offsite pumpers. This would provide the ability to route independent hoses or to augment the system flow. The compartmentalized configuration of the plant, and the use of portable fire extinguishers, could have provided the ability to provide some containment of the fire while system restoration was ongoing.

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ANALYSIS OF EVENT

Areas of the plant protected by carbon dioxide suppression systems, (i.e., computer room, auxiliary instrument rooms, diesel generator rooms, fuel oil pump rooms, and diesel generator electrical board rooms) were not effected by the loss of HPFP system water pressure.

The loss of HPFP system pressure also impacted the system's ability to provide emergency feedwater to the RCS steam generators under flood conditions, as described in UFSAR, Section 9.5.1. However, due to the relatively short duration of this event compared to the flood notification and preparation time described in UFSAR, Appendix 2.4A, the unavailability of flood mode feedwater had no significant impact on safety.

CORRECTIVE ACTION

Upon discovery of the condition, actions were taken to locate and isolate the problem. When is was determined that system pressure was not available, LCOs 3.7.11.2 and 3.7.11.4 were entered. Actions began to isolate the turbine building and transformer yard open head sprinkler systems to prevent inadvertent spray down of plant equipment upon the system being returned to service. A review of compensatory actions indicated that the available established fire watches, in conjunction with detection and compartmentalization, were appropriate during system return to service. The incorrect valve alignment was corrected, and a pumper was utilized to begin system repressurization following isolation of the turbine building and transformer yard sprinkler systems. The system was returned to normal at 0129 EDT on July 23, 1991.

The Operations personnel responsible for incorrectly positioning the valves have received appropriate disciplinary action for their failure to follow procedures.

An operations review team is evaluating this event relative to the role that communications played. The results of this evaluation will be discussed with Operations personnel as "lessons learned" information.

ADDITIONAL INFORMATION

A review of previous LERs did not identify any similar occurrences of a loss of fire suppression water system header pressure, which caused all sprinkler and spray systems and hose stations to be declared inoperable.

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ADDITIONAL INFORMATION

The review did identify a number of events associated with inappropriate personnel performance, e.g., inadequate and/or ineffective communications, inadequate self verification test steps performed out of sequence, etc. Administrative Instruction (AI) 30, "Nuclear Plant Conduct of Operation," and SSP-8.1 provide guidance to plant personnel for the performance areas described above. Corrective actions for some events included specific enhancements to AI-30 and SSP-8.1. In general, these procedures provide the rules and instructions governing the conduct of daily operational activities, including testing. If correctly applied, this guidance would have prevented this event. The guidance cannot be effective if it is not followed or applied correctly.

COMMITMENTS

1. The results of the operations review team evaluation of communication will be discussed with Operations personnel as "lesson learned" information by September 6, 1991.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	336/91-010
Event Description:	Reanalysis of main steam line break
Date of Event:	October 18, 1991
Plant:	Millstone 2

Summary

Reanalysis of a postulated main steam line break (MSLB) at Millstone 2 under limiting conditions shows that containment pressure and temperature design limits would be substantially exceeded.

Event Description

A reanalysis at Millstone 2 of the postulated double-ended MSLB between the steam generator (SG) outlet and the steam line flow restrictor has shown that the temperature and pressure design limits of the prestressed, reinforced concrete containment building would be exceeded. Limiting conditions in the reanalysis were assessed to be full-power operation of the plant with failure to close of the main feedwater regulating valve of the affected SG. The peak containment pressure and temperature are predicted to be 93 psig and 427°F, respectively. The Millstone 2 containment design pressure is 54 psig, with a design limit temperature of 289°F.

Short term justification for continued plant operation is the stationing of a reactor operator dedicated to closure of the main feedwater block valves in the event of any reactor trip. Corrective hardware fixes were to result in automatic closure of the main feedwater block valves on receipt of a containment isolation actuation signal.

Additional Event-Related Information

Prior MSLB analysis had assumed limiting conditions in which the reactor is at hot zero power on the basis that the SGs would have their greatest inventory of hot water in this operational mode, resulting in the maximal discharge to the containment. However, in these conditions, moisture carryover to the containment would limit the containment temperature to saturation temperature associated with the containment pressure. Under the modified limiting conditions, i.e., at full power with failure to isolate feedwater, the deposition of superheated steam into the containment would preclude saturation constraints on peak temperature conditions.

While the modified analysis predicts that design pressure limits will be exc ded, comparison of resultant pressure peaks with the ultimate containment strengths est nated in NUREG-1150 for a similar containment design indicates that uncertainty remains regarding containment survivability under the limiting MSLB conditions.

ASP Modeling Assumptions and Approach

This event has not been modeled as an accident sequence precursor.

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TITLE (4): Reanalysis of Main Steam Line Break Exceed Containment Design Limits

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8)
1 0	1 8	9 1	9 1	0 1 0	0 0	1 1	1 5	9 1	0 5 0 0 0
									0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

- X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Robert A. Borchert, Unit 2 Reactor Engineer, Ext. 4415

TELEPHONE NUMBER: AREA CODE 2 0 3 | 4 4 7 - 1 7 9 1

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) ☐ NO

EXPECTED SUBMISSION DATE (15): MONTH 1 2 DAY 3 1 YEAR 9 2

ABSTRACT (16)

On October 18, 1991, at 1305 hours, with the plant in Mode 1 at 100% power, a reportability determination was made concerning a re-analysis of the main steam line break event inside the containment. The re-analysis has shown that the assumptions made for the existing (1979) main steam line break analysis were non-conservative with respect to power level, break size, and single active failure. Using more restrictive assumptions, design limits for containment pressure and temperature could be exceeded. NNECo determined that this condition was reportable as a condition outside the design basis of the plant. An Immediate Report was made to the NRC, and the unit immediately commenced an orderly downpower to approximately 3% power (Mode 2). The existing main steam line break analysis remains valid for Mode 2 operation.

A Justification for Continued Operation (JCO) was developed to allow the unit to return to power operation by stationing a dedicated reactor operator to close the main feedwater block valves following any reactor trip. The JCO documents the basis for reasonable assurance that, with the actions of a dedicated operator, containment pressure will remain below the design basis value for all postulated main steam line break events. The unit was returned to power operation on October 22, 1991.

Short term corrective hardware changes are being developed to automatically close the main feedwater block valves given a Containment Isolation Actuation Signal (CIAS). The current schedule is to have these short term hardware changes installed and tested by November 30, 1991. Permanent hardware and setpoint changes will be installed during the 1992 refueling outage.

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Estimated burden per response to comply with this information collection request: 50.0 hrs. Forward comments regarding burden estimate to the Records and Reports Management Branch (p-530), U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503.

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

I. Description of Event

On October 18, 1991, at 1505 hours, with the plant in Mode 1 at 100% power, a reportability determination was made concerning a reanalysis of the main steam line break event inside the containment. The re-analysis has shown that the assumptions made for the existing (1979) main steam line break analysis were non-conservative with respect to power level, break size, and single active failure. Using more restrictive assumptions, design limits for containment pressure and temperature could be exceeded.

The existing (1979) main steam line break analysis assumes a postulated double-ended (6.3 ft^2) break of the main steam line between the steam generator outlet and the steam line flow restrictor at hot zero power, with the worst single active failure being a failure of a diesel generator and the resultant loss of one-half of the emergency safeguards features which reduce containment pressure (1 containment spray pump and 2 containment air recirculation fans). The peak containment pressure and temperature for this analysis is predicted to be 47 psig and 274°F.

It has been determined that the limiting containment pressure and temperature are attained by postulating a double-ended break of the main steam line between the steam generator outlet and the steam line flow restrictor at full power, with the single active failure being a failure of the main feedwater regulating valve of the affected steam generator to close. This analysis also assumed operator actions to secure feedwater to the affected steam generator at 10 minutes following the reactor trip. The peak containment pressure and temperature for this analysis is predicted to be 93 psig and 427°F. These results exceed containment design pressure and temperature.

An immediate report was made to the NRC and the unit immediately commenced an orderly downpower to approximately 3% power (Mode 2) by plant operators. The existing main steam line break analysis remains valid for Mode 2 operation. No automatic or manual safety systems were required to respond during this event.

II. Cause of Event

The root cause of the event has been determined to be an incorrect assumption, made in the FSAR analysis, that the limiting condition, for the containment response due to a Main Steam Line Break (MSLB), was hot zero power. This incorrect assumption was based upon the judgement that at hot zero power the steam generators contain the largest inventory of hot water and thus, resulted in the largest discharge to the containment. However, recent MSLB sensitivity studies have shown that this case is not limiting.

As a result of the planned steam generator replacement, the containment response due to a MSLB was being reviewed. In order to assess the impact of the new steam generators, the current analysis results were used to benchmark new steam generator and containment models. During the benchmarking of the current analysis modeling the current steam generators, it was discovered that the hot zero power condition was not limiting.

The peak containment temperature is highly dependent on the moisture carryover that occurs from the break. Moisture carryover is important in that with a significant moisture carryover the containment temperature will be limited to the saturation temperature corresponding to the containment pressure. If no moisture carryover occurs and pure steam is discharged, superheating will occur and containment temperature will not be limited to the saturation temperature.

At hot zero power, the large steam generator inventory will assure that moisture carryover will occur for most break sizes. However, at full power, with the reduced inventory, moisture carryover is not predicted to occur. Thus, for peak containment temperature, the limiting condition would be full power.

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Further, the limiting single failure is dependent upon the power level. At hot zero power, the main feedwater regulating valve will be closed at the initiation of the event and would remain closed throughout the transient. Thus, at zero power, the main feedwater regulating valve is not subject to a failed open condition. However, at full power, the main feedwater regulating valve would be open at the initiation of the event and thus would be subject to a failed open condition. With a main feedwater regulating valve failure, the feedwater addition would more than offset the difference in initial inventory between full power and hot zero power. Thus, the limiting condition for maximum mass discharge to the containment would be full power with a failure of the main feedwater regulating valve.

These factors were not taken into account in performing the FSAR analysis. Further, they were not explicitly taken into account in the MSLB analysis performed to support the TMI action plan item to implement an automatic system for initiation of auxiliary feedwater nor the response to the NRC Inspection and Enforcement Bulletin 80-04 where additional MSLB spectrum studies were requested.

In response to an NRC request for information on automatic initiation of the auxiliary feedwater system made on December 21, 1979, the design basis steamline break analysis was reevaluated. In the analysis, the additional mass releases to the containment due to auxiliary feedwater addition were added to the FSAR case and shown to have no impact on the peak containment pressure and temperature. Since this study was aimed at only assessing the impact of the new automatic initiation system, the original FSAR assumptions were not reevaluated. This was supported by evaluations done by the NSSS vendor, Combustion Engineering. This analysis was submitted to the NRC on January 27, 1980. Since the information requested in the I&E Bulletin 80-04 issued in February 1980 was very similar to the request made in December 1979, it was assumed that this analysis was also sufficient to respond to the Bulletin. Therefore, no new analysis was performed for the Bulletin. A Safety Evaluation Report was received from the NRC on October 7, 1982. The non-conservative assumptions were not discovered until the MSLB was reviewed to evaluate the impact of the planned steam generator replacement.

It should be recognized that in determining the cause of this event, reliance has been placed upon the available documentation for the analysis and evaluations performed in the 1974-1980 time period. Because these evaluations were performed over ten years ago, not all of the documentation has been retrieved. However, from the documentation that we have retrieved, we believe we have been able to reconstruct the logic used to justify the previous submittal and have determined the root cause of the event.

III Analysis of Event

This event is being reported in accordance with 10CFR50.73(a)(2)(ii)(B), which requires the reporting of any event or condition that results in the nuclear power plant being in a condition outside the design basis of the plant.

The safety consequences of this event are the potential overpressurization of the containment with subsequent damage to the containment structure and safety related equipment required for safe shutdown of the plant from a postulated MSLB event. The safety consequences are minimal, however, upon consideration of containment design margins, safety related equipment qualifications, and standard post trip operator actions.

In considering the safety consequences of this event the following items were addressed:

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

(a) **Containment Structural Integrity.** The Millstone 2 containment consists of a prestressed, reinforced concrete cylinder and dome connected to and supported by a massive reinforced concrete foundation slab. The containment was designed for an internal pressure of 54 psig, and was tested to 62 psig during the structural integrity test. The working stress design method was used to design the containment structure for various load cases, including the case of a design pressure of 54 psig. The containment structure was checked for factored loads and load combinations, including the case with a 1.5 load factor on the design pressure., which corresponds to 81 psig. The code requires that "strength be adequate to support the factored loads and that servicability of the structure at the service load level be assured." (ACI-318-71 Commentary Section 9.1.1)

The ultimate capacity of containments has been studied and documented by many sources recently. In general, the anticipated ultimate capacity of a containment structure has been found to be 2 to 2.5 times design pressure. NUREG-1150 entitled "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," studies the ultimate capacity of typical containment structures. Included in this study was Zion, which is a prestressed containment, with a design pressure of 47 psig. The evaluation determined that a lower bound on the ultimate capacity was around 100 psig (a factor of 2). These detailed studies have taken into account material strengths being higher than assumed, code allowables being conservative, as well as a detailed evaluation of structural behavior during beyond design basis events. A similar detailed study has not been performed for Millstone 2, but the same factors which contribute to a lower bound ultimate capacity of 2 to 2.5 times design exist in the Millstone 2 containment structure. This evaluation of studies relative to ultimate capacity further substantiates that the containment can support the factored load case and beyond. These postulated load cases are beyond the design basis of the containment structure, but within the overall load carrying capability of the structure.

(b) **Equipment Qualification.** The electrical equipment in the containment required for safe shutdown following all MSLB events has been qualified to 10CFR50.49 requirements with temperatures ranging from 324°F to 448°F and pressures ranging from 70 to 127 psig. The original containment qualification profile for this equipment was based on a LOCA event with a maximum temperature of 289°F and pressure of 54 psig.

For a full power MSLB with no automatic feedwater isolation and no operator actions to isolate feedwater for 10 minutes, the predicted peak containment pressure and temperature is 93 psig and 427°F. Although this temperature and pressure would have exceeded the qualification of required equipment, we have determined that equipment required to be available to mitigate this event would have remained operable.

Thermal analysis has shown for the predicted short duration temperature peak at superheated conditions that the surface temperature of safety related equipment will not rise above the saturated temperature of the partial steam pressure in containment. This method of analysis has been presented by the NRC in NUREG 0588, paragraph 1.2(5), NUREG 0510 and NUREG 1511. There have been a number of vendor test results which have also demonstrated this phenomenon. The postulated partial steam pressure of the containment during the accident is estimated by subtracting 14.7 psi, i.e., the initial partial atmospheric air pressure, from the absolute pressure of the accident analysis. The resulting maximum steam temperature during the above MSLB accident is thus predicted to be 322°F. At this temperature, all of the required safe shutdown equipment in containment would be qualifiable.

The predicted MSLB accident pressure of 93 psig is slightly higher than the qualification pressure of some of the safe shutdown equipment in containment. The lowest qualification pressure of this equipment is 70 psig. In general, electrical equipment is more sensitive to higher temperature and humidity than higher pressure. The following equipment has been analyzed for operability at this pressure condition.

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(1) Westinghouse Containment Air Recirculation (CAR) Fan motors would have been operating prior to the pressure peak. The increase in the CAR fans brake horsepower, due to the higher density air during the accident, has been determined to be within the qualification requirements of the CAR fan motors.

(2) Conax Electrical Penetrations are qualified to pressures in excess of 110 psig. They would have been operable and qualifiable.

(3) ASCO Solenoid valves control various containment isolation valves. Following containment isolation, these valves would be deenergized and would remain deenergized through the pressure peak.

(4) Foxboro and Rosemount pressure transmitters are used to transmit pressure and level signals to the reactor protection system. Although the accuracy of level transmitters may be slightly affected by higher static pressure, they would remain operable.

(5) Weed RTD's monitor RCS temperature. The operability of an RTD is not affected by pressure changes of the magnitude expected by the MSLB.

(6) Inadequate Core Cooling Monitoring System consists of in-core heated junction thermocouples to monitor reactor vessel water level and core exit thermocouples to monitor core outlet temperature. The system does not contain any pressure sensitive components.

In summary, all required safe shutdown equipment in containment has been determined to be operable for all MSLB events.

(c) **Main Feedwater Block Valves.** Evaluation of the original valve specification for the main feedwater block valves, 2-FW-42A and 2-FW-42B, indicated that the valves would have closed in the event of a main feedwater regulating valve failure coincident with a MSLB. Specifically, the worst case differential pressure was determined to be 991 psid, which is significantly less than the original valve specification of 1600 psid. Additionally, plant startup data demonstrated valve closure within 10 seconds as required by the original valve specification.

(d) **Operator Actions.** Prior to the event, the Emergency Operating Procedure (EOP) for Standard Post Trip Actions provided instructions for establishing proper main feedwater system configuration following a reactor trip. This configuration requires verification that the main feedwater regulating valves are closed. The contingency actions state: "IF main feed flow is excessive, THEN (i) Manually close main feed regulating valves or blocking valves and control feedwater flow using bypass, OR (ii) Trip the main feed pumps."

The standard post trip actions are normally completed within 2 to 3 minutes following a reactor trip. While these actions would not have been performed quickly enough to prevent containment pressure from exceeding 54 psig, standard post trip operator actions would have isolated feedwater much faster than the 10 minutes assumed in the re-analyzed MSLB events.

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IV. <u>Corrective Action</u>

A Justification for Continued Operation (JCO) was developed to allow the plant to return to power operation by stationing a dedicated reactor operator to close the main feedwater block valves following any reactor trip. A main steam line break event was analyzed for a double-ended break at full power, with a failure of the main feedwater regulating valve to close on the affected steam generator. This analysis assumed operator action to close the main feedwater block valves within 35 seconds following the reactor trip with a 10 second closure time of the valve. The peak containment pressure and temperature for this case is predicted to be 54 psig and 413°F. This JCO documents NNECo evaluation of operator actions following a reactor trip, feedwater block valve operation under postulated accident conditions, containment structural integrity, and equipment environmental qualification. Diagnostic testing of the motor operated main feedwater block valves was performed in accordance with established procedures developed under the Northeast Utilities Generic Letter 89-10, "Motor Operated Valve Test Program." This JCO provides reasonable assurance that, with the actions of a dedicated operator, the containment pressure will remain below the design basis value for all main steam line break events. Although the predicted MSLB temperature peak exceeds the containment qualification temperature of 289°F, all of the required safe shutdown equipme[illegible] ualifiable based on a maximum saturated steam temperature of 285°F. Given this justification for c[illegible]ed operation, the unit was returned to power operation on October 22, 1991.

As part of the JCO, short term corrective hardware changes are being developed to automatically close the main feedwater block valves given a Containment Isolation Actuation Signal (CIAS). The current schedule is to have these short term hardware changes installed and tested by November 30, 199[illegible]. Permanent long term hardware and setpoint changes will be performed during the 1992 refueling outage. Following these changes, the predicted MSLB peak containment pressure and temperature will be equal to or less than 54 psig and 413°F, therefore, the required safe shutdown electrical equipment will remain qualifiable.

A revised response to IE Bulletin 80-04 will be submitted in 1992 to update our previous submittal for containment response and return to power for MSLB events.

V. <u>Additional Information</u>

There were no failed components during this event.

Similar LERs: 77-23, 80-05, 83-07, 85-01 and 86-10.

<u>Main Feedwater Regulating Valves</u>

Manufacturer	Copes-Vulcan
Model	P-200-12 Angle
Size	14 inch 900#
EIIS Code	SJ-LCV-C635

<u>Main Feedwater Block Valves</u>

Manufacturer	Crane
Model	L-900 Gate
Size	18 inch 900#
EIIS Code	SJ-ISV-C654

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	369/91-006
Event Description:	Potential failures in containment spray and air return
Date of Event:	February 15, 1991
Plant:	McGuire 1

Summary

Containment pressure suppression in event of a loss-of-coolant accident (LOCA) is provided at McGuire by a containment spray cooling system and a containment air return fan system, which circulates the containment atmosphere through ice condensers. These systems are designed to start automatically when containment pressure reaches 3.0 psig to remove heat from the containment steam / air atmosphere, thereby reducing containment pressure. When containment pressure drops to 0.35 psig, containment air recirculation and containment spray are terminated. This is to ensure that containment pressure does not fall significantly below atmospheric pressure, a condition for which the containment was not designed.

A design review identified that the containment underpressure protective feature at 0.35 psig was implemented as a permissive. Once the containment spray and containment air recirculation systems were first started and then stopped by the 0.35 psig permissive, they would restart as soon as pressure rose above 0.35 psig. No significant "deadband" was incorporated to prevent rapid cycling of the controlled systems. The review identified that the containment cooling systems were not designed to cycle in this manner and were likely to fail as a result.

Event Description

The containment air recirculation system is designed to force air from the upper portion of containment through the lower portion of containment. This acts to reduce hydrogen accumulations in "dead" spaces and increases cooling of the containment atmosphere by the ice contained in baskets in the ice condenser system. This system starts when containment pressure reaches 3.0 psig. In addition, a permissive signal indicating containment pressure greater than 0.35 psig is required.

The containment spray system is designed to spray cool water into the containment to assist in condensing steam and cooling the post-LOCA containment atmosphere. Water is initially drawn from the refueling water storage tank; when this supply is exhausted, water is recirculated from the containment sump, through heat exchangers, and back to the containment spray headers.

During a LOCA, the containment spray system actuates when containment pressure reaches 3.0 psig. Containment pressure of 3.0 psig and a permissive indicating containment pressure equal to or greater than 0.35 psig will also initiate the containment air recirculation system. These systems, in conjunction with the ice condensers, act to maintain containment pressure below its upper design limit of 15 psig.

The systems are also designed to prevent containment pressure from falling below the lower design limit of -1.5 psig. To prevent exceeding this limit, containment spray and containment air return operation are terminated when containment pressure drops to 0.35 psig. When containment pressure increases above 0.35 psig, the systems restart, and when it decreases to 0.35 psig, they stop. This cycling could be expected to impose severe stresses on electric motors and electrically operated valves in the systems, resulting in their failure.

The same concerns described also apply to the containment hydrogen skimmer system; however, there is a redundant system available for hydrogen control that would not have been affected. The hydrogen mitigation system would not have been subject to cycling-induced failure.

Additional Event-Related Information

Given the design problems described, the containment air recirculation system at McGuire would be rendered inoperable before completing its safety function following a LOCA. Concerns are raised about the capability of containment spray, the redundant containment-cooling system.

The utility believes that the containment spray system should not be considered to be rendered inoperable by the control system design, indicating that the system should be able to perform its design function before failing. This would be the case if only one operation of the system were required. However, since the system is designed to operate during the recirculation phase as well as the injection phase of a LOCA, it is not clear whether this is the case for all possible accident scenarios. The licensee event report indicates, "At the time the VX [containment air return] system failure would have been assumed to occur, containment pressure would have been low, approximately 0.35 psig. At that point, containment pressure control has been accomplished and sufficiently low pressures could have been maintained by the available containment spray (ND system) [actually a possible alignment of the RHR system]." (Note: Brackets, "[]", indicate comments supplied by the ASP reviewer. Material in parentheses inside quotations was contained in the text.) The report also says, "Containment spray ... operation is automatically terminated upon pressure decay to 0.35 psig, thereby, controlling containment pressure." In addition, it is stated that, "... personnel could not prove that the NS [containment spray] system pumps ... would not burn up as a result of exceeding their specified cycling duty." These statements imply that the containment spray system could also fail before completing its safety function, although containment cooling might still be provided by the RHR system.

The utility also refers to potential "deadheading" concerns (pump operation with little or no flow, leading to pump damage) with respect to the containment spray system, but these concerns were not described.

ASP Modeling Approach and Assumptions

The discovery identified in this event appears to indicate that two redundant systems intended to provide containment cooling could fail during some accidents. One other source of containment cooling might remain available. This event relates to containment functionality and has not been modeled as an accident sequence precursor.

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LICENSEE EVENT REPORT (LER)

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Title (4): Technical Specification 3.0.3 Was Entered On Units 1 And 2 When The Containment Air Return And Hydrogen Skimmer System Was Declared Inoperable Due To A Design Deficiency

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Docket Number(s)
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									0 5 0 0 0

This report is submitted pursuant to the requirements of 10 CFR § (11): [illegible] — X, X, X, X

Licensee Contact for this LER (12)

Name	Telephone Number
Alan Sipe, Chairman, McGuire Safety Review Group	704 875-4183

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): Yes (If yes, complete EXPECTED SUBMISSION DATE) [ ] — No [X]

Expected Submission Date (15): Month | Day | Year

Abstract (16)

On February 15, 1991, Problem Investigation Report (PIR) 0-M91-0032 was initiated as a result of a concern expressed by a McGuire Nuclear Production Engineer during requalification training. The Containment Spray (NS) system pumps and the Containment Air Return (CAR) and Hydrogen Skimmer System (VX) fans had the potential to dead head due to the Containment Pressure and Control System (CPCS) permissive logic. The possibility also existed for the NS system pumps and VX system fan motors and damper motors to exceed their cycle duty. As a result of the Operability Evaluation (OE) performed by Design Engineering (DE) personnel, the VX system was declared inoperable on Units 1 and 2. Subsequently, Technical Specification (TS) 3.0.3 was entered on Units 1 and 2 on February 26, 1991 at 2057. Units 1 and 2 were in Mode 1 (Power Operation) at the time of this event. This event has been assigned a cause of Design Deficiency. To prevent this event from recurring, DE, Projects, and Compliance personnel are currently working on a comprehensive resolution to ensure long term reliability of the NS system pumps and VX system fans and dampers, thus eliminating pump dead heading and fan and damper cycling.

EVALUATION:

Background

The VX [EIIS:BB] system is designed to rapidly return air to lower Containment after initial loss of coolant blowdown following a Loss of Coolant Accident (LOCA). This is accomplished by the use of air return fans [EIIS:FAN]. A secondary function of this system is to prevent the build-up of hydrogen in dead ended compartments resulting from a loss of coolant accident (LOCA). This is accomplished by continuously drawing air out of the dead ended compartments at a rate that limits the hydrogen concentration to less than 4 percent.

The system contains two 100 percent capacity air return fans, each with a capacity of 30,000 cubic feet per minute (cfm). Both fans are automatically started when Containment pressure reaches 3.0 psig and a Containment Pressure Control System (CPCS) start permissive signal is received. The fans force the air from upper to lower Containment, thereby, returning the air which was displaced by the blowdown. An isolation damper [EIIS:DMP] is provided on the discharge of each fan and acts as a barrier between upper and lower Containment to prevent the air flow from bypassing the ice condenser [EIIS:COND].

The system also contains two 100 percent capacity hydrogen skimmer [EIIS:SKR] fans, each with a capacity of 3,000 cfm. A normally closed, motor operated valve [EIIS:V] on the hydrogen skimmer header prevents the air flow from bypassing the ice condenser during initial blowdown. It remains closed until the end of initial blowdown. After initial blowdown, a start permissive and a Phase B, Containment isolation at 3 psig, (Sp) signal open the valve coincident with Containment air return startup. After the valve has fully opened, the hydrogen skimmer fan will start.

The NS system [EIIS:BE] is designed to spray cool water into the Containment atmosphere when appropriate in the event of a LOCA assuring that the Containment pressure does not exceed its design pressure of 15 psig. This protection is afforded for all pipe break sizes up to and including the double-ended rupture of the largest pipe in the Reactor Coolant system (NC) [EIIS:AB]. The NS system is made up of two redundant trains. Each train consists of one pump [EIIS:P], a heat exchanger [EIIS:HX] and associated piping, valves, and a spray header. This system can be supplemented with the Residual Heat Removal System (ND) [EIIS:BP]. The NS system is actuated by an Sp signal initiated either manually or on a two out of four high high Containment pressure signal. Following the injection phase, the spray pumps are realigned to draw a suction from the Containment sump during the recirculation phase.

The CPCS is part of the Engineered Safety Features System (ESF) and is provided to prevent exceeding the negative design pressure of the Containment structure. The systems permissive and termination features are redundant and are accomplished by independent pressure switches [EIIS:PS] which provide

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interlocks to prohibit Containment spray, air return fan, and hydrogen skimmer fan operation when Containment pressure is below 0.35 psig. The system is designed such that no single failure can prevent proper Containment spray or Containment air return and hydrogen skimmer fan initiation nor can it allow Containment spray or Containment air return and hydrogen skimmer fan operation when not required. The 0.35 psig permissive termination feature is automatically reset such that under accident conditions Containment spray, hydrogen skimmer and air return fan operation is automatically terminated upon pressure decay to 0.35 psig, thereby, controlling Containment pressure.

Operability Evaluation for PIR 0-M91-0032 states, in part:

Excessive cycling will be prevented in the interim by implementing a station operating procedure assigned to a dedicated operator. This procedure will employ manual actions and/or install jumpers to accomplish the following functions:

Following CPCS stopping of the fans and closing of the dampers at 0.35 psig, the operator will manually restart the fans and open the dampers when pressure increases toward 3.0 psig. The operator can also allow the fans to start and the dampers to open automatically at 3.0 psig by Solid State Protection System (SSPS) actuation. (Note 1)

Following actuation of the hydrogen skimmer fans on an Sp signal, the fans will remain in operation.

Following opening of the hydrogen skimmer fan dampers (valves) on an Sp signal, the dampers will remain open.

With these compensatory measures, the safety functions of the VX system will be ensured. The second and third actions are consistent with the current Catawba design, and are already planned for implementation at McGuire as MEVNs 2417 and 2418. The dedicated operator associated with the first action will ensure that the design function of the air return fans (start at 3.0 psig and stop at 0.35 psig) is maintained. A 50.59 evaluation has been completed and determined that no unreviewed safety questions exist.

Based on these compensatory actions it is concluded that the VX system is conditionally operable.

NOTE 1: These jumpers must be installed after the VX fans are started and prior to their trip at 0.35 psig.

Technical Specification (TS) 3.6.5.6 states that two independent Containment Air Return and Hydrogen Skimmer systems shall be operable in Modes 1, 2 (Startup), 3 (Hot Standby), and 4 (Hot Shutdown). With one Containment Air Return and Hydrogen Skimmer system inoperable, restore the inoperable system to operable status within 72 hours or be in at least Hot Standby within the

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next 6 hours and in Cold Shutdown within the following 30 hours. With two Containment Air Return and Hydrogen Skimmer systems inoperable comply with TS 3.0.3.

TS 3.0.3 states, in part, that within 1 hour action shall be initiated to place the unit in a Mode in which the specification does not apply by placing it, as applicable, in:

a. At least Hot Standby within the next 6 hours,

b. At least Hot Shutdown within the following 6 hours, and

c. At least Cold Shutdown within the subsequent 24 hours.

Description of Event

On February 26, 1991, at 2057, Units 1 and 2 entered T.S. 3.0.3 after an OE performed by DE personnel determined that the VX system fans and dampers/valves motors [EIIS:MO] could exceed the specified cycling duty after an automatic (auto) actuation. This rendered the VX system inoperable on both units. The determination was made by DE personnel as a result of a concern expressed by a Nuclear Production Engineer regarding the NS and VX systems. The Engineer was concerned about the possibility of the NS system pumps dead heading as a result of the CPCS permissive logic. Upon discussing this concern with another Engineer, it was determined that the possibility also existed of exceeding the cycle duty on the VX system fans and dampers/valves. This concern generated PIR 0-M91-0032, written by the Nuclear Production Engineer, February 15, 1991. During the OE, it was determined that DE personnel could not prove that the NS system pumps or the VX system fans and damper/valve motors would not burn up as a result of exceeding their specified cycling duty. However, DE personnel did determine that since the NS system pumps would complete their design function prior to any postulated motor damage, they did not present a problem from a safety or operability concern. Therefore, the OE would focus on the VX system. However, a resolution to the dead heading problem is being pursued by DE personnel.

To prevent the VX system fans and damper/valve motors from exceeding their cycle duty it would be necessary to manually control the starting and stopping, and opening and closing of the fans and dampers, respectively, after the auto stop signal had been received. The manual operation would be controlled by a dedicated Control Room Operator under a Temporary Operating (TO) procedure. To implement the compensatory action, procedures, TO/1,2/9600/059 and 060, Emergency VX System Operation Following A Safety Injection, were developed. These procedures would guarantee that the dedicated Control Room Operator would ensure that the design function of the VX system (start at 3.0 psig and stop at 0.35 psig) was maintained.

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The compensatory measures set forth in the OE by DE personnel rendered the VX system conditionally operable on February 27, 1991, and Operations (OPS) personnel were able to exit T.S. 3.0.3 on February 27, 1991, at 0335.

To compensate for the cycling effect of the Hydrogen Skimmer fans and dampers following an auto actuation, it would be necessary to install jumpers, thus defeating the interlock and allowing the fans and dampers to operate continuously. To implement the continuous operation of the Hydrogen Skimmer fans and dampers, a modification would have to be implemented. Previously, in the spring of 1990, PIR 0-M90-0047 had been generated to perform this modification. The PIR had been written when it was noted that the Catawba VX system fans and dampers operated continuously after an auto actuation and according to the McGuire Final Safety Analysis (FSAR), the VX system was designed to also operate continuously. In actuality, the fans and dampers will cycle on and off. Therefore to correct the discrepancy, McGuire Exempt Variation Notices (MEVNs) 2417 and 2418 were initiated on Units 1 and 2, respectively.

During the time of this event the modifications were scheduled to be implemented on night shift and were completed during the first week in March. As a result of the modifications, the TO procedures were revised to exclude the Hydrogen Skimmer fans and dampers.

Conclusion

This event has been assigned a cause of Design Deficiency because of unanticipated environmental interaction. The interaction between the cycling of the fans and dampers with the cycle duty of the fan and damper/valve motors had not been previously evaluated. The fans and damper motors were designed to cycle and the cycle duty for each is known. It is also known that during a LOCA, there will be pressure fluctuations in Containment. However, this information (Containment pressure fluctuations and cycle duty) was generated by different design groups when designing the VX system several years prior to this event. At that time, it was not recognized that the interaction between the Containment environment and the cycle duty of the affected motors could present a problem. The problem with exceeding the cycle duty of a motor presents the possibility of equipment failure. Motors are designed to start and stop a certain number of times within a certain time frame (cycle duty) depending on their particular application. When a motor is started, it pulls approximately 7 to 9 times more than its full load rated current, because the stationary or stator coils create a rotating magnetic field which the rotor assembly is trying to align itself with. This inrush of current generates excessive amounts of heat. Therefore, if the motor exceeds its design capacity for cycle duty, it runs the risk of failure as a result of a break down in the insulation, shorting, or grounding caused by excessive over heating.

To prevent exceeding the cycle duty on the Hydrogen Skimmer fans and dampers/valves, the modifications were implemented to allow the fans and

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dampers to operate continuously after receiving an auto actuation instead of cycling off and on. These modifications were completed in March, 1991.

DE, Projects, and Compliance personnel are currently working on a comprehensive resolution, including design changes, TS change submittal, and modification implementation, to ensure long term reliability of the CAR fans and NS system pumps.

A review of the Operating Experience Program (OEP) data base for the previous 24 months prior to this event revealed one TS violation with a contributory cause of Design Deficiency. LER 369/88-19 documented the failure of the Unit 2 Hydrogen Skimmers to achieve the flow rates listed in the FSAR because of a defective procedure and equipment configuration. The corrective actions for this event were specific to the flowrate problem because the concern with the cycle duty had not been identified at that time. This is, therefore, not considered to be a recurring problem.

There were no personnel injuries, radiation overexposures or uncontrolled releases of radioactive materials to the environment as a result of this event.

CORRECTIVE ACTIONS:

Immediate: The VX system on Units 1 and 2 was declared inoperable and TS 3.0.3 was entered on February 26, 1991 at 2057.

Subsequent:

1. DE personnel issued an OE for conditional operability of the VX system.
2. Procedures TO/1,2/A/9600/059 and 060, Emergency VX System Operation Following A Safety Injection, were developed by OPS personnel to allow for manual operation of the VX system following an auto actuation.
3. TS 3.0.3 was exited on February 27, 1991, at 0335 by OPS personnel.
4. MEVN 2417 and 2418 were completed in March, 1991, thus defeating the interlock, allowing the hydrogen skimmer fans and dampers to operate continuously after receiving an auto actuation.
5. The TO procedures were revised to exclude the hydrogen skimmer fans and dampers.

Planned: DE, Projects, and Compliance personnel are currently working on a comprehensive resolution including design changes, TS change submittal, and modification implementation, to ensure long term reliability of the CAR fans and dampers and NS system pumps.

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SAFETY ANALYSIS:

The VX system for Units 1 and 2 was declared inoperable on February 26, 1991 at 2057. This was as a result of the OE which determined that the tolerance of the bistable associated with the CPCS was so small that under certain accident conditions cycling of the VX system equipment could occur. Even though the equipment is designed to cycle, the number of acceptable cycles is unknown. Therefore, compensatory measures had to be taken. These measures included developing TO procedures and appointing a dedicated Control Room Operator to implement the procedure(s).

In the event of an accident scenario which required the VX system, it would have performed its design function, initially. However, the possibility existed of equipment failure as a result of exceeding the cycle duty of the system fans and dampers.

In the event of a VX system failure, an alternate method for controlling hydrogen pockets would have been available. The Hydrogen Mitigation System (EHM) is designed to prevent the accumulation of hydrogen for accidents which are beyond the design basis to the plant. If the VX system had failed, hydrogen concentrations might have slightly exceeded the design basis, but the EHM system would have prevented hydrogen accumulation to levels which would have threatened the Containment.

At the time the VX system failure would have been assumed to occur, Containment pressure would have been low, approximately 0.35 psig. At that point, Containment pressure control has been accomplished and sufficiently low pressures could have been maintained by the available Containment spray (ND system).

During the time the VX system was inoperable, there were no incidents that challenged the design function of the system.

The health and safety of the public were not affected as a result of this event.

NRC FORM 366A (9-83)

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	424/91-009
Event Description:	Instrumentation problems lead to RHR pump vortexing and loss of shutdown cooling during reactor cavity draindown.
Date of Event:	October 26, 1991
Plant:	Vogtle 1

Summary

During a refueling outage, after completion of core reload, a residual heat removal (RHR) pump was used to pump the reactor cavity inventory to the refueling water storage tank (RWST). The intent was to lower level to 2 ft below the reactor vessel flange to allow reinstallation of the vessel head; however, operational errors resulted in reduction of vessel level to below mid-loop. The RHR pump in service for decay heat removal experienced vortexing problems, and decay heat removal was lost for a period of about 50 min.

Event Description

After refueling operations were complete, the 1A RHR pump was used to pump down the reactor cavity to the RWST. RHR pump 1B was in service at the time for decay heat removal. The intent was to pump down level to 2 ft below the reactor vessel flange, equivalent to a plant reference elevation of 192 ft. An assistant plant operator (APO) was stationed in containment to monitor reactor level using a temporary tygon tubing sightglass. The control room cold-calibrated pressurizer level indicator was also monitored.

Misunderstanding his instructions, the APO proceeded to monitor a newly installed permanent reactor coolant system (RCS) level sightglass, which was isolated. About an hour later, when the APO was relieved by a plant equipment operator (PEO), the PEO noted that the sightglass isolation valves were closed and notified the control room. The PEO and the APO then attempted to correctly align the sightglass. At the time, a clearance tagout existed for the sightglass supply piping upper and lower isolation valves; however, the tag for the lower isolation valve was missing. The lower isolation valve was opened, but the upper valve was left closed and the existence of the clearance was not recognized. Believing that the sightglass was then providing accurate indication, the operators continued the draindown.

Subsequently, an alarm relating to vessel level caused operators to note a discrepancy between control room level indication and level reported by the PEO. The control room gauge initially indicated agreement with the value reported from the sightglass, 194 ft. However, when operators tapped on the gauge, indicated level dropped to 190.75 ft. The draindown was interrupted while operators conferred with an instrumentation and controls foreman, who suggested that the control room gauge could be in error. Confirming that the sightglass, the temporary tygon tubing, and visual observations of vessel level all indicated a level near the reactor vessel head flange, the control room operators decided to rely on the reported sightglass level as they proceeded with the draindown, at a rate of approximately 675 gpm (at this rate, reactor vessel level would be expected to drop about $^1/_2$ ft/min).

Both the temporary tygon tubing and the permanent sightglass were connected between the loop 1 intermediate leg and the pressurizer. The control room level instrumentation upper tap was connected to the pressurizer as well. A safety valve had been removed from the pressurizer to vent it to atmosphere; however, this opening had been aligned via a flexible hose to the suction of a fan-driven high-efficiency particulate air (HEPA) filtration unit. The suction from the HEPA filter fan and the falling RCS level caused a partial vacuum to develop in the pressurizer, and the hose connection to the filter collapsed. The vacuum that resulted as pressurizer level continued to drop caused the level instrumentation in use to indicate a falsely high level.

Approximately 16 min after resuming the draindown, the indicated RCS level had dropped about 1 ft to around 193 ft when operators noted oscillations in the indications of discharge pressure, flow, and motor current for RHR pump 1B. Concluding that the pump was cavitating or vortexing, they placed it on minimum flow recirculation. Control room instrumentation was then observed to indicate a level around 187 ft, corresponding to vessel mid-loop elevation. Presumably, once RCS level stopped dropping, pressure in the pressurizer stabilized at a value close to atmospheric, and the control room level indication was approximately correct. The 1A RHR pump was aligned to the RWST and used to increase RCS level by roughly 3 or 4 ft. An attempt was then made to restore shutdown cooling, but signs of pump cavitation were noted. The 1A pump was again aligned to make up from the RWST, and RCS level was raised to 194 ft. RHR pump 1B was then realigned for shutdown cooling and operated satisfactorily. Shutdown cooling was unavailable for a total of about 50 min, during which time the RCS temperature increased 19 degrees to 107°F.

ASP Modeling Assumptions, Approach, and Results

During this event the reactor head was removed. Had the RHR pumps failed, successful core cooling would have required sufficient makeup flow to compensate for boil-off, which could have been provided by gravity feed from the RWST or through use of a safety injection or charging pump. Because of the time available, all valve operations could have been performed manually, which considerably increases the likelihood that reactor vessel makeup could have been provided before core uncovery. The core damage probability estimated for this event is $<10^{-6}$, and therefore the event was not identified as an accident sequence precursor.

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER)

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APR 29 1992

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TITLE (4)
LOSS OF RESIDUAL HEAT REMOVAL PUMP FLOW DURING DRAINDOWN OF REACTOR CAVITY

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ NUM	REV	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 0	2 6	9 1	9 1	0 0 9	0 0	11	22	91		0 5 0 0 0

OPERATING MODE (9): 6

POWER LEVEL: 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR (11)

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	AREA CODE	TELEPHONE NUMBER
MEHDI SHEIBANI, NUCLEAR SAFETY AND COMPLIANCE	404	826-3209

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORT TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORT TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

On October 26, 1991, Unit 1 was in a refueling outage. Core reload was complete but the reactor head had not been installed and the reactor cavity was flooded. At 1833 EDT, the 1A residual heat removal (RHR) pump was started to lower the cavity to just below the reactor flange to allow reinstallation of the head. During the last segment of the draindown evolution, indications of vortexing and air entrainment were observed for the 1B RHR pump which was operating at a higher flowrate in the shutdown cooling mode. Operators took action to reduce the flow of the 1B pump and to stop the draindown via the 1A pump. However, the discharge pressure for the 1B pump remained low. A subsequent review of computer data indicated the 1B pump was operating at or near no-flow conditions. The 1A pump was realigned to raise the reactor coolant system (RCS) level. Reduced shutdown cooling, via the 1B pump, was reestablished within 16 minutes from the time the 1B pump started showing indication of vortexing, and full shutdown cooling was reestablished within 50 minutes.

The event was caused by inaccurate RCS level indication due to an inadequate pressurizer vent path. A pressurizer safety valve had been removed, and it was thought that an adequate vent path existed; however, a high efficiency particulate air (HEPA) filter had been attached (via a flexible duct) to the flange opening for the safety valve and obstructed the vent, causing a vacuum to develop during the draindown resulting in false high RCS level indication.

Corrective actions include revising procedures to ensure verification of vent paths for all evolutions and tightening controls for HEPA filter installations.

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A. REQUIREMENT FOR REPORT

This report is required per 10 CFR 50.73 (a)(2)(v) since the inadvertent draining of the reactor coolant system (RCS) to a level less than that indicated by available level instrumentation could have potentially prevented the fulfillment of the residual heat removal (RHR) safety function of the RHR system.

B. UNIT STATUS AT TIME OF EVENT

Unit 1 was shut down in Mode 6 (Refueling) with the reactor vessel head removed. Core reload had been completed and the upper internals had been reinstalled. The Train B RHR pump was aligned to provide recirculation shutdown cooling and was operating at a flowrate of approximately 3000 gal/min. The Train A RHR pump was aligned to drain the reactor cavity by taking suction from the RCS loop 1 hot leg and discharging to the refueling water storage tank (RWST) and was operating at a flowrate of approximately 675 gal/min. RCS system temperature was approximately 88 F and RCS pressure was atmospheric since the reactor head was removed.

C. DESCRIPTION OF EVENT

At 1724 EDT on October 26, 1991, post refueling operations were initiated per the instructions of Unit Operating Procedure 12000-C, "Post Refueling Operations (Mode 6 to Mode 5)." The reactor cavity water level was at an elevation of 210 ft 4 in. and the first major task to be accomplished was to lower the level to 192 ft (i.e., 2 feet below the reactor vessel head flange level) to allow the reinstallation of the reactor vessel head. (Note: Unit 1 "mid-loop" elevation is 187 ft and reduced inventory controls are required by procedure whenever level is reduced below 191 ft.) To lower the level, Procedure 12000-C directs the operator to establish draining using the RHR system per operating instructions provided in Procedure 13011-1, "Residual Heat Removal System."

Prior to commencing the draindown, control room operators contacted Maintenance Department and Outage Support personnel to determine the status of the pressurizer code safety valves. Information was provided that one of the code safety valves was removed. Just prior to the start of cavity draining, an assistant plant operator (APO) in the Unit 1 containment was contacted and directed to establish a watch at the tygon tube which is used for monitoring RCS level during draindown and "mid-loop" operations. During the outage, a modification had been implemented to install a "permanent" sight glass (a permanently installed piping system connected to a tygon tube with a mounted scale) in the Unit 1 containment for use in monitoring RCS level. Although it had been installed, the new sight glass had neither been tested nor released for operations use. The APO was not aware of the modification status of the new sight glass. He had noticed the sight glass after it was installed, had received training on the sight glass, and during the previous Unit 2 outage, had seen an identical sight glass being monitored in the Unit 2 containment. Therefore, the APO interpreted the control room instruction as direction to monitor the new "permanent" sight glass versus the backup "temporary" tygon tube which is installed and removed during each refueling outage. Based on his understanding, the APO proceeded to the new sight glass and established communications for monitoring the draindown.

At 1833 EDT, the draindown was started with the 1A RHR pump being used to pump water at a flowrate of approximately 1000 gal/min to the RWST. The 1B RHR pump was opera[illegible] to provide recirculation shutdown cooling at a flowrate of approximat[illegible]00 gal/min. At 1848 EDT, the night shift unit shift supervisor (USS) [illegible]ved the day shift USS. [illegible] reactor cavity water level was noted to be [illegible] elevation of approximately [illegible] ft as indicated by the pressurizer cold calibrated level indicator ([illegible]). At 1930 EDT, a night shift plant equipment operator (PEO) arrived in the Unit 1 containment to relieve the day shift APO who was perf[illegible] the tygon tube wat[illegible] control room reported that level was approximately 207 ft. This me[illegible] sight glass being monitored should be coming on scale; howe[illegible] no level indication could be observed in the sight glass as yet. Investigation by the oncoming PEO then found the permanent sight glass was not valved-in correctly. The control room was informed and the draindown was stopped while the problem was investigated. The PEO and the APO then proceeded to valve-in, fill, and vent the permanent sight glass and the sight glass level rose to 205 ft 6 in. In valving-in the permanent sight glass, the PEO and the APO did not utilize procedural guidance and, consequently, an upper isolation valve was inadvertently left closed. This error was not recognized at the time, apparently because the level indicated by the permanent sight glass was then consistent with the level indicated by the temporary tygon tube and with control room indication. The sight glass was believed to be providing an accurate indication of level.

At approximately 2010 EDT, the draindown was resumed. A draindown flowrate of approximately 1000 gal/min was maintained until indicated reactor cavity level was at 202 ft 6 in. The flowrate was then increased to a reading of approximately 2500 gal/min, which was maintained until the indicated level was at 197 ft. The flowrate was then reduced to approximately 1800 gal/min, and within approximately 6 minutes, to approximately 900 gal/min.

At 2200 EDT, with a reactor cavity level of approximately 194 ft being reported by the tygon tube watch, annunciator ALB06 D03, "Accumulator #4 Hi/Lo Level," was received in the Unit 1 control room. This annunciator was part of a recently added modification to provide a temporary RCS high level alarm (setpoint 192 ft 6 in) during refueling operations. On receiving the annunciator, the control room reactor operator observed level indicator

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1LI-957 to be at top of scale (100 percent) and tapped on the indicator. This caused 1LI-957 level indication to drop to 60 percent (i.e., 190 ft 9 in). The draindown was stopped by realigning the A RHR pump so that it temporarily recirculated to the RCS. The PEO performing the sight glass watch was directed to visually verify RCS level. The PEO reported that the level appeared to be even with the reactor vessel head flange (194 ft), which agreed with the level indicated by the permanent sight glass and the temporary tygon tube. The control room contacted an Instrumentation and Controls (I&C) foreman and discussed the 1LI-957 indicated level. The I&C foreman indicated that the reference leg for 1LI-957 might need to be filled. Therefore, it was decided that 1LI-957 was not providing an accurate indication of level and, since it was believed that three reliable indications of level (i.e., vessel visual, the permanent sight glass, and the temporary tygon tube) were available, it was decided to continue with the draindown to 192 ft.

At approximately 2217 EDT, the draindown was resumed at a reduced flowrate of approximately 675 gal/min. At approximately 2233 EDT, with a level of approximately 193 ft being indicated by the sight glass, a control room operator observed discharge pressure, flow, and motor current oscillations for the 1B RHR pump, indicating that vortexing or cavitation of the pump was occurring. Operator action was taken as directed by Abnormal Operating Procedure 18019-C, "Loss of Residual Heat Removal," to close the discharge valves for the 1B RHR pump, putting the 1B RHR pump on miniflow. Motor current readings for the 1B RHR pump stabilized; however, discharge pressure remained low. At this time, 1LI-957 was observed to be at approximately 30 percent (i.e., 188 ft 3 in) and narrow range instrument 1LI-950 was observed to be at approximately 60 percent (i.e., 187 ft 6 in).

At approximately 2234 EDT, the draindown was stopped by closing the discharge valves for the 1A RHR pump so that it was operating on miniflow. The 1A RHR pump was then shut down and its suction was realigned to the RWST. At approximately 2239 EDT, the 1A RHR pump was restarted and operated at a flowrate of approximately 400 gal/min to transfer water from the RWST back to the RCS. Shortly after beginning the refill of the RCS, the discharge pressure of the 1B RHR pump began to show some improvement and a recirculation cooling flow of approximately 350 gal/min was reestablished. At approximately 2244 EDT, the 1A RHR pump discharge valves were closed, placing the 1A RHR pump on miniflow. The 1A RHR pump suction was realigned to the RCS and leakage through the discharge valve provided a recirculation cooling flow of approximately 350 gal/min. At this time, an attempt was made to increase the recirculation cooling flow of the 1B RHR pump. However, after increasing flow to approximately 2600 gal/min, indications of vortexing or cavitation were again observed. The 1B RHR pump flow was reduced to 1800 gal/min and the pump operated satisfactorily with no indication of vortexing or cavitation. (Note: A subsequent review of computer data indicated that RCS temperature began to decrease at this time.) Additional refill of the RCS appeared to be required to obtain

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full recirculation cooling flow of the 1B RHR pump. Therefore, the 1A RHR pump was again aligned to take suction from the RWST.

At approximately 2256 EDT, the refill of the RCS was reinitiated at a flowrate of approximately 400 gal/min. The refill was terminated at approximately 2310 EDT, and level as indicated by the sight glass was 194 ft 10 in. A visual check of the reactor vessel level was made and level appeared to be almost even with (i.e., 1 in below) the vessel flange. At approximately 2316 EDT, another attempt was made to obtain full recirculation cooling flow for the 1B RHR pump. The 1B RHR pump flow was increased to approximately 3000 gal/min and the pump operated satisfactorily with no indication of vortexing or cavitation.

Due to concerns about the adequacy of the level instrumentation that was monitored during the draindown, a senior reactor operator (SRO) and a PEO were dispatched to containment to walkdown the tygon tube and the sight glass level indicators. They found the upper isolation valve for the sight glass closed and hold-tagged. This indicated that a clearance was in effect for the sight glass. Subsequent investigation determined that a hold tag had also been installed on the lower isolation valve but must have fallen off since it was not present at the time the sight glass was put in service. The clearance for the sight glass was released and the upper isolation valve was opened. It was also discovered that a HEPA filter unit was connected via a flexible duct, to the opening where the pressurizer safety valve had been removed. At the time of discovery, the HEPA unit was running and the flexible duct was found collapsed. The collapse was apparently due to the vacuum created by the running HEPA filter and RCS draindown. The HEPA unit was turned off and a vent port on the unit was opened to relieve the vacuum on the pressurizer.

D. CAUSE OF EVENT

The direct cause of the event was false high RCS level indications which led to the RCS level being inadvertently lowered to the point where vortexing occurred. The false high indications of level were caused by an inadequate pressurizer vent path and by the closed upper isolation valve for the sight glass. RCS level instrumentation utilized at VEGP for mid-loop and reduced inventory operations provides level indication based on differential pressure as measured between the hot legs of RCS loops 1 and 4 and the pressurizer (for the level transmitters) and between the intermediate leg of RCS loop 1 and the pressurizer (for the permanent sight glass and the temporary tygon tube). The pressurizer serves as a common reference point for all mid-loop reduced inventory level instrumentation (wide range and narrow range indication provided in the control room, and permanent sight glass and temporary tygon tube indication available in containment). Consequently, any blockage of the pressurizer vent path would affect all reduced inventory level instrumentation. During a draindown of the RCS, a vent path blockage such as that which occurred in this event would induce a vacuum on the reference leg of this instrumentation inducing a false high indication. Although engineering review has determined that no permanent damage would have occurred to the instrumentation, each channel would have presented a false high indication. While the sight glass was actually

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isolated from the pressurizer (due to the upper isolation valve being inadvertently left closed), the valving error also made it subject to vacuum effects and explains why it also presented a false high indication of level.

The root cause of the event was procedure inadequacy. Procedures for reducing RCS level during refueling operations provide sufficient steps to ensure the proper installation of level instrumentation and the adequacy of vent path(s) during the initial RCS draindown; however, sufficient steps to reverify these items were not included in the procedures for the subsequent draindown evolution. Additionally, administrative controls were inadequate in addressing the reviews and documentation required for the attachment of HEPA filter units to plant equipment. In this case, the HEPA filter unit was installed without a temporary modification or a work order. Since such controls were not applied, the control room was not aware of the installation.

A contributing cause was the failure of the operating staff to sufficiently investigate the cause for the receipt of the RCS "high" level annunciator or the cause for the ensuing "low" level indication of 1LI-957. Had troubleshooting or a containment walkdown of the level instrumentation been initiated at the time of these occurrences, then the problem affecting the level instrumentation may have been recognized. One of the causes for not implementing troubleshooting of 1LI-957 at that time was apparently the reliance placed on the visual verification of RCS level. Since the upper internals were installed, it cannot readily be determined whether this was an accurate indication of level since the upper internals tend to retain water. The lack of awareness by the operators of the specific status of the permanent sight glass modification is seen as an additional contributing cause. Since the sight glass confirmed the temporary tygon tube and visual level indications, operators felt that they had multiple accurate level indications. On this basis, they delayed troubleshooting of 1LI-957.

E. ANALYSIS OF EVENT

Certain items were noted which helped to lessen the consequences of the event. The first was the operating crews' practice of assigning a dedicated reactor operator to monitor the RHR system during the draindown evolution. The second was the extensive training the operators had received on industry events involving loss of RHR. This included training and simulator scenarios on operator response to a loss of RHR during the requalification training segment prior to the refueling outage. In addition, a previously implemented modification allowed trending of RHR pump motor current on the emergency response facility (ERF) computer display. Together, these factors helped the operators diagnose the occurrence of vortexing and take corrective actions to mitigate the effects of the event.

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During the event, the 1B RHR pump was unavailable to provide recirculation shutdown cooling for approximately 16 minutes and full recirculation cooling flow was not reestablished until approximately 50 minutes after the first indications of vortexing and air ingestion. While a subsequent review of computer data indicates that the pump was operated at or near no-flow conditions for approximately 13 minutes, all available data indicate that the pump experienced vortexing but did not experience cavitation. When vortexing occurs, it causes air to enter the suction of the pump. This will cause the pump performance to decrease but will not necessarily cause damage to the pump such as would be expected should cavitation occur. However, if enough air is introduced into the suction of the pump, it will cause the pump to become air bound and the pump flow to stop. When flow stops, it is possible to overheat and subsequently damage the pump. Due to concerns that operation of the 1B RHR pump under these conditions may have caused damage to the pump, vibration measurements and comparison with the pump's characteristic curve were satisfactorily completed on October 28, 1991, with no indication of pump damage. On November 1, 1991, the inservice test (IST) for the pump was reperformed. The results of the IST confirmed that no degradation of the 1B RHR pump had occurred.

For the 1A RHR pump, operator action was effective in preventing degradation of the pump. After observing indications of vortexing for the 1B RHR pump, control room operators responded appropriately per the contingency actions provided in AOP 18019-C for such an event. This included operator action taken to reduce the flow of the 1B RHR pump, stop the RCS draindown via the 1A RHR pump, and realign the 1A RHR pump to raise RCS level. Based on our understanding of the event at the time, a determination was made on October 26, 1991, that the event did not represent a reportable condition pursuant to 10 CFR 50.72 (b)(2)(iii). However, a subsequent detailed review of computer data which were not available to the operators at the time of the event indicated that possible air ingestion for the 1A RHR pump may have started to occur shortly before the pump's discharge valve was closed. This manifested itself in the form of a slightly reduced discharge pressure and flow. Based on this new information from the post-event critique, a determination was made that the event could have possibly prevented the fulfillment of the RHR function of the RHR system. Therefore, an Event Notification pursuant to 10 CFR 50.72 (b)(2)(iii) was made on November 6, 1991. Although the 1A RHR pump had not been operated under any apparent adverse conditions, the IST for the 1A RHR pump was also reperformed. No degradation in pump performance was indicated by the IST for the 1A RHR pump.

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The lowest RCS level occurred at the time the 1A RHR pump's heat exchanger discharge valve was closed. As noted above, there is some evidence to suggest that air ingestion for the 1A RHR pump may have started to occur at that time. Based on our analysis of the available data, the lowest RCS level during the event was in the range of elevation 186 to 187 ft.

While Georgia Power Company now believes that a possibility did exist for a loss of RHR as provided by the RHR system, calculations have determined that the event did not pose any threat to plant safety or the health and safety of the public. The estimated decay heat being produced at the time of the event was 0.1022 E8 Btu/hr. A subsequent review of RHR heat exchanger inlet temperature data suggests that the RCS actually experienced an average heatup of 19 F (i.e., 88 F to 107 F), which is reasonable considering the maximum calculated local RCS temperature. The maximum local RCS temperature was calculated to be approximately 116 F. Further calculations were made to determine the time before boiling and the core uncovery based on conditions at the time of the event and assuming a total loss of RHR and no makeup to the RCS. The time to boiling was determined to be 82 minutes and the time to core uncovery was determined to be 543 minutes. It was also calculated that a flowrate of approximately 400 gal/min, either from the RWST or by one of the RHR pumps operating in the shutdown cooling mode, would have maintained the RCS water temperature at or below 140 F. If needed, the calculated required flowrate of 400 gal/min could have been supplied by aligning a centrifugal charging pump or a safety injection pump to take suction from the RWST. Therefore, it is concluded that the event did not represent a potential for causing a release or an adverse radiological condition either within containment or external to the plant. Furthermore, the containment equipment hatch was in place and negated the need for precautionary action to replace it.

F. CORRECTIVE ACTIONS

1. All procedures used for draindown of the reactor vessel will be reviewed to ensure sufficient steps are included for verification of vent path adequacy for all draindown evolutions. Additionally, the review will ensure that precautions are included as applicable regarding the use of visual verification from the refueling deck as a reliable means of determining RCS level during draindown evolutions with the upper internals installed. Procedure revisions, as necessary, are expected to be completed by December 30, 1991 (prior to future "mid-loop" operations).

2. Administrative controls will be revised to ensure appropriate reviews and documentation for the attachment of HEPA filter units to plant equipment. This revision is expected by January 15, 1992.

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3. The reduced inventory RCS level instrumentation will be reviewed for procedural or hardware modifications to reduce common mode effects of a single vent path. This review is expected to be complete by January 15, 1992.

4. Shift personnel involved in the event have been appropriately disciplined and counseled regarding the need for additional emphasis on maintaining awareness of plant configuration status and for investigating problems/inconsistencies noted during major evolutions.

5. A case study will be developed by the personnel involved in the event and will be presented to the Operations staff. The case study will emphasize lessons learned from the event, including the importance of establishing an adequate vent path; the proper steps that should have been taken for the problems/inconsistencies that occurred during the event; the importance of utilizing procedural guidance for placing the sight glass in service; and the need for appropriate communications, turnovers, and briefings. The case study is expected to be presented by March 1, 1992.

6. The modification status system will be reviewed for possible enhancements to make modification status more readily available to the Operations staff. Revisions to the program, as necessary, are expected to be complete by January 21, 1992.

7. Abnormal Operating Procedure 18019-C will be reviewed against Westinghouse Abnormal Response Guideline ARG-1, "Loss of RHR While Operating At Mid-Loop Conditions," to evaluate the adequacy of specified actions for stopping a RHR pump or other actions to take after indications of vortexing or pump cavitation are observed. This review is expected to be complete by December 30, 1991.

G. ADDITIONAL INFORMATION

1. Failed Components Identification

   None.

2. Previous Similar Events

   None.

3. Energy Industry Identification System Codes

   Reactor Coolant System (PWR) - AB

   Residual Heat Removal System (PWR) - BP

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	528/91-001
Event Description:	Reactor coolant pump seal heat exchanger tube failure could result in non-isolable loss of coolant outside containment.
Date of Event:	January 10, 1991
Plant:	Palo Verde 1

Summary

An engineering analysis at Palo Verde determined that the failure of a reactor coolant pump (RCP) seal cooler tube could result in a nonisolable loss-of-coolant (LOCA) accident outside containment, if the cooler inlet or outlet valve to the reactor coolant system (RCS) could not be closed. These valves are not supplied with emergency power.

Event Description

RCP seals at Palo Verde are cooled by heat exchangers in which heat is transferred to the nuclear cooling water system (NCWS). Failure of a cooling water tube in an RCP seal heat exchanger would allow high-pressure RCS inventory to flow into the low-pressure NCWS. Motor-operated isolation valves are provided on the RCS inlet and outlet connections to the seal heat exchangers, but they are not provided with an emergency power supply. Should a seal heat exchanger tube fail, failure to manually close the inlet or outlet motor-operated valve, or loss of normal power supplies, could result in a nonisolable loss of reactor coolant to the NCWS. As neither NCWS cooling nor seal charging flow could be provided to the affected RCP seal, the RCP seal would be degraded. An engineering analysis performed by Palo Verde determined that as much as 58 lb/mass/s (roughly 600 gpm) would flow into the NCWS in this case.

NCWS supply pressure is less than 80 psig, and return pressure is only a few pounds above atmospheric. Since the associated pumps, valves, and piping are rated for low-pressure application, the NCWS containment isolation valves could not be relied upon to isolate the postulated failure, and an unisolated seal heat exchanger failure would therefore result in overpressurization of the NCWS. Overpressure protection is provided for the NCWS at the system surge tank, located on the auxiliary building roof. A small relief valve is connected to the tank by a 2-in. diameter line. The utility indicates that the flow into the NCWS would exceed the capacity of the relief valve, resulting in failure of the surge tank, which has a design pressure of 15 psig. This would fail the NCWS and permit the escape of reactor coolant to the environs. The utility analysis indicates that as much as 487,600 gal of reactor coolant leakage could be expected before RCS pressure would drop sufficiently to allow isolation of the leak.

An evaluation of the radiological consequences of these failures indicated that, under design basis conditions, offsite doses would exceed 10CFR100 limits within 30 min. At the time of the evaluation, fuel failures and reactor coolant activity were less than assumed in the design basis, and potential offsite doses were calculated at values below the 10CFR100 limits.

Additional Event-Related Information

The NCWS supplies cooling to nonsafety-related potentially radioactive heat loads. These include sample coolers, radwaste loads, nonsafety-related HVAC chillers, the letdown heat exchanger, fuel pool cooling heat exchangers, control element drive mechanism (CEDM) coolers, an auxiliary steam vent condenser, the RCP motor coolers, and the RCP seal coolers.

Closed cooling for safety-related loads is provided by the essential cooling water system (ECWS). Its loads include the shutdown heat exchangers and the essential HVAC chillers. It is possible to crosstie the ECWS to the NCWS to supply certain NCWS loads, including the fuel pool cooling heat exchangers, normal HVAC chillers, RCP seal and motor coolers, and the CEDM coolers. By design, the ECWS will not be used to cool RCP heat exchanger loads after a loss of coolant accident.

There are four RCPs in the primary system at Palo Verde. The seals on each pump are normally cooled by NCWS as well as by seal injection flow supplied by the charging pumps. During the scenario postulated, NCWS would be lost to all RCPs. Maintenance of injection to the pump seals not impacted by the heat exchanger tube failure should ensure their continued integrity. This might require closure of the air-operated injection isolation valve for the failed seal. Failure of this "fail-open" valve to close or remain closed could possibly increase accident severity by allowing additional RCP seal failures.

ASP Assumptions and Approach

This event was identified as containment related and was not modeled as an accident sequence precursor.

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TITLE (4): Postulated Reactor Coolant System Leak Not Included In Design Basis

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 NAMES	DOCKET NUMBER(S)
									Palo Verde Unit 2	0 5 0 0 0 5 2 9
0 1	1 0	9 1	9 1	— 0 0 1 —	0 0	0 2	1 1	9 1	Palo Verde Unit 3	0 5 0 0 0 5 3 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[X] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Thomas R. Bradish, Compliance Manager	6 0 2	3 9 3 - 2 5 2 1

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
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

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

At approximately 1500 MST on January 10, 1991, Palo Verde Units 1, 2, and 3 were in MODE 1 (POWER OPERATION) at approximately 100 percent power when PVNGS Engineering determined that a postulated break in a Reactor Coolant Pump (RCP) high pressure seal cooler could result in a reactor coolant system (RCS) leak outside containment. A conservative evaluation of this postulated event based on assumptions used in the Standard Review Plan (NUREG 0800) determined that the Exclusion Area Boundary cumulative thyroid dose could exceed 10CFR100 limits. An evaluation based on existing RCS activity showed that doses would be a small fraction of 10CFR100 limits.

The cause was that a tube rupture in the seal cooler and its effect was not considered in the original plant design.

Immediate corrective actions were taken to: 1) monitor RCS activity to ensure 10CFR100 limits would not be exceeded as a result of this postulated event and 2) monitor the Nuclear Cooling Water System to provide early detection of a seal cooler leak. A design change is being developed to mitigate the postulated event described in this LER. The design change is expected to be completed in Units 1, 2, and 3 by July 1993.

No previous similar events have been reported in accordance with 10CFR50.73.

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

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

At approximately 1500 MST on January 10, 1991, Palo Verde Units 1, 2, and 3 were in MODE 1 (POWER OPERATION) at approximately 100 percent power.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: A condition that was outside the design basis of the plant.

At approximately 1500 MST on January 10, 1991, PVNGS Engineering determined that a postulated break in the Reactor Coolant Pump (RCP)(P)(AB) high pressure seal cooler (SEAL)(CLR)(AB) could result in a reactor coolant system (RCS)(AB) leak outside the Containment building (NH). A conservative evaluation of this postulated event based on the assumptions used in NUREG 0800, Standard Review Plan (SRP) determined that the Exclusion Area Boundary (EAB) cumulative thyroid dose could exceed 10CFR100 limits. An evaluation of this postulated event based on existing RCS activity showed that doses would be a small fraction of 10CFR100 limits. The evaluation also showed that this postulated event would not result in any fuel damage.

During an evaluation based on the recommendations in NRC Information Notice 89-54, "Potential Overpressurization of the Component Cooling Water System," PVNGS Engineering identified a postulated scenario in which a double ended guillotine break of a RCP seal cooler tube could result in overpressurization of the Nuclear Cooling Water System (NCWS) (CC) and therefore, the potential existed for a leakage path outside of Containment. This failure could result in high pressure, high temperature RCS fluid entering the low pressure, low temperature NCWS piping. Most of the RCS leakage would flow from the RCP body through clearances between the impeller hub and bearing sleeve, through a clearance between the bearing sleeve and stop seal, into a flow passage in the bearing sleeve, and through drilled clearances in the RCP seal housing. This leakage would then proceed to the RCP seal cooler via the seal cooler inlet valve (ISV)(AB). A parallel flowpath would also be established past the journal bearing and the RCP seal cooler outlet valve (ISV)(AB).

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APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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Calculations using two-phase choked flow models, assuming only the hydraulic resistance of the limiting restriction in the flow path, indicate the initial leakage flow rate through a doubled ended guillotine break of the tube would be approximately 58 pounds mass per second (lbm/sec). Since NCWS containment isolation valves (ISV)(CC) are not designed to isolate or remain isolated against pressures that could result from this RCS leakage, RCS fluid from the tube failure is postulated to flow into the NCWS providing a potential release path outside Containment through the NCWS surge tank pressure relief valve (TK)(RV)(CC) on the Auxiliary Building (NF) roof. This relief valve [set at 10 pounds per square inch gauge (psig)] discharges to an open atmospheric scupper on the Auxiliary Building roof. Since the magnitude of the break exceeds the capacity of the pressure relief valve, the design pressure of the surge tank (15 psig) could be exceeded.

In addition to the above, a postulated catastrophic high pressure cooler tube rupture may simultaneously initiate degradation of the RCP seals of the affected pump because cooling and lubricating flow would be diverted to the break and any residual fluid remaining in the seal housing would be evacuated via the auxiliary impeller in the RCP seal housing. However, this degradation does not increase the radiological consequences of this postulated event since the leakage would be confined to Containment.

The NCWS is a closed loop cooling system which provides cooling water to numerous heat exchangers that contain radioactive water. The NCWS is constantly monitored by an on-line radiation monitor (MON)(IL) which alarms in the Control Room (NA) when the cooling water activity reaches a maximum preset level. The radiation monitor is capable of detecting RCS in-leakage of 0.08 gallons per minute (gpm) within one hour after the leak begins.

An evaluation of the radiological consequences of this scenario using postulated design basis conditions [i.e, constant, continuous reactor coolant leakage rate and accident dose parameters (iodine spiking factors, reactor coolant activities corresponding to one percent failed fuel and no operator actions) as specified in the SRP for Chapter 15 FSAR analysis] indicates that EAB cumulative thyroid dose could exceed 10CFR100 limits within 30 minutes. An evaluation using existing conditions at PVNGS showed that EAB dose will be limited to a small fraction of 10CFR100 limits. Evaluations of limiting design basis events also show that this postulated event would not result in fuel failure.

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C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

Not applicable - no structures, systems, or components were inoperable at the start of the event which contributed to this event.

D. Cause of each component or system failure, if known:

Not applicable - no component or system failures were involved.

E. Failure mode, mechanism, and effect of each failed component, if known:

Not applicable - no component failures were involved.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no component failures were involved.

G. For a failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

Not applicable - no failures were involved which rendered a train of a safety system inoperable.

H. Method of discovery of each component or system failure or procedural error:

Not applicable - there have been no component or system failures or procedural errors identified.

I. Cause of event

The postulated event discussed in Section I.B was not considered in the original design of the plant (SALP Cause Code B: Design, Manufacturing, Installation Error). The design basis of the RCP seal coolers described in the Combustion Engineering Standard Safety Analysis Report (CESSAR) and the NRC Safety Evaluation Report for Palo Verde was that any leakage from the RCS would be detected by a combination of the NCWS radiation monitors and the high surge tank level switches which alarm in the Control Room. Once leakage is detected it would be isolated using the RCP seal cooler isolation valves. The possibility of a tube rupture in the seal cooler and its subsequent effect on the NCWS was not considered in the original plant design.

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No unusual characteristics of the work location (e.g., noise, heat, poor lighting) contributed to this postulated event. The postulated event was not a result of personnel errors nor procedural errors.

J. Safety System Response:

Not applicable - there were no safety system responses and none were necessary.

K. Failed Component Information:

Not applicable - no component failures were involved.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

The postulated event discussed in Section I.B would be a small break loss of coolant accident (LOCA) based on the criteria specified in operating procedures. Control Room personnel would respond by entering and executing the actions for a small break LOCA. RCP alarm response procedures would direct the operators to close the seal cooler isolation valves to terminate the event. The valves are designed to operate against full differential RCS pressure, however they do not receive emergency power. If the affected seal cooler could not be isolated, the RCS would be depressurized to allow the NCWS containment isolation valves to be closed to isolate the leak.

A conservative evaluation of the radiological consequences of a postulated guillotine break of the RCP seal cooler tubing was performed. This evaluation used a constant, continuous reactor coolant leakage rate to the atmosphere of 58 lbm/sec and accident dose parameters (i.e., iodine spiking factors, reactor coolant activities corresponding to one percent failed fuel, no operator action to isolate the leak, etc.) assumed in the SRP for Chapter 15 accident analyses. The evaluation assumed all of the leakage was released to atmosphere and took no credit for iodine partitioning factors. This evaluation indicates the EAB cumulative dose would exceed 10CFR100 limits for dose to the thyroid within 30 minutes of the postulated event. If iodine partitioning factors, flashing and time dependent leakage were considered in this analysis, the results would be less than 10CFR100 limits.

An evaluation of the consequences of the postulated guillotine break of the seal cooler tubing was also performed using existing conditions at PVNGS rather than the conservative parameters specified in the SRP. The evaluation used an iodine spiking factor of 40, iodine 131 dose equivalent concentration of 8.0E-2 microcuries per milliliter (uci/ml) and eight failed fuel pins, all based on actual worst case data for

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PVNGS Units 1, 2, and 3. An initial, continuous reactor coolant leak rate to the atmosphere of 58 lbm/sec (i.e., no credit taken for reduced leak rate due to system depressurization), no operator action, no partition factor, and accident (SEP specified) Chi/Q values were conservatively used. This evaluation resulted in radiological consequences which are a small fraction of 10CFR100 limits. The EAB 2 hour cumulative thyroid dose would be 10.2 Rem and the Low Population Zone (LPZ) 24 hour cumulative thyroid dose would be less than 13 Rem. The 30 day Control Room thyroid dose was calculated to be 1.9 Rem.

The potential leak was also evaluated based on leak before break criteria. If a leak were to develop by some preexisting flaw or unidentified mechanism, the low stresses in the piping would result in a stable crack up to a leak rate of approximately 1.3 gpm. This stable crack size was determined using the methodology of NUREG/CR-4572 "NRC Leak Before Break (LBB.NRC) Analysis Method for Circumferential Through-Wall Cracked Pipes Under Axial Plus Bending Loads," which includes loads during normal operation and a safe shutdown earthquake. NUREG 1061 "Evaluation of Potential for Pipe Breaks," requires the application of a factor of safety of two to the critical crack size to arrive at a leakage crack size. The resulting leak rate including this safety factor is 0.8 gpm. Recognizing that the tubing would leak before breaking, NUREG 1061 requires that the leak detection system used be capable of detecting a leak equivalent to one tenth of the leak rate expected from the leakage crack size. In this case that value would be 0.08 gpm. On-line radiation monitoring and chemical sampling are capable of detecting leakage at this level.

An evaluation of the radiological consequences of small leakage through the high pressure seal cooler tubing was performed based on leak before break criteria. This evaluation was based on a constant leak rate of 1.3 gpm to conservatively bound the maximum stable crack size leak rate analyses. The evaluation assumed reactor coolant activity corresponding to one percent failed fuel, a partition factor coefficient for iodine species of 0.01, and accident Chi/Q values. The results show that for this scenario, the radiological consequences are well below 10CFR100 limits. The EAB 2 hour cumulative thyroid dose would be approximately 1.7E-5 Rem and the LPZ 8 hour thyroid dose would be approximately 4.1E-5 Rem.

Due to uncertainties in the failed fuel predictions and the spiking factor, PVNGS will monitor RCS I-131 dose equivalent concentration levels. If these values exceed a level of 3E-1 uci/cc RCS I-131 dose equivalent, EAB doses will be reevaluated and additional actions will be taken if required. With the activity at or below this level, offsite doses will be limited to a small fraction of 10CFR100 limits.
The double ended guillotine break of RCP seal cooler tubing was

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evaluated to assess the potential for causing fuel failure by examining the spectrum of break sizes for a small break LOCA. A failure of the RCP seal cooler would correspond to a break size of 0.0047 square feet. The smallest break size evaluated for small break LOCA analysis is 0.02 square feet, and does not result in fuel failure. This break size bounds all break sizes less than 0.02 square feet, and is considered bounding for this postulated event. Based on this analysis, the RCP seal cooler tube failure postulated event would not result in fuel failure.

The capability of the Refueling Water Tank (RWT)(TK)(BP) to provide makeup water for this postulated event was evaluated and the RWT inventory demand was determined to be approximately 487,600 gallons. Technical Specification 3.1.2.6 specifies a minimum RWT inventory of 600,000 gallons, based on an RCS average temperature of 565 degrees Fahrenheit. Therefore, the RWT inventory is adequate for this postulated event.

Based on these evaluations, it is concluded that although the consequences of a postulated guillotine break of the seal cooler tubing using SRP specified parameters exceeds regulatory limits, an evaluation of this postulated event using existing PVNGS data demonstrates radiological consequences below 10CFR100 limits. An evaluation of the small leakage that might occur before identification and isolation based on the application of leak before break criteria also demonstrates radiological consequences below 10CFR100 limits.

III. CORRECTIVE ACTION:

A. Immediate:

The consequences of this postulated event were evaluated and a Justification for Continued Operations (JCO) was developed and submitted to the NRC (161-03709-WSC/JST, dated January 18, 1991).

To ensure that any leak of the RCP seal cooler will be detected in a timely fashion the following compensatory measures (only applicable in Modes 1 through 4, POWER OPERATION through HOT SHUTDOWN) have been put in place:

1. Chemistry sampling and abnormal occurrence procedures have been changed to provide for backup grab samples to be taken at least every 14 hours with the NCWS radiation monitor (RU-6) operable. This method will detect in-leakage lower than 0.08 gpm and also provide a confirmation of RU-6 operation. If RU-6 is out of service the chemistry samples will be taken at least every 5 hours.

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2. The radiation monitor RU-6 alarm response procedure and chemistry sampling procedure have been revised to require specific actions be taken quickly to identify the source of any in leakage to the NCWS.

3. In the event manual sampling detects short lived fission product activity (indicative of Reactor Coolant Leakage into the NCWS) or a radiation monitor alarm is received and manual sampling detects short lived fission product activity, an orderly plant shutdown to Mode 5 (COLD SHUTDOWN) will commence. Sampling will continue during shutdown to monitor the leakage and to determine the source of the leakage.

   If RCS in-leakage through the seal cooler is determined not to be the source, the plant will not be shutdown and sampling shall continue. Manual samples will be taken at least every 5 hours to ensure that no RCS leakage in the NCWS would go undetected by the radiation monitor due to higher background activity.

4. RCS I-131 dose equivalent concentration levels will be monitored. If these values exceed a level of 2E-1 uci/cc, RCS I-131 dose equivalent, offsite doses will be reevaluated and additional actions will be taken if required.

B. Action to Prevent Recurrence:

A design change is being developed to mitigate the postulated event described in this LER. Implementation of this design change is expected to be completed in Units 1, 2, and 3 by July 1993.

IV. PREVIOUS SIMILAR EVENTS:

No previous similar events have been reported in accordance with 10CFR50.73.

Appendix D

POTENTIALLY SIGNIFICANT EVENTS THAT WERE CONSIDERED IMPRACTICAL TO ANALYZE

Appendix D

POTENTIALLY SIGNIFICANT EVENTS THAT WERE CONSIDERED IMPRACTICAL TO ANALYZE

Thirty-three licensee event reports (LERs) were identified as potentially significant but impractical to analyze. Such events are believed capable of impacting core damage sequences. However, they involve component degradations where the extent of the degradation could not be determined or where the impact of the degradation on plant response could not be ascertained.

For many events classified as impractical to analyze, an assumption that the impacted component or function was unavailable even over a 1-yr period (as would be done using a bounding analysis) resulted in the conclusion that a significant event existed. This conclusion was not supported by the specifics of the event as reported in the LER or by the limited engineering evaluation performed in the Accident Sequence Precursor (ASP) Program. A reasonable estimate of significance for such events requires far more analysis resources than can be applied in the ASP Program.

Brief descriptions of these events are provided in Table D.1.

Table D.1 Events identified as potentially significant but impractical to analyze

Potential for heating steam pipe break in cable spreading area at Haddam Neck (213/91-015). A postulated rupture of a 10-in. heating steam line in the cable spreading area of the service building could adversely affect safety-related equipment due to pipe whip or jet impingement. Pipe supports were not consistent with original design drawings.

Containment isolation valve electrical separation deficiencies at Millstone 1 (245/91-020). Isolation condenser logic does not meet separation criteria, and all four containment isolation valves for isolation condenser are powered from the same electrical division. A single failure of the S2 DC power supply along with a loss of offsite power (LOOP) could result in failure to isolate an isolation condenser line break. Use of the emergency diesel generator (EDG) would result in a delay of the line break isolation. Additional separation deficiencies were identified with the recirculation isolation bypass control switch and reactor water cleanup (RWCU) containment isolation valve.

Safety-related circuit routing deficiencies at Palisades (255/91-014). A number of apparent discrepancies in circuit routing have been identified. Approximately 40 circuits that were believed to be safety related were routed with opposite channel circuits. Several circuits had not been completely evaluated at the time of the LER, but all other circuits have been dispositioned as being nonsafety-related or of no safety concern.

Stress corrosion cracking of 37 out of 72 control rod drive housing screws at Monticello (263/91-008). Inadequate design resulted in stress corrosion cracking of 37 out of 72 control rod drive housing flange cap screws. Control rod drive loads can be supported by three uniformly distributed uncracked screws. Failure of five or more screws on a single housing could allow separation of the housing from the reactor vessel flange.

Inoperable fire barrier penetration seals at Point Beach 1 (266/91-007). Holes were discovered in two fire barrier penetration seals in the walls of the safety injection (SI)/containment spray (CS) pump room. The openings measured approximately 6x12 in. and 6x15 in.

Cell cracking causes station batteries to be inoperable at Fort Calhoun (285/91-018). Numerous battery cell cracks occurred since 1982. The battery cell terminal post seals were inadequately designed and did not allow for corrosion product buildup at the positive terminal. This corrosion product buildup caused cracking of the seal nut and subsequent case cracking as stress relief mechanisms.

Cable separation barrier inadequacies at Indian Point 3 (286/91-008). Some electrical cable trays contained redundant safeguards equipment cables, and fire barriers were not installed between trays.

Existing degraded voltage setpoints inadequate at Pilgrim (293/91-018). Sufficient voltage may not be available to certain 480-VAC and 120-VAC loads when switchyard voltage decreases below 349 kV. A 1988 analysis that specified the degraded voltage setpoints did not utilize the worst-case scenario.

Safety-related 480-VAC circuit breaker failure at Pilgrim (293/91-019). A 480-VAC circuit breaker (GE, type AK-2A-50) that is part of a safety-related bus transfer scheme did not close during a planned bus transfer, resulting in a deenergized safety bus. The breaker failed because of a fabrication error. Five other type AK-2A-50 safety-related circuit breakers could potentially experience similar failures.

EDG breaker potential lockout at Maine Yankee (309/91-011). If the EDG is phased onto the bus and a plant trip occurs concurrent with a loss of offsite power, the coincident open and close signals for the breaker may lock out the breaker due to its anti-pumping feature. At the time of discovery, one EDG had been running phased to its emergency bus for approximately 24 h while the redundant EDG was out for maintenance.

EDG exhaust and ventilation environment qualification (EQ) documents missing for tornado effects at Cook 1 (315/91-005). Design documents could not be located that would demonstrate the capability of the EDG combustion air engine exhaust and room ventilation systems to withstand the effects of a tornado.

Expansion joint material not qualified for fire conditions at Sequoyah 1 (327/91-010). The expansion joints between the auxiliary building and shield buildings contain a material for which specific documentation supporting fire resistiveness to an accepted standard is not available. Therefore, the configuration cannot be considered a credible fire barrier.

EDGs potentially inoperable due to Appendix R fire concern deficiencies at Fitzpatrick (333/91-010). Postulated fire scenarios could have resulted in loss of ventilation fans for spaces containing equipment required for safe shutdown, including the EDGs. Fire dampers, penetration seals, and cable separation were also deemed inadequate for certain postulated fires.

Fire damper closure rendered emergency service water (ESW) room ventilation inoperable at Fitzpatrick (333/91-021). Closure of six fire dampers for modification work restricted air flow resulting in an exhaust fan for one of two safety-related pump rooms tripping on thermal overload. A postulated fire scenario was identified that could result in loss of ventilation, potentially degrading ESW, residual heat removal service water (RHRSW), and electric- and diesel-driven fire pumps. Loss of service water could render the EDGs and residual heat removal (RHR) system inoperable.

Safety division motor control center (MCC) cable conduit not embedded in concrete, susceptible to fire at Fitzpatrick (333/91-023). A portion of safety division 1 MCC feeder cable conduit was found not to be embedded in concrete, as it was indicated to be in the original Appendix R evaluation. Both trains of safe shutdown equipment could potentially be damaged by a common fire due to this conduit not being adequately protected from fire.

ESW return piping incorrectly installed at Fitzpatrick (333/91-031). The common 12 in. ESW return header from the four EDG jacket coolers discharges into the train A ESW and RHRSW pump bay. Heated water from the EDGs could recirculate through the EDG jackets eventually failing the EDGs.

Intake de-icing heaters potentially inoperable due to postulated fire at Fitzpatrick (333/91-032). During a postulated fire in the control room, the existing design of the circulating water system intake structure de-icing heaters is outside the design bases of the plant. The control switches for these heaters are located next to one another in the control room and are susceptible to coincident damage during a fire.

Inadequate ventilation flow from high head safety injection (HHSI) pump cubicles at Beaver Valley 1 (334/91-032). Actual measured ventilation flow from each HHSI pump cubicle was found to be less than the flow rate required to maintain motor temperatures within required EQ limits due to a manual damper, common to all three HHSI pumps, that was failed in a partially closed position. This potentially degraded the plant's safe shutdown capability. Also, the cubicles were designed to use temporary ventilation mechanisms during an accident, but this requirement was never incorporated into emergency operating procedures.

Potential for fire-induced spurious operations to adversely affect safe shutdown at Trojan (344/91-008). Potential fire-induced spurious operations of the pressurizer auxiliary spray valve, steam generator power-operated relief valves (PORVs), and the reactor coolant system (RCS) charging flow control valve could have adversely affected the ability to safely shut down the plant. These potential spurious operations were not completely addressed in the Appendix R review.

Electrical components not qualified for operability at low temperatures at Trojan (344/91-009). Containment isolation valve limit switches, auxiliary feedwater (AFW) isolation control relays, AFW control valve relays, control room ventilation control relays, freeze protection for service water differential pressure switches and reactor water storage tank (RWST) level sensing lines were not qualified for low-temperature operation due to design bases deficiencies.

Potential inability to depressurize and cool down the plant in case of fire at Trojan (344/91-021). It could not be verified during the simulation of emergency fire procedure "Alternative Shutdown for Control Room Evacuation Caused by Fire" that the plant could be cooled down and depressurized to residual heat removal (RHR) system conditions following a postulated worst-case fire. The safe shutdown analysis did not specifically address a plant cooldown and depressurization using only those components expected to remain available following a postulated worst-case fire.

Gain setting for overtemperature delta-T (OTDT) setpoint would exceed hardware limits and delay reactor trip at McGuire 1 (369/91-009). The gain setting corresponding to the average reactor coolant temperature input for the OTDT setpoint would saturate the process electronics prior to reaching normal operating temperature. Departure from nucleate boiling (DNBR) limits could be exceeded for an uncontrolled rod control cluster assembly bank withdrawal due to a delayed reactor trip.

Open fire barrier penetrations discovered at LaSalle 2 (374/91-001). One open fire barrier penetration in the EDG cooling water pump room, two open fire barrier penetrations in the high-pressure core spray (HPCS) room, and various open fire barrier penetrations in the turbine building were discovered during a surveillance. These fire barriers had been in a degraded condition since initial plant startup.

Safe shutdown equipment could fail due to a postulated Appendix R fire in the control room at Susquehanna 1 (387/91-016). A postulated Appendix R fire in the control room could result in a hot short in the control circuit of one of a number of components required to shut down the unit from the remote shutdown panel. Approximately 90 valves are impacted on each unit from the RHR, ESW, RHRSW, and reactor core isolation cooling (RCIC) systems.

Gain setting for OTDT setpoint would exceed hardware limits and delay reactor trip at Catawba 1 (413/91-009). The gain setting corresponding to the average reactor coolant temperature input for the OTDT setpoint would saturate the process electronics prior to reaching normal operating temperature. DNBR limits could be exceeded for an uncontrolled rod control cluster assembly bank withdrawal due to a delayed reactor trip.

Pressurizer level indication errors due to inadequate design at Millstone 3 (423/91-008). The pressurizer level reference legs were angled upward such that noncondensible gases accumulated in the condensate pots. This condition resulted in two independent channels being inoperable in a single system designed to mitigate the consequences of an accident. With the errors postulated, these transmitters would have provided operators misleading information.

Plant shutdown due to circulating water system pipe rupture at Perry (440/91-027). A nonisolable break occurred in a section of 36 in. circulating water pipe, which supplies water to the auxiliary condensers. A fast reactor shutdown from 100% power was initiated following the rupture. An open manhole cover allowed water into the underdrain system, exceeding the capacity of the underdrain pumps. Flooding occurred in the service water pump house and safety-related switchgear. Several equipment malfunctions and anomalies occurred after the shutdown, including a 13.8-kV bus failure to transfer, motor feed pump breaker failure to close, startup transformer deluge initiation, and scram discharge volume failure to drain.

Gain setting for OTDT setpoint would exceed hardware limits and delay reactor trip at Byron 1 (454/91-003). The gain setting corresponding to the average reactor coolant temperature input for the OTDT setpoint would saturate the process electronics prior to reaching normal operating temperature. DNBR limits could be exceeded for a boron dilution accident due to a delayed reactor trip.

Gain setting for OTDT setpoint would exceed hardware limits and delay reactor trip at Braidwood 1 (456/91-008). The gain setting corresponding to the average reactor coolant temperature input for the OTDT setpoint would saturate the process electronics prior to reaching normal operating temperature. DNBR limits could be exceeded for a boron dilution accident due to a delayed reactor trip.

Mispositioned SI throttle valve caused inoperability of both SI pumps at Callaway 1 (483/91-003). The SI cold leg injection throttle valve had been mispositioned for over 2 yr. This condition would have caused the SI flow upper limit of 655 gpm to be exceeded, rendering both SI trains inoperable. Calculations by the utility determined that the maximum flow rate would be 706 gpm with the recirculation line open and throttle valve mispositioned.

Normal room cooling not adequate for engineered safety features (ESF) pump room loads at Palo Verde 1 (528/91-007). Normal room cooling system cooling to various ESF pump rooms is not adequate to meet essential cooling loads because it is not 100% redundant to some components served by the essential heating, ventilation, and air conditioning (HVAC) system. Therefore, when the essential chilled water system was removed from service, normal HVAC would not adequately cool the AFW, essential cooling water, CS, and high- and low-pressure SI pump rooms.

Design basis fire in control room could result in RCS leakage exceeding makeup at Palo Verde 1 (528/91-008). A design basis Appendix R fire in the control room could result in loss of reactor coolant pump (RCP) seal cooling. This in turn, could result in RCP seal damage, which may result in RCS leakage in excess of available charging makeup capacity.

Loss of essential air handling unit (AHU) due to postulated fire at Palo Verde 1 (528/91-011). A design basis Appendix R fire in the control room could result in the loss of one train "B" essential AHU. The train "B" AHU provides cooling to train "B" ESF equipment, train "B" DC equipment, and train "B" DC battery rooms. The train "B" equipment is necessary for safe shutdown in the event of a fire in the control room. This design error was caused by a failure of the original Appendix R evaluation to recognize the control circuit for the AHU being located in the control room.

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

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IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)

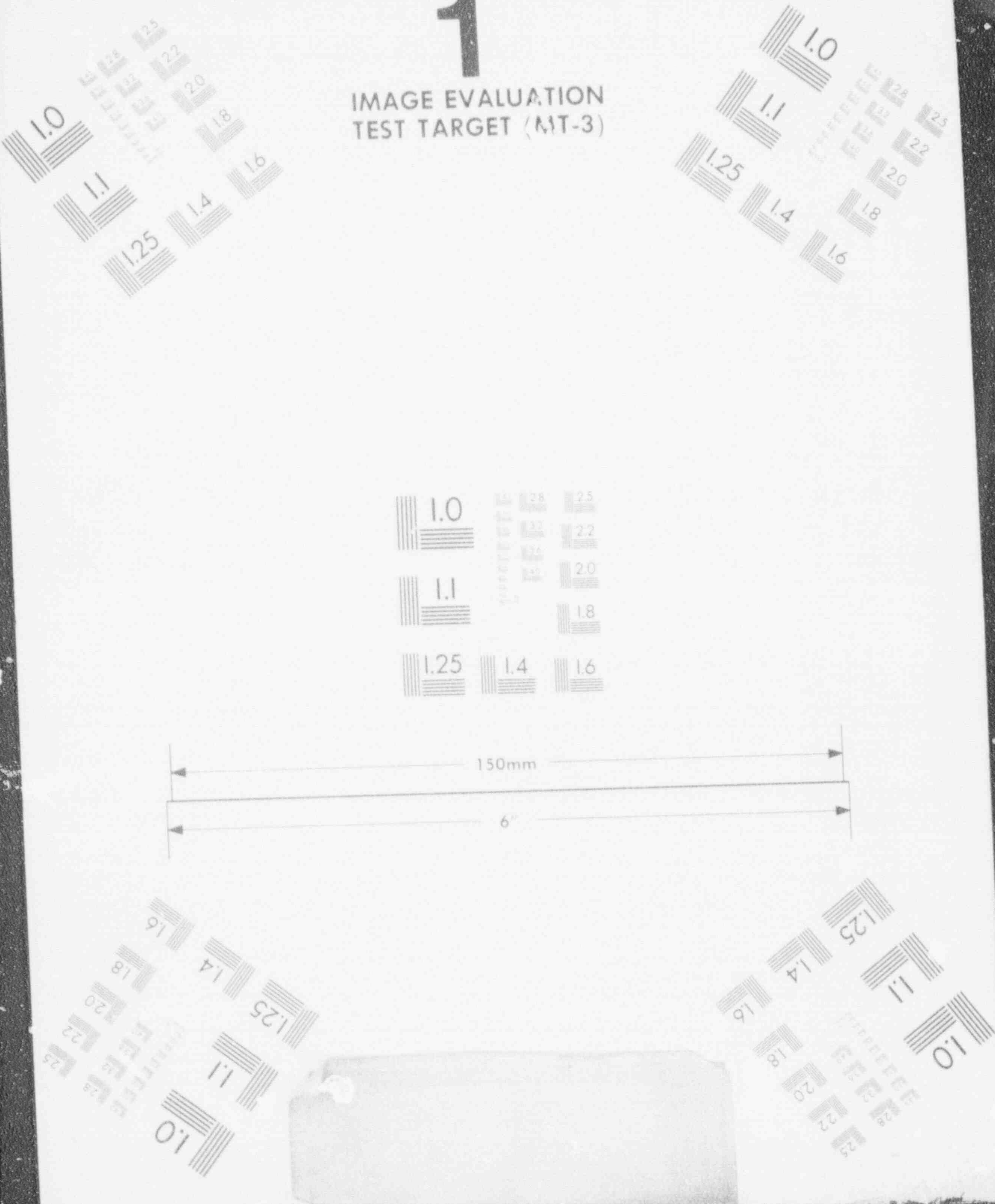

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IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

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Twenty-eight operational events with conditional probabilities of core damage of 1.0 X 10^{-6} or higher occurring at commercial light-water reactors during 1991 are considered to be precursors to potential severe core damage. These are described along with associated significance estimates, categorization, and subsequent analyses. This study is a continuation of earlier work, which evaluated the 1969-1981 and 1984-1990 events. The report discusses (1) the general rationale for this study, (2) the selection and documentation of events as precursors, (3) the estimation and use of conditional probabilities of subsequent severe core damage to rank precursor events, and (4) the plant models used in the analysis process.

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