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

> 9210070034 920930 PDR NUREG CR-4674 R PDR

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

Appendices B, C, and D

Manuscript Completed: August 1992 Date Published: September 1992

Preparer by J. W. Minarick*, J. W. Cletcher, D. A. Copinger, B. W. Dolan*

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Oak Ridge National Laboratory Oak Ridge, TN 37831-6285

Prepared for Division of Safety Programs Office for Analysis and Evaluation of Operational Data U.S. Nuclear Regulatory Commission Washington, DC 20555 NRC FIN B0435 Under Contract No. DE-AC05-84OR21400

*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

APPENDIX B.	Page PRECURSORS
APPENDIX C.	CONTAINMENT-RELATED AND OTHER
	EVENT DOCUMENTATION

LIST OF ACRONYMS

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

PWR	pressurized-water realtor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residuai heat removal
RHUSW	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

Table	Pres
B.1	Index of precursors
	Index of containment-related and other events
D.1	Events identified as potentially significant but impractical to analyzeD-1

Appendix B

PRECURSORS

Appendix B

PRECURSORS

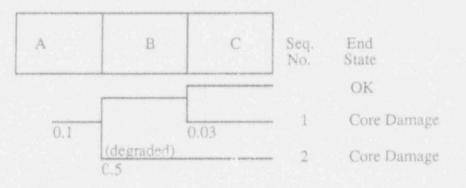
Reactor plant operational events for 1991 were selected for documentation as precursors, containment-related, and other events based on the selection criteria described in this report. Precursors are documented herein.

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

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:

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

 $[0.2 \times 0.5] - [0.1 \times 0.01] = 4.9 \times 10^{-2}$

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.

LER No.	Event title	Plant name	Page No.
029/91-002	Loss of offsite power caused by lightning strike	Yankee Rowe	В-7
206/91-014	Inoperable volume control tank level transmitters	San Onofre 1	B-24
247/91-001	Reactor trip and auxiliary feedwater pump failure	Indian Point 2	B-37
269/91-010, 270/91-003	Potential for hydrogen entrainment in HPI pumps	Oconce 1, Oconce 2, Oconce 3	B-47
271/91-009, 271/91-012	Extended loss of offsite power	Vermont Yankee	B-77
272/91-030	Both PORVs failed due to leaking actuators	Salem 1	B-106
278/91-017	Control wiring for ADS/relief valves found damaged	Peach Bottom 3	B-117
280/91-017	Both emergency diesel generators for Unit 2 inoperable for 13 h	Surry 2	B-147
287/91-007, 269/91-009	Reactor trip due to LOFW plus degraded EFW	Oconee 3	B-157
293/91-024, 293/91-006 293/91-021, 293/91-025	Loss of offsite power and RCIC trip	Pilgrim	B-186
304/91-002	Loss of offsite power with one diesel generator out of service	Zion 2	B-222
304/91-004	Main feedwater pump trip with one AFW pump failed	Zion 2	B-264
321/91-001	Loss of feedwater with HPCI degraded and RCIC failed	Hatch 1	B-274
323/91-003	Containment sump isolation valves and containment spray pumps deenergized during hot shutdown	Diablo Canyon 2	B-288
325/91-018	Loss of feedwater with degraded HPCI system	Brunswick 1	B-301
33/91-006	Trip with both LPCI trains inoperable	Fitzpatrick	B-312
33/91-014	Hydraulic pressure locking of two low-pressure ECCS injection valves	Fitzpatrick	B-324
36/91-009	Both diesel generators unavailable and unit shut down	Millstone 2	B-339
68/91-012	Both normal service water trains fouled by debris	Arkansas Nuclear One, Unit 2	B-349

Table B.1. Index of precursors

369/91-001	Switchyard breaker test results in loss of offsite power	McGuire 1	B-373
400/91-008	HPI unavailability for one refueling cycle because of inoperable alternate miniflow lines	Harris 1	B-397
400/91-010	Reactor trip breaker fails to open on trip	Harris 1	B-410
410/91-017	Loss of five nonsafety uninterruptible power supplies	Nine Mile Point 2	B-419
423/91-011	Both trains of HPSI inoperable due to relief valve failure	Millstone 3	B-458
440/91-009	Two EDGs inoperable	Perry	B-467
443791-008	Loss of offsite power	Seabrook	B-479
445/91-012	Potential charging pump unavailability due to hydrogen void expansion	Comanche Peak 1	B-489

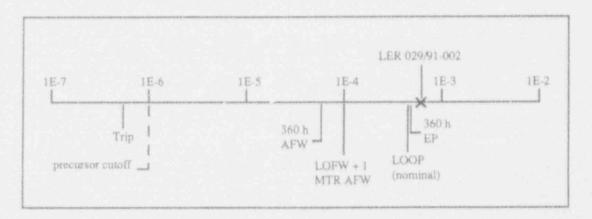
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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

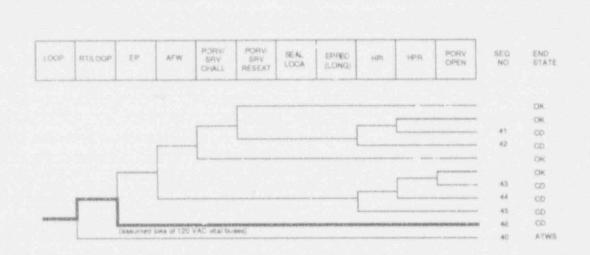
The station service system consists of three 2400-V buses, each supplied from an SST. Each 2400-V bus, in turn, supplies a 480-V station service switchgear bus. Three emergency 480-V buses (vital bus 1, vital bus 2, and transformer A bus) are fed independently from the 480-V station service buses or, 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 Assumption: and Approach

The event has been modeled as a plant-centered loss of offsite power (LOOP). Probabilities for LOOP nonrecovery (short term) and fai'ure 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 stead 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: 0.29/91-0.02Event Description: LOOP and degraded instrument power caused by lightning Event Date: 06/15/91 020/91-002 INITIATING EVENT NON-RECOVERABLE INITIATING EVENT PROBABILITIES SEQUENCE CONDITIONAL PROBABILITY SUMS 6.18-04 ATWS -1.008 SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER) End State N Rocks Sequence Prob -4.6 LOOP -rt/loop emerg.power 2.28-04 4.0E-01 1500 -rt/loop -emerg.power afw/emerg.power hpl(//b) 1000 -rt/loop -emerg.power afw/emerg.power -hpl(//b) -hpr/-hpl 45 2.0E 04 1.48-01 43 1.78-04 1,78-01 parv.open 1000 -rt/loop -emerg.power afw/emerg.power -hpl(f/b) hpr/-hpl 1.78-05 1.78-01 ** non-recovery credit for edited case REQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER) Sequence End State Prob N ROL . + 43 - LOOP -rt/loop -emerg.power afw/emerg.power -hp1(f/b) -hpr/-hp1 1.7E-04 1,78-01 porv.open 44 LOOP -rt/loop -emerg.power afw/emerg.power -hpi(f/b) hpr/-hpi LOOP -rt/loop -emerg.power afw/emerg.power hpi(f/b) LOOP -rt/loop emerg.power 1.7E-01 1.78-05 48 2.08-04 1.4E-01 2,28-04 4.08-01 ** non-recovery credit for edited case SEQUENCE MODEL: 01148011989102991002.cmp

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BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 029/91-002

Branch	s,stem	Non-Recov	Opt Fall
trans	2.5E-04	1.02+00	
LCOP	1.6E-05 > 1.6E-05	5.3E-01 = 5.0E-01	
Branch Model: INITOR Initiator Frequ	1.68-05		
loca	2.4E-06	4_38-01	
rt	2.8E-04	1,28-01	
rt/loop	0.0E+00	1,08-00	
emerg.power	5,4E-04	8.05=01	
efw	1,3E-03	2.62=01	
alw/emerg.power	1.0E-01	3、4E=01	
mfw	2.0E-01	3、4E=01	
porv.or.arv.chall	4.08+02	1,05+00	
porv.or.arv.rement	2.02+02	1,1E-02	
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D: June 15, 1991, at 2350 hours, while in Mode 1 at BBX reactor power. a lightning strike resulted in destruction of a lightning accestor on the No. 3 Station Service Transformer (SST) and flashover of an insulator on the 2 186 115 kV transmission line disconnect switch. As a result, all offsite AC nower was lost, an automatic reactor scram and turbine trip occurred, and all three EDDs operated as designed. On June 15, 1991, at 0010 hours, an UNUSUAL EVENT (LE) was declared based on the loss of offsite power and a fire emergency (smoldering arrestor). At 0016 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 indeventent SI actuation signal was initiated at 0155 hours. Following restoration of the attemption systems and plant equipment, the ALERT was decescalated to an UE at 0450 hours, and the UE was terminated at 0925 hours.

The nost cause of this event has been attributed to lightning-induced transients. Inmediate corrective actions involved repairing and testing of affected electrical and mechanical equipment and plant instrumentation, and returning normal and energency communication equipment back to service. A vankee investigation Team was assembled to evaluate the event and develop immediate and long-term corrective actions. There was no adverse effect to the bublic health on safety.

LICENSEE EVENT REF	PORT (LER) TEXT CONTINU	ATION APPROVE	1 DILLATOR 7 COMMUNER 7 DIME NG 3150-0104 (31/86
CILITY RAMS (1)	UCCRET NUMBER Q1	LER NUMBER (8)	PAGE (B
fankee Nuclear Power Station Nowe, MA 01367		VERN MUSEEN MUSEE	
	0 6 0 0 0 0 2 9	911-0102-01	0 0 2 0 1 1
CT de mare apour à requirat, van adultional IRC Form 2004 a. (17)			
INITIAL CONDITIC.3			
The plant was in Mode 1, at pressure of 2000 psig, an a boron concentration of B14 level to comply with temper by the National Pollutant D 15, 1991, at 2010 hours, th activated. Sustained winds no further action was requi	iverage temperature of 5 opm. The plant was ope ature limits on the cir uscharge Elimination Sy we weather alert radio i in excess of 73 MPH we	El degrees Fahrenhei mating at a reduc?" culating water syste stem (NPDES) Permit. In the Control Room w	t and a power m imposed Dn June as
EVENT DESCRIPTION			
On June 15, 1991 at approxi- experienced a lightning str transmission lines. The li- lightning arrestor on the N art flashower of ar insulat switch. Table 1 provides a	ike which affected both ghtning strike caused d to, 3 Station Service Tr or on Phase A of the 2-	i of the independent lestruction of the Ph ransformer (SST) [E1] 126-5 115 kV discorn	offsite ase A S:xFMR) ect
As a result of the lighthin four (24) sinutes. An auto three (3) emergency diese EDDs Nu - 1 and 3 started au two offsite transmission) anti-spation of securing th systems in accordance with statilized the plant in a h circulation cooling.	matic reactor scram and generators (EDGs) (E115 itomatically in response nes. EDG No. 2 was mar le main generator, durin plant procedures. The	I turbine trip occurr DBJ operated as des to the deenergization mully started by open ng realignment of ele control room operato	ed, All igned, on of the rators in ctrical rs
On June 16, 1991, at 0010 h loss of offsite power and a arrestor on the No. 3 SSTI to the States of Massachuse damage to plant communicati notifications to the states outside telephone line.	i fire emergency (due to lasting greater than te atts and Vermont was de on systems (EIIS:FII)	o the smoldering light nn (10) minutes. Not layed due to lightnin Alternate means for	itning ification of induced these
At DOIN hours, one source o restored. Damage to the 11 control circuit relay on DC offsite AC power (Cabot, Y-	ightning arrestor on No. 19 v-177 delayed restora	. 3 551 and failure (ition of the second s	1 0
Hn GLERT was declared at 01 Who determined that existin activation of All emergency	ig plant conditions warn	ranted a precautionar	y .

B-14

(9-4.3)		EVENT REPO	RT (LER) TEXT CONTIN	UATION	v	APPROVED DAT	NO 3180	(34436) (85-0 -0104
FACILITY NAME	01	Called a first she also again to reach	DOCKET NUMBER (2)		LER HUMBER (8)		FAGE	130
	Nuclear Power St A 01367	ation		****	NUMEL N	NUMBER		T
	and the second		0 6 0 0 0 0 0 2 9	9 1	- 0 0 2	-0100	13 0	F 31
	manpower. This de	termination	was based on the con mergized state of th	tinued	inoperabi	lite of		
	plant equipment (s	er supply (ee Table 11.	NEUPS) (EllS(UJX), a	nd the	existence		aded	
	inadvertent safety 0155 hours. Main d	injection a polant syst tion (\$1) p	e emergency busses t actuation signal (SIA em (MCS) pressure re sumps: therefore, no SI occurred.	(S) EEI mained	above the	shutoff	nead	
	and E vital bus LE realigned to an of Following the rest equipment and with	(IS:BU). Em faite power ration of e the concurr	the normal bower suppliergency electrical b source and EDUs No. ssential communicati ence of the States o an UNUSUAL EVENT at	usses 2 and ph svs f Mass	No. 2 and 3 were sec tems and p workusetts	3 were uned. lant		
			i at approximately 07 0715 hours, with lim				ial.	
	On June 17, 199), hours, The UNUSUAL	the plant at EVENT was	tained a cold shutdo terminated at 0925 h	wn (Mo ours)	ide 5) cond	itio a	0755	
	inarmed and develop Investigation Team	immediate focused on	is assembled to evalu and long-term correc the following areass ion systems and emer	tive a plan	ctions. 7 At operatio	ne Venke nsv	ns Ie	
	CAUSE OF EVENTS							
	equipment on both a Subsequent to the 1 on the No. 3 SST a arrestur subtained	if the 115 k lightning st eiled to re consequenti	as been attributed to V transmission lines rike, the Phase A lines set and was destroye al damage. As a resimatic reactor scram	servi ghtnin d: an ult, b	ng the pla g arrestor adjacent l oth source	nt. (EllSi ightning s of off	site	
	been attributed to failed to automatic to communication so	lightning. ally transf stems equip	of various plant com Subsequent to the l er to its backup sou ment at the plant, trumentation associa	ightni ncei t The lo	ng strike. he NEUPS o ss of NEUP	the NEL rolides S also b	IPS : ps wer lausen	
	after the NELPS was	reenergize	d loss of the plant d wat a voltage-indu ostible cause of thi	ced fa	ilure of t	ab priti		

B-15

		16	

	NATIONAL CONTRACTOR OF A		e na chian a cana i	DOCKET NUMBER				EXPIRES &/SI/#	
		and the set				TEAP	ER RUBBER I		*AUE (2)
	Nuclear Po A 01367	wer Stati	on				SUMBER .	MACH ROA	
				0 6 0 0	0 0 2 9	911-	0 0 2	- 000	14 01 11
(7 B ^e mare again	e à raquarest une actriteurus	(APR) Agenc 208(4:9) (12)							
	induced vol independent	tage spike of the lig	that cam htning s	e into the trike affi	PBX throu ecting the	igh the 115 kV	telephor transmit	e lines, sion lin	es.,
	The root ca and Emerger following:	use of the icy Operatio	sustaine ns Facil	d loss of ity (EOF)	communicat (EIIS:NC)	ion sys has be	items bet en aitrit	ween the loted to	plant the
	Capabili was rest	of plant PB ty over loc ored due to t failures	al lines lighteir	 The los induced 	New Engla	ines co nd Tele	ontinued	after the	e PBX
	 Loss of the EOF the plan 	control of due to ligh t.	the Mt. M thing ac	lassamet a Livity sep	nd Bordon arate froe	Mountai that r	n transe Hørriend	itters fr ed local	oe iv at
	everideus.	the VNPS Nu v notificat of equipmen	ions to i	the states	, the pref , due to N	erred a ET circ	eans for uit fail	making ure and	
	- Lowe of	two'r trig-do	en circú	its due to	NET circu	it (ai)	ures.		
	The root can extensive by actuation ra the cause of inconclusive that a cono No. 1 during attanpting inadvertent to their by iightning-ir	ench testinn Flavi to sin f the spurin r and did no ination of i pastdown to realign i SIAS, Vita bass supplis	g was con mulate th ous SIAS. It defini voltage a of EDG N Emergency I Bunses PS. EDGs	ducted us e actual The rys tively id ind freque 0. 1. aft Bus No. No. 1 ani	ing spare instrument ults of th entify a r ncy reduct er it was l to offsi d 2 had bo	instrum loop o e bench oot cau ion exp tripped te powe	entation peration testing se. It erienced by the c, resul	(bistab) and dete were IS Susper by Vita) operators ted in tr	le and reine 'ed i Bus i When
	CURRECTIVE /	CT LONS							
	A. <u>Electric</u>	A. Systems							
	three su the perf damaged festing	e coirectiv s on both N rge arreste ormance of insulator p of selected breakers on	No. 8 551 rs on th acceptab n the 2- L plant p	and No. e main tri le tests, 126-5 disc rotective	3 SST were insformer + the No. 3 onnect swi relays. vi	replac vas rep SST wa itch was	ed, Als laced, 1 s reener s replace	o, one of Subsequen gized, T d. Exte	the t to he

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FARILITY NAME (1)	n an	DOSTRET NUMBER (2)	LER NUMBER (6)	FAGE (3)
Yankee Nucl	ear Power Station			EVISION LUNGER
Rove, MA 01				
THE R LEWIS COMPANY	d, una mAddhacoar AddC Asame MRA a) (17)	0 6 0 0 0 2 9	911-002-	01001501111
TEXT OF EAST APRIL & MILLION	a, una mananalicae nenti, mante datta si (177)			
	conducted. This testin relay functions.	ç ensured the adequacy	of all tran. Jissi	an line
a strategy in				
	An evaluation of other could have been affecte	electrical equipment at d by the ligh ning str	nd plant instrumen ike was also perfo	rmed.
	Miscellaneous instrument was also repaired.	tation (power supplies	, amplifiers, reco	rders, etc.)
Β.	Communication Systems			
	Immediate corrective ac communication equipment		ng normal and emer	gency
	At 0235 hours, on June returned to service who NEUPE: Ewergency Notifi paging system (two out commercial phone system capability at 0715 hour	en power was restored b cation System, Nuclear of three transmitters s (PB() was roturned to	y manually bypass Alert System and operable). The p service with lim	ing the plant radio lant ited
C.,	Pestars Action liters			
		ve actions were develop ted prior to transition		
		a procedure which provi S, so that the NEUPS d er sources.		
	2. Train operators on	performing the NEUPS (manual bypass func	tion.
	3. Revise procedure 0 Loss of AC," to:	P-3501, "Restoration of	Normal AC Power	After a Total
		s to check the status o gning the Emergency Di		
		aligning of the EDGs a actifieding the associa		
		ice on how to backfeed wen only one outside to		
		nspection of all solid to lightning strikes an		

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U.S. NUCLEAR REQUESTORY COMMISSION APPROVED ONE NO. 3150-0104 EXPIRES 8-31-86 B-18

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12. Farter Mills 637		LICENSEE EVENT REPOR	T (LER) TEXT CONTINU	ATION		APPROVED CAR EXPRES 2 31 10		
UTE (TV MASES 17)			DOCKET ROMBER (J)		NUMBER (8)		FAGI	(3)
Ankee Nucle lowe, MA 0130		Power Station		100	NUMBER .	Ad via cost to congo a		
R? If more grant is reputries, of		in the second	0 5 0 0 0 0 2 9	911-	0 0 2	-101010	16 10	1111
Ct of mean grant is required, or	no seu	Revolation of the second address of the second se						
6		Include alternate staf Plan Implementing Proc contingency actions to	edures (EPIPs), Which	h provid	les app	ropriate		
ė		Revise EPIPs to includ (ERF) personnel log-in		ingency B	lespons	e Facil	¥	
		Resolve inadvertent sa actuation cause and in					i di ala	le
4		Revise EPIPs to includ for inclusion in motif				logical (ata	
	ł.,	Provide guidance on a ERFs.	ll rapabilities of e	ach teles	phone t	ope at a	4	
		Distribute access cont timely controlled acc ecoropriate controls (eas for equipment op	eration.	Estat	(L) sh	is sur	*
ΰ.		LOW-ME ACLIEG INSA						
		following long-term co extigation Tean	prrective actions we	re devel	oped by	the Yan	e.e.	
		Review lightning prot Marriman (2-186) tran Specifically address wire) on shese lines, in order of priority.	services in the services of a gro	uding ti und wire	e swit: (stat	chyard. Ic wire,		
		Review lightning prot ANSI/NEPA-75 and Repo order of priority.						
		Perform a station gro those of a previously improvement as approp	-conducted test. Ma				e11)	
	6. v	Review all solid stat to determine if surge logific enhancements	protection capabili					
		Determine if the stat coordination with Cal improvement. Provide	ict and Harriman sta	tions is	adequa	te or in		st.

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REAC Partie 2006.5 NA NUCLEAR REQULATORY COMMISSION LICENSEE EVENT REPORT (LER) TEXT CONTINUATION APPROVED DAIS NO 1150-2104 EXPRES 1.31 M PARELITY RAME INC DERCART HUMBER LT LER NUMBER IS PAUL 13 YEAH REDUENTIAL NUMBER NUMBER Yankee Nuclear Power Station Rove, Nº 71367 0 0 2 DIT OF 0 16 0 0 0 0 2 9 9 1 TROTT III more smaan is required, use antificence hits. Form Mild. 1, 1171 6. Evaluate parameters requiring verification in procedure OP-3051. "Savety Injection Termination Following Spurious Initiation," and relive 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. B. Evaluate EDP ES-1.1. SI TERMINATION, to determine the need to direct the operator to realign the Safety Inje. ion System for automatic initiation. vide improved guidance and training on the use of communications runipment 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. IF. Assemble and stage a telephone equipment repair kit. 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 lain 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 matural 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 (ELIS:INVT) automatically transferred to their individual backup sources (EDGs No. 1 and 3) and www.m reenergized by the associated EDG. Approximately two hours into the event, control room operators attempted to restare 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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where the provide the state of the art of

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	U.S. MURCLEAR REGULATORY COMMISSION APPROVED ONE NO 2150-0004 EXMILS 5-21.00
Yankee Nuclear Power Station	84816 (8) PAGE (3)
TETT If more areas & required, our applicance Artic Ar. Affic a: (17)	
SIAS occurred after meturing the EDG. The operators immedia EDG to restore power to the No. 1 Vital Bus. The SIAS was v inadvertent.	
Subsequent to the SIAS, all high pressure and low pressure a pumps started as designed. Due to the pressure in the main water injection did not occur.	
At no time during this event was the plant in an unanalyzed condition that was outside the design basis of the plait. I Safety Feature systems and equipment operated as designed, health and safety of the public were not adversely affected event.	All Engineered Therefore, the
SIMILAR EVENIS	
Similar events at the YNPS involving lightning dis urbances plant trip have been previously reported in LER 88-08, Rev. LER 83-22, LER 82-17 and LER 80-21.	resulting in a No. 1, LER 86-04,
ANG ALLAN MAN	a ji 3 (pHD) - 1864 (1824 5.36 a) -

B-20

NAC Face Bala (9-87)	LICENS	CÉ EVENT REP	ORT (LER) TEXT CONTIN	UATION	4	APPROVED DI			
FACINITY BABIE (1)			DOURET NUMBER (2)	T	LER NUMBER (6)	Contraction of the second s			
Yankee Nuclear Rowe, MA 01367	Pover	Station		19-4	NONER CAL	NU-MACH		T	
mental states with the states of the			0 6 0 0 0 2 9	911	- 01 01 2	- 010	019	SF 1 P	
WALL IN SHAFE LOOSE & MANAGER, LAN AN	ditoriar leftic faun	e MMER ar (19)				er de la de la de	indainde -	and in the	
	1		TABLE 1						
			SEQUENCE OF EVENTS						
6-15-91	8350	Lightnin, s	strike						
		Loss of bot	h offsite AC power so	ITCES1					
		- Harriman - Cabot (V	(2-186) transmission «177) transmission []r	line' W					
		Automatic t sources	ransfer of Vital Bussi	is No.	1 and 2 t	p their	backs	ia -	
		Automatic r	eactor scran and furbi	ne traj	p				
		Loss of non instrumenta	essential uninterrupti tion associated with i	ble po	wer suppl	(NEOP)	ii and		
		 Sequence Stear ge Radiation 	arameter display syste of events recorder (S nerator (SG) process r n monitoring instrumen emergency feedwater fi	ER) ecorder 1 panel	r 5.	ili feur			
		Loss of mist arbliflers.	ellaneous instrumenta recorders etc.)	tion (p	томет жирр	lien _i			
		Loss of sele	icted communication sy	stensi					
		- Nuclear A - Flant rad	Notification System Hert System (NAS) Ho baging system mercial phone system (
		Loss of sele	cted security system (equipme	mta				
		 Security effects o system. 	Event Report RI-SOI wi C lightning strike on	11 pro the YN	vide a de PS physic	ecriptio al seco	in of		
		Two emergenc one EDG many	v diesel generators (E ally started	00s) a	utomatica	ly star	185 -		
		Rubture disc	é blown on LP turbine	CUREME	out of to	kur⇒			
ADAM MAL		e se contra como se construir de se con		****			1455.017		

B-21

181 Farm 266.5 9-63	LICENS	EE EVENT REP	ORT (LER) TEXT CONTINU	ATION		AUCLEAR REGU AF-HDILED DAN EXPHES \$ 51.8	1.140 213	
ADULTY ACAR (1)			DODERSY NUMBER 181	1	LER NUMBER (8	T	P.A.	04.18
Yankee Nuclear Rowe, MA 01367	Power	Station		1928	STOLES			
TEXT IF many games - requires, can ave	derival hitt: Fact	w MRA 6/117	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	19111-	-101012		10	ov[1]
	2355	Initiated :	procedure OP-3251, "Lo	ss of 3	AC Supply			
		Report of s surge arres	unoke from No. 3 Static stor	sn Serv	rice Tran	sformer	SET	
		Eire brigåd	ie activated					
6-16-91		UNUSUAL ÉVE	INT declared					
	0014	Offsite AC transmissio	power partially resto on line	#d - 1	(arrinan	(2-12b)		
		Reat remova	Steam-driven emergency boiler feed pump operating/core deca- heat removal occurring through emergency atmospheric steam dump valves					
			mul level, pressure an SG (Channels 2 & 4)	nd feed	indicet	inn an N	14 R	
		Main coolant system pressure stable at 2000 psig						
	00.30	Fire energe established	nty teorinatéd. firé i	brigadi	e sécure	i jand Kun	e wij	tch :
			rocedure OP-2501, "Re tal Loss of AC"	storati	ion of No	risal AC I	'Ower	
	0047	Connurwealt	n of Massachusetts no	Lifted	of UE			
	0050	State of Ve	ermont notified of UE					
	0058	NRC notifie	d of UE					
	0130	ALERI decia	ir ed					
	0141	Conmonwealt	n of Massachusetts no	tified	of ALERT			
	.0145	State of Ve	ermont notified of ALE	RT				
	0155		safely injection acts emergency busses usi			STAS) wh	le	
			rocedure OP-3051, "Ba Spurious Initiation"	fety 17	istion	Terminal	an	
	02.5	NPC retifie	D OF ALERT					

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B-23

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION										
FACILITY REAMS (3)	-		DOCKET NUMBER D		LER NURMER	8	T	FAQE ()		
Yankee Nuclear Rowe, MA 01367	Poyer	Station		1848	RUNDER C	1 Mil + di ki N - Mig 3		T		
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and a serie way a selection of the										
	0835	NEUPS restored								
	084Ó		cation lines with NR one! operational in			onel en	Sta	tes		
		Plant radio pag	ging system operatio	nal						
	0410	Restored norma	l power supply to No	. 8 yi	tal bus					
		Secured No. 3 i	:06							
	0413	Restored norma	I power supply to No	- 1 - v)	tal bus					
	041\$	Secured No. 2 EDS								
	0450	Returned 480v Station Service Bus 5-3 to service - power being supplied by No. 1 EDG								
			int notified and con Massachusetts noti							
		Restored power	to meteorological m	onitor	ing syst	isten				
	0455 NRC notified of devencelation to UNUSUAL EVENT vi Phone					via ENS Red				
	0555	SB Channels 2 &	4 returned to serv	1.04						
	0685		lant cooldown - mai psig and 494 °F	n cool	ant sys)	ien (MCS				
		Pressuriser lev	61 at 124 inches							
		50 feed with na	in feedwater system							
		Steam released	through emergency a	tmosph	eric sta	ian dump	valv	es		
		Preparing to bp	rate MCS and restart	. main	coolent	pumps				
	0715	Operability of limited function	plant commercial pho nality	ine sy	iten rei	tored w	i th			
$h = 2^{(m_1,m_2)}$	0755	Plant attained	cold shutdown (Mode	5) cor	ndition					
		Termination of 1	NUSUAL EVEN?							

The second state of the second states

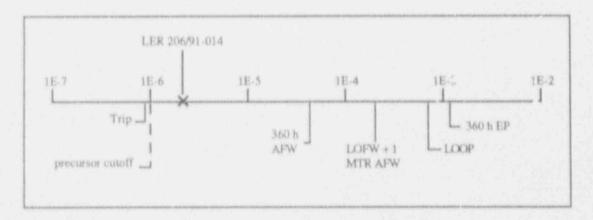
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT

LER No:206/91-014Event Description:Inoperable volume control tank level transmittersDate of Event:August 7, 1991Plant: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 \sim 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 switches initiate closure of the associated VCT isolation valves.

On 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.

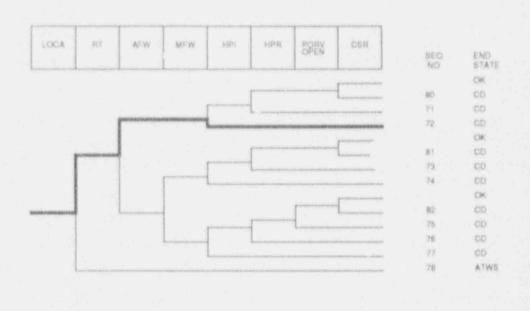
The valves controlled by LT-1100 and LT-2550 were still capable of being repositioned by their safety injection (SI) contacts. However, for certain small LOCAs, the VCT would have drained and the charging pumps would have been damaged before the reactor coolant system depressurized to the SI setpoint.

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

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 206/91-014 Event Description: Inoperable Volume Control Tank level transmitters Event Date: 08/07/1981 Plant: Ban Onofre 1

URAVAILABILITY, DURATION- 17

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANE LOOP LECA	2.05+03 1.95-08 1.05-05
REQUENCE CONDITIONAL PROBABILITY FORE	
Rod State/Initiator	Fridabillity
CD	Y-38-09
LOOP LOOK	5/9E-09 2.1E-06
Total	2,38-06
ATWS .	
YPANS LOOP LOOA	0,0E+00 0,0E+00 0,0E+00
Total	0.08+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Seguence	Und State	Prob	N Repair
72 Jack et afg HP1		7,18-06	5.28-02
** non-recovery creatil for edited case			
SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)			
Sequence	End State	Proh	N Recen
22 loca -rv -afw 001		2.16-0.6	5,28-02

** 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. Vatenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MEDELI	- c:\asp\1989\pwrbsea)	, amp
BRANCH MODFL:	Oflampill000/manonol.	112
PROBABILITY FILE:	ci/asp/1989/pwr_ball	ords.

No Recovery Limit

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Event Identifier: 206/97-014

BRANCH PREQUENCIES/PROBABILITIES

Branch	figure en	Non-Recive	der Fall
trant	1.28-04	1.08.490	
loop	2.08-05	当,我把一位3	
DIFFA	2.4 -04	4,35-01	
	2.1.5+04	1.28 - 0.1	
10710ap-	0.06400	1_08+00	
armo sig , privairi s	2.98 mil.	#,UE-01	1,48-03
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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 apposite train level transmitter (LT-2550). These level transmitters function to realign the charging pumps from the VCT to the refucling 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, shudown of Unit 1 was initiated at 1800 per TS 3.0.3. SOL 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 NRO 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.

SAN ONOFRE NUCLEAR GENER	NATION STATION	DOCKET NUMBER 05000206	LER NUMBER 91-014-00	PAGE 2 of 8
Unit: One Reactor Vendo	ofre Nuclear Gen r: Westinghouse uugust 7, 1991			
A. CONDITIONS AT	TIME OF THE EVE	NT 1		
Mr.e. 1. Pow	ver Operation			

BACKGROUND INFORMATION:

. Charging Fump 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 Coolent Accident (LOCA) scenarios, the centrifugal charging pumps [CB,F] 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 evenus. Each train consists of a VCT level transmitter [LT] and an associated control loop, ϵ 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 (MCV-1100D and MO'-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 alars in the control room 17-1100 miss automatically maintains VCT level by controlling makeup

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

AN ONOFRE NUCLEAR GENERATION STATION	DOCKET NUMBER 05000206	LER NUMBER 91-014-00	PAGE 3 of 8
RWST To Refueing Water Pumps	MOV-11000 MOV-11000 FOV-5051	Chi Col	injection, rging, d Leg culation
NOTES			

CD Opens MOV-1100 B & D on Low-Low VCT Level.

MOVa 1100 B & D Open Contacts Initiate Closure of MOV-1100 C & E.

CD Stops Charging Pump on Low-Low-Low VCT Level.

Figure - Charging Pump Low VCT Level Protection

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 critica³. TS 3.3.1, A(3) requires, in part, that valves and interlocks associated with the SIS be maintained operable but doss 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 JT-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

SAN ONOFRE NUCLEAR GENERATION STATION	DOCKET NUMBER	LER NUMBER	PAGE
UNIT 1	05000206	91-014-06	4 01 8

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.

DESCRIPTION OF THE EVENT:

1. Event:

On August 7, 1991 at 1135, with Unit 1 in Mode 1 at approximately 90% power. WCf 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 p-tential 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 v-rbally approved the waiver at approximately 2000 on August 8th. The unit shutdown was then suspended.

SAN ONOFRE UNIT 1	NUCLE	AR CEI	VERATIO	N STATION	DOCKET NUMBER 05000206	LER NUMBER 91-014-00	PAGE 5 of 8
	2.	Inopa Event		Structures,	Systems or Components	that Contributed to	o the
		Not a	opplica	ble.			
	5.	Seque	nce of	Events;			
		DATE	TIME	ACTION			
		8/2	1135	and E place	d LT-2550 removed from ed in menual control; ing pumps is blocked.		
		8/8	0440		and E were restored to harging pump VCC-G8B 1d		
		8/8	1700	TS 3.0.3 1	s entered.		
		8/8 -	1800	Unit shutde	own initiated and UE 30	clared.	
		8/8 -	1922	UE exited.			
		8/8 -	2000	Waiver of 1 suspended.	IS compliance granted a	ind the unit shutdow	en 1.6
		B/9 -	1635	to automati	stored to operability, ic actuation, and the c rip is restored.		

4.1. Method of Discovery:

Operators observed differences in the indicated VCT level between the two level channels (1.7-2550 and 1.7-1100) and erratic level indication by LT-1100.

Due to the erratic behavior of 1.7-1100, a temporary design change was requested to switch the successic VCT level control function from 1.7-1100 to 1.7-2550. 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.

Personnel Actions and Analysis of Actions:

Not applicable.

6. Safety System Responses:

Not applicable.

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N OB	NOFRE	NUCLEAR	GENERATION	STATION	DOCKET NUMBER	LEF NUMBER	PAGE
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D. ROOT CAUSE OF THE EVENT:

 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 locse.

The safety function of the charging pump suction isolation values and the charging pump trip was determined to be satisfied wir's 'he 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 potent'ally 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:

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. Corrective Actions Taken:

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

- - 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.
 - 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.
- 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:

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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.
 - 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 autor tic 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.

X

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

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maintain core cooling. Therefore the conditions described above are of minimal sefety significance.

G. ADDITIONAL INFORMATION:

1. Component Failure information;

1.7.1100 is a forgue 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 T5 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 13 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:

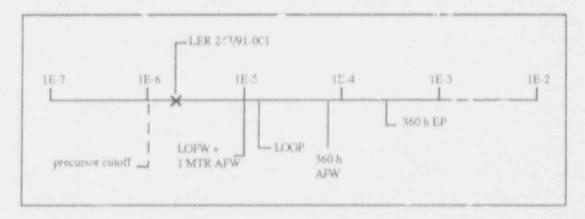
By letter dated August 26, 1991, R. W. Krieger (SCE) to USNRC Document Control Dosk. "Level Transmitter Surveillances - Safety Injection," SCE requested a temporary weiver of compliance from the requirements of T5. 3.0.3, without fully complying with the requirements of TS 3.3.1. The purpose of this request was to avoid unnecessary plant shurdowns while the affected level transmitter (LT-1100 or LT-2550) is removed from service for surveillance testing and for the performance of any corrective asintenance 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.:247/91-001Event Description.Reactor trip and auxiliary feedwater pump failureDate of Event:Ianuary 7, 1991Plant: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 2.0×10^{-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 offected. During this time, the affected transmitter falsely indicated a low pressurizer pressure. While the sensing line was being restored to service, a 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 on 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 milcalibration 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.

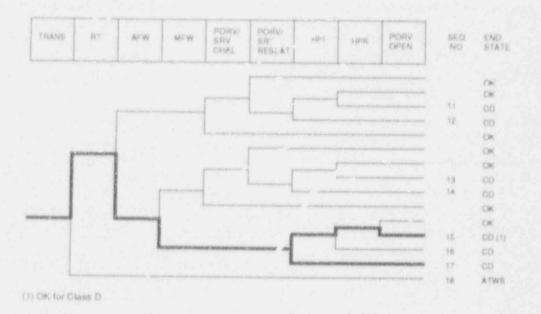
ASP Modeling Assumptions and Approach

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

CUNDITIONAL CORE DAMAGE PRUBANALITY CALCULATIONS

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Event Identifier: 247/91-001

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amerg.power	5.68-04	8,08+01
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alw/emerg.power	5.06-02	3.48-51
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FLANT AND SYSTEM IDENTIFICATION.

Vestinghouse & 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

FAST SIMILAR OCCURRENCE:

None

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DESCRIPTION OF OCCURRENCE:

On January 7, 1992 at 11:02 a.m., with the unit operating at 96.52 power, the reactor tripped. Earlier that morning, at approximately 10:58 a.m., a containment entry was made by plost 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. FT 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-O "Reactor Trip or Safety Injection" and began to effect the shutdown of the reactor.

LICENSEE EVENT REPO TEXT CONTINUATIO		антярной рокатор и раз В калака тере произвание и раз Сарана тере произвание и произвание положит току соружет току народнет соружет току соружет току народнет положит току соружет току народнет положит току соружет току народнет положит току соружет току народнет положит получет получет току народнет соружет получет таки рокатор и получет по народнети на получет на народнет соружет получет таки в полоту на народнет соружет получет току получет на народнет соружет народнети таки в полоту на народнети	C DOMPLY WITH THUS BOD HMS FORMWARDS ATV 10 THIR RECORDS FAND, U.S. NUCLEAR DS DE 2005A SALES CATAGODAL DATION
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DESCRIPTION OF OCCURRENCE: (continued)

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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 0.5 seconds after the reactor trip signal. Both motor driven AFVF 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 AFVP No. 21 was made by the operators, subsequent to which the pump was declared inoperable. Consequently, at approximately 11:05 m.m., the plant entered a 72 hour limiting condition of operation (LCO) as stipulated by Technical Specification 3.4.8(1)(a). Feedwater flow was re-established to SGs No. 21 and 22 st approximately 11:06 a.m. via the steam driven AFWF No. 22 and the LCO was subsequently terminated at approximately 06:46 p.m.

The immediate determination of the cause for the APVP No. 21 trip was determined to be overcurrent, as reflected by the pump breaker indicators. Further investigation found no mechanical or electrical problem with APVP 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 setuoint 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. I: was observed that the setpoint could be inadvertently moved if, in a process of breaker handling, plant personnel were to touch the amptector setpoint adjustment wheel.

In regards to the failure of AFVP 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,

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would indicate a "trip" cond is the AFWF No. 21 breaker "t energized in the control room light energized, the operator automatically start as require pump from the control room do	mismatch" contact, the a m. With only the green rs believed AFVP No. 21 red, and proceeded to ma	amber light was not breaker "open" did not anually start the	
Consequently, the reason for given a manual start signal i attributed to the fact that to following a trip, was not fin done for the reasons discusse subsequently replaced.	from the control room in the pump's circuit break rat reset by the operato	s therefore (er, as required ors. This was not	
The Chemical Volume and Contr occurred because the control (LT 460) went below the 18% 1 setpoint. It was later obser considerably from the other t above 20% of pressurizer leve revealed all channel readings later. This appears to indic necessary. An operational ch subsequently performed by Ins identified deficiency. These to be calibrated during the u	ling pressurizer level 1 letdown isolation presso rved that this channel v two channel values which el at the same time. Da s converged approximatel sate instrument recalibr neck on instrument chann strument and Control per s pressurizer level chan	instrument channel irizer level value deviated i vere indicating ita analysis turther ly 400 seconds cation may be real LT 460 was connel with no inels are scheduled	
The bank "C" rod "L3" control not illuminate. This was imm defective bulb was subsequent	mediately attributed to		
Later in the day, the AFWP No with approved plant procedure replaced and also tested in a procedure and returned to ser AFWP No. 21 and its circuit amptector long delay pickup s the generator breaker: were c approximately 08:36 p.m.	es. The pump's circuit accordance with approved vice. Having verif.ed, meaker, and having corr setting, plant restart w	breaker was I plant test the operability of ected the incorrect (as initiated and	
ANALYSIS OF OCCURRENCE:			
This report is being made sin system (RPS) occurred. Any m reportable under 10 CFR 50.73 implications for this event. The exception of the componen design envelopes were not exc corrected.	<pre>anual or nutomatic actu (a)(2)(iv). There were All systems performed its mentioned previously</pre>	ation of the RPS is no adverse safety as expected with . Equipment	

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of p pres valv this	reactor trip occurred as a result reasurizer pressure transmitter P sure transmitter PT 455, on a com ed back in service. Our review o event, did not reveal the phenom instance.	T 474 while anot son sensing line f industry exper	her pressurirer , was being ience, prior to	
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renu 8 pr Nors and	CVCS normal letdown isolation occ it of the controlling pressurizer essurizer pressure level below 18 al letdown isolation. The isolat setpoint value. However, the rea cate recalibration may be necessa	level instrumen 1, which is the ion occurred at dings for all ch	it channel sensing value for CVCS the correct time	
Room	cause for bank "C" rod "L3" contr not illuminating was immediately replaced.			
CORP	ECTIVE ACTION:			
1)	Engineering was requested to ove prevent inadvertent amplector se February, 1991 refueling outage.	iting adjustment		
2)	Calibrate pressurizer level inst refueling outage	iuments during (the February 1991	
3.)	The breaker for AFWP No. 21 was subsequently tested in accordance			
43	The blown bank "C" rod "L3" cont control room was replaced.	rol rod bottom	light in the	

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.

NHL East MALL 1039

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant:

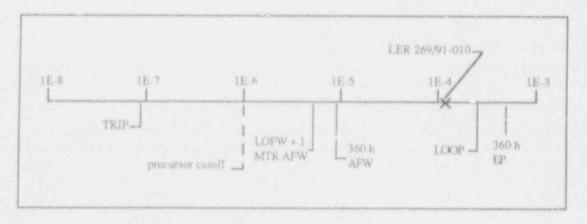
269/91-010, 270/91-003 Potential for hydrogen entrainment in HPI pumps September 19, 1991 Oconee 1, Oconee 2, and Oconee 3

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 ... e 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 'ow-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 Getected).

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 Lermissible bydrogen 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

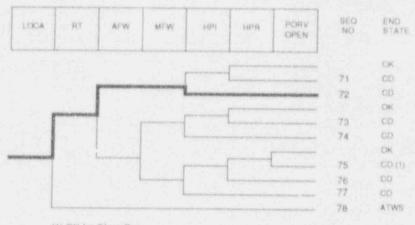
The event has been modeled as an unavailability of HPI and feed and bleed period for situations in which either of the two BWST-to-HPI-pump suction valves (HP-24 or HP-25) fail to open. The probability of HP-24 or HP-25 failing to open was assumed to be 0.02, based on the probability values typically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



(1) OK for Class D

Dominant core damage sequence for LER 269/91-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Sty.

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

UNAVAILABILITY, DURATION- 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS LOOP LOCA	3,91-01 2,36-02 6,38-03
SEQUENCE CONDITIONAL PROBABILITY SUMS	
End State/Initiator	Probabili

	LOOP LOCA	4.6E-08 1.2E+04
	Total	1.28-04
ÅΤ	15	
	TRANS LOOP LOCA	0.0E+00 0.0E+00 0.0E+00
	Total	0.08+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Becas
32 loca ert eafw HPI			1,22-04	4.36-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	seguence		End State	P200	A Reces
72 loca ert -afw HPI				1.28-04	4,38+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. Parenthetica, values indicate a reduction in risk compared to a mimilar period without the existing failures.

SEQUENCE MODEL:	c:\asp\1989\pwrdseal.cmp
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PROBABILITY FILE:	c:\asp\1989\pwr_ball.pro

No Recovery Limit

Event Identifier: 269/91-010

BRANCH FREQUENCIES /PROBABILITIES

Branch	Eystem	Non-Recox	Opr Pell
Leans	6.48-05	3,02+00	
loop	1.62-05	2,48-03	
leba	2,48-06	4,3E-01	
PD	2.81-04	1.75-01	
rt/inop	0.02+00	1.08.+00	
emains (g , persent)	2,98-03	8.08-07	
atw	3,88-04	2.68-01	
afw/ampro.power	5,05-02	3,48-01	
INT N	2,08-01	3,48-01	
perv.or.srv.chall	8,08+02	1.08+00	
DOTV.DI.STV.TESEAL	1,02+02	1,18-02	
porv.or.srv.reseat/emotd.power	1.08-02	1.02+00	
seal.lona	0,08+00	1.05.+00	
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EVALUATION:

BACKGROUND

The High Pressure Injection (HPI) System [EIIS:BQ] controls the Reactor Coolant System (RCS) [EIIS:AS] 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 (RCCS) 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 borsted 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, 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 RPI 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 Occure 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 MPI 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 slurm 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 (DHD) 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 (B6W) for the B6W 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 value. HP-23 is considered non-wafety related and does not have eafety 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-wafety related squipment and operator action within this short time period in order to prevent loss of the HP1 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 acenarios: 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 16, 1991, DE initiated a Problem in-estigation 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, DZ 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 NPI system. This scenario assumes a small break LOCA with a concurrent single failure of either NP-24 or NP-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 entrairment of hydrogen from the LDST and eventual pump damage.

This conclusion, which applied to all three Ocones 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 NPI 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 ind Low Pressure Injection (LPI; [ENIS:8P] 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 BPI 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 BGW 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 Fower 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.

CONCLUMMONS

The root cause of this event is besign Deficiency, (Functional Design Deficiency, Hechanical) 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 wystems function assuming a failure of a single active component.

The operational curve was provided by Babcock and Wilcox (BGW), 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, .t 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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epecifically 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 relasues 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 "Ars 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 graphe and curves iv 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 Linensee 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 ' \sim operating in an unanalyzed condition due high tilt and imbalance following a dropped rod [E'ISIROD]. 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 ava.'able to Duke Power, but it is recognized that some vendor information will not be readily 'ailable.

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

CORRECTIVE ACTIONS Immediate

Operations personnel were provided verbal guidance for maintaining setdown 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

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

 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.

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

 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 notor 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 f 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, (B4W) 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 HFI 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.

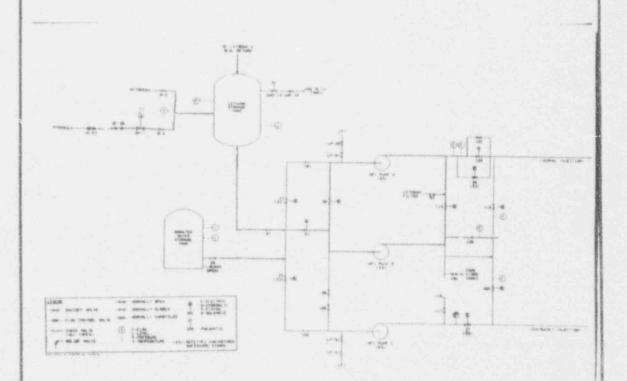
The analysis for a Maximum Hypothetical Accident (MNA) as described in the "inal Safety Analysis Report assumes that some core damage occurs. That analysis shows .nat IOCFRIOO limits would still be met.

Therefore, while it is not expected that the mituation would actually result in pump damage, damage is assumed in the low probability event that a small break LOCA occurred mimultaneously with mingle failure of one HPI muction valve from the BWST. The assumed loss of mystem function is still bounded by FSAR analysis. Therefore, the health and mafety of the public was not affected by this event.

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Attachment 1

Righ Pressure Injection System



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Attachment 2 Recu sing Design Deficiencies

LER Number Title/Problem inadequate Design Analysis of the High Pressure Injection System in the 269/88-06 Emergency Cor: Cooling System Sump Recirculation Hode. (Found that Design (B6W) did not calculate/verify required HPI pump NPSH in "Piggyback" mode.) Unanticipated System Interaction During Undervoltage Condition in the 269/90-04 230RV 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.) Design Deficiency/Unanticipated Interaction of Systema Results in the 269/90-05. Potential Closure of the Startup Transformer "E" Breaker on to a Degraded (Low Voltage) Switchyard. (Protective relay setpoint would permit selection of an .no. r voltage power source, leading to Engineered Safeguards equipment .ailure.) Potential Failure of Engineered Safeguards System by Improper Valve 269/90-10 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 eystem, technically inoperable.)

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Attachment 2 <u>Page 2</u> 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 Reswee 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 "usak. 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 Dise 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 Bydro 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.)

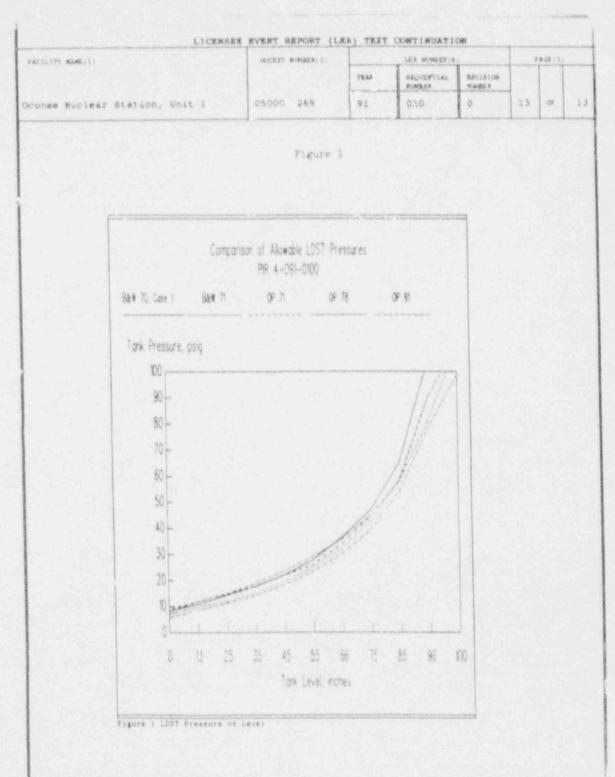
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Attachment 2 Page 3 Recurring Design Deficiencies

LER Number 269/91-07 Title/Problem

Breaker Coordination Problem Due to Design Deficiency Results in Technical Inoperability of Safety Related Equipment. (Failure of nonsafety related equipment could cause loss of power to safety-related equipment, including HP-25.)

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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/O/A/106/17. "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 desire pressure.

Value 2H-1. (Unit 2 LDST Supply). is a 3/4 inch, solenoid operated value. It requires power to open and fails closed when the coil is de-energized. The value position indicating lights and Operator Aid Computer inputs are actuated by contacts on the switch [EIIS:XIS] rather than actual value 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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EVENT DESCRIPTION		
Room Operators (CROs) on du (LDST) pressure had decreas LDST level. Bi inches, this normal operating range as a curve in Enclosure 3.13, "H OP."O/A/1106/17, "Hydrogen S generator [EIIS:GEN] and Un the CROs began planning the primarily entailed coordina and assigning Non-Licensed	sty observed that the sed to approximately 3 s represented the low shown on the Maximum P (ydroget. Addition to U ystem" (see Attachmen off 1's LOST also requi- routine evolution to tion between the CROS Operators (NLOS) to o	Unit 2 Letdown Storage Tank 5 psig. At the current pressure boundary of the ressure vs Indicated Level Init 1. 2. or 3 LDST" of it A). Unit 2's main irred filling. Therefore add Hydrogen. This assigned to the two units
the Auxiliary Building and ((LDST LF Control Bypass), A Block) while NLO B opened vi	LICENSEE EVENT REPORT (LER) TEXT CONTINUATION The sum of the sum	tion. She opened N-93 ck), and IN-26 (Unit 1 LDST Storage Tank building to
building was lined up. CRO 4 Room to open 2H-1, (Unit 2 1 approximately the same time LDST Supply). The Unit 2 0 documented that the 2H-1 val three times between 15:59:41 minutes and six seconds. The also operated three times do minutes, twenty eight second switch while he observed LDS [EIIS:XI]. He watched press point he operated the switch observed the position indica and heard the OAC alarm type but assumed that the typer e He then observed the pressur	A operated the contro LDST Supply), at 1559 , CRO B operated the perator Aid Computer lve control switch wan 3 and 16:06:01, for a he Unit 1 OAC alarm to using this period, and ds. CRO A stated tha ST pressure on an adju- sure rise to approxima h to close 2H-1. He is ating lights change to entry was documenting	<pre>1 switch in the Control (43 hours. At switch for IH-1. (Unit 1 (OAC) slarm typer s in the open position total duration of five yper shows that IH-1 was d was open a totsl of three t he kept his hand on the acent indicator guage ately 39 psig, at which states that next he o show the valve closed, not walk over to the typer the 2H-1 position change.</pre>
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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 incidiately 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 (o lower the LDST pressure by venting the excess Hydrogen into the Gassous Waste Disposel (GMD) header in accordance with OF/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 285190. 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 value 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 romputer 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/O/A/1106/07, "Hydrogen System," does not include a "Limit and Precaution" or "Caution" to warp 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 *raining.

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 LOST 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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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 $\text{OP}/0/\text{\AA}/1106/17$, "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 MPRDS reportable equipment failures have been confirmed, pending further inspection during a future outage. There were no injuries, releases of radioactive materials, or personne/ iver-exposures as * result of this event.

CORRECTIVE ACTIONS

Immediate

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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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 HFI 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 scenaric could lead to damage to all three HPI pumps which would correspond to loss of system function.

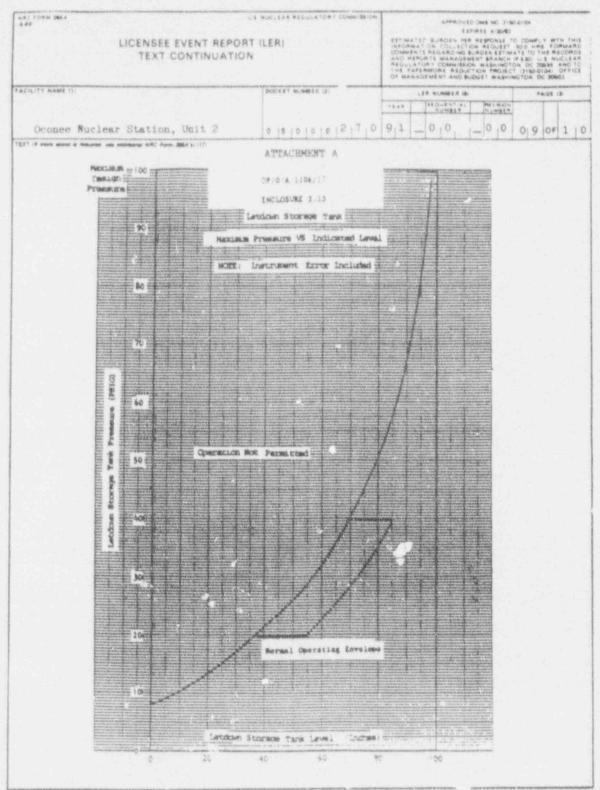
However, Design Engineering calculations show that the Hydrogen gas would not expand into the pump suction header until the BWST level had been reduced to near the minimum post-LOCA level. This would take several hours, even for the largest break sizes for which HPI is required. During this time. LDST 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 preventative action. Possible actions would be 1) to isolate the LDST by closing 2NP-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 Gaiseous Waste Disposal System.

If a loss of the HPI System were to occur, the Emergency Operating Frocedure 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 IOCFRIOD 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 \mathbb{N} of 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.

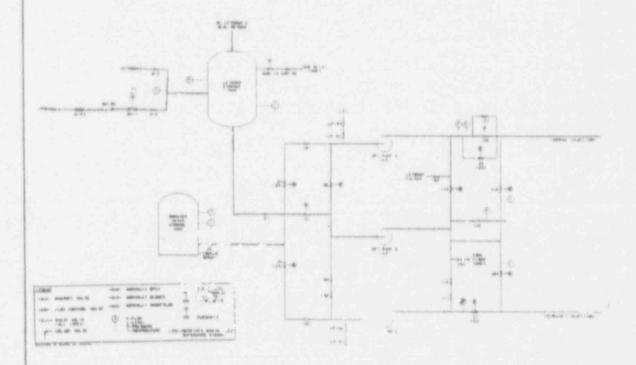
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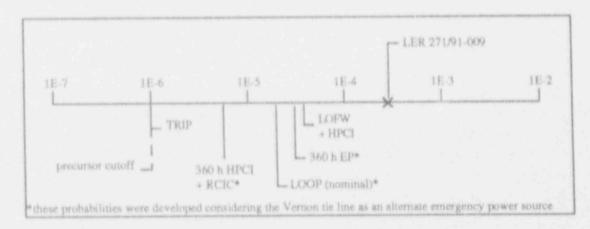


ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 271/91-005 271/91-012 Extended loss of offsite power April 23, 1991 Vermout 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.



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.

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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 coaclusion 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 vent, 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 indicased by a voltmeter and ammeter adjacent to the control switches. In artition, 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 switchvard 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 wa' 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 fail 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 ft3. 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 breake closed, a decision was made to leave EDGs connected to buses 3 and 4.
21:12	Torus water volume again above 70,000 ft3 and could not be readily reduced
	April 24, 1991
04:10	Back-feeding 345-kV power through station auxiliary transform v completed
04:30	Both emergency diesels secured.
19:25	Torus water volume reduced below 70,000 ft3.
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 Turbing building cooling water Drywell cooling

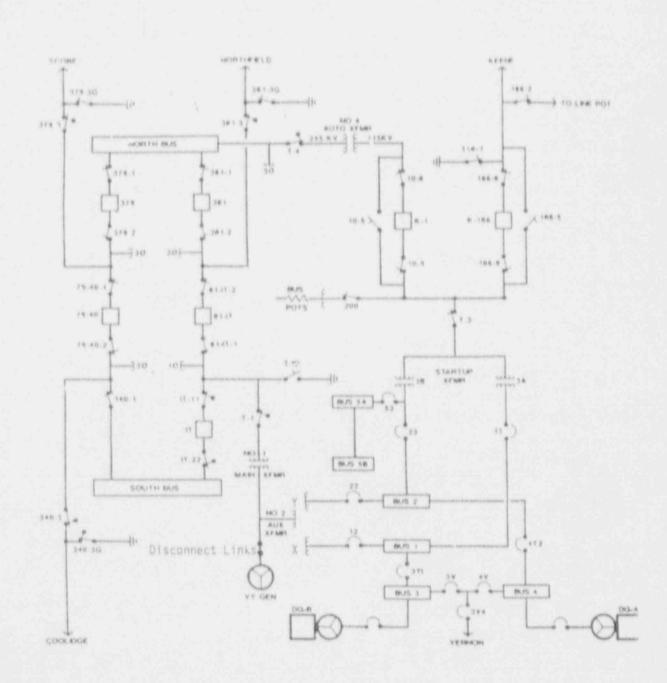


Figure 1. Vermont Yankee AC power system

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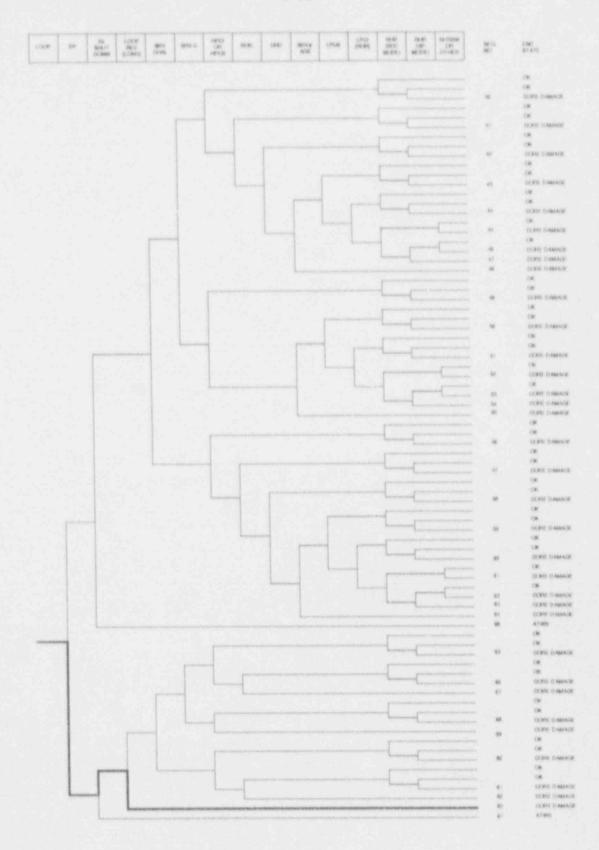
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Dominant core damage sequence for LER 271/91-009

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CONDITIONAL CORE DAMAGE FROMABILITY CALCULATIONS

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ABSTRACT (limit to 1400 spaces, i.e., approx. fifteen single-space typewritten lines) (14)

On 04/23/91 at 1446 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 effsite 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 in 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 04/25/91. 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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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 responsest

- Generation of 345KV Breaker Failure Signal
- Opening of 345KV Breakers 381 and 17
- 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:

- Hain Turbine Trip Opening of 345KV Breaker 81-1T and Northfield Line trip at Northfield
- Attempted Fast Transfer of 4XV 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 tation output, which is designated as a delayed access off-site power source, was available inclusion 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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DESCRIPTION OF EVENT (Cont.)

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trip of Reactor Protection System (RPS)(*JC) *A" and "B" NG sets and receipt of Primary Containment Isolation Signals (PCIS)(*JN) Groups 1, 2, 3 and 5 resulting in the required closure of PCIS Groups 1, 2, and 3 isolation valvos. (Motor operated valvo ciocares 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 to ough 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 m.de. Both RPS MC 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. Frior 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 MPCI, 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 teceiving 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

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*Energy Information Identification System (EIIS) Component Identifier

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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 T rus 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 HANUAL 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 Rmergency Diesels connected to 4FV Buses 3 and 4. This would ensure that power to 4KV Buses 3 and 4 would not be interrupted it shother LNP occurred.

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DESCRIPTION OF EVENT (Cont.)

At 1950 hours on 04/24/91, based on normal off-site power having been restored and Torus vater 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 trouvleshooting, 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 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 sttempting 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 Bi-IT 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 offsite transmission line (Keene Ki86 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 B1-1T, 381 and K1 breakers. The cards for 381 and K1 breakers were found to have failed zener diodes. The B1-1T (SBFU) relay was found to be functioning properly.

Discussions with the manufacturer indicated that the zener diodes are no longer employed on never 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 diafted 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 B1-1T 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 preexisting 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 crossconnected 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 FVENT (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 blacks 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

- 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-6A) rendering them susceptible to a single system transient.
- The switchyard battery chargets were in a degraded mode such that they created DC bus control voltage disturbance when the chargets were disconnected from associated batteries. This included the installation of incorrect capacitor fuses and other degraded components.
- Lack of Switchyard battery charger and overall Switchyard preventative Maintenance.

ANALYSIS OF EVENT

The events had minimal adverse safety implications.

- 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 offsite power was restored.
- 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

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

LONG YERE CORRECTIVE ACTIONS

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.

- Representatives of Vermont Yankee and REMVEC aet 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 o, 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.
- 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.
- Procurement of new switchyard breaker failure relays (BFR) has been initiated. Installation is scheduled to be completed during the March 1992 Refueling Dutage.

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LONG TERM CORRECTIVE ACTIONS (Cont.)

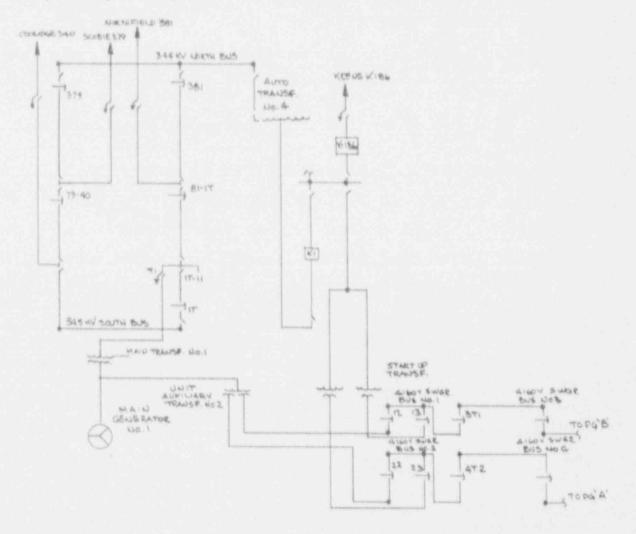
- 5. Administrative controls for switchyard activities, which are important to safety or plant reliability, will require additional management review, including PORC review, as determined by the K.intenance Supervisor. This enhancement is effective immediately and ongoing.
- 6. Vermont Yankee vill evaluate 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.
- 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.
- 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 nonnuclear 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.
- 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.

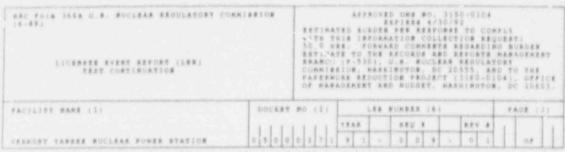
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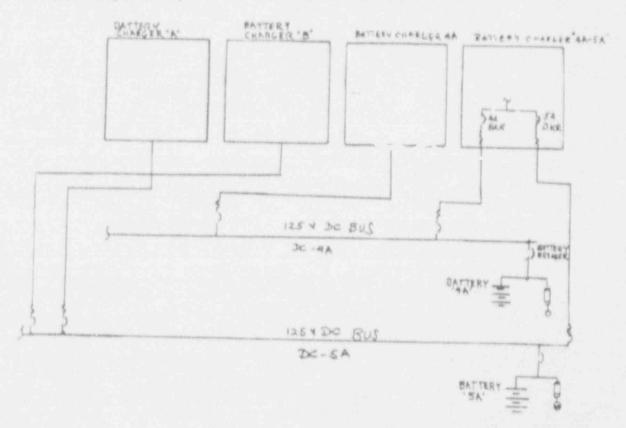
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SWITCH YARD DISTRIBUTION

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SWITCH YARD DC BUS SYSTEM

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On April 23, 1991, at 1448 hours, and at 100% pover, a Loss of Normal Pover (LNP) va* experienced. Following the expected start of both Emergency Diesel Generators (EDG), it vas observed that the EDG heat exchangers were operating at reducei 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.

NRC FORM 366 (6-49)

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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)(11) 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 s, tems important to the operation of the plant and is sutside 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 Vater 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 tovers 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 lower is provided via valve V70-11.

RAC FOIR 1664 U.E. RUCLEAB REGULATORY COR (6-89) LICERSEE RVERT REFORT (LER) TERT CORTINUATION	*1**10*	W17 50, 887 88A CON FAP	目 年10 日 年10 日 年11 日 日 年11 日 年11 日 年11 日 年11 日 年11 日 1	8.8 P1 (10 BU) (18 18) (18 18) (18 18) (18 10) (18 10) (18 10) (18 10) (18 10) (18 10) (18 10) (18 10) (18 10) (18 18) (18 18)	NURR PORMA DRWA FER DI FARH DUCT	A P 1 A F 1 F A T 10 A T 10 E E C 0 E E E E E E E E E E E E E E E E E E E	本 冬 第 8 年 1 日 0 約 日 1 日 0 約 日 第 0 初 1 1 日 初 1 1 1 日 初 1 1 1 日 初 1 1 1 日 初 1 1 1 日 初 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	4/3 あらします の あ ま し ま う の し ま つ し ま う の よ う の ま う の ま の し ま う の ま の し の う の の の の の の の の の の の の の の の の	0/9 888 8071 8 81 10 81 10 10 81 10 10 81 10 10 10 81 10 10 10 10 10 10 10 10 10 10 10 10 10	2 10 10 10 10 10 10 10 10 10 10	000 829 128 128 128 128 128 128 128 128 128 128	RG RA RD 104	5寸: あい あん での 1,	THE CPF	49 208
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TEXT (If more space is required, use additional NRC Form 366A) (17)

CAUSE OF EVENT (Cont.)

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 rander the EDGs inoperable. This same high backpressure also closed the pressure control valves on the station air compressor coolers, opened the "B" sir compressor relief valve and created a reduced/reverse flow condition to the drain on that unit.

Auditional 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 Jummer operations. An alternate (SB-1 closed, V70-11 Jummer operations. An alternate (SB-1 closed, V70-11 open) valve lineup was determine. De acceptable and became the "normal" year round system lineup. This configuration creates, gnificant backpressure conditions to the Service Vater system due to the higher resistance of this flow path and the cooling tower deep basin head of vater. The resultant backpressure is preferred during normal operations for control of heat exchanger discharge flows and provides very favorable conditions for certain Service Vater 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 Gene-ator 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 EDC heat exchangers discharge into a common 8° discharge line which is also shared by the station sir compressor coolers. During the LNP both EDCs auto started and were disch-"ging to the single 8° line. The EDCS have independent 8° supplies. During surveillance testi 4, 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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YEXT (If more space is required, use additional NRC Form 356A) (17)

ANALYSIS OF EVENT (Cont.)

The Service Vater system is identified to be subject to attack by merobic microbes (HIC) 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 Vater System flow was higher than normal due to the operation of two EDGs, four Service Vater Pumps and two RHR Service Vater 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 S8-1 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 - loulation that if the service water inlet temperature had beer 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 LNF, 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 Vater system configured with the SB-1 valve open and the V70-11 clused 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.

NEC FORM SEEA (6-20)

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INMEDIATE CORRECTIVE ACTIONS

- . Both Emergency diesel Gener: . remained operable and were closely monitored throughout the event.
- During the LMP event, a , ______ autie 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 pre-sure 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.

- The Service Water System was reconfigured to position SB-1 open and V70-11 closed. This lineup accures that the excessive backpressures developed during this event cannot recur.
- A review of Service Water System loads was performed to verify optimum system performance.

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

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LONG TERM CORRECTIVE ACTIONS (Cont.)

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

Eme FF

- Alternate methods for cooling tower deicing and normal cooling tower makeup ate 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.
- 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.
- 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.
 - The SV 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 SV surveillance testing program. Specific SV surveillance test procedures will be revised by December 31, 1991.

ADDITIONAL INFORMATION

9.

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

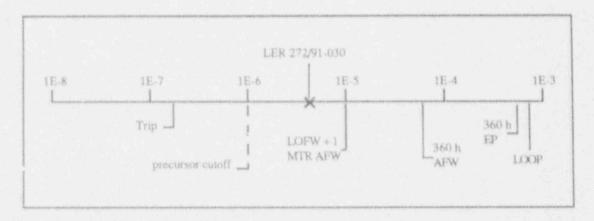
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No: Event Description: Date of Event: Plant: 272/51-030 Both PORVs failed due to leaking actuators September 20, 1991 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 are 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 Salern 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 ($T_{avg} \le 20' \cdot 7$) 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 rc m alarm for PORV accumulator low air pressure actuated. Investigations showed that both the 11°R1 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 IPR1 and IPR2 actuator diaphragms appeared to be in a functional condition. Further assessment showed that the diaphragm sterial (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 IPR1 and IPR2 actuator diaphragms had been replaced on March 21, 1991, and April 12, 1991, respectively.

Additional Event-Related Information

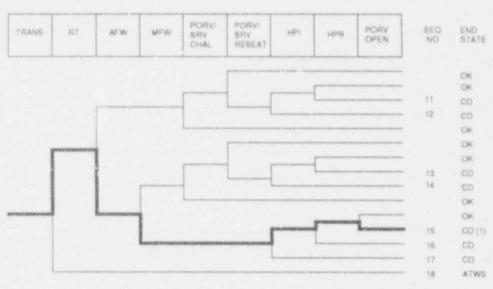
At Salem, the PORVs and pressurizer spray valves are used to hclp mitigate the consequences of a steam generator (SG) tube rupture. Additionally, the PORVs are used for a total loss of feedwater (LOFW) accident. During a LOFW with failure of auxiliary feedwater, decay heat removal would be provided by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



(1) OK for Class D

Dominant core damage equence for LER 272/91-030

CONDITIONAL CORE DAMAGE PROHABILITY CALCULATIONS

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

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Event Identifier: 272/91-010

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BRANCH FREQUENCIES/PROBABILITIES

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On 9/20/91, a plant shutdown was in progress. Operated Relief Valves (PORVs) are used to prov protection at low Reactor Coolant System temper with Surveillance 4.4.9.3.1.1 the PORVs were ful Both valves failed to open. The IPRI valve did limit indication and though the IPR2 valve indi apparently did not reach its full open limit. that both the IPR1 and IPR2 valve actuators leas diaphragm bolts were observed to be loose allow flange bolting area. The root cause of the val continuing. The IPR1 and IPR2 valves are Copes air actuated globe valves. Investigation indic appeared to be in a functional condition. Furt	ide overpre atures. In nctionally not lose i cated movem Investigati. ked. The v ing air leal ves failing -vulcan rev ated that t	ssure accordance checked. ts closed ent, it on showed alve actuator kage from the to open is erse acting

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PACE
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 $|\mathbf{x}\mathbf{x}|$

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 OCCUERENCE.

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. Fer 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) IABI are used to provide Pressurizer overpressure protection. Therefore, in accordance with Technical Specification Surveillance 4.4.9.3.1.1 the PORVs well functionally checked (at 0115 hours) using Operations procedure II-2.3.4, "Pressurizer Overpressure Protection -Operability". Both valves failed to open upon demand. The IPR1 valve did not lose its closed limit indication and though the IPR2 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(0)4.0.5-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

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 13 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 deneral 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

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
Unit 1	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, S'ation 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 matter 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 Coclant 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 values.

The PORV's also provide Preasurizer 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 paig.

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.
- Low-temperature overpressure protection of the reactor vessel during startup and shutdown, or
- 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 PCRVs are specifically taken credit for a "loss of all feedwater" accident. This accident is not addressed by the Updated Final Safety Abalysis 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".

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
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ANALYSIS OF OCCURRENCE: (cont'd)

With both FORVs 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 1CCFR 50.72(b)(2)(iii)(D). This event is also reportable to the NFC in accordance with 10CFR 50.73(a)(2)(v)(D) and 50.71(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 3 valves were successfully tested.

CORRECTIVE ACTION:

The diaphreims were replaced in all Copes-Vulcan actuators located inside the Unit 1 Freesurizer. These included the PORVs (1PR1 and 1PR2) and the Pressurizer Spray valves (1PS1 and 1PS3). The latest revision to procedure SC.IC-FM.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 (2** 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.

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
Unit 1	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.

Eller Monda

General Manager -Salem Operations

MJP:pc

SORC Mtg. 91-107

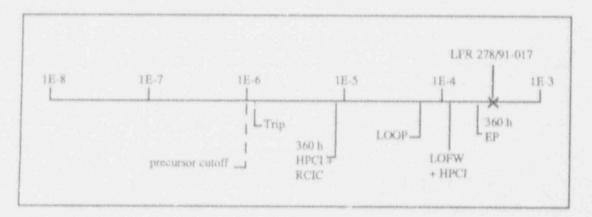
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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

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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.

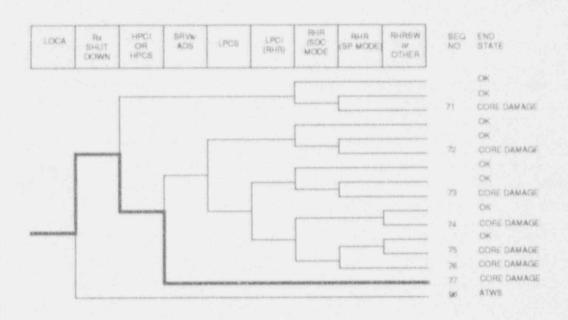
The ASP Program estimates the small-break LOCA frequency at 3.3 x 10⁻⁶/h, with a nonrecovery probability of 0.5, and these values were used in this analysis. The ASP Program normally estimates a HPCI failure-on-demand probability of 0.029. In this case, however, data regarding HPCI unavailability during 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 l-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 DAMADE PROHABILITY CALCULATIONS

Event Identitier: 278/91-017 Event Description: Control wiring for SRVs found damaged (TI LOCAs) Event Date: 09/24/91 Flant: Peach Bottom 3

URAVAILABILITY, DURATION- 6132

NOR RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3,4£+00 20-3£,5
SEQUENCE CONDITIONAL PROBABILITY SUME	
End State/Initiato:	Probability
TRANS LOOP	1.5E-07 1.5E-07
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TRANS LOOP	0.05+00 0.05+00
Total	0,0E+00

SQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequance	End State	Prop	N Rec**
38	trans -rx,shutdown pca/trans arv,chall/transseram arv,close fw/pcs,trans HPCT srv,ads	CD	1,58-07	1,78-01
55	loop ~emerg.power ~rw.ahutdown arv.chall/loop, =scram arv.cl.se RPCI arv.ads	CD	3.,38~07	1.28-01
67	loop emerg.power -rx.shutdown/ep -ep.rec srv.chall/loopscram -arv.close HPC: rcic	CD	9.78-0.9	9.46-02
69	loop emerg.power ~rx.shutdown/ep ~ep.rec srv.chall/loop.~s>ram arv.close HPC1	CD	A., 78-09	1.38-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PHOHABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	H Rect+
20	trans -re.ahutdown pos/trans erv.ohall/trans.~soram erv.close fw/pos.trans HPCI erv.ada	CD	1.56-07	1.78-01
\$5	loop "emerg.power -rs.shutdow: srv.shall/loopacram arv.close RPC' arv.adu	СВ	$\mathcal{T}^* \mathcal{B} E = 0.A$	1,28-01
6.7	imp emerg.power -rs.shutdown/sp esp.rec srv.chall/loopscram -srv.close NPC1 role	60	9,78-69	9,45-02
6.0	loop emerg.power -rs.shuidown/op -ep.ren srv.ohall/loopscram srv.close HPCI	CD	8.78~09	1,36-01

Event Identifier: 278/91-01:

$^{\star \star}$ non-recovery oradit 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 bwrcasal.comp
BRANG, MODEL:	c:\asp\	1989\pwach.sll
PROBABILITY FILE:	C:\280\1	1989\bwr csll.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Brench	System	Non-Recov	Opr Fall
trata	5,55-04	1.02+00	
loop	a.,6D+05	2.46-01	
losa	3.38+06	5.09-01	
rx.shutdown	3.06-05	1.02+00	
rs.shutdows/ep	3.5E-01	1.0E+00	
pus/trans	1.78-01	1.02+00	
siv.chall/transaccam	1,02+00	1.0F.+00	
arv.chall/loopscram	1.02+00	1,08+00	
arv.close	3,68-02	1.02+00	
emerg, power	1.48-03	8,08-01	
ep.red	2.16-01	1.02+00	
fw/pos.trans	4.68-01	3.42-01	
fw/pcs.loca	1,02+00	3.48-01	
HPCI	2,92-02 > 4,72-02	7.06-01	
Branch Model: 1.0F.1			
Train 1 Cond Probi	2.9E-02 > 4.7E-02		
reic	6.02-02	7.02-01	
ard	1,08-02	1.08+00	1,05-02
sty.ads	3.7E-03	7,18-01	1,08-02
lpcs	3.02-03	3,46-01	
lpci(thr)/lpcs	1,0E-03	7.1E-01	
chr(sdc)	2,18-02	3,48-01	1.08-03
chr(sdc)/-1pc1	2.08-02	3.4E-01	1,08-03
phr (ado) / lpc1	1.02+00	1.05+00	1.06-03
the (spcool) / thr (sdc)	2,08-03	3.48-01	
rhr (spcool) / «lpci, rhr (sdc)	2,05-03	3,48-01	
thr (apcool) /lpci.thr(adc)	9,3F+02	1,05,+00	
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* branch model file ** formed

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Event Identifier: 278/91-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifiers 278/91-017 Event Description: Control wiring for SRVs found damaged (non-RV LOCAs) Event Date: 09/24/91 Peach Bolton 3 Flants UNAVAILABILITY, DURATION- 6132 WON-RECOVERABLE INITIATING EVENT PROBABILITIES 1.02-02 LOCA SEQUENCE CONDITIONAL PROBABILITY SUMS End State/Initiator Frobability LOCA 3.38-04 Total 3.32-04 ATWS 0.08+00 LOCA D.0E+00 Total SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER) End State Prob N Rec** Seguence 77 loca -ra,shutdown HPCI SRV.ADS 3.38-04 3.58-01 ** non-recovery credit for edited case SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER) Sequence End State Prob N Rec** 77 loca -rs.shutdown HPCI SRV.ADS CD-3.38-04 3.58-01 ** 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. c:\aap\1989\bwrcaeal.cmp c:\aap\1989\peach.sll SEQUENCE MODEL: BRANCH MODEL: PROBABILITY FILE: c:\asp\1989\bwr_call.pro No Recovery Limit BRANCH FREQUENCIES/PROBABILITIES Branch System Non-Recov Opr Fall trana-5.58-04 1.08+00

Event Identifier: 278/91-017

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Peach Bottom Atomic Power Station Unit 3	0 15 10 10 10 217 6	9 1 - 0 1 7 - 0 0	0 2 08 0 5

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Requirements for the Report

This report is being submitted to satisfy the requirements of 10 CFR 50.73 (a)(2)(11)(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 Titage in 1989. This caused an unusually high temperature environment in the 1 mediate 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 env onment 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.

NAC Form M6A (6-89)

**	IS NUCCEAR REQUIRTORY COMMISSI	APPROVED DMB NO. 3150-0104 EXPIRES 4/30/82
LICENSEE EVENT REPO' (LER) TEXT CONTINUATION		STIMATED BUNDLER FER RESPONSE TO COMPLY WYH INFORMATION COLLECTION HEDDIST RED HMS TOWN COMMENTS REGARDING REPORT STRATT TO THE FLO AND DECORTS MANAGEMENT REAMING HED. U.S. NUCL REGULATORY COMMUNICATION DC 20000 AND THE PREFERENCE REDUCTION PROJECT TESTOTION DC DT MANAGEMENT AND SUBJET WAYHING TON, DC 20000
ACILITY NAME (1)	COCKET NUMBER (2)	LER NUMBER IS RASE (3)
Peach Bottom Atomin Power Station Unit 3		TRAN STOLENIAL RECEIDS
ST of more space a required, use additional HRC Form 3864 $\omega/\odot71$	10 10 10 10 217 1	8 9 1 - 0 1 7 - 0 0 0 3 OF
Analysis of Event		
The MSRV SVs and associated wiring w condition which provides some basis prior to and possibly during a desig	to expect the MSRV's	sted in a cold s to be functional
If a design basis event had occurred HPCI system was available approximat operating cycle. HPCI is used to pr (EIIS:RPV) pressure to allow the Low the Core Spray (EIIS:BM) Systems to	ely 96.4% of the tim ovide core cooling a Pressure Coolant Ir	me during the last and to reduce reactor
During the time that the HPCI system Isolation Cooling (RCIC) System (EII: cooling but its capacity may have be events.	S:BN) was available	for high pressure core
The safety consequences of this cond under review. The SVs will be tested The test findings will be used to det safety consequences of this event. A fully analyzed, and the root cause in revision to this report will be submit	d under simulated ac termine the actual A When these results h ovestigation has bee	cident conditions. DS operability and ave been received.
Corrective Actions		
After discovery of the event, the Uni reinstalled and the SVs were replaced	t 3 MSRV thermal in	su'ation was properly
The maintenance procedure will be rev to ensure that RV thermal insulatio controlled.	ised to include the n removal and insta	appropriate details llation is properly
The same insulation on Unit 2 was ver configuration prints during a recent concern does not exist on Unit 2.	ified to be properly plant shutdown. The	y installed per erefore, the same
Eight of the Unit 3 MSRV SVs and asso facility to undergo testing in an acc findings will be used to determine the consequences of this event.	ident environment.	The test result
A formal root cause investigation is a significant causes, failed barriers, a corrective actions that may be warrant revision to this report as necessary.	generic implications	, and associated
The pertinent information from this ex Maintenance personnel and members of t	vent will be provide the plant staff.	d to the appropriate
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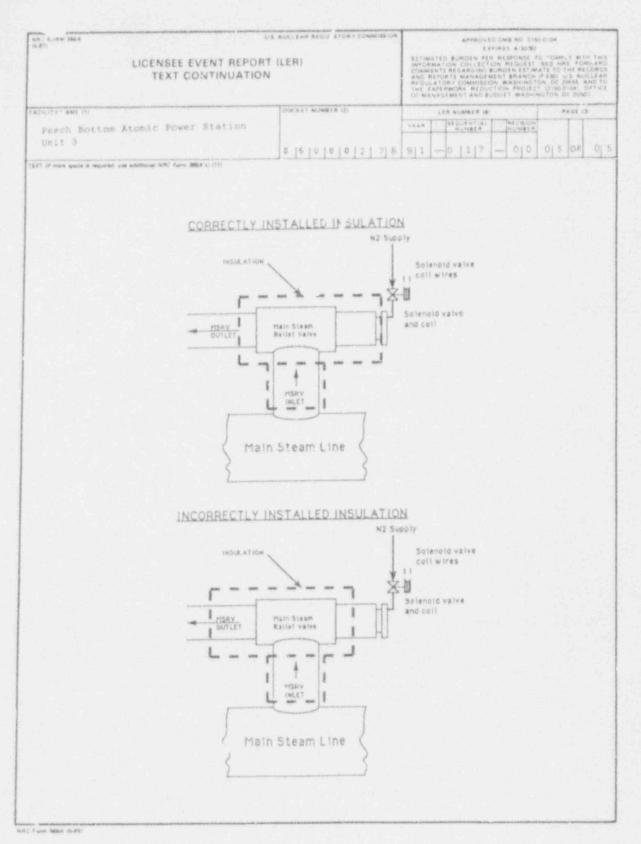
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Previous Similar Events

NRC Form 368.5 (6-89)

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



U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/91-33 50-278/91-33	License Nos
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	

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:

r. Dberflein, Chief Reactor Projects Section 2B

Reactor Projects Section 2B Division of Reactor Projects

12/23/2 Date

DFR-44 DPR-56

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, diation 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 weaknesser 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 Foensee 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 existent 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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9.0	MANAGEMENT MEETINGS

DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)"

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 to a excess of 400 Fabrenheit (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.

The inspection procedure from the NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section. 2

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 erable designation). Five of the SRVs are dedicated to ADS, RV-3-16-71A, 'B', 'C', 'G' and 'C'. 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 safe-ty-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 backward' installation of the thermal insulation of all 'SRVs'. It appeared that the insulation had be('t is dified to allow the backwards installation. The licensee initiated Reportability Evaluation Eve.' 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 1S 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⁺ POVs were verified to operate in the shutdown environment by audible click. All of the scirical 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 cortractor 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. Preiiminary 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 repeired, 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, Relision 4. The drawing clearly indicated the configuration of the SRV insulation. The walkdown found that the

"IT 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

To the early an independent laboratory test eight of the SRVs to determine if ADS would bars for the stand the loss of coolant accident (LOCA) conditions. The components associated to the stand SRVs, 'B', 'J', and 'L', were lost after removal. The components were subject as to either a test simulating the envoronment that would exist following a break inside or ou side containment, followed by a seismic test. For the test the components were configured is 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 v/as 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 property. 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.
- Ladure 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-2-16-25B 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

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valves and performed the appropriate diagnostic testing. Local leak rate test (LLRT) ST/'LRT 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 S12T-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 (1&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 S12T-13-4936-C1CQ. During the test a KCIC 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 1&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 t'as 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 PO 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 20 that the test was completed. At that time, the technicians noticed that the ECIC isolation alaria 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 rebuil 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, 1&C technicians re-performed S12T-13-4936-C1CQ and a RCIC isolation did not occur. 1&C technicians also performed S12T-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 lic, see personnel and reviewed the results of surveillance tests \$12T-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 Emergeous y 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 individual was treated from the hospital.

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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) a'l 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 bostom 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 vestal 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 retirculation, 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 inspector 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 rafety conscious decision to proceed with the inspection and cleaning of all of the fuel burfles. The licensee's decision to inspect and clear the bottom head drain demonstrated their clubre to fully evolute 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 a vallable 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.

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8.0 PREVIOUS INSPECTION ITEM ULDATE (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 weskness 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 mainten-nce 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 config ured 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:

Dats	Subject	Report No.	Inspector	
11/4 to 11/22	Emergency Service	Water 91-31	Prividy, She.	a. Jones.
			Maneria Livine	

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 (10076884	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

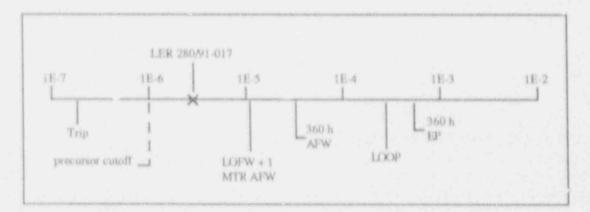
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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

8-148

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

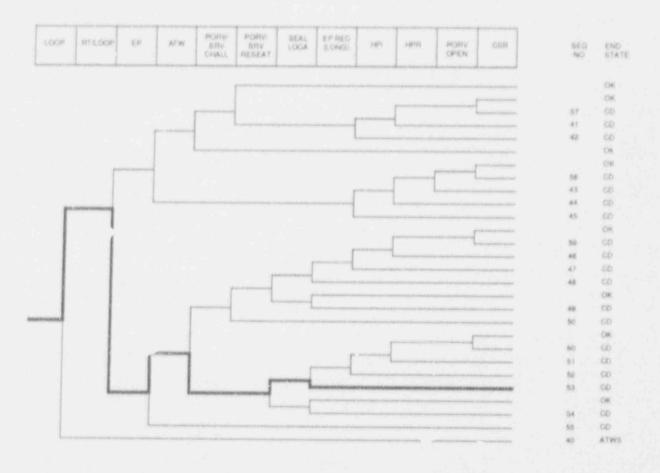
The emergency power system for Surry consists of three EDGs for the two units. EDG 1 is dedicated to Unit 1, EDG 2 is dedicated to Unit 2, and EDG 3 is a "swing" diesel that serves as a backup for either Unit 1 or Unit 2. Each EDG has 100% capacity and is connected to independent 4.16-kV emergency buses. 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 ellimated 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 COME DAMAGE PROBABILITY CALCULATIONS

1.18-64

Event Identifier, 200/91-017Event bescription; Moth EDGs for Unit 2 Inoperable for 13 K Event Units: 05700/91Flant; Builty 2

UNAVAILABILITY, DURATION- 11

ROP RECOVERABLE INITIATING EVENT PROBABILITIES.

LORDP.

REQUENCE CONDITIONAL PROBABILITY SOFS.

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	LOOP	0.08+00
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** non-recovery credit for willed case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

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** non-recovery credit for edited case

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

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1.0 DESCRIPTION OF THE EVENT

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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 \$70 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, EDO #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 *P*-justments 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 previou...y 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 sbutdown within the required seven day period in accordance with Technical Specification 3.16.B.I. During the time period EDG #3 was inoperable, the redundant emergency power

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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 evice of loss of off-aite power (LOOP). The system consists of three 100% cape ity 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 fod from an independent offsive power source, with the EDGs functioning as on-site backup power intrees.

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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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 or 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 acribe 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.

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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 an, Failure Analysis Evaluation Teams are reviewing testing data and overall EDG performance to ensure continued EDG reliability and availability.

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7.0 SIMILAR EVENTS

None.

8.0 ADDITIONAL INFORMATION

None.

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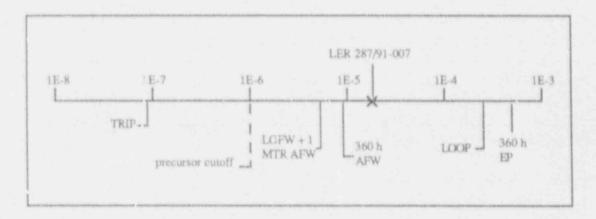
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No: Event Description: Date of Event: Plant: 287/91-007, 269/91-009 Reactor trip due to LOFW plus degraded EFW July 3, 1991 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

157

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 hect 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 , Jetermined 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:

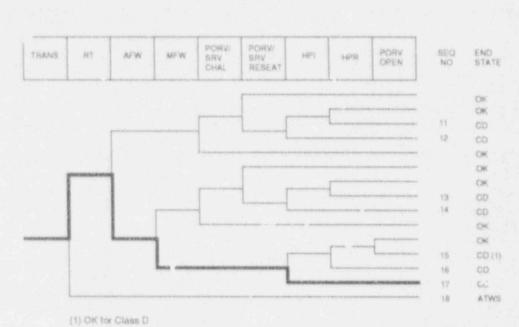
p(EFW) = [p(MTR PMP 3A) × p(MTR PMP 3B | MTR PMP 3A fails) + p()-4 (R PMP 3A) × p(TURB PMP) + p(MTR PMP 3B) × p(TURB PMP) + p(common cause)] × p(NON REC) + p(second EFW flow control valve fails) × p(fail to manually control flow from control room)

 $p(EFW) \approx [0.01 \times 0.1 + 0.01 \times 0.05 + 0.01 \times 0.05 + 0.00028] \times 0.26 + 0.1 \times 0.04$

 $p(EFW) \approx 4.6 \times 10^{-3}$

Analysis Results

The conditional pr_bability 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.



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Dominant core damage sequence for LER 287/91-007

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event identifier Event Descriptio Event Date: Flant:	1 287/91-007 ni Reactor trip due to LOFM plus degra 03/03/91 Ounnee 3	ded EFW		
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BRANCH FREQUENCIES	PROBABILITIES			
Branch	System	Non-Recov	Opr Fail	
6 rana	1.58-04	2.05.+00		
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Event Identifier: 287/91-007

1.08-02 1.08-03

loop	1,62-05	2,48-01
100a	2.42-06	4,38-01
et	2,81-04	1,28-01
rt/loop	0,0E+00	1,0E+00
emerg, power	2.9E-03	8,05-01
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ep.recial)	0,0E+00	1,0E+00
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hpl	3.0E-04	8,45-01
hp1 (1/b)	3.0E-04	B.4E-01
hpr/shp1	1.58-04	1.00+00

* branch model file ** forced

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BACKGROUND

The Condensate System [EIIS:5D] has three main system functions:1) to deliver condensate from the condenser hotwell to the suction of the main feedwater [EIIS:5J] 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 (Powdew) [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 (precosting). Precoating is performed as needed on a staggered schedule to avoid having several cells out of service simultaneous? A master controller [EIIS:65] provides a pneumatic control signal to the solution of the 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 control ers showed 100 % demand for full flow. As part of this modification, the controllers for several valves including the condensate demineralizer system (Fowdex) 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 menually 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 Eypass Valves were closed.

On July 3, 1991. Unit 3 was operating at 100 % full power when Operations and Chemistry personnel begin the routine operation of precoating a cell in the Fowdex. At 0950 hours: Control Room Operator (CRO) a placed the control for Fowdex bypass calves in manual and opened them to maintain adequate Condensate Flow and Condensate Booster Fump (CBF) suction pressure. At approximately 0952 hours. Chemistry Technician A (CT A) placed the Fowdex master controller into manual and took one of five cells out of service to precoat the cell by closing its inlet and outlet values.

HARC & area Desca Inc. 1

U.S. NUCLEAR RECOLATORY COMMENDICA е илина в часки ватоматар выявляет и воловат то ингомматион орсталтон веконат тормаетие и водатоно волятся затом ало времята маладамант волятся то волатон сомакарают на волято тна газа висота в долаго и волято и маладариета на волостика нарина и маладариета на волости и нарина LICENSEE EVENT REPORT (LER) TEXT CONTINUATION ENDER & T. MILMARE R. LT. ON PROPERTY OF THEVBON NUMBER HEALIGHY IS ... 0 0 0 0 0 0 2 8 7 911 01017 - 010 013 0F 111 Oconee Muclear Station, Unit 3 TERY of entry anero a conversal, say adultionar ARC. Parce 2004 at (11) 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 B5 % of total condensate flow and the remaining 15 % flow was routed through the bypass. The bypass controller was left in Manual during the precost cycle

At 0952 hours CRO 7, started Low Pressure Injection (LPI) [EIIS:BF] 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 1947 hours. He set the flow rate as required by the test procedure, and left the control room to perform other lities after giving verbal turnover concerning the tasks in progress to CROs B and C. and

After the Powdex cell was precoated. CRO B increased Powdex Bypass flow by opening C-14 and C-15 again at 1046. CT A valued 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 & 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 r and 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 LPT pump P and subsequently aligned and started LPT pump C at 1117 hours.

At 1117.33 alarms were received in the control room to indicate high differential pressure across the Fowder, high Hotwell Pump discharge pressure, and low CBF suction pressure. Alarms also indicated low botwell flow and an automatic start of the standby CBF. At 1117.36 the integrated Control System (EIIS JA) reached a feedwater (EDW)/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 actual free field. The operators investigated the alarms full being 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 CBF suction pressure indicated low, which caused a trip of all three CBFs, followed rapidly by trip of both Main FDW Fumps, which in turn, caused an anticipatory trip of the reactor.

Several immediate automatic actions occurred. All three Emergency FDW [EIIS.BA] Fumps started. The Control Rod Drive [EIIS.AA] breakers [EIIS ERF] opened and all control rods were inserted into the core

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LICENSES EVENT REPORT		 ARD 1 	81 P.O.		27183 8 58 8081 8081	BR & BCH	10 00000 80.0 HT	C. 8 . 661.4	C1848
FACTLITY MARE (1)	DOCKET RUMBER (2)		1,8	EA ANUMBER I			and the second second	PA64 (F
물건 물건 물건 것 같아요. 이 것 같아요.	사람은 영화되었다.			NUMBER .	-	ME-BOA			
Oconee Muclear Station, Unit 3	0 16 10 10 10 12 18 17	91		01017	-	0 0	0 14	OF	111
TEXT /# means denses a requirea, une antificanse to/FC Poune (\$66.5 g) (12)	and the draw draw of an electric descention of the				-	allow and the set	- Arrentered		
shotting down the reactor. Th auxiliary power [EIIS.EA] swit power, and the Main Steam Reli opened	ched from normal to a	tart-	up	(Emerg	enc				
The operators also took manual turbine had tripped, verified monitored for proper operation a second High Pressure Injecti opened HF-26. HFI Loop A Emerg maintain Pressurizer level.	that the Emergency FD of other automatic e on (HPI) [EIIS: BG] p	W Pun quipm ump A	ips ien it	had st t. The 1118:36	art y s an	ed, a tarte d	nd		
At 1118:47 CBF suction pressur psi (Hotwell Pump discharge pr and the Main FDW Pump suction discharge pressure : omentarily approximately 250 p=ig. At 11 stopped and Main FDW pump dis psig.	essure). Pressure be increased to 750 psi. increased to 1145 ps 19 both "D" heater dr	tueer Mai i the ain p	i ti Lri Sin Sum	he CBP FDW Fum decayed ps were	dis p tc ma	icharc inual)	je Ly		
Also at 1119, the operators sh Pump, after confirming that be operating.									
At 1120 the operators closed H	(P-26 and stopped the	seco	nd.	HPI pur	φ.				
As Steam generator level dropp observed that FDW-315 Emerger was not controlling properly a approximately 1122.	ncy FDW throttle vilve	103	Ste	am Gen	tra.	tor A			
One of the Turbine Bypass Valversatically in Automatic folls operators took Turbine Bypass	owing a previous Unit	3 tr	ip	on 6-9			the		
The operators observed that the Motor Driven Emergency FDW Fue Licensed Operator was dispatch that Flow was indicating high	mp B did not reset as hed to check the loca	expe and	c14 154	ed. All ation a	Non ori				
Two Main Steam Relief Valves was reduced to approximately (ore		
Specific post-trip parameters Coolant System (RCS) [FIIS:AB Homentary operation of the se maintain Pressurize: incentor; time of trip and a low of 89 to approximately 555 F. Stea of 1111 prio and was controlly	pressure ranged bet cond NFT pump enabled y on scale between a 5 inches. RCS temper m Generator pressure	veen the high ature reach	LB Op of sd	55 and erators 230 in converg A post	220 10 01+ ed - 02	s at s at smoot	the		

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LICENSEE EVENT REPOI TEXT CONTINUATIO	Талионая «2004) Натиматар нижова нея варичная то сомин, никомнаятион соры встали ярошаят во емя социналита вараморика фонкция катимата то акоо делонта вараморика фонкция катимата то варистия социналися и ванисти и нако варистоя социналися на накото накото от кале боли социналися накото накото от кале боли по накото накото накото от кале боли на колони накото накото от кале боли накото накото накото варисти накото				
ADILITY BALMER (1)	DOCKET MUMBER (2)	LER MUNICIPAL INTERNAL VERS BEGUENTIG, BREVERICA REVERSE Provession	PADE IR T		
Oconce Buclear Station, Unit 3	0 0 0 0 0 0 0 0		01 1		
pressure was reduced to appro relief valves. Steam general prior to the operators taking	or inventory reached a	minimum of 21 inches			
An investigation was started CBP emergency low suction pre- be leaking. It was isolated observed that one of four hou- in place was missing. The ter- circuit open, clearing the fr subsequent restart of a CBP. diaphragm, was replaced prior thought to have been the rause suction pressure signal, sust- CBPS, cause the Main FDW Pumps However, Transient Honitor [E1 a real flow reduction occurred discharge pressure increased, system.	ssure switch, PS-228 [4 and found to have a sp sing bolts which hold chnician left the press ip signal to the CBPs. The entire switch asso to unit restart. This e of the trip, because ained for 30 seconds s to trip and result [15:10] and control ran d prior to the trip.	EllS:XIS], was found to lit diaphragm. It was the diaphragm assembly sure switch electrical and permitting embly, including s failure was initially an emergency low cill trip all three n a reactor trip. m indications show that lise, the Hotwell Pumm			
Therefore, the Powdem was chec to have failed, which caused t demineralizer cells to close w controller was further investi switch was found to have the A from a worn rubber seal. The	the outlet valves on the when they should have b spated. A pneumatic AU APTO position air port	e individual een open. The TO/MANUAL transfer			
After the unit was stabilized to restart the main FDW pumps, starting a CBF in condensate : routed from the Hotwell throug Water in the UST is then used drops. However, n procedure the existing conditions. Npec a CBF would cause hot water for UST raising the UST temperature primary source of water for the maximum supply temperature asso the required Emergency Feedwate power. Several procedures in contained caution statements the F with the Reactor critical be subcritical.	*1 hat shutdown. Opera One of the first ste ecirculation mode. In the Powdes to the Upper to makeup to the Hotwe specifically covered r ifically, a concern we am feedwater heaters to the above 130 %. The D e Emergency FDW pumps used in Design Enginee er flow rates following cluding the Reactor Tr hat the UST temperatur. It is could be up to 1 personnel were consul- mit applied because the set of the UST temperature.	ps to do so required which condensate is Surge Tank (UST). 11 as Hotwell level estart of a CBF under s reised that starting o be pumped into the ST almo serves as the and 130 F is the fing calculations of g * trip from full IP Recovery Frecedure. e must be less than 130 30 F with the Reactor ted and concurred with a Reactor was			
At 1530, the operators restarts recirculation. As expected in within ten minuter. Shortly i	of temperature rose to	ADDITONIONATWIN 1775 F.			

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LICENSEE EVENT REPORT (LER)		LICENSEE EVENT REPORT (LER)						LY WITH S AGR THE REC US MUS COSES A DIGAL C DC 2050	THIS WARD CORDS CLEAR ND TO IFFICE 3
FACILITY NAME (1)	New York of the set of the law of the law of the law of the set of the set of the set	ENDER ET INGABLER (2)	Resources rate					PA-64 13	accession a
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Courses Bucklass	Onetice Delt 3	0 16 10 10 10 12 18 17	0.1			0.0	0.6	nel	11
LICODER INUCLES	Station, Unit 3	0 6 0 6 0 6 0 1	1314	1-1-1	- III		1010	Tort	-
flow from Make-up f receives basement flow was level ing Frocedury which stat than fior The oper Emergency reactor of at 0230 f Analysis Feedwate oil pres start sin low Main condensa setpoint Analysis feedwate Emergency	n several sources sho flow was increased fi overflow from the U floor. This indicat then isolated. A w strumentation. Subsi- e revealed another co- ated that the UST co- e hours after the re- ators started a main y FDW pumps at 1427. went critical at 231 hours. 7-4-91. of Fost-Trip data a r Pumps were started sure on the Hain FDW gnal from the other FDW Pump discharge te/feedwater system due to continued op showed this phenome r events for all thr y FDW actuation logi	Specifications, despite ould have been causing t urther and the Condensal ST, began to overflow or ted that the UST was act ork request was initiate equent review of the Rev aution, on a later page uld not exceed 130 F un actor trip. FDW pump, and stopped terminating the loss o 0 hours and the turbine lso showed that, althou by one actuation path. Fump turbines, they di actuation path, The se pressure. It was obser stayed higher than the seration of both "D" hea non to be a potential o te Doonee units, theref is has been technically reported separately a	the lite St nto to tuall ed to actor than less the m f fee was gh th i.e. cond to ter c i.curr ore c inope	evel t orage he tury y full invess Trip the i it had otor of dwaten placed te Emen due rece path hat p iischa irain ence an path stable	o inc Tank, bine i, so stigat Recov first d been drives d back to lo ive a is ac ressu rge p pumps on lo th of for	rease. which build: make-u e the very caution h great nt. Th k on-li y w contr timely tuated ressure ss of some	ng p er ne by		
CONCLUSI	2M2								
controll age degr Cl23MT S internal calibrat	er, a Foxboro model adation of a rubber witch Assembly. Thi to the controller a ion or routine maint	is Equipment Failure. 52% "Consotrol" failed seal which is a compone in failure is NFRDS repo and is not specifically tenance. It has apparer initial installation pr	due nt o rtab insp tly b	f a pa le. T ected been i	mal w irt nu his s dur r n ser	Wear an Imber Weal is Wice f	or		
Action w required coptrol walows w across t failed s which st are clos	here the proper acti i action was omitted in AUTO. the unit tr ould have been able he demineralizer sys hut on loss of air ates that the contro ed. This is accomp	is event is Inappropriat ion was chosen but exect Had URO B placed the rip could have been avoi- to respond to the incre- stem as the Powdex cell The Powdex Bypass Val- of she 1d be placed in A lishe, simply by pressin geable of this requirem	ution Fowd ided eased flow ve co AUTO ng a	faile ex Byp becaus press contr ntrol whenes button	d bec bass b sure the sure to has bas the n on	cause a Valve • bypas frop alves a label he valv the	S W 5		

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PACILITY MAME []]	UNIXER \$7. NUMBER (2)	-	1.81	-	-	CHINE STREET	PAGE (2		
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Oconee Muclear Station, Unit 3	0 16 0 0 0 0 2 8 7	911	-	01017		0 0	0	7 01	11
none involved the Powdex	a have occurred recently do system controls and none of a failure. Therefore, this	of the		rrectiv	78. I	actio	0.5		
but were not causal facto	ment failures/problems acco ors of the event. Subseque eral apparent causes of some	ent in	VE	tigatio	on l	by			
PDW-315, the Emerge	e (SV) failure disabled th ency Feedwater Loop A thro	erle :	11	ve. Th	e 5	oleno	id		

value is normally energized but is required to operate to the deenergized position upon Emergency FDW actuation to permit automatic control. This failure is NFRDS 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 no maily energized and operates at an elevated temperature lapproximately 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 Fump 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 rooling 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 diaphrage on TR-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 reted for 320 psig. Markings on the component indicate a date of manufacture of 1971. Maintenance records indicate that the switch has not been replaced since initial installation prior to Unit d startup in 1974. The mode of failure was a crack on the outer edge of the a-tal switch displacem. The presence of some rust on the

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16-29-	£0	FUCLERS REDULATORY COMMUNETOR	APPENDIVED DATE NO STEDUCES						
	LICENSEE EVENT REPORT TEXT CONTINUATION	EXPERSE A20090 ESTIMATED BUILDEN FOR RESPONSE TO COMPLY WITH THIS INFORMATION DOLLECTION REDUKST BOD NRL YOMMANG COMMINTS REGARDING DURINGE STIMATE TO THE RECORDS AND REPORTS REGARDING DURING RETHINETS TO THE RECORDS AND REPORTS REGARDING NR AND NOT TO THE SACRESS TO THE FAREMOUNK REDUCTION REMOVED TO THE SACRESS OF MARAGEMENT AND SUDGET MARINETON DU SPOL OF MARAGEMENT AND SUDGET MARINETON DU SPOL							
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	lear Station, Unit 3	0 16 0 0 0 0 2 8 7	91 - 01017 - 010 0	8 OF 1					
ENT OF IMPRE ADDRES IN ORDER	inat, and additional defit frame differ (r (17)								
	inside surface of the cra period of time, then fail failure of FS-228 was prin influenced by the missing holds the switch diaphrage flexing at its periphery. allow the diaphrage to fl the point of failure to s out efter a gasket was po- hole. It was not possibl- it, or why the person(s) that the bolt could be pr housing is not disassembl- and the degradation would This failure is NFRDS rep 2221-32.	ed under higher than marily due to age but belt on the unit how m securely, and rest The absence of the ex at its outer edge tress fatigue. The l orly installed such e to identify when t involved failed to r operly installed. I ed during routine ca not have been visib	normal pressures. The t may have been using. The housing cains the diaphragm from housing bolt could subjecting the area at bolt was apparently left that it blocked the bolt his occurred, who did ealign the gasket so t was noted that the libration of the switch le without disassembly.						
	5. For approximately thir Surge Tank (UST) level in minimum level required by the UST being overfilled was established. The ove level instrument reference the differential pressure erroneous low reading. B than as indicated, the Te resulting overflow of und floor did not impact safe temperature was exceeded. Engineering calculations assumed FDW supply temper Emergency FDW system did temperature was higher th procedure limit being esc information and Poor Fore on different pages.	strumentation indica Technical Specifica when the Condensate rfilled condition al e leg, which should seen by the instrum ecause the actual US chnical Specificatio ontaminated water to the Miss temperature 1 This temperature 1 of the minimum Emerg atures for removal of adequately remove de an the procedure Ta ied is Defective F of in that limits we	ted 1-ss than the tions. This was due to recirculation line-up lowed water to enter the be dry. This reduced ent resulting in an T level was full rathe in was not violated. The the Turbine basement ocedural limit on UST imit is based on Design pency FDW flow rates at of RCS becay Heat. The cay heat while the UST mit. The cause of the Procedure Ambiguous are presented different!						
	e were no personnel injurie partice materials associate		res, or releases of						
CORR	ECTIVE ACTIONS								
(mme	diat*								
	 Operations personnel 1 Operating fromedure and 2 to bring the unit to a sl 	Annormal Procedure 5	ions per the Emergency of Loii of Dain Feeduate						

NRC Fame 398.8 (3-3)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			APPROVED USES AND STREETLON REPORTS ADDRESS ADDRESS REPORTS ADDRESS ADDRESS REPORTS ADDRESS AD							
PACILITY NAME (1)	DOCART NUMBER (2)	LER MURRER 16					ABHINEGTON DC 206431			
		Y8.4#		CUTENT LAL NUMBER	TTP	AVALUN VALA		TT		
Oconee Nuclear Station, Unit 3	0 0 0 0 0 0 0 2 0 7	9.1	1	01017	1.1		0.9	OF	11.1	
(EP) if each dense is repaired, use an attracts ARC Field (EQ.4 , 112)		de la de se		NA CAR	1-1	-	1.1.5	dinid.	-1-	
Subsequent										
1. The solenoid valve on	FDW-315 was replaced									
2. The Motor Driven Emerg Was calibrated.	ency Feedwater (FDR)	pump	8.7	ov fl	он а	larm				
 The operation of the M and determined to be acce been revised to better de to improve Post-trip dete 	ptable. The Fost-Tr fine the MSRV perfor	ip Re Mance	V主要な を用す	/ proc	ess ions	has				
4. PS-228 pressure witch replaced. Equivalant sol	including the diap tches on Units 1 and	hrage 2 ve	85) (6	iembiy inspec	ted.	5				
5. The seal on the Fourder	master controller u	48 1.6	pla	ed.						
6. The Upper Surge Tank (refetence legs dried.	UST) level instrumen	ti ve	en i	checke	d ar	d th				
7. Control Operator 8 has Inappropriate Action in t	been counselled con his event.	cerni	ng I	118						
8. A problem was discover for actuation of Emergenc main feedwater as detecte and the corrective action 269/91-09.	y Feedwater pumps in d by low discharge p	reap	00%	to 1 That	OSS. DYC	of blem				
Flanned										
 The solenoid value mod improved model in ell saf 	lel used on FDW-315 s fery related applicat	ill b lobs	e r st	eplace Oconee	d w)	th a	n			
2. Instrument and Electric communicate to IAE rechnic switches with missing/loc	cians the potential	nanes failt	ent.	viil mode o	ť pi	e 5 5 1	ιre			
 The equivalent seals of will be inspected and rep 		9, 1949	5.01	00071	011	Y 5				
 Operating Procedures s conflicting guidance on T 	A. Operating fracedures will be revised as necessary to eliminate conflicting guidance on UST temperature limits									
5. à Station Problem Repo logic of Powdex Bypeis va pressure drop while in Ma	trves to allow them t	t te i te int	eo i ipon	se the d to t		tro) Pove	le ja			

18.5 FORME 2000.6 U.S.	NOCLEAR REPORT OF COMPRESSION	KAMMOVED DALE NO 3180-01	104					
LICENSEE EVENT REPORT TEXT CONTINUATION	ILERI	Волять алиста водать составлять поставлять интернатор неризона от ток обставлять поставлять поставлять по таките за поставлять поставлять по поставлять и поставлять по по поставлять по поставлять по по поставлять по поставлять по по поставлять по поставлять по поставлять по поставлять по по поставлять по поставлять по по поставлять по поставлять по поставлять по поставлять по поставлять по поставлять по по по поставлять по поставлять по по по по по по по по по по по по по по по по поставлять по п	\$0.0 HRS FORWARD 5.75 TO THE RECORDS (F & 30) U.S. MUCLEAP ON DC PREAS AND TO 1.0160-0104: CFF3CE					
ACILITY RAME (1)	DIDERS! HUMMES (2)	LER MURIERS IE	PA.94 13					
Oconee Ruclear Station, Unit 3	0 16 10 10 10 12 18 17	911 - 01017 - 010	10 01 11					
EXT IN more assess a required, use appleasury MRC fairs 2005.4 (17)	and a second and a strend and the second second	der ek medener kansk ander ak meden dar iken. Ko	-ddede-s-ede					
SAFELY ANALYSIS								
Failure of the Condensate Demin clogged control air path result controllers for five parallel d These valves all went closed, a the condensate flow path. The removed from service due to the the Bypass valves been in servi alternate flow path and to avoi condensate flow path constitute	ed in a loss of cont emineralizer resin to a designed, resultir Powdem system Bypass inappropriate action ce, they should have d a system transient	rol signal to the ank flow control valves, g in the isolation of valves were effectively n of an operator. Had opened to provide an . The loss of						
Loss of FDW is an anticipated t the Final Safety Analysis Repor- trip and starts the Emergency F roolant pump heat removal. In systems operated as designed to FDW. As expected, low Condensa detected and instrumentation tr Main FDW pumps tripped as expec- hydraulic dil pressure in the M initiated the Loss of FDW trips provides the start signal to th FDW pumps started and the unit	t (FSAR). Loss of F DW System to provide this event, most of mitigate the conseq its Booster Pump suct ipped the Condensate ted. Instrumentatio tain FDW pump turbine of the Main Turbine Emergency FDW Syst	DW initiates a reactor decay heat and reactor the equipment and unnees of the Loss of ion pressure was Booster Fumps. The m detected the low control systems and and the Reactor and em. All three Emergenc						
The failure of the redundant tr failure if the system to reach discharge pressure, is describe had no safety significance in t	the actuation setponed in a separate lice	int For Main FDW pump lo	w					
The failure of the solenoid in valve being unable to respond 4 was a single failure within the The operators took appropriate and maintained proper level in event. Mad the operator failed generator would have boiled dry been carried by the other stead	to control signals wh e design basis of the action to take manu- the affected steam of the take proper act. y and the entire RCS	This in automatic. This s Emergency FDW System. Al control of the valve generator throughout thi ics, the affected scame that load yould have						
The failure of the diaphrams on had occuried at some other time transient associated with this loss of feedwater trip. This trip due to single failure	 e. independent of the trip, the result we 	e condensate system. uld have been another						
The postflow of the Uppet Sung that it demonstrates that both instrumentation can be made in instruments are intended to be source of sater for the Emerge	trains of post-acci- operable by over fil- used to velify the	dent level mobiloring ling the tank. The lev adequacy of the OST as	o.1 a					

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FACILITY NAME (1)	DISCN ET HUMMER (3)			-				*#.64 1	*
						MUMBES.			
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The series a second of example of the example of the second of the se	the Hotwell. This real f a similar loss of 1 ing such an event, con to performing unnect f water. However, if ed, as occurred in this ures in excess of pro- exceeding design ba- sical or physical inop- mit of 130 F is based removal capability is single Emergency FDW mit of 190 F is inter irements for the scer al hours after a trip edurally required fiv was able to provide However, two Emergence lable if needed rath esign calculation. I umps was assumed to f might not have been a in decay heat remova ikely event that a fa time, the Turbine Dri ther options include u ber options include u ber options include u rvice Water System or the High Pressure In r Operated Relief Val iate procedures.	aligni evel nside essar is even sis eve	mendbart lung resil dury hit straduut to	t requ ication le ope ctions oneous limit mption t, of esign orst c. nediat reflec ere a his casion the or f the y f the y f the or f the y f one y repose or y supply be Star coolir System l of th estar	in ats systematic tid Directors	s that courre- or tim order rae lso hat tems of after he s of ypsed remove s were al he her the w pump of coler y af the of	t ed me r		

Connec Muclear Station, Unit 1 This is One of Two Diverse Actuation Systems for Loss of Main Feedwa Pound Inoperable Due to a Design Deficiency	5 1 0 1 0	And in case of the local division of	$\begin{array}{c} \begin{array}{c} \textbf{APPROVED DARA NO 3180-6104}\\ \textbf{EAPRESA SCORE}\\ \textbf{EAPRESA SCORE}\\ ESTIMATED BURDEN FRY REPORTS TO COMPLY WITH THIS INFORMATION COLLECTION ATOUST 500 HET FORMATO COMPLY TO THE RECORD SCORE BY AND BETMATE TO THE RECORD STATEMENT ATO AN EXCLUSION OF THE FARMENCE COMPLETE SCORE SCOR$							
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from the independent signal. The problem was caused by the pumps (HDP) charging the closed feedwater system. The othe units were subject to the same potential problem. The root event was a design deficiency. failure to anticipate the in systems, during the original design of the these systems. reduced power to 72 percent FP to remove the D HDPs from se increased power to 71 percent FP, but did not place D HDPs feedwater pump low discharge pressure serpoints were change all units prior to allowing HDP operation and a return to 1 July 7. 1991.	hours. mained y Feedw em anti s preve did act D heate two Oc cause of teractic Units 1 rvice. in servi d to BOO	A post slight vater control two two two two two two two two two two	st- tly ory the in s 3							

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BACKGROUND

There are three systems at Oconee which are designed to automatically actuate when main feedwater (HFDW) [EIIS:SJ] flow is lost: the Emergency Feedwater (EFDW) [EIIS:BA] system, the Reactor Protective System (RFS) [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 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:SH] to pump condensed extraction steam to the condensate [EIIS:SD] and feedwater systems. The DI and D2 HDPs combined flow at 100 percent full power is approximately 9,000 gpm. The EI and E2 LDPs have a combined flow of approximately 9000 gpm. Attachments I and 2 show the general arrangement of these pumps in the condensate system. Because of the significant amount of flow of the D Heater Dr. in 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 teach 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 1 tripped due to a loss of all main feedwater. This event is reported in LER 200/91-09. 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 bydraulic oil pressure on the MFDWP turbines. The unit was stabilized at bot 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 [EIISISB] 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 HDF hypothesis was the most likely. When the D HDFs 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 NFDW 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 resured 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 the feedwater pump low discharge sense feedwater pump low dischar asked to perform an operability System (RP5) anticipatory trip. Safety Actuation Circuit (AMSAC seponnts. On July 5, 1991 De systems would be operable with justifying this determination w data at shutoff conditions and tank. The pump manufacturer ba degradation would tend to decre experially aince they are multi pressure at shutoff conditions. Less than the new 500 paig sets drift and calibration tolerance AMSAC calibration procedure be tolerance. This is less toleran. The investigating team discusses recirculation valves were opener able to develop sufficient preas discharge pressure setpoint. The of flow to be recirculated back pumps on Unit 1 were operated in approximately 30 minutes each. Di HDP and 720 psing for 102 HDF shutoff head conditions, these of between the pump discharge press setpoints to ensure loss of feer was decided to operate with a per- throttled open on all three unit the mergin between D NDP dischar- low discharge pressure setpoint accordingly. The setpoint changes and proceds system the AMSAC system, and the 1991. As these changes were con- to service and power increased a request. All three units were s 1991.	pe actuation signals we g to 500 psig on press (rige pressure. Duke De (determination for the the EPDW system, and) system based on the sign Engineering deter the new setpoints. The mere based on manufactor the relief valve setti- s stated that pump cas- ase the HDP performance stage pumps. The maxi- was found to be 773 ps- oint, which provides a A condition of ope- changed to require a l- nor than what was prev- d the possibility that d the D heater drain- sure to stay above the his slignment would al- to the D Flash Tanks. n this manner on July Their discharge press P. Since these tests values dd not provide sure and the low MFDW dwater system actuation ectroulation pathway to the since this mode of rige shutoff pressure a . Operation procedure are revisions were per- te FPS system on all to percent full power of 100 percent full power of 100 percent full power.	As to series series series the new mine is can is can	change t awitches Engineer Ctor Frot ATWS Mill 800 psig d that al loulation s origina erving th wear and er time. D HDF dis This is gin for i lity was ig as-lef ly allowe the D HD s would n dwater put a certain th D heat 991 for were 710 not done were 710 not done to Flash retion in the feedwa ce change spatcher. Spatcher. ay 0100 of	he which ing was ective gation 1 three s 1 pump e D Flas charge 27 paig nstrumen that the 27 paig nstrumen that the 5 d. P ot be mp low amount es drain paig fo at source ess, it Tanks creases ter pump d se EFDW duly 6, returne s n July 7	n t		

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<text><text><text><text><text><text><text></text></text></text></text></text></text></text>	 a. All of these switten. a used for alarm indic or signal. Feedwater p AMSAC Channel 2. The t to Hotwell pump and rip. D and E Heater Dr d. on Units 2 and 3. A ttch. which also serve a setpoint of 800 psig fication. This setpoint and April 2. 1991 on U on Unit 1 and the set till 800 psig. b perform a past operation of the stem. the loss of feed units 2 and 3. Ad been resoure portion of the stem. the loss of feed units 2 and 3. Ad been re operating since the s based on the following the following the MFDW pump RPS inticipatory trip as installed on Units hes which trip the D feed which trip the D feed which a loss of main resence of a low Main feedwater pump hydra uated on the low hydre in following the 	ches f ation ump re- remain Conder ain pi MSAC f s to 7 nt chi nit 3 point bilit uation actu bater i syste tems. actuat actuat bater syste 2 and HDPs we ad sys feedwa Feedwa feedwa feedwa ffeedwa ffeedwa ffeedwa ffeedwa	Integra ccirculat ing pres hate Boo ump feedw Channel 1 trip the 50 psig d ange was . The for the y evaluat n showed ation cir anticipa ems' orig nside ati ion signe Ps upon 1 witches v scharge p ms. (3, the P tere set 1 tem. (1) press pressure pumps. Their	set at ted ion sure ster pum ater pum . This Heater uring th approved AMSAC ion of that that cuitry tory RPS final ons: ave .em was tls. loss of could ha pressure MEDW pum below th selow th selow th try tory RPS fould happed to could happ	ip ie i ve		

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on the pump suction, maintaine 750 psig setpoint until the D					abo	ve	the			
The result of an operability e the feedwater pump low dischar circuitry of all channels of t anticipatory loss of feedwater system, and the ATWS Mitigation technically inoper-ble while th AMSAC systems were declared tec installation.	ge pressure portion of he Reactor Protective S pumps trip, the Emerge n Safety Actuation Circ he D HDPs were operation	the System ency l buit	nct Fee (AM RP	uat RPS dwa SAC S. 1	ion) ter) we EFDW	(E) r#	FDW)			
The technical inoperability of operability evaluation was performed, conservative actions units and remove the D HDFs fro within the required times of T- Selected Licensee Commitment 16 increase power but was prohibit evaluation showed that securing mitigation systems operable whe setpoints were at 750 psig. Th feedwater discharge pressure se restarting the D HDFs and incre	formed. While the eval s were taken to reduce on service. These acti- schnical Specifications 5.7.2. Unit 3 was allo red from using its HDFs of HDFs made the loss on the low main feedwat re corrective actions o suppoints to 800 psig wa	luations power lons wed to of fe ler di of res	on i rer .1. to teed iscl	was n ti e c: 3.4 stai opei wati hari tin	bei he o ompl 4. a rt u rabi er ge p g lo	ng per nd pi lit res	ed and Ly ssure sain	3		
The root cause of this event is interaction of systems, design modification in 1979 which adde instrumentation and controls di the installation of the loss of also did not consider the role related HDP pressure switch tri still is on Unit 1. This setpo during a loss of main feedwater calibration drift or even compl could have prevented the main f reaching its low setpoint.	oversight. The design d the motor driven pum d not consider the rol feedwater anticipator of the HOFs. At that p setpoint was 800 psi int should be sufficie transient. However. ete switch failure occ	of e ps an e of y RPS time g for nt to if ex urs.	HDI HDI ti ti ti ti ti the	ajoi Upqi Pa: rip he i ll i rip ssiv an t	EF ade Si in ion- init the the	d (mi) 198 sat s. ND	larly. H Aty As it P:			
The AMSAC system utilizes the s HDPs on feedwater pump low disc the setpoint to 750 psig for th inadvertent AMSAC operation pri- system was installed on Unit 2 1991. Again, when the setpoint setpoint on HDP operation and s	harge pressure. The A ese switches to minimi or to EFDW system actu in October, 1990 and o s were changed, the ef	MSAC ze th ation n Uni fects	des tes tot	sign Doss The in f th	AM AM AM AP	anq lit SAC ril owe	ed y of			

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It is noted that the identifi requires knowledge of several system, which changed the D is the Electrical Section of De- electrical circuitry, the ope trip operation of the conden- foresee the problem. Integri disciplinary approach to Nuc- for some NSMs where such an - Design Review was performed personnel will review the cr disciplinary reviews with re- disciplinary reviews with re- A review of Oconee Problem In indicates that two separate - AMSAC systems which have eit described in FIR-090-0042. In that event, the discharge pr Pumps exceeded the design pr pump was run is the recircui i-091-0035 and LER 287/91-05 to anticipate certain electr Diverse Scram System led to reactor trip. None of the i involved in these events. T recurring.	I areas of expertise. T HDF trip setpoint to 750 sign Engineering. A know- erating parameters of th- sata-feedwater system wo ated Design Reviews, whi- lear Station Modification approach is deemed appro- for the AMSAC modification iteria used when perform spect to system interact investigation Reports over events occurred which in- her a root or contributi- ipste the interaction of nvolved the Emergency Fer- essure of the recirculat ation mode. Another ev- involved the AMSAC syst- ical circuit phenomenon control rod insertion ar- oss of main feedwater ac-	he design of the AMSAC psig, was performed by wledge of the e D MDFs, and the post- uld be required to ch take a multi- n design, are performed priate. An integrated on Design Engineering ing these multi- ions. T the last two y, wis wolve the EEDW . 'S or ng cause of design systems. One event edwater system. In en Emergency Reedwater ion piping when the want, described in FIR- em design. A failure of the associated id subsequent manual tuation circuits were					
This event did not involve r material. No personnal inju failure which would require	ries were involved. The						
CORRECTIVE ACTIONS							
Immediate							
	E the Emergency Feedwatt verse Unitiation logic						
Subsequent							
	was formed to determine pump discharge pressure						
 Units 1 and 2 reduced secured. 	power and their lieater	orain pumps (HDF)s vere					
3. Unit 3 was allowed to	restart but was not per	mitted to use its HDPs.					

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4	Pressure switches which detect low main feedwat pressure and actuate EFDW. Reactor Protective 5 Mitigation Safety Actuation Circuits were reset an operability evaluation which justified these retpoints will be maintained until a permanent problem has been resolved. Instrument and Elec well as Operations procedures were revised to re- setpoints.	ystem, and ATWS to 800 psig following setpoints. These solution to the trical procedures as	P
s.,	The recirculation flow paths of lle D heater dr such that a larger difference occurs between the discharge pressure and the 800 psig setpoint. Not required to maintain EFDW, RPS, or AMSAC op- increase the erigin between the actual pump dis- against chutoff conditions and the revised setpo	e D HDP shutoff These alignments are erability, but further charge pressure	
Plar	med		
λ.	A Station Problem Report will be initiated which permanent solutions to this problem.	will consider	
2.	Oconee operator training will be enhanced by chi- material to reflect the new MFDW pump discharge and by making the required setpoint changes to t	pressure setpoints	
3.	The Safety Parameter Display System, used by the be changed to reflect the new MFDW pump discharg		
4.	The EFDW Design Basis Document will be revised a discovered in this event.	o reflect problems	
5.	Design Engineering will review the criteria used interdisciplinary reviews of design packages.	t to perform	
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sign unab by ti Feed ATWS can 1 press actu press press were	his event, the low Main Feedwater (MFDW) pump disc sl, used to detect and mitigate a loss of feedwate le to independently actuate the required systems. This degradation are: the Emergency Feedwater Syste- vater Anticipatory Trip of the Reactor Protective Mitigation Balety Actuation Circuit (AMSAC). Eac e actuated from a separate signal which monitors nure, indicating a tripped condition, on the MFDW ition is also possible. The degradation of the MF nure portion of the actuation circuitry depends on nure of the D heater drain pumps (MDP). When the operating against a shutoff head, the feedwater p mig setpoint.	r, was found to be The systems affected m (EFDW), the Loss of System (RPS), and the h of these s items low hydraulic cil pumps. Manual DW pump discharge the discharge D heater drain pumps	

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There is no safety significance discharge pressure signal if the as designed. The loss of MFDW is actuations would take place. The the D heater drain r mps were no power. In this situation not continue to be available, but the would also function.	e hydraulic low eil p would be sensed and t here would also be no ot operating, as in t only would the hydrau	ress he ap safe he co lic o	ure ppro ety sse oil	sign opria sign of a pres	al te ifi lc sur	ac sy ica oss	tuate stem nce i of signa	f			

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 the 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 firm 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 Low. 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 EFDWFs 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 MEDWF 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 MEDW 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

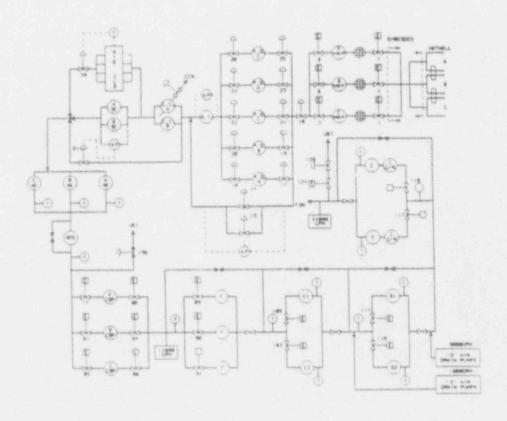
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 manually tripped ifith MFDWFa be tripped but not as quickly operational. The longer delay transient. If pressure reaches setpoint of 2000 psig) then the [EIIS.AB] will open to relieve. The AMSAC system is designed to associated with an ATWS event, when required. Tripping the to due to moderator temperature efforts streamer reactivity coefficiency for the low discharge pressure provent actuation of the system of ERW system actuation of the system reductor section of the EOP of trip both the reactor and the system reductor systems to start the aready automatically initiate. Although the AMSAC system is design aspect is not creduction will start the EFDW independent systems on low so that the EFDW system on low so the start the EFDW system on low so the start the EFDW system on low so the start the EFDW system on low so the theready automatic of is witch must RFS anticipatory trip from occand Loss of Feedwater procedure in it at manual actuation if a feedwater anticipatory trip is pressure or temperature. The circuitry are redundant. 	as when the anticipat may result in a highe 2450 psig (150 psig Filot Operated Relie RCS pressure. I ensure that the main there is a loss of a in this event, the r maine ensures that pr ffects. Because of a fects. Because of a ent, overcooling of 4 water is actuated as SAC system uses a two ilure of a hydraulic of e signals are inopera. The Unanticipated requires that the rea- main turbine. As pre- operator initiate EFD d. esigned specifically C and normal EFDW act be EFDW pumps. Both pumps whether or not ited in the basis of ited in the basis of ited in the basis of ited in the basis of it	ory trip or RCS pre- above the above the of Valve (above the f Valve (above vill negative the RCS w) a backup out of the oil pressi- able will Nuclear (the RCS w) a backup out of the oil pressi- able will Nuclear (the SFDW the SFDW These mod ater pump bave sep re signal event the y Operati edural guile not occ is trips and AHSAC wered by '	is ssure RCS t PORV) trips (ater fils to not in modera ill res to the o chan ire swi theref power ator ma tated. ly if r actuati formal social social as occi %pecif actuati ificat: low d arate is s. Mo norma ng providance ur. T on hig EEDW	rip and trip crease tor ult in normal nel tch ore mually the Los bot ion serve i ison serve i ison serve i ison tion tion tion tion tion tion tion ti	8 15 15			

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ATTACHMENT 1

CONDENSATE SYSTEM ARRANGEMENT



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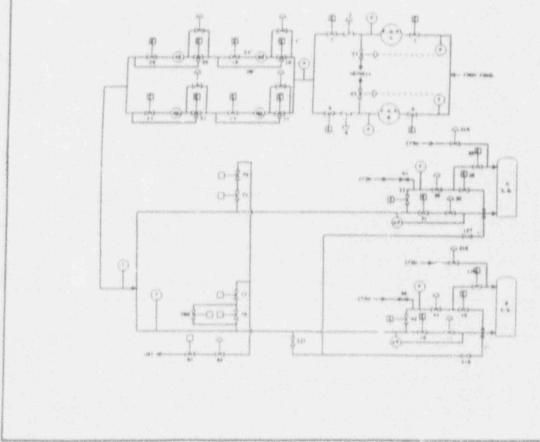
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ATTACHMENT 2

FEEDWATER SYSTEM ARRANGEMENT



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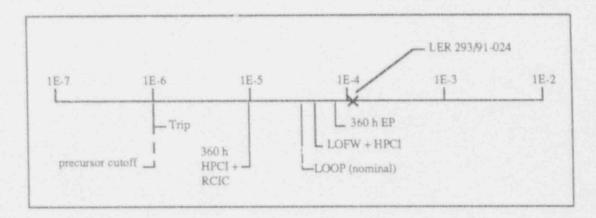
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 293/91-024, 293/91-006, 293/91-021, 293/91-025 Loss of offsite power and RCIC trip October 30, 1991 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 ¹¹, es providing preferred offsite power. The second line was deenergi ed when ACB 102 tripped open in response to operation of relay 62/5, which is a time delay rela signed 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 turkine 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 Gow. The operators responded by manually shuttin/, 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 reenergization 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.

The source 125-VDC ous 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 \approx 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).

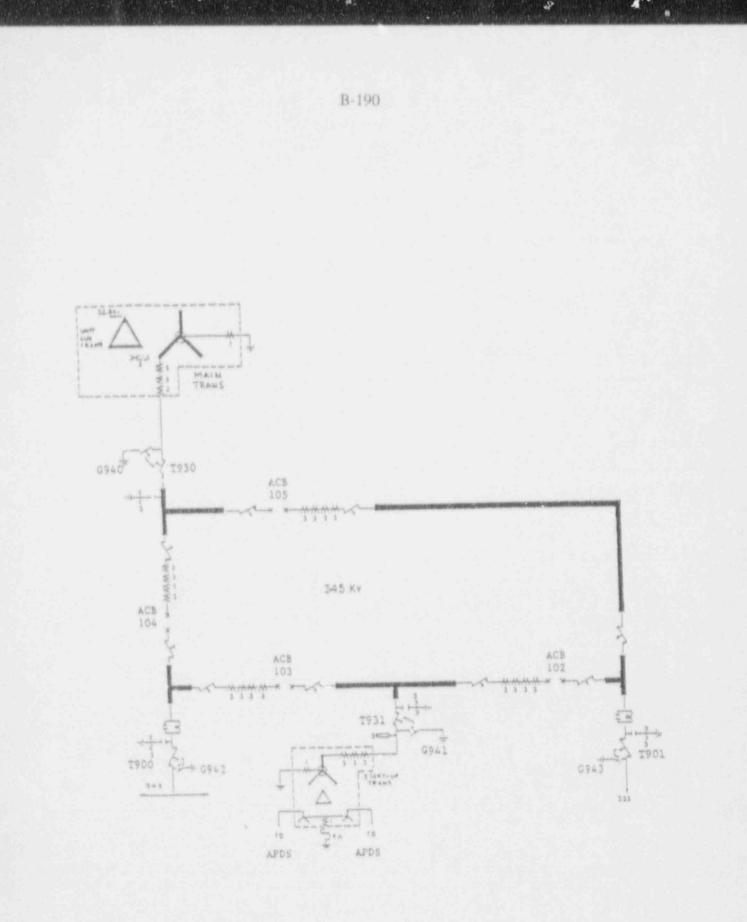
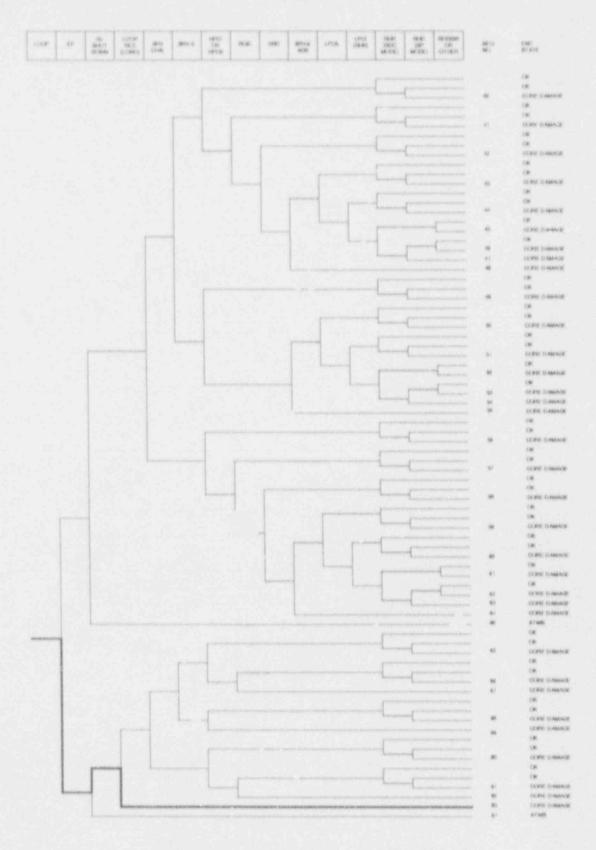


Fig. 1. Pilgrim 345-kV di tribution system

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Leminant core damage sequence for LER 293/91-024

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

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Pileris Nuclear Power Station

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 sait deposits on the 345 KV switchyard and insulators. The storm that produced the dry winds and resulting salt deposits on t' switchyard insulators was rate. The rareness of the storm is important but notewo, thy is the period of the sustained dry northeastern onshore winds. ih.

Seaweed was transported to the Intake Structure as a result of the winds and tides. Contliuous operation of the traveling screens that are part of the Circulating Mater 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 cubesheets, and increased Circulating Water pump motor amperages were also noted. Reactor power was reduced to backwash the Main Condenser

At O521 hours, while lowering reactor power to backwash the Main Condenser, the Control Room received a Recirculation Pump Motor 'B' lower bearing 'C+ 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 t-ipped 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 Powe: 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.

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and the approxi with pr the SHL scram i includd ACB 109 normal in expr Contair System because after n The PCI * * *	reactor mode selector se mately 30 percent reactor occedure 2.1.5 Attachment TTDOWN position resulted ' signal and scram. The sci ed a decrease in the Reac' s and trip of the Turbine response to the scram. Sected designed responses iment Isolation Control S. (RBIS). At 1711 hours, i e of the indicated position (RBIS). At 1711 hours, i e of the indicated position (RBIS). At 1711 hours, i e of the indicated position (RBIS). At 1711 hours, i e of the indicated position (refying the inserted po- IS actuation included the The inboard and outboa (two)/Sampling System The inboard and outboa System isolation valve IS actuation included the The inboard and outboa System isolation valve IS actuation included the The inboard and outboa System isolation valve IS actuation included the The inboard and outboa System isolation solve IS actuation included the The inboard and outboa System isolation solve IS actuation included the The inboard and outboa Building ventilation solve The SCS/Standby Gas Tr automatically.	witch was moved to the r power. These action I section G. The mov- in the expected Reacto- ram resulted in expect tor Vessel (RV) water Generator. The RV was The decrease, to appro- that included an actua- ystem (PCIS) and React Emergency Operating Pr- on of some control rod sition of all control following designed re- rd Primary Containment isolation valves that rd PCS Group 3 (three) s remained in the close rd PCS Group 6 (six)/F s closed automatically following designed re- rd Secondary Containment upply and exhaust damy eatment System (SGTS)	or Building Isolation Control ocedure EOP-02 was entered is and was exited at 1714 hours rods. sponses: System (PCS) Group 2 were open closed automatically. //Residual Heat Removal (RHR) red position. Reactor Hater Cleanup (RHCU)
distur was ma hours, System	bance) and ACB 104 (in th nually closed via control the RPS was reset and th	e open position) rema switch in the Contro e PCIS/RBIS was reset the Reactor Building	ined open as designed. ACB 103 1 Room at 1720 hours. At 1729 at 1800 hours. The RHCU dampers were reopened and the

SGTS was returned to normal standby service. The Main transformer/345 KV switchyard mechanical disconnects (1930) 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.

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EVENT DESCRIPTION

Cn 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 inclusion became de-energized because ACB 102 (line 355) and ACB 103 (line 342) were open. Here 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 (EDSs) 'A' and 'B' started automatically and re-energized emergency Buses A5 and A5, 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 NPCI System was manually started for RV pressure control purposes and the RNR 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 cli offsite power and an Unusual Event was declared at 2003 hours.

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(DT 0 mem every a required in element ATC for Next (DT) At 2028 hours, Emergency Operating Suppression Pool bulk water temper HPCI and RCIC turbine operation), temperature of approximately 107 c At 2030 hours, the HPCI and RCIC t when the RV water level resched th approximately +46 inches). At 203 relief valve RV-203-38 (pilot ser control in accordance with EOP-01 psig and increasing. The valve we pressure was approximately 600 psi RCIC high water level isolations a started in the full flow test mode manually started in the injection	g Procedure EOP-03 wa rature exceeding BO d A maximum Suppressi degrees Fahrenheit oc turbine-pumps tripped he high water level s 31 hours, the Main Si ial number 1040) was because the RV press as manually closed at ig and decreasing. J were reset and the Hi e for RV pressure com	is entered due to the segrees Fahrenneit (due on Pool bulk water courred at 2033 hours. d automatically as des setpoint (calibrated at team/Target Rock two-s manually opened for p sure was approximately t 2032 hours when the At 2033 hours, the HPC PCI System was manuall ntrol and the RCIC Sys	e to igned tage ressure 800 RV I and y
At 2142 hours, the SUT was return control switch in the Control Roor re-energized by the regional powe reset of protective relaying. The (345 KV line 355) to the SUT and 2 hours. This restored the secondar Bus A5 and Bus A6.	m. This action was f r authority following is restored one source APDS. The SDT was re-	taken after line 355 w g a switchyard inspect ce of preferred offsit estored to service at	ras ton and te power 2210
At 2216 hours, safety-related 480 (powered by EDG 'A' via Bus A5) to Emergency Bus A5 was then transfe B6 was manually transferred from 1 Bus A6 was then transferred from 1 down. At 2230 hours, the Unusual and 'B' were put into service in	o Bus B2 (powered by rred from EDG 'A' to Bus B2 to Bus B1 (po ECG 'B' to the SUT, Event was terminate	EDG 'B' via Bus A6). the SUT. At 2225 hou wered by the SUT via B and ECGs 'A' and 'B' w d and the RHR System 1	urs, Bus Bus A5). Were shut
At 2335 hours, a PCIS Group 6/RWC was being returned to service. T 91-026-00. The PCIS was reset an hours. At 2336 hours, the Suppre inches and a Limiting Condition f was terminated on October 31, 199 inches (LR-5038).	he event is separate d the RWCU System wa ssion Pool water lev or Operation (LCO A9	ly reported via LER s returned to service el was noted as exceed 1-277) was entered.	by 2339 ding -3 The LCO
On October 31, 1991 at 0026 hours the MSIVs were re-opened. This r from the RV to the Main Condenser control and shut down at 0029 hou control and shut down at 0035 hou placed into service at 0041 hours	estored the Main Ste . The HPCI System w rs. The RCIC System rs. The Main Conden	am piping as a steam p vas removed from RV pro was removed from RV	pathway essure level

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LICENSEE EVENT REPORT TEXT CONTINUATION		ESTIMATION RUPER PRAMERATION AND AND AND AND AND AND AND AND AND AN	TO DOMAL & WITH THIS SOLD WHS, FORWARD RATE TO THE RECORDS IF SUC US MUCLEAT TON DE POSSA AND TO TO STEPSE AND TO TO STEPSE AND TO TO STEPSE AND TO TO STEPSE AND TO ADDITIS, SEC 2006(5)
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At 0248 hours, a PCIS Group 6/RHC the RHCU System valve MO-1201-85 reported via LER 91-026-00. The service by 0254 hours.	was being adjusted.	The event is separate	1y
By 0257 hours, the RV pressure wa RHR System/Shutdown Cooling (SDC) (calibrated at approximately 122	suction piping high	pressure isolation si	and the gnal
By 0421 hours, the Suppression Po (LR-5038) and EOP-03 (Suppression hours. At 0433 hours, the RHR Sy operation.	Pool water temperatu	(re) was exited at 042	3
By 0927 hours, the RV pressure had hours, the Main Steam drain line	d decreased to approx isolation valves were	imately zerr psig. A opened.	t 1000
At 1632 hours, an RHR Loop 'B' pur by 1643 hours the RMCU System inle was less than 212 degrees Fahrenhe The other RHR Loop 'B' pump was a	et water temperature elt and cold shutdown	(i.e. RV water temperature was achieved at that	time.
The RV head vent valves were open	ed at 2300 hours.		
Failure and Malfunction Report (F& secondary offsite power and F&MR S preferred offsite power and Unusua of the Unusual Event in accordance hours. A followup telephone call October 31, 1991 at 1915 hours to 2007 had been recorded correctly. Suppress' in Pool water level excee document related events that occur	H-447 was written to Event. The NRC Op with 10 CFR 50.72 of to the NRC Operation ensure the communica F&MR 91-466 was writeding ~3 inches. Oth	document the loss of erations Center was no n October 30, 1991 at s Center was made on tions on October 30, 1 tten to document the	2007 991 at
CAUSE			
The causes and related corrective offsite power are separately descr	actions for the loss ibed as follow:	of preferred and seco	ndary
1. Loss of Preferred Offsite Powe	r (345 KV)		
The 345 KV tranmission system (lin Transformer, and SUT are equipped of (local and remote) relaying. This detection (phase, phase to phase, p 104, 105), transfer trip, 345 KV bi 103), Main Transformer differentia out (ACBs 104 and 105).	with protective prima relaying consists of phase to ground), stu us differential, SUT	ery, secondary, and ba F disiance, high speed Jok breaker (ACBs 102, differential (ACBs 10	, fault 103, 2 and

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$\mathbf{K}(t)$ (it more grade a negative) see additional $\delta(\theta_{1})$ from $\mathrm{SR}(\delta(y_{1})(1))$		
transfer trip signal to rem occurred on a 345 KV insula environmental conditions, functioned as designed in t de_energizing of line 342	i.e. sait deposits on the in response to the flashover. removed line 342 as one sour	use of a flashover that e flashover was the result of ssulator, and the equipment
relay 62/5 (ACB 105 stuck) breaker scheme is designed devices at the offsite (re TD-50 time delay relay (se satisfied the protective c and 104 (already open) and	to generate a trip signal ' mote) end of line 355. Reli t at 100 milli-seconds). Th ircuit 'ogic that generated devices at the remote (off	perated. The ACB 105 stuck to ACBs 102 and 104 and to ay 62/5 is a Westinghouse type
operation of the ACB 105 s fault analysis equipment i insulator column) occurred breaker circuit operation individual relay testing, functional timing tests, a type SI) in the ACB 105 st of the tests confirmed the was found to have a loose capacitor is designed to a	ndicated only one fault (fl . The root cause investiga consisted of circuit analys ACB 105 timing tests, overa ind special tests of relays tuck breaker circuit. Except a components functioned as d connection that was subsequ	Investigated. Remote, offsite ashover on the ACB 104 ition on the ACB 105 stuck is, component testing, ill relay and ACB system 62/5 and 50/5 (Westinghouse ot for a filter capacitor, all designed. The filter capacitor pently tightened. The 5 from voltage transients or
interference with a poten for the ACB 105 stuck brea signal of unknown origin transmission system elect breaker circuit through m special monitoring to ide recorder will be purchase circuitry. The installat 1992. To preclude the po relay will be replaced. 1991. Also, a possible m	aker circuit operation is be or the infrequent development rical events which results ofse coupling. Typically, in tify and remedy the cause is d and installed to monitor ion of the recorder is expe- tential for future improper The replacement is expected odification of the stuck br	relay 62/5. The root cause elieved to be either a random nt of some sequence of 345 KV in self excitation of the stuck these conditions require of the condition. A high speed "plicable switchyard cted to be completed in January operations of relay 62/5, the to be completed in December

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NOT FORM DAYS US NUCLEAR REDUCTORY D. MARIER DA APPARTUR I DAMA AND STRUCTURE REPORTS AFROND ESTIMATED BUILDES AND RESPONDENT LICENSEE EVENT REPORT (LER) It's Protein A Trid Mcg. Col 1. B Hour's A PORTS ARE а спарад тола замата в проданского ф но времата марианского Сол атоль созданено а католь созданено а католь в созданено создано создано созданено создано создано создано создано создано создан TEXT CONTINUATION DATACHEY ALLANDER LL -----ALC: 18 Filgrim Nuclear Power Station Q 2] 4 010 0 18 01

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, 1.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 failen 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 "hreat 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 's to provide a single failure proof source of onsite AC power adequate for the safe shutdown of the reactor following sunormal 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 AS and AG, and the related electrical system in response to the loss of power to Bus AS and Bus AG.

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 Sceam 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 selpoint (calibrated at approximately -45 inches) and the level (-127.5 inches) corresponding to the top of the active fuel zone.

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107 degrees F than the max1 Specification	ahrenheit which occur mum water temperature 3.7.A.1.h during RV	red after the shutdo (120 degrees fahren isolation conditions		
(LR-5038). T Suppression P 3.7.A.1.b. A of +6 inches less than the	he level was less that opl volume of 94,000 Suppression Pool vol	in the level correspondule cubic feet specified lume of 94,200 cubic inches (LI-1001-604 el switches (LS-23514	by Technical Specification feet corresponds to a level A/B). The level was also	
maintained be 3.00 and 3.21 corresponds i submergence v conditions (period when 600 psig (de approximatel accordance w Attachment 1	tween -6 to -3 inches i feet, respectively. o a downcomer submer alues were based, in .e., approximately 11 the Suppression Pool creasing). The water y six hours. The Sup ith Procedure 2.1.15 (daily log test #15) is verified to be gre	s which corresponds 1 A Suppression Pool gence of 3.42 feet. part, on reactor op 035 psig). The maxim level was greater th level was decreased pression Pool water (currently Rev. 87), As part of this t	ession Pool/Chamber be to a downcc er submergence of level of -1 inches The specified downcomer eration at full pressure mum RV pressure during the an -3 inches was approximately to less than -3 inches in level is logged daily in "Daily Surveillance Log", est, the Suppression Pool and less than -3 inches	
This report automatic ac	is submitted in accor tuations of the RPS,	dance with 10 CFR 50 PCIS, RBIS, and EDGs	.73(a)(2)(1v) because of the	

This report is also submitted in accordance with 10 CFR 50.73(a)(2)(1)(B) because the Suppression Pool letel 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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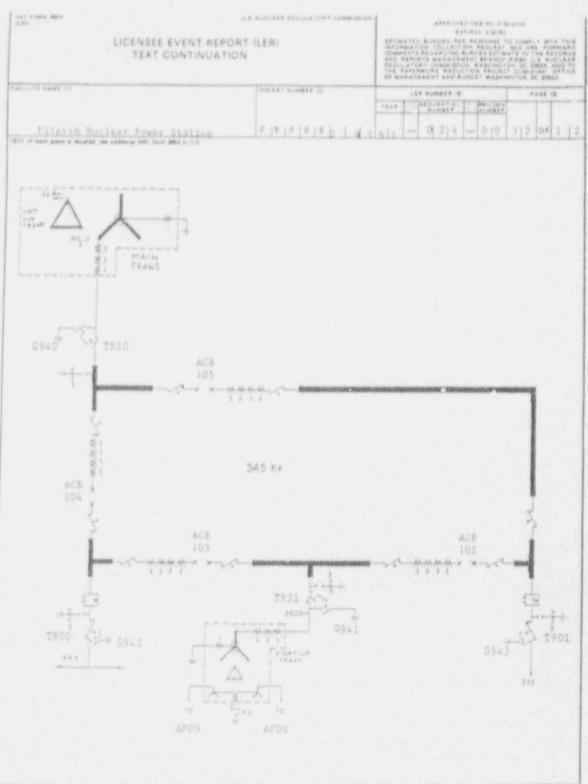
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 For LER 89-010-00, a loss of pref down on February 21, 1989 at 0450 355 were in service and powering offsite power (23KV) was availabl power occurred when ACBs 102 and underground portion of one of the side ('X' winding) of the SUT and actuated the differential ground caused ACBs 102 and 103 to open. to the emergency buses and relate failure was cable jacket damage d action taken included replacement For LER 87-014-01, a loss of pref down during a severe storm on Nov event, ACBs 102, 103, 104, and 10 lines 342 and 355 were in service because of modification activitie event occurred as a result of a 1 fault approximately one minute 1a of ACBs 103 and 104. ACB 104 ope circuitry to operate and caused A remote (offsite) end of line 342. (0205 hours) but tripped open app automatically and supplied power system. ACB 102 opened as a result the circuitry operated because of tripped the differential protection out ACB 103 (already open) and to preferred offsite power was a ser tripped the differential protection out ACB 103 (already open) and to preferred offsite power was a ser tripped the differential protection out ACB 103 (already open) and to preferred offsite power was a ser tripped the differential protection out ACB 103 (already open) and to preferred offsite power was a ser tripped the differential protection out of service. The 345 KV transmission system (lines 342 and SUT was in service providing power out of service for maintenance. It tagged out of servi	D hours. At the time the SUT via ACBs 102 le via the SDT. The 1 103 tripped open beca SUT phase 'C' power i nonsafety-related 41 current relay that tr The EDGs started aut d electrical system. Suring original cable of the failed section erred offsite power (C ember 12, 1987 at 020) 5 were in the closed p and powering the SUT s related to the black ine 342 ground fault a ter. The line 342 fau ned slowly and caused CB 105 to open and a ACB 102 remained clo roximately one minute to the emergency buses it of the SUT different an increasing voltz-poin relay. The relay f trip open ACB 102. is sof storm related to d 355) remote from the rred offsite power (34 1987 at 0845 hours. S ACB 102 was tagged mission lines 342 and r to the APDS except f EDG 'A' was in standby ance. The EDG 'A' s' A' and the related ele when ACBs 103 and 104 a broken static line. line 342 conductors was	of the event, lines 342 and and 103, and secondary oss of preferred offsite use of a cable fault in the cables between the secondary 60 VAC Rus A4. The fault 1pped lockort relay 186-4 a omatically and suppiled pow The cause of the cable installation. Corrective n of cable. 345 KV) occurred while shut 6 hours. Just prior to the position, and transmission . The SOT was not in servi- kout diesel generator. The at 0205 hours and a line 35 ult resulted in the opening the ACB 104 stuck breaker transfer trip signal to the osed during that sequence later. The EDGs started s and related electrical ntial protection circuitry. per-hertz condition that functioned properly to lock The cause of the loss of faults in the 345 e switchyard. 455 KV) occurred while shut Just prior to the event, ACI open for maintenance and wi 355 were in service and the for Bus A6 that was tagged y service and EDG 'B' was inted automatically and ectrical system. The loss of the location where the as several miles from the	y nd er 5 5 5 5 5 5 5

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For LER 86-029-00, a loss of prefe down on December 23, 1986 at 1120 switchyard phase 'C' insulator los being washed. The insulator washi open, and the SUT was being powere of the insulator, overspray onto a line 355 and the SUT became de-end the related electrical system. Ef start, and the SDT re-energized Bi cause was a wind change causing ov over to energized insulators.	hours. At the time cated between ACB 104 ing was being conduct ed from line 355 via an energized switchys ergized. EDG 'A' sta DG 'B' had been remov us A6 and related eli	of the event, a de-energized I and disconnect 1048 was ted with ACBs 103 and 104 ACB 102. During the washing and insulator caused a loss of arted and powered Bus A5 and ved from service and did not ectrical system. The root
For LER 86-027-01, a loss of prefi severe storm while shut down on No powered from lines 342 and 355 thi At 0819 hours, ACBs 103, 104, and open and the SUT became de-energi power to the emergency buses and investigation and inspections det preferred offsite power to have b transmission) lines due to ice an	ovember 19, 1986. Pr at were in service, a 105 tripped open. A zed at that time. Th related electrical s ermined the most pro een arcing of the hi	rior to the event the SUT was and the SDT was in service. At OB40 hours, ACB 102 tripped he EDGs started and supplied ystem. Subsequent bable cause of the loss of
ENERGY INDUSTRY IDENTIFICATION SY	STEM (EIIS) CODES	
The EIIS codes for this report an	e as frilows:	
COMPONENTS		CODES
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(PCIS, RHIS, RPS) Emergency Onsite Power System (ED Heat Rejection System (Circulatin Main Steam System Medium Voltage Power System (4.16 Plant Prote Ton System (RPS) RHCU System	ng Water System)	EK KE TA EA JC CE



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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 RCI Systems inoperable. The Recirculation Pump was being started because of a prior even, that resulted in a lockout of the emergency 4160 volt bus A-6 and subsequent trip of the '8' 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 MPCI and RCIC. respectively.

Corrective action was taken to reset the inverters at DO52 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 IOCFR 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 as 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 bittery 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 \pm 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 HPC1 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).

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CORRECTIVE ACTION

Immediate corrective action was to follow the Alarm kesponse 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 inverser 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.

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ENERGY INDUSTRY 1	DENTIFICATION SYSTE	M (EIIS) CODES	
The EIIS codes fo	r this report are a	s follows:	
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Pilgrim Nuclear Power Station Minute Reactor Core Isolation Cooli Battery Charger Test	ng System De	clare	d Ino	je perable Di	le to In	ufficient	1 040 1 3
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On October 9, 1991 at 1802 hou declared inoperable and a seve that time. The system was dec available to demonstrate that existed if a 125 VDC Bus 'A' w is possible if an AC voltage t the 125 VDC battery charger. in service supplying power to was identified.	n day Limiti lared inoper sufficient m oltage trans ransient of The 125 VDC	ng Co able argin ient suffi Batte	nditi becau to t were clent	on for Op ise suffic he RCIC 1 to occur magnitud and bac	ieration lent tes nverter The DC le occurs kup batt	(LCO) begint data was trip setpone trip setp	an at s not pint transient nput of er were
The RCIC System was maintained service as a result of declar from the requirement to shut of granted by the NRC on October result of this condition. The unrelated to the RCIC System of the implementation of modific occurring on the 125 VDC Bus This condition was identified switch in the RUN position. Vessel (RV) pressure was 1028 Fahrenheit. This report is s	ing the syste lown on Octob 16, 1991. (plant was in CO. Correct itions to pro- "A". during powe the reactor in osig with t	em ind per H Compen thut i tive i aclud r ope power he RV	operat 5, 19 isator fown c action e una ration leve wate	ole. A wi) because ry measure on October n planned cceptable n with th 1 was 100 r tempera	ritten r. e of thises were r 30, 19 consist voltage e reacto percent ture at	equest for s condition implemente 91 for rea s of testi transient r mode sel The Rea S48 degree	ellef www.s d as a sons ng and/o s from ector ictor is
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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 3.5.0 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 Fahrenh. t.

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

April 2 and march 11.5

On October 9, 1991 at 1862 hours, the RCIC System was declared inoperable and a seven day Technical Specification 3.5.0.2 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 own during the recent refueling outage (RFO B). 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.

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This condition was identified during switch in the RUN position. The Rea water temperature at 548 degrees Fah backup battery charger were in servi	power operation wi	
charger 'A' was not in service.	ictor Vessel (RV) pr trenheit. The 125 i	ressure was 1028 psig with the RV VDC Battery 'A' and 125 VDC
A request for relief from a shut dow submitted to the NRC on October 15, requested prior to 1800 hours on Oct of Pilgrim Station due to the seven hours. Discretionary enforcement wa October 16, 1991 at 1620 hours. The at 1102 hours until such time the NR change request to extend the RCIC Sy	1991 (BECo Letter 1 tober 16, 1991 to p day LCO that began is granted by the Ni e request was grant RC could act upon a	91-300). The relief was reclude an unnecessary shut down on October 9, 1991 at 1802 RC for an additional 24 hours on ed by the NRC on October 17, 1991 n exigent Technical Specification
CAUSE		
The 125 VDC Battery 'A' and backup RCIC inverter via the 125 VDC Bus 'J test data from the 125 VDC battery of indicated the RCIC inverter trip set sufficient test data for the backup that sufficient margin to the inver- declared inoperable.	A' when this condit charger 'A' and bac tpoint would not be battery charger wa	ion was identified. Extrapolated kup 125 VDC battery charger reached. However, because s not available to demonstrate
When this report was prepared, the identified in an update of LER 91-00 approximately 1946 hours, after a si LCO, a RCIC inverter trip occurred. LER 91-025-00. The root cause, the en update of LER 91-006-00.	06-00. However, on hut down for reason The inverter trip	October 30, 1991 at s unrelated to the RCIC System will be separately reported via
COMPENSATORY MEASURES		
The following compensatory measure trips, as indicated by Control Room Failure", the licensed operator wil response procedure ARP-904L alarm w the RCIC controller to manual, adju RCIC inverter, and transferring the	Panel C-904L annun 1 immediately perfo indow I4. The oper sting the flow cont	nciator 14, "RCIC Inverter orm section 3 (three) of the alarm rator actions include transferring croller to minimum, resetting the
CORRECTIVE ACTION		
The alarm response procedure ARP-90 The change identifies specific oper the RCIC System is operating or is	ator actions to tak	te if the RCIC inverter types when

449	A RUCLEAR REQUERTORY COMMUNIC	APPINITURE DISAMB NO. 2140-0124 B APPINITE RESULT
LICENSEE EVENT REPORT TEXT CONTINUATION		CETRACTED CONDERS FOR REPORTED COMPLETED COMPLETED. TO COMPLETE AND COMPLETED CONTRACTOR OF A DESCRIPTION
ACTIVE READE IN	DISC # E.1. NUMBER # 12	LER NUMBER & FADE LE
		veral BESCHER AL
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T if must grave a required time additional to $h_{i}^{2}h_{i}^{2}$ from $\mathrm{SR}(A_{i}, i, j)$		and a standard and a standard and a standard standard standard
A proposed change to Technical Spe submitted to temporarily extend th inverter trip concern. The propose Letter 91-136). The extension work modifications to be implemented. October 30, 1991. Therefore, the withdrawn. When this report was prepared, con and/or testing. The purpose of the transients from causing unaceptable capability of the RCIC System to p testing was to ensure normal AC voltage transients. The modificat	te seven day RCIC Sy sed change was submi- uid have permitted to However, the plant proposed change is rective action plan he modifications was le DC voltage transi- perform its intended pltage transients wo	stem LCO to 97 days for the RCIC tted on October 24, 1991 (BECo esting to be conducted or was shut down on no longer valid and will be ned consisted of modifications to preclude normal AC voltage ents, 1.e. affecting the function. The purpose of the uld not cause unacceptable DC
January 14, 1992. As a result of the shut down that mentioned modifications and/or ter	occurred on October	30, 1991, the previously
SAFETY CONSEQUENCES		
This condition posed no threat to	the public health a	nd safety.
The Core Standby Cooling Systems Depressurization System (ADS), Co System/Low Pressure Coolant Injec- provision for high and low pressu- operability at least monthly and is failure had occurred when its ope actuation of the ADS would reduce cooling provided independently by	re Spray System, and tion (LPCI) mode. I re core cooling. Th was operable. In th ration was necessary the Reactor Vessel	Residual Heat Removal (RHR) he design of the CSCS includes e HPCI System is tested for e unlikely event a HPCI System (, an automatic (or manual) pressure for low pressure core
This report is submitted in accord System was declared inoperable.	dance with 10 CFR 50	.73(a)(2)(v)(D) because the RCIC
SIMILARITY TO PREVIOUS EVENTS		
A review was conducted of Pilgrim January 1984. The review folused inoperable or becoming imperable previous event reported via LER 5	on LERs involving t due to a RCIC inver	ent Reports (LERs) issued since the RCIC System being declared ter trip. The review identified a
VDC Bus 'A' and Battery Charger '	The inverters trips was restarted. At A' were supplying po 'B' and the 125 VDC ter via 125 VDC Bus	ed when the Recirculation System the time of the event, the 125 VDC over to the RCIC inverter via 125 C backup battery charger were 'B'. The 125 VDC battery charger

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ABSTRACT LINE IN 1820 and is approximately from	ean alogre aperie typeserverse linear 1981			And the second second second	er an er en	-decidentiday	
On Octobe: 30, 1991 at turbine tripped as oper water level control. I However, the RCIC inves pump was started at 194 flow. The operators may restarted the system si The RCIC turbine tripped not open the injection steam inlet valve. Dur Model 125-GM-125 [60]) RHR pump was started. DC output during AC vo Corrective actions for valves to be opened sit new RCIC and High Press setpoint and an automate ensure the inverters w trip and inverter trip position. The RV press degrees Fahrenheit. T	ators manually star the trip was reset a ter had tripped whe l6 hours resulting i inually shut down th incessfully. ad due to mechanical valve within four (ring system restorat tripped due to a DC The battery charger ltage transients cau the overspeed trip multaneously. A mod sure Coolant Injecti tic reset function. 111 (of trip due to occurred with the r	ted the sy nd the RCI n the "A" n the RCIC e RCIC Sys overspeed 4) second 1on the RC voltage was not ised by st include c iffication on invert Extensiv DC voltag eactor ho	ystem for IC System Residual C System n stem, rese d. The II s after op CIC invert transient originally arting lan hanging th was compl ers having e testing e transien de select	Reactor was manu- Heat Ren oot react t the in censed opening to ter (Top- caused opening y design rge AC m te proce leted th g a high was per nts. Th switc	Vessel Jally s Boval i hing ra hverter operato he turb az Elec when th ed to m otors. dure to at inst er tripp formed e RCIC h in th	(RV) tarted. RHR) ted and r did ine tronics. e "A" waintain require alled tc turbine te REFUE	

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LICENSEE EVENT REPORT TEXT CONTINUATION		ЕЗЛИЧЕТ И ОКАЗАНИЕ В ИЗИЧЕТ И ОКАЗАНИЕ ТО ИНГОММАТОРА СОСЛЕСТКОМ НЕОДИТИ СОМИНИТОРА СОСЛЕСТКОМ НЕОДИТИ СОМИНИТО ВИСОЛИСТКОМ НЕОДИТИ НОВИТСКИМИ И ОКАЗАНИИ ТО НЕОДИТИСТ СОМИНИТОРА ТО И КАЗАНИИ И ОКАЗАНИИ ТО И КАЗАНИИ ТО И КАЗАНИИ И КАЗАНИ И КАЗАНИ И КАЗАНИ И КАЗАНИ И КАЗАНИ И КАЗАНИ И КАЗА	IN DIC 20035 AND TO US150-0104. DEFICE
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BACKGROUND			
 water to the reactor sersel follow release of radioactive materials to cooling. The system is required to coolant in the reactor vessel so it is not compromised. The RCIC System accident, a loss of feedwater for Each of the events results in an in pressure boundary. Reactor water followed by a "boil down" as the S The RCIC System is designed to auto of the boiling rate. Technical Sy operable whenever there is irradio greater than 150 psig, and reactor Fahrenheit. The RCIC inverter converts 125 VD converter and flow controller in power supply. With the inverter minimum speed. An inverter trip during RCIC System operation. The flow control is available to the powered from the 125 volt DC Bus VDC Battery "A" in parallel with aligned to the "A" Bus due to the of sufficient magnitude at the in voltage transients at the output excess of the overvoltage trip se As discussed in the Similar Event 	to the environs as a to operate automatica that the integrity of tem is designed to co w transient, and a lo isolated reactor vess level will drop as a Safety Relief Valves tomatically restore 1 pecification 3.5.D re ated fuel in the reac r coolant temperature C (nominal) to 120 VA the RCIC flow control tripped, the RCIC Sys would not prevent sys e capability for subs operator in the Contr "A". The 125 VDC Bus a battery charger. H "A" charger being in put of the 125 VDC ba of the battery charge troint can cause the	result of insufficient lly to maintain suffic the radioactive mater pe with a control rod ss of offsite power tr el with no breach of t result of the initiat (SRVs) relieve on high evel by providing flow quires that the RCIC S tor vessel, reactor pr is meater than 365 d C to power a square ro circuit and the test tem could start and op tem initiation or caus equent restoration of rol Room. The RCIC inv normally receives pow iowever, the backup cha operable. AC voltage trey charger can caus r. DC voltage transie RCIC inverter to trip	core ient ial barrier drop ansient. he primary ing events pressure. in excess ystem be essure is egrees of circuit erate at rea trip RCIC System rerter is ver from 125 irger was transients se DC ents in
As discussed in the Similar Event ction (HPCI) in erter trips h event, Plant Design Change (PDC) Outage No. 8 (RFO 8). This PDC r VDC to 150 VDC. This setpoint ch recirculation pump is started. T identified that the inverters may Diesel Generators (EDGs) supplyin Failure and Malfunction Reports 9 transient DC voltage obtained dur was reduced from 134 VDC to 132 V The lower float voltage has the e voltage transient caused by start was believed the lower float volt reported in LER 91-021-00, the RC because sufficient test data was RCIC inverter overvoltage trip sw occur. Compensatory measures we October 16, 1991 to allow an add	ave occurred. In res 91-34 was implemented raised the inverter of hange was made to pre- festing performed prio y trip the safety related 91-363 and 91-368 were ring this testing. The VDC to prevent an inve- effect of lowering that t of a large motor. tage would preclude an CIC System was declar not available to dem etpoint existed if a	sponse to the March 26 d in July 1991 during l vervoltage trip setpoin vent an inverter trip of or to startup from RFO otor is started with t 4160 VAC Buses A5 and e written to document he battery chargers' f erter trip under this e peak DC voltage duri The plant was restarte n inverter trip. Howe ed inoperable on Octob onstrate adequate marg 125 VDC Bus "A" transi	, 1991 Refueling nt from 140 when a 8 he Emergency A6. the peak loat voltagi scentrio. ng an AC d since it ver, as er 9, 1991 in to the ent was to

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EVENT DESCRIPTION		
On October 30, 1991 at 1942 hou manually started the system for System was being started follow reported in LER 50-293/91-024-O manually restarted the RCIC Sys Electronics, Model 125-GM-125 [(RHR) pump was started at 1946 i start caused an AC voltage tran 152.5 VDC that was above the 150 resulted in the RCIC System being manually shut down the RCIC System successfully for RV water level	Reactor Vessel (RV) wa ing a Loss of Offsite P O. The operators reset tem. However, the RCIC 60]) had tripped when t hours for suppression p sient that resulted in 0 VDC inverter overvolt ing unable to attain rat tem. reset the inverter	ter level control. The RCIC ower (LOOP) event which is the turbine trip and System inverter (Topaz he "A" Residual Neat Removal col cooling. The RHR pump a DC voltage transient of age trip setpoint. This ed flow. The operators
Failure and Malfunction Reports inverter trip and turbine trip, notified during the LOOP event a October 31, 1991 a followup noti events identified during the LOO	91-445 and 91-448 were respectively. The NRC ind was informed of the fication was made to en	Operations Center was plant conditions. On usure all of the renortable
A Multidiscipled Analysis Team (with the LOOP, including the RCI	MDAT) was formed to rev C System turbine trip a	view the events associated and inverter trip.
These events occurred with the r position. The RV pressure was 9 degrees Fahrenheit.	eactor mode selector sw 20 psig and the RV wate	ritch in the REFUEL Fr temperature was 530
CAUSE		
The direct cause of the RCIC turl overspeed trip setpoint (5512 rps percent of rated speed (4500 rpm) turbice speed reaching 5607 rpm. operator manually starting the RC sufficient time to provide a flow Cooling System", Rev. 36 Attachme operation or Reactor Vessel inje valve (MO-1301-61) be opened firs when the RCIC turbine increased s sequence. The computer traces sh the turbine reached overspeed wit was opened. When the steam inlet to the Suppression Pool via the m 1360-3) for the flow transmitter turbine control logic is located no flow was sensed by the flow tr	m to 5737 rpm) is appro Plant information c The turbine oversped CIC System did not open (path. Procedure 2.2.2) int 8 provided instruct action. Step 5 require it with the injection vi- peed. These steps were lowed the turbine steam hin four (4) seconds by valve was opened all i inform flow bypass line (FT 1360-4) that provid downstream of the minimum	<pre>ximately 125 percent ± 2 omputer traces showed the because the licensed the RCIC injection valve in 2, "keactor Core Isolation ions for manual RCIC System d the turbine steam inlet alve (MO-1301-49) opened e to be performed in close inlet valve was opened and efore the injection valve the pump flow was directed e. The flow element (FE des input to the RCIC mum flow human licenses </pre>

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Performance Evaluation reas that contributed to		tion revealed there we

- 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.

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- 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 i* not a time sensitive operation.
- 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 virification 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.

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The maximum AC voltage transient occurs during battery charger power-up after a shutdown 3/* 10 seconds, as would be experienced during a Loss of Coolant Accident with a Loss of Offsite Power (LOCA/LOOP) event. The "J" 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 mien compared to the "B" battery charger. The "slow response", control modules installed in the "A" and "Backup" charger. The "slow response", control modules installed in the "A" and "Backup" charger. The "slow response", control modules installed in the "A" and "Backup" charger eliminate the startup DC voltag "ransients by delaying the power-up following the LOCA/LOOP event. The limit is transient for these chargers is when the EDGs are supriving the sufety 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 (REI) 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 revision 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.

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LICENSEE EVE TEXT CON	NT REPORT IL	ER)			EST IM. INFOR COARD AND P REQUI THE P OF MA	ATED BU ALATION ENTER. LEPONTS ATONT APERADO NAGENIE	HDEN RE COLLECT SARDING MANAGEN COMMISSI RK REDU NT AND B	N RESIDENT I ION R BURDE RENT I ION WI CTION	PONSE TO EGUEST NEST (M ERANCH SALNEST(ENO./EC)	6 6060 60.5 MR 61.5 TG 1 9.5 301 L 19.5 301 L 19.5 30 1.3 150 0 6 10 N 0	Y WTH TI S FDRWA HE RECOR I NUCLE SUB AND USAL OFF C 20501
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The overspeed trip of steam inlet valve is o operators promptly res to operate the RCIC Sy	pened and th et the overs	e injectio	on va	lve #	ainta	ined	clos	ed.	The		
The trip of the RCIC 1 condition. The invert RCIC System operated s	er was reset	approxim	ately	1 90 s	econd	is af	ter t	rip	ping		the
This report is submitt RCIC System became inc		ance with	10 0	CFR 50).73(a	(2)	(V)(D) b	ecau	e th	e
SIMILARITY TO PREVIOUS	EVENTS										
A review was conducted since January 1984. T turbine overspeed and/ identified previous ev and 91-021-00.	he review fo or inverter	cused on trips due	LERs to	invol the s	lving Imila	RCIC r cau	or H	IPCI Th	Sys e re	tem vlew	06-00
For LER 85-029-00, the 1985 at 1545 hours. T fluctuation of the inv approximately 60 secon	he most prob erter input	able caus DC voltag	e of e.	the i The i	HPCI nvert	inver er wa	ter i is re:	trip	was		18,
For LER 90-013-00, the September 2, 1990. Th sequence specified in 33. Section 7.4 spect injection valve opened Plant computer traces could be opened. Corr operators to open the and the turbine increa	e overspeed Procedure 2. fied that th after the p showed that ective actio injection va	occurred 2.22 "Rea e turbine ump disch the turbi n taken i	as a ctor ste arge ne o nclu	resu Core am in pres versp ded r	It of Isol let v sure ed be evisi	the atlor alve equa fore ng 2	manu be o ls re the 2.22	al 1 ling pene acto inje to	injec j Sys ed an or pr ectio dire	tion tem" d th essu n va ct t	Rev. e re. lve he
For LER 91-006-00, the operation on March 26, Recirculation System L of the event, the 125 to the RCIC inverter v backup battery charger "8". The 125 VDC batt from Bus A5 via Bus Bi	1991 at 004 oop 'B' moto VDC Battery 1a 125 VDC B were surply ery charger	3 hours. r-generat "A" and B lus "A". ing power "A" and b	The or s atte The to acku	inve et/pu ry Ca 125 V the H p bat	rters mp wa arger DC Ba PCI 1	tri s re "A" tter nver	pped start were y "B" ter v	whei ed. suj ani la	n the At pplyi d the 125 V	the ng p 125	ower VDC Us

NML FORM INGA SIGN SUB	NUCLEAR REDUCTION COMMUNIC	N #PPROVED 0446 (60) 3140-0104 4 XPURC 4 X0000
LICENSEE EVENT REPORT TEXT CONTINUATION	(LER)	ESTIMATES BUILDER FER REPORTS ALDER Information Collection Regulation and the Administration comments Recombing Subjects to an and the Administra- and Remains and Administration (Collection) of the Recom- and Remains and Administration (Collection) of the Recom- and Remains and Administration (Collection) of the Administration (Collection) and the Remains (Collection) and Collection (Collection) and Collection (Collection) of Managements recourting Remains (Collection) of Managements and Collection (Manifestion) (Collection)
FACIN (FT WARNE (1)	DON & LT MUMBER (2)	LEM NUMBER (6: PAGE (3)
		VEAN SECONDARY MALE MELSION
Pilgrim Nuclear Power Station	0 [8 0 0 0 0 2 9]3	911 - 01215 - 010 0 17 05 01
For LER 91-021-00, the RCIC System 1 1802 hours and a seven day Technical (LCO) was entered. The RCIC System data for the backup 125 VDC battery RCIC inverter would not trip 1f a 12 At the time the RCIC System was decl charger was supplying the RCIC inver relief from a shutdown specified by to the NRC in October 15, 1951. The 1991 until the NRC could act upon an request. The exigent Technical Spec withdrawn due to the October 30, 199	I Specification Lim was declared inope charger was not av 25 VDC Bus "A" volt lared inoperable, t ter via the "A" 12 Technical Specific request was grant exigent Technical ification change r	itting Condition for Operation rable because sufficient test allable to assure that the age transient were to occur. he 125 VDC backup battery 5 VDC bus. A request for ation 3.5.0.2 was submitted ed by the NRC on October 17. Specification change equest was subsequently
ENERGY INDUSTRY IDENTIFICATION SYSTE		
The EIIS codes for this report are a	s follows:	
COMPONENTS		CODES
Charger, Battery Inverter		BYC INVT
SYSTEMS		
DC Power System (125 VDC) Low Voltage Power System (480 VAC) - Medium Voltage Power System (4160 VAC RCIC System HPCI System	Class IE C) - Class IE	EI ED EB BN BJ

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

 LER No.:
 304/91-002

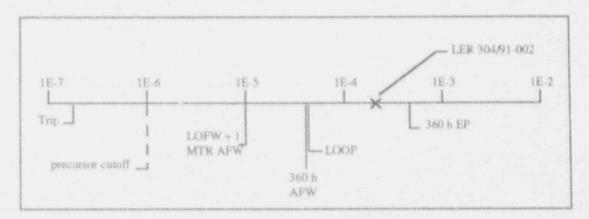
 Event Description:
 Loss of offsite power with one diesel generator out of service

 Date of Event:
 Ma 21, 1991

 Plant:
 Z² 2

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 motordriven 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 LC_P) 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.

- 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.
- 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.
- 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 i.i 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 trainlevel screening probabilities typically employed in ASP calculations results in the following branch estimates for these functions:

x 10 ⁻³ * ~8.4 x 10 ⁻⁵ * * ~2.8 x 10 ⁻² *

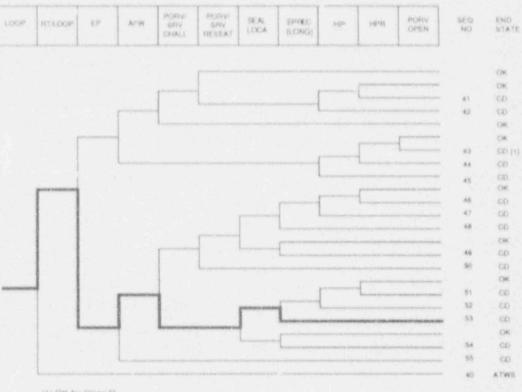
*conditional on unavailability of EDG 0 and PORV 455C

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.



(1) OK for Class D

Dominant core damage sequence for LER 304/91-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Dates		EDG out of service ionly \$1 fo	¢ H₽T)
INITIATING EVERY			
NON-RECOVERABLE IN	ITIATING EVENT	PROBABILITIES	
LOOP			5.05-01
SEQUENCE CONDITIONS	AL PROBABILITY	SUMS	
End State/Init	iator		Probability
¢ρ			
LOOP			Z.18-04
Total			2.1E-04
ATWS			
1.00P			0,0E+00
Total			0.06+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	S Rec**
53	LOOP -rt/loop EMERG.POWLR -afw/emerg.power -porv.or.arv.chall REAL.LOCA EP.REC(5)	CD	1, , 25 - 04	4.0E-01
43 55 54	NEALLOCH EPIREC(SU) LOOP -rt/loop =EMERG.POWER afw -HPI(F/B) -HPR/-HPI PORV.OPEN LOOP -rt/loop EMERG.POWER sfw/emerg.power LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.stv.chall -	CD CD CD	4.8E-05 1.9E-05 7.9E-06	1.3E-01 1.4E-01 4.0E-01
4.8	BEAL.LOCA EP.REC LOOP -rt/loop EMERG.POWER -afw/emerg.rower porv.or.srv.chall - borv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD	5.12-06	W.0E 1

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	P 22.3	N Rec**
43 40	LOOP -rt/loop -EMERG.POWER afw -HPI(F/B) -HPR/-HPI PORV.OPEN LOOP -rt/loop EMERG 'WER -afw/emerg.power porv.or.stv.chail - porv.or.stv.reseat/emerg.power SEAL_LOCA EP.REC(SL)	00 00	4,8E+05 5,1E+06	1,38-01 4.0E-01
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	co	1,28-04	4,06-01
54	LOOP -rt/loop EMERG.POWER -afw/amerg.power -porv.or.stv.chall + SEAL.LOCA EP.REC		7 _ 95 = 0.6	4,02-01
55	LOOP -rt/loop EMERG,POWER afw/emerg.pow.r	CD	1,98-05	1.48-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp

Event Identifier: 04/91-002

SQ

BRANCH GEDEL: 0:\asp\1989\rion.all PROBABILITY FILE: 0:\asp\1989\pwr_ball.pro

No Recovery Limit

10

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5

1

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fall
trans	1,58-04	1.02+00	
LOOP	1,62-05 > 1,62-05	5,38-01 > 5,08-01	
Branch Hodels INLFOR			
Initiator Frequ	1.66-05		
loca	2.4E-06	4,38-01	
28	2.88-04	1,26-01	
rt/100p	0.0E+00	1,05+00	
EMERG, POWER	5.4E=04 > 2.9E=03	卷,0至-01	
Branch Models 1.0P.0			
Train 1 Cond Probi	5,010-02		
Train 2 Cond Frobi	5,78-02		
Train A Cond Probs	1.9E-01 > Unavailable		
ate	3,8%~04	2.68-01	
afw/amerig.power	5,02-02	3,48-01	
mfw	2.08-01	3.48-31	
porv.or.arv.chall	4.08-02	1.08+00	
porv.or.srv.reseat	2.08-02	1,18-02	
porv.or.srv.reseat/emerg.power	2.08-02	1,02+00	
SEAL, LOCA	2,76-01 > 2,46-01	1,02+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob;	2,78-03 > 2,48-01		
EP, REC(SL)	5,78-01 > 4,88-01	1.0E+00	
wianch Hodel 1.09.1			
Train 1 Cond Probs	5,72-01 > 4,82-01		
EF, REC	3.12-02 > 9.72-03	1,02+00	
Branch Model: 1.OF.1			
Train 1 Cend Prob:	3.18-02 > 9.78-03		
HP7	1.0E-03 > 1.0E-07	8.41-01	
Branch Model: 1.0F.2			
Train 1 Cond Probt	1,08-02		
Train 2 Cond Prob:	1.0E-D1 > Unavailable		
HFT (F / H)	1.0E-13 > 1.0E-02	8.46-01	1.0E-07
Branch Hodal: 1.OF.2+opr			
Train 1 Cond Probi	1,08-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
HPR/~HP1	1.5E-04 > 1.6E-02	1.02+00	1.02-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.08-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
PORV.OFEN	1.0E-02 > 1.0E+-0	1.08+00	4.02-04
Branch Hudel: 1.0F.1+opr			
Train 1 Cond P-obt	1.02-02 > Failed		
	ANY AND A DESCRIPTION OF A DESCRIPTION O		

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* branch model file ** forced

Minarick 05-22-1992 17150106

Event Identifiar: 304/91-002

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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 ied irom the SAT automatically transferred to the LAT. 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 as an essential bus was no² - utomatically re-energized. A Generating Station Emergency Plan (GSEP) Unusual Event (EAL 3D) was declaied at 1335 and both is were started toward Cold Shutdown. The event was caused by spurious actuation of the Unit 2 trans ormer'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 canditions for operation. Various corrective actions have been developed to address the concerns that were raised as a result of this event.

ZDVR(ER-255(2))

ACILITY NAME (1)	DOCKET NUMBER (2)	LER I	NUMBLE	R (6)		1	P.	ige (3)
		Year	111	Sequential X mber	14	Revision Number			
Zion Unit 2	0 5 0 0 0 3 0 4	611	1	01012		0 1 0	0 12	01	0 17

A. CONDITION PRIOR TO EVENT

Unit 1

MODE 3 - Hot Shutdown RX Power 05 RCS (AB) Temperature/ Pressure 510.8*F (2235 prig

Unit 2

MODE 1 - Power Operations RX Power 99.5% RCS (AB) Temperature/ Pressure 55',7"F/ 2235 psig

B. DESCRIPTION OF EVENT

At 0930, during the performance of Operating Periodic Test (PT)-211. Net Pipe Sprinkler System Test, the Unit 2 Unit Auxiliary Transformer (UAT) and the Main Power Transformers (MPT) were inadvertently deluged. Verification was mude that no fire was present and the deluge isolation valve for both 1's 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 reciosed the manual isolation valve. The Shift Supervisor (SS) verified that there was no fire and no water actually sprived on the MPT/UAT.

At 1245, PT-211 was resumed on the Diesel Generator Oil Storage ank room fire protection system without Incident. At 1303, PT-11, Diesel Generator Loading Fest, was started on 2A DG to satisfy the surveillance requirements with "O" D/G Out of Service (OCS) for maintenance. After the DG was run for approximately 5 minutes the Nuclear Station Operator (NSO) closed the output breaker of the DG and Toaded it to 1 MH. While holding at 1 MH, 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 fA 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 005 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 on reverse power but it immediately closed in again on the Loss of Offsite Power signal to energize wssential service bus 248. 2B Compared Diesel Generator (EDG) automatically started, re-energizing essential service bus 249. The 0 EDG, which provides power to bus 247 was 005 for maintenance, so bus 247 was manually transferred to bus 141 which is the reserve feed for the Unit 2 essential buses.

ZOVRLER-255(3)

FACILITY NAPE (1)	DOCKET NUMBER (E)	LER					the second second states and the second s				Rev 2.0		
		Year	144	Sequenti Number	1/1	(Z.)	Revisi Numbe	1.1	-		T		
Zian Unit 2	0 5 0 0 0 3 0 4	911	-	0101	2	T	0 1 0	٦,	1.12	in	la i		

B. DESCRIPTION OF EVENT (con't)

At 1935, a Generating Station Emergency Plan (GSEP) Unusual Event (EAL declared. The proper notifications were made and the Technical Support Center (TSC) was a 1410. At 1426, boration to Cold Shutdown began for Unit 2, and at 2045 cooldown was initiated. T.

After the action elan for SAT repairs had been determined and the necessary paperwork assembled, the SAT was taken DOS 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 DOS was cleared, and the SAT was re-energized at 0112.

Once the SAT was returned to service, the Unsua' Event classification was changed from EAL 3D to EAL 3A. Equipment in Technical Specifications degraded such that the Limiting Condition for Operation (LCD) requires a shutdown, because 0 D/G was OOS for maintenance. A Temporary Waiver of Compliance had allowed maintenance to be perform. Un 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.

APPARENT CAUSE OF ELENT

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 celuge system was due to a mechanical/hydroulic 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 Nall 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 eader into the MPT/UAT delu-e valve clapper protective cover and dislodge the dead weight that causes the deluge value to open. The water was able to flow back through the common 2" drain value 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 a, 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 values 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 hed 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 conductor 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 feedwaler pumps supplying the Steam Generator tripped when the SAT tripped.

20VRLER-255(4)

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					Year	114	Sequential Number	17771	Revision Number			
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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 aT! the associated safe studown 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's cross-tie. All three essential buses were available from this point. Two essential 'uses 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 (5/6) heat removal following the Reactor Trip was controlled by the atmospheric relief valves. Adequate 5/6 feedwater was supplied by the three auxiliary feedwater (AFW) pumps.

The Reactor Coulant System (RCS) pressure was controlled by the pressurizer heaters and the pressurizer auxiliary spray. The Reactor Coulant Pumps were not available because they are fed from the non-essential bases 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 SSL8 F which was below the Safety Limit soutlined on Technical Specification Safety Limit Table (fig. \sim 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. All control rods inserted correctly, and the Reactor Trip was completed is a normal manner.

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.
 - The Manapement Information System (MIS) department will review the Sequence of Events recording priority with the Operating department and resise if appropriate. (304-180-91-022-01)
 - 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.
 - fechnical Staff (fech Staff), Electrical Maintanance (EM), and Engineering will review for adequacy and consider raplacing the doluge alves with either new values or with a different type of value. Unit 2 deluge values will be replaced prior to entering Model. The Unit 1 deluge values will be replaced, invever, replacement may ont be completed prior to entry into Modell (304-380-91-022-06)

ZTWRLER-255(51-

FACILITY NAME (1)	DOCKET	MUMBER (2)	LER H	RANELER	(6)		P,	age (1)	
			Year	14	Soquentiel Number	111 Revision 111 Number		T	
Zion Unit 2	0151	0 0 0 3 0 4	911	-	01012	- 0 10	0.15	or o	14

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 delugs 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)
- Tech Staff, Engineering and EM's will inspect, repair or replace the SAT fire protection detector system as required. (304-180-91-022-07)
- 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)
- Tech Staff, Engineering, and Operating will perform testing during the Unit 2 SAT outage to validate root cause of the deluge actuation. (304-180-91-822-89)
- 6. Operating Department will review the current finde 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)
- Jech Staff and Engineering will determine the proper position of all transformer fire protection deluge nozzles and correct as r: * sary. (304-180-91-022-13)
- Regulatory Assurance will review the root cause methodology to investigate the previous event documented under DVR 2-90-138. (304-180-91-022-14)
- Toch 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.(304-186-**.022-76)
- 10. Operating will rs new PI-21) for human factoring and technical adequacy. (334-180-91-022-28.1)
- 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.
 - 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)
 - Onsite Muclear Safety will issue a latter 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)

20VRLER-255(6)

TACILITY NAME [1]	DOCKET NUMBER (2)	LER NU	PBIR	(6)		Page (3)
		Year	144	Sequential Number	A Revision Number	
from these 2	0 5 0 0 0 3 0 4	911	-	01012	- 0 1 0	0 16 0/ 0 12

- C. LORRECTIVE ACTIONS (cont.)
 - 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.
 - Operating will establish a breaker and relay target logging system. This is a short term item until the log Keeping Committee identifies a premanent solution. (304-180-91-022-018)
 - Jech Staff and Engineering will perform testing during Unit 2 SAT outage to validate root cause of the SAT trip. (304-180-91-022-19).
 - 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)
 - Items that need to be completed on both units prior to Unit I 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.
 - Emergency Preparedness will review different options of keeping unnecessary people out of the control room during GSEP activities. (304-180-91-022-21)
 - 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 trup.
 - Security Department will review compensatory measures for security doors based on this event. (304-380-91-022-22)
 - Security and Operating departments will review the need for vital area keys for operators outside the vital area. (304-180-91-022-29)
 - 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.
 - Engineering will review the design features that cause a deluge actuation to trip oil preps and cooling fans but allow the SAT to remain energized. (304-180-91-022-23)

ZEWRLER-255(7)

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I. CORRECTIVE ACTIONS (Lont.)

- H. Ilees that need to completed on both units prior to Unit I Power Operations (Mode I) to determine whether the staticn properly implemented the terms of the Temporary Waiver of Compliance.
 - Regulatory Assurance will ensure that future Temporary Waivers of Compliance specifically address applicability in the event of plant events. (304-180-91-022-24)
 - Operating and Administration will review and verise, if necessary, the Standing Order distribution list. (304-180-91-822-25)
 - 3 Operating and Administration will review the method of delivering Standing Orders and revise this method if necessary. (304-180-91-022-26)
 - 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 Grew Interaction Training which has just finished being presented to all Operating personnel. The concepts of this Grew Interaction Training are also being shared with the rest of the station through various other training programs during 1991.

. FREVIOUS EVENTS

DVM 22-2-90-11M documents a similar event when the Unit 2 SAT was deluged and a D/G (IA) was DDS for maintenance. The investigation did not determine the cause of the deluge, but it was noted that the automatic deloge 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.

COMPONENT FAILURE DATA

Hanufacturer

Numanclature

Automatic Sprinkler Corporation

Automatic Deluge Valve

TOVREER-255(B)

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

B-236

Report No. 50-304/91006(DRF)

Docket No. 50-304

6

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 - 26, 1991

inspectors:

M. J. Farber D. S. Butler R. A. Westberg R. J. Leemon C. P. Patel J. N. Stang G. E. Kelly

Approved Ey:

UD Shafen, Chief Reactor Projects Branch 1

1/17/91

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.

<u>Results:</u> The team concluded that the System Auxiliary Transformer (SAT) fault and subsequent reactor trin were the result of an inadvertent transformer deluge, that the plant responded puperly, and that the licensee responded appropriately to the event.

9104300219 910417 PDR ADOCK 05000304 Q PDR The team identified 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 345Kv 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.

Augumented Inspection Team Report

50-304/91006

- 1. INTRODUCTION
 - A. AIT Formation
 - B. Charter

11. DESCRIPTION - EVENTS OF MARCH 21, 1991

- A. Overview of Event
- B. Sequence of Events
- C. Equipment Problems/Failures
- D. Plant Staff Response

111. INSPECTION EFFORTS

- A. System Auxiliary Transformer Deluge Sys -- Actuation
- B. Transformer Failures/System Interactions
- C. Reactor trip
- D. Deluge system design deficiencies
- E. Management involvement and administrative controls

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IV. LICENSEE INVESTIGATION

- A. AIT assessment
- B. Licensee Conclusions

V. SUMMARY

- A. Safety Significance
- B. Concerns
- C. Conclusions/Recommendations

VI. CHARTER COMPLETION

V11,	EXIT	
VI11.	ATTAC IMENTS	
	Attachment <u>Number</u>	Description
	1 2 3 4 5 6 7 8 9 20 11 12	Confirmatory Action Letter AIT Charter Shift Engineers Log - March 21, 1991 Unit 2 Operators Log - March 21, 1991 Sequence of Events Report Unit 2 Pre-Reactor Trip Report Unit 2 Post-Reactor Trip Report Prime Computer Point Plots Strip Charts Zion AC Electrical Distribution Drawings Request for Temporary Waiver of Compliance Standing Order 91-07
	13 14	Unit 2 Supervisor Turnover Sheets PT-211, "Wet Pipe Sprinkler Test"

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1. 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 nower and forced to rely on natural circulation to remove decay heat wich 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 Tack 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 R. B. Landsman, Project Engineer, Personnel: 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

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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 RI.; personnel.

The AlT was terminated on Monday, March 25, 1991 by the Deputy Regional Administrator.

С. Persons Contacted

Commonwealth Edison

*T. Joyce, Station Manager K. Graesser, General Nanager, 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
- *k. Souires, Off-site Nuclear Safety
- *W. Stone, Assistant to Technical Superintendent
- *A. Valos, Zion Project Engineering Support Group
- *T. VanderVoort, Maintenance Staff *R. Khittier, 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.

11. 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 (O EDG). Major evolutions in progress included the repairs to the O EDG, routine surveillance testing of unit 2 EDGs, 18 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 restor 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 vitalbus 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 incluations 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.

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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 wich identifying root causes but to also provide recommendations for corrective actions and improvements.

E. Sequence of Events

The AIT and the licensee compiled sequence of events listings using control room logs, operator interviews, computer and alarm printouts, and cortrol 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 Plaining as a Technical Specification guarterly surveillance.
- 0930 While performing the 2" drain line portion of PT-211 for the Unit-2 wall, Unit-? Main Power Transformer (MPT)/UAT and SAT deluge scluated. 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 value 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 M' / 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 MMe.

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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 28 EDG oil storage tank rooms, and no valve manipulations have taken place at the deluge station.

B-245

1309.32 Computer "2A D/G output BKR closed". At this point the EDG is being loaded to 1MWe as part of FT=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 EKR 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 to	rip 85%,	- This	15	5850	d on		ChD6.	100100	riou py 1	tue
	Unit	Supervi	sor.	Read	tor	trip	breake	rs are	verifi	ed open.	

1310:16 Rods falling

- 1

13311.14 Gen Hatts low alert (20MW)

Unit SUF saw 2 loop loss of flow after performance of immediate action in EOP-O. 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-O to Es 0.1 (Natural circulation cooldown).

- 1335 Declared an Unusual Event
- 1350 Notified NARS, NRC, Resident Inspe------ and Cration ruly officer.
- 1400 TSC activated
- 1405 Bus 247 crossfied to Unit 1
- 1426 Starting 1000 gal boration
- 1429 TSL 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 ESO.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 Ul, 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 FZR to charging.
- 2330 Opened 2ADV-VC8146 & closed 2ADV-VC8169 to depressurize RLs.

March 22, 1	991
0015	Opened OCB 23 & 24 in preparation for closing disconnects and energizing the SAT.
0113	SAT energized
0145	U2 service busses all energized, 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 cDGs
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 GDP-4 from from the EOPs.
0857	Started depressurization of RCS to 900 PSIG using Aux. spray because normal spray is ineffective (normal spray boing investigated).
	이 그는 것이 많은 것이 같은 것이 같은 것이 같은 것이 많이 많이 많이 많이 했다.
1220	2 PCV-RC 455C (PORV) failed PT-2T and IM calibration. Work request initiated and valve declared inoperable. PORV 455 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 is made on termination of U/E GSEP. NARS notification of GSEP termination secured cooldown U2, maintaining Mode 4.

C. Equipment Problems/Failures

3.

The following equipment problems or failures that occurred during or immediately after the station blackout event are considered to have safety significance.

Security Invertor - Some security doors between the service buildings and the power block failed locked, due to equipment 3.4 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 All 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.

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- 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 celection 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.
 - 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 off: te power event, but are not considered to be safety significant.

- 1. Component Cooling Water Pump DA 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 DA was operating when the loss of offsite power occurred. The CCW pumps are powered off of Class 1E busses. Pump DA 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.
- Padiation Monitors Some of the radiation monitors failed to power up (PR 40).
- 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.
- E. 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 Start 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 Auxillary 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. Ar operator had to go to the atmospheric relief valves and bleed off the control air to close them. One of the stmospheric 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 ZA 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.

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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 Technic: 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" 3G 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 U 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 chited 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.

111. 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, 1981 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 c.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 pecturbation 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 Eus 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 ACR 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 1:03 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 (867242) 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 (ART) of non-essential bus Nos 243 (along with the 2A EDG) and 244 to the bAT. 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, Pus 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 30, 2481. The Bus No. 268 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 sitisfactorily picked up loads. 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:

- The physical evidence indicated an arc strike on the C phase transformer bushing.
- 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 courred, 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 (SDE) 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 SC 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 less 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, t'ey were not able to avoid the reactor 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. Deluge system design deficiencies

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 ...pingement 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 th: 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 O EDS. 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 Tes*," (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 smergency diesel generatur, clectrical 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 compressiony 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, Piocedure 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.

T a 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 inter- lews 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 cafety 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 at a routine test. Given that FT-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. LICENSES INVESTIGATION

A. AIT assessment

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G. 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.

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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 perticipated 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 \$: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. SUMMERY

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 black ut 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 ...y 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 AlEOKY 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 O EDG is unavailable, both units nave to shutdown causing additional thermal cycling of the units. When the EDGs at Zion are operating properly, the design of the unit 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 All 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.

Sperific 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 bazard and that the control and alarm panels are not Underwrite: 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 soltage 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 Probablistic 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 concirned 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 All 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 , 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 invertigation and review, it is important that events be properly classified to ensure an adequate management evaluation.

The team concluded that the comper...tory measures in the TWOC were weak in that only safety-related equipment was adoressed 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 Jeveloped 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 - 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 if : the read or 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. Fangement 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

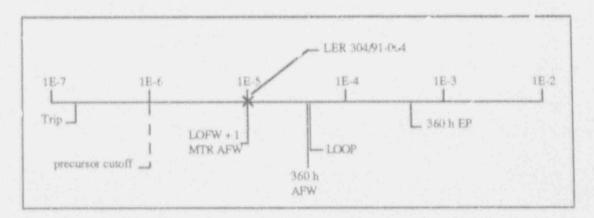
B-264

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:304/91-004Event Description:Main feedwater pump trip with one AFW pump failedDate of Event:June 11, 1991Plant: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 put ps 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

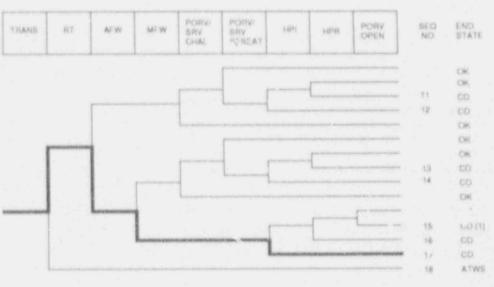
Zion 2 has two motor-driven AFW pumps and one turbine-driven AFW pump. The AFW success criterion for decay heat removal is one pump out of three.

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.



(i) OK for Class D

Dominant core damage sequence for LER 304/91-004

B-267

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

7otal 3.4E=05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

 Sequence
 End State
 Prob
 N Rec**

 17
 trans -rt
 AFW
 MFW hp1(f/b)
 hpr/-hp1
 Cb
 5.1E=06
 7.4E=02

 15
 trans -rt
 AFW
 MFW hp1(f/b)
 hpr/-hp1
 porv.open
 Cb
 5.2E=07
 8.8E=02

 16
 trans -rt
 AFW
 MFW +hp1(f/r)
 hpr/-hp1
 AFW
 3.4E=05
 1.2E=01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	and State	Prob	N Rec**
<pre>15 trans oft AFW MFW -hpl(f/b) -hpr/-hpl porv.open 16 trans oft AFW MFW -hpl(f/b) hpr/enpl 17 trans oft AFW MFW hpl(f/b) 18 trans ft</pre>	CD CD CD ATWS		

** non-recovery credit for adited case

SEQUENCE MODELI	C1/995/	2.9.8.81	Detspage 1	comp:
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PRODABILITY FILE:	ci/asp/	10893	per heil	pro

No Recovery Limit

BRANCH PREQUENCIES/PROBABILITIES

Branch Bystem Non-Recov Opr Fall

Event Identifler: 304/91-004

1,08-02 1,08-03 4 08-04

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loca	2.48-06	4,35-01
28	2.82-04	1.20-01
re/toup	0.05400	1.02+00
emerg.power	5,48-04	8,02-01
AFW	3,85-04 + 3,38-53	2.68-01
Branch Model: 1.OF, 3+ser		
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Train 2 Cond Prob:	1,08-01	
Train 3 Cond Probi	5,06-02	
Serial Component Frohr	2,48-04	
stw/wmw.rg.powet	5.02-02	3.48-01
MPW	2,08=01 - 1,08+00	3.45-02
Branch Model: 1.07.1		
Train 1 Cond Probi	2.0E-01 > Unavailable	
porv.or.stv.chall	4,08-02	1,06+00
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porv,or.srv.resest/emerg.power	2.08-02	1.02+00
seal.loca	2,78-01	1,08+00
wp.ruc(sl)	5.78-01	1.05+00
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Pigià	1.02-03	8.48-01
hpl (CZb)	1.08-03	8,48-01
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* Branch model file ** forged

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Event Identifier: 304/91-004

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On June 11 1991, during Unit 2 plant startup, several unsuccessful attempts were made to use the hypass Feedwater Regulating Salves (FRV) [53] in the automatic mode to c ntrol steam generator (5/6) isvel [38] while the unit operators were aligning the main feedwater pumps. The main feedwater system (53) was successfully aligned with the hypass 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 5/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 fechnical Specification limiting Conditions for Operation and there was no safety significance to this event. Corrective actions included determining the robt cause of she capacitor failure, reviewing the S/G level control system to determine what information should ' provided to the unit operators, identifying recurring feedwater System problems, and verifying the calibration of the bypass FRV controller.

20V#LER-304(2)

FACILITY NAME (1)	(KOCKET MUMBER	(2)	LES	KR, HEELE &	(6)			P	age i	(3)
	위에 안전했다.		Year	14	Seguential Number	144	Revision Number			T
Zian Unit 2	1 51010	0 13 10 14	911	-	01014	-	010	6 12	or	0.11

CONDITION PRIOR TO EVENT

HODI __ - Power Operation RX Power _ 17% RCS (A0) Temperature/ Pressure 549 17/ 2235 psig

. DESCRI LON OF EVENT

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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 Precedure (GDP)-2 "Plant Startup". Auxiliary Feedwater Pumps (AFP) (BA) were feeding the steam generators (5/6). At 0935, 20 Main Feedcater Pump (MEP) (SJ) was being started and lined up to feed the S/Gs. The Bypass Feedwater R: viating values (FRV) [53] were placed in automatic to control 5/6 level (JB). 5/6 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 values set to produce 110 gpm flow to each 5/G. While the operators were concentrating on aligning the AFP for power operation, one AFP failed to strating uses declared inoperable at 0946. While the AFPs were being aligned for power operation, the S/Gs were continuing is fill due to improper operation of the bypass TRV. At 0957, 5/6 2A reached 70% level and the High Steam Generator Level Permissive (P-1d) 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 5/6 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 5/6, the 2C main fredwater pump (HEP) tripped and the typass FRVs closed as designed. Although the operators had noticed improper operation of bepens FRVs, the consensus of the Control Room personnel was that it was the distraction of aligning the AFP or power operation, along with feedwater valve leakage that caused the high level in the S/Gs. Teedwater valve leakage has been a historical problem at Zion. Operator experience lead to the assumption that must 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 ((CO) 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 recommended 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 20% in 2 S/Gs. A second attempt was made to start 2C MFP at 2035. Bypr s FRVs were kept in manual atthough automatic operation was attempted. Turbine rollup commenced at 2054 and the turbine reached 500 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 reach d on 2D 5/6 and a P-14 signal was generated. The 2C MFP tripped along with the main turbine.

20VHLER-304(3)

B-271

FACILITY HAME (1)	DOCKET NUMBER (2)	LERI	机开始行	R (6)		P	Page (4)			
		Year	1914	Sequential Number	111 Revision 111 Number			1		
linn Unit 2 11x1 - Energy Industry Ide	0 1 5 1 0 1 0 1 0 13 17 14	9.11	-	0 0 4	- 010	6.13	61	01		

B. DESCRIPTION OF EVENT (CONT)

A new shift came on at 2300. The feedwater containment isolation valves were throttied for A. B. and C. 5/6 and the D.S/6 containment isolation valve was 3-5 seconds open (60 seconds is full stroke time). The bypass VRVs were in manual and the shift turnover report stated that the bypass FRVs word is not control in automatic and were leaking severely. The feedwater pump differential pressure control was considered difficult to control. At 2311, 20 MFP was started again. Although difficult to control, the main feedwater system was placed in service and the main turbine speed was increased to 1900 kPM. After these evolutions, the 5/6 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 SZ/min to 12/min. As the main fRVs mere placed in automatic to open, the bypass FRVs were closed in manual per procedure. The main fRVs man generated at 2355. This tripped the main turbine and the 20 MFP, and close/ the main fRV and bypass FRV. Since power was greater than 10% a sector trip also eccured. The plant emergency procedures were entered and the reactor was stabilized in Articipation.

APPARENT CAUSE OF EVENT

The primary cause of this event was the failure of a capacitor in the power supply circuitry of the S/D 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 caccing the limiting components (o fail. Because the limiting components provide a reference level signal to the S/D level controllers, when these components failed, the level controller supplied the S/D with a reference level of 100%. When the main fRVs were placed in automatic and the bypass fRVs were placed in manual, the 100% setpoint from the level controller caused the main fRVs to continue to fill the S/G until the 70% setpoint from the level controller 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 staget of the FW system L artup, 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 hoard indications did not completely agree with this diagnosis (i.e. bypass FRVs went open when placed in auto even while at or shove program level and the pSS 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 hased on a history of problems with values 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.

20VRLER-304(4)

FACILITY NAME (1)	DOCKET MAMBEL	(3)	LER P	AMBER	(6)		1		ape (5)
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Zion Unit 2	0151010	1 0 13 10 14	911	-	0 0 4	-	010	0 14	105	0 15

C. APPARENT CAUSE OF EVENT (COMIT)

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Also contributive 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 prissure. This was done because the differential pressure indicator is more useful during power operations that 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 120P-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 realuation to approve hypassing step 60, the level program error may neve been recognized.

D. SAFETY AVALYSIS OF EVENT

During this event all failures and actions token were within the bounds of the Technical Specification. Limiting Conditions for Operation. There was thorefore no safety significance to this event. All safe shutdown features worked as designed. Steam Generator Hi-Hi Override (P-14) is a turbine protoction signal to prevent damage from moisture impinor \cdot 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:

- Tech Staff, Mechanical Maintenance and Operating verified that all mechanical overrides were intact and not impeding the proper operation of the -alves. Additionally, with no demand on the M/A stations, 0 psi diaphrage pressure was verified on all the valves per disign.
- 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)

20VRL_R-304(5)

FACILITY MAPE (1)	(200)	ET N	1,10	ER.	(2	}		Т	11	R M	MELER	1 (6)				T	PI	hg# (1	63
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C. CORRECTIVE ACTIONS (CONT)

- A review of the 5/G level control system will be performed to determine what control information should be provided to U + operators. (304-160-91-01302)

- A multi-department walkdown and review of the FW system will be performed to identify any recurring FM 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)

F. PREVIOUS EVENIS

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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. Some of the corrective actions taken would have prevented this event.

DV0 1-88-13781 documents an event where failed capacitors in the S/G level controller nearly caused a reactor trip. The corrective actions from DVR 1-88-13781 would not have preventes this event.

G. COMPLHENT FAILURE DATA

Manufacturer Momenclature

Hagan Controls Summator

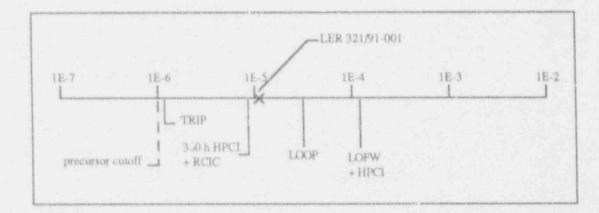
20VRLER-304(5)

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 321/91-001 Loss of feedwater with HPCI degraded and RCIC failed January 18, 1991 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 w is operating at 100% of rated power at 1500 hours on January 18, 1991, when an offsite 2^{-0} -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 cau d 1 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 autor. ally initiated both HPCI and RCIC. HPCI tripped on overspeed more than 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 ... woard injection valve held 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 mestablished approximately 47 min after the scram.

Additional Event-Related Information

The HPCI system is a high-pressure injection system designed for small-break loss-ofcoolant accidents (LOCAs) that do not depressurize the reactor. HPCI is an independent system, using a urbine-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 AS⁻ model for Hatch, results in a conditional core damage probability estimate of 1.5×10^{-5} .

B-277

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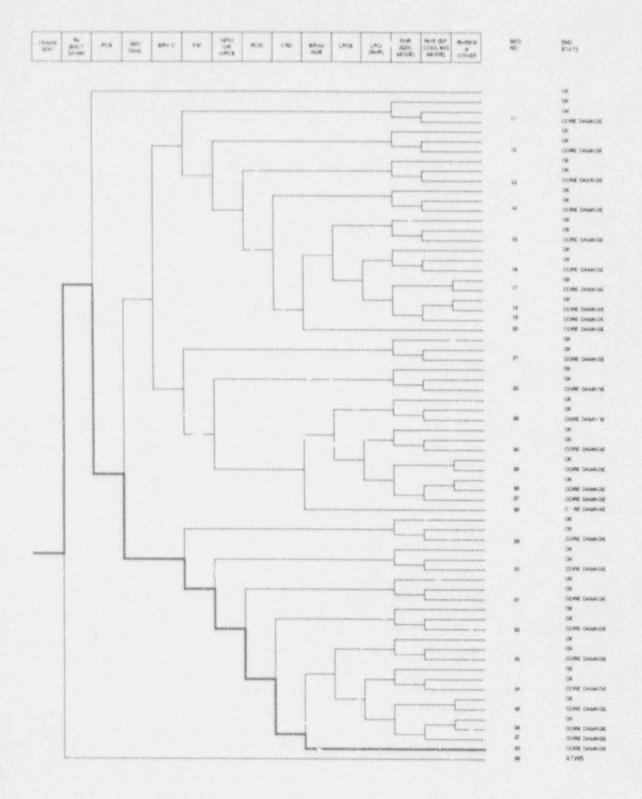
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Dominant core damage sequence for LER 321/91-001

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: Event Description: Event Date: Plant:	321/91-001 LDFW with HPCI degraded and RCIC (411e 01/18/91 Hetch 1				
INITIATING EVENT					
NON-RECOVERABLE IN	ITIATING EVENT PROBABILITIES				
TRANS		and the second			
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SEQUENCE CONDITION.	AL PROHABILITY SUMS				
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ATMS					
TRANJ		3.02-05			
Total		3.02-05	3 45-55		
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	Sequence	End State	Prob	N Rec**	
99 trans in sh			1002		
99 trans tx.sh	ur down	ATWS	3.08-05	1,00+00	
** pou-lecowerk ci	edit for edited case				
REQUENCE CONDITION	AL PROBABILITIES (SEQUENCE ORDER)				
	Sequence	End State	Prob	N Rec**	
99 trana re.ak	out down	ATWS	3,0E-05	1.0E+00	
** non-recovery cr	redit for editud case				
SEQUENCE MEDEL: HRANCH MODEL: PROBABILITY FILE:	ci\aap\1989\bwrcawal.oop ur\aap\1989\bwrcawal.oop ci\aap\1989\bwr_csll.pro				
Ho Recovery Limit					
BRANCH PREQUENCIES	PROMABILITIES				
Branch	System	No.4-NRCOV	Opr Fall		
trans	6,18-04	1,05,00			
loop	1.4E-05	3.68-01			
loca	3.36-06	5,0E-01			
tx.shukdown	3,02-05	1.02+00			
rs.ahutdown/eç	3,58.404	1,06+00			

Event Identifiet: 321/91-001

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PCS/TRANS	1.72-01 > 1.96+00	1,08+00	
Branch Model: 1.0F.1			
Train 1 Cond Probi	1.72-01 > Unavailable		
SRV. CHALL/TRANS SCRAM	1.00+00 > 0.00+00	1.02+00	
Branch Models 1.09.1			
Train 1 Cond Probi	1.02+00 > 1.02+00		
srv.ohall/loopscram	1.08+00	1,0E+N0	
ary close	3.68-02	1.05+00	
ener .power	5.4E-04	8.06-01	
4D.74C	1.62-01	1,02+00	
FW/PCS, TRANS	4,6E=01 > 1.0E+00	3.92-01 > 5.3E-0)	
Brinch Models 1.0F.1			
Train 1 Cond Probs	4,6E-01 > Unevailable		
fw/pcs.luca	1,06+00	3.42-01	
HPCI	2,98-02 > 1,08+00	7,0E=01 > 4,0E=02	
Branch Model: 1.OF.1			
Train 1 Cond Probi	2,9E-02 > Falled		
ACIC	6,0E-02 > 1,0E+00	7.0E+01 > 1.0E+00	
Branch Model: 1.07.1			
Train 1 Cond Prob:	8,0E-02 > Failed		
erd	1,08-62	1,08+00	1,0E-02
ary, and	3.76-03	7,1E-01	1.06~02
Ipos	3.05-03	3,48-01	
ipdi(me)/ipda	1.08-03	7.1E-01	
rhr (adc)	2.18-02	3,4E-01	1,08-03
thr (adc) /=lpc1	2.0E-02	3.46-01	1,0E-03
the (sdc) / ipci	1,08,+00	1,0E+90	1.0E-03
(* '(speco))/rhr(sde)	2.0E-03	3.48-01	
the (special) /- lpc1, thr (sdc)	7 08-03	3,45-01	
rhrispeonl)/lpri.chrisde)	9,38-02	1.02+00	
chiraw	2.0E-02	3.48-01	2,08-03
2014.0T			
* branch model file			
AN Assessed			

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Binarick 05-06-1992 10:09:13

Event Identifier: 321/01-001

LICENSEE EVENT REPORT (LER)							946-467-1198 81 4/98/492	TIE						
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191.8		NEWTER	TON LTN	B \$2771881	E COUPLE	ו אדדע מ	WITC	MVARD	REFAKE	R FATURE	CAUSES REA	CTOR SCR	HA	of Mindowers
	T DATE			ER HUNDER		REPORT				N.R.WO.	ACILITIES			
OFTH	DA.Y	YEAR	16.4.3	880 MUM	8.5.4	PROFTI	1.44	TEAS		CILITY BAR		DOCKEY BU		
		1						-	PLANT	HATCH, UND	72	0500	0	300
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	8 (9)	14	20.43			20.4051			X	50.731n113		73.711		
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-	- L		(a) 10.110	651#512512 651#512315	and the second	50.36(c 50.73(x		33	-	50.721c112		Abelis		ecity in below?
			1000	05(*)(\$)(;	and the second	30.7314	11(21)	111	-	50.731#1(2				
-			20 41	05(#)(1)!*		50.711			LES IN	50.75(a)(3)(#1			
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											AREA CODE			
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			in the second se	ABUYAC-	REPORT	THE EACH	PATCO	7	Acres in succession of	IN TRIE REI	RABUTAC-	ALPORT	-	
AUES.	WTATEP	CORPOR		TURER	TO MPRD	6		CATEE	STRTEM	COMPONENT	TURER	TO NPA	15	
x	8 J	sc	4	2.9.0	Ϋ.Ε.5			x	BN	¥ U	B 5 6 9	N O	1	
x	8.0	DHI	в	237	NO			X	YE	BKR	NIA	NO	1	
			-	SUPPLEMENT	AL FEFOR	T GREETI	ED it	0			EXPECTED		NTH	DAY
				EXPRCTED 5			-	- 80			BURNISSI DATE 115	(389)		
	app At the 230 fau loc in the aut man all the sys	roximu that support kV so lt cookout turn, Unit omati ually owing intent tem (ste po time, orting witchy nditio relay. resul 1 non c tran resto for t	wer leve a remote electri ord fail ns resul This s ted in i essention offer to inted to i he init o recov	of of 20 concerning to led to liting in resulter a react al elec the al nonesse iation er reac	436 CMW transm vet. I fully c h the t d in ma or stra trical ternate ntial of open tor va	<pre>/T (a issi in ad open trip in g in busi e sup toadu tatou ter</pre>	opprox on li ditio in re of th genera This tes ar oply c s with r acti level	imate ne fa spons ie Uni itor a also id the lue to hin ap ions t	iy 106% r iled at i breaker i e to the t t main d main i resulted preventi the tran proximato o restor	Run mode ated the is attac n the P. sensed e transfor urbine t in a los ion of th hsfer log ely 2 to e feedwat	rmal pow hment pr ant Hatc lectrics mer auxi rips, wi s of pow e norma ic. Pow 3 minute er flow	in h lli ver ver ver	t to ary to vas
	vas Rea The the	r test actor r root r fail	HPC1) utimat ored a pressu cause ute of	ic mode and main are vas es of th t the ma	, it wa tained control e scram in brea	s succe vith H) led by vere ker to	essfi PCI i the the ful	Alti ully d until fuib failu ly op	hough sontro feedu ine by re of en. T	it exhib lled man ater flo pass val the high he root	ited erra ually and v was res	tic beh Water Hored pover l the err	avi lev ine	tion or el and

LICENSEE EN	PILEPORT (LER)	8 AJ996CR05 (396 85 1155 8184 83391885 (4/36/43						
FACILITY RAME (1)	DOCREY WOMBER (2)	La	CR BRUNGERS (5	1	FLOE (131		
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PLANT BATCH, UNIT 1	0 5 0 0 0 3 2 1	91	001	00	2 08 8			

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor Energy Industry Ident fication System codes are identified in the text as (EIIS Code XX1.

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 CMVT (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. Pover 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 vater level was restored and maintained with HPCI until feedwater flow was restored. Reactor pressure was controlled by the turbine bypass valves (BPV, EllS 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 APCI 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 (FCB, EIIS Code FC) 490 and 500 in the Plant Hatch 230 VV switchyard. Phase 2 of FCB 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 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 milling through other circuits fault existed.

6-49)	LICENSEE D		(LER)		APPRIX (M) (H) KCP (1965	6 NO 1156 6/38/92	0104		
	TEXT CONTINU	ATTING MITCHA					-		
ACILES	TY BEAME (1)	(1) DOCKEY MURCHER (2)						PAR	1 13
		単分支対応		TRAR	B R-C) SPC/R1	REY			
MANT	HATCH, UNIT 1		05000321	91	001	0.0	3	Œ	8
	HATCH, UNIT 1 Continued movement of f phase 2 and this time of conducting path between ground fault. This fau phase 2 in PCB 500. The resulted in the breaker tripped a lockout relay in turn, initiated a ma occurred at greater that design. The main turbi- reactor pressure trans- measured and post-event in vith the main transform electrical loaus were a supplied through the ma automatically transfer transfer to occur, the 500 and 510 open. Beer the PCB was lost (expla- alternate supply was p- deenergized. Among the condensate booster pump 5D), and reactor recire. Without the condensate suction pressure. Lack decreased to approxima 15:01 C5T. initiating of required Group iI valve reactor water level re- automatic initiation of (RCIC. EIIS Code BN), isolations. The PCIS Unit 2 Standby Gas Tre- as designed. Upon fee demonstrated erratic of trip. The control roo functioned normally. wates approximately 10 i inches above the top of	ontacting the phase 2 and lit current will resumption failure rel. in the Unit is generator in 30% reactor ne bypass va- ent, limitin y 1095 paig. Investigation wer disconnec nutomatically in transfer to their alt transfer log use one phas vined later i evented and ese loads ver pained later i evented and ese loads ver paine normal i tely 12 inche a Primary Con- and another es closed as ached 35 inch f the HPCI ar as well as Pr Group V isola atment System eperation resu a operators to Thus, with th The minimum nches below	ase 1 line resulte e electrical tover the electrical tover of fault current as supplied throug of fault current and main turbine r pover, resulting ives opened, as du g reactor pressure No safety relief confirmed none we ted from the grid disconnected sim- er. The nonessen ernate supply. Bu ic circuit must si e of FCE 500 did n this report), a Unit 1 nonessenti s. the reactor fe eactor feedwater is above instrument tainment Isolation scram due to low designed. At app tes below instrume d the Reactor Cor IS Group V and se tion occurred as ms (SGTS, EIIS cod outo start signal, fling in more tha rook manual contro the APCI and RCiC s in water level obse instrument zero.	ed in it as vel over, cr th the is through The bi trip. g in a esigned a during t valve ere req is nones ce they tial lo ovever, ense al not ope utomati al load pumps (ating v r sets edpumps (ating v r sets flow, r i zero n Syste reactor roximat nt zero e Isola contary designed the Hi is the Hi is the Hi is the Hi is the Hi is the H	t again co ll This reating a still-close h this bra- reaker fai rol circu This tur reactor s- , to mili- g the tra- s (SRV, E uired to sential s are norm ads are d in order l phases n and ind c transfe s remaine EIIS Code ater pump (EIIS Code tripped eactor wa by approx- med. Both started an PCI system injecting uring the the started and PCI system ater injecting uring the	intacti provid phase bed pool eaker ilure i itry wi sine in tram provid pate in tram provide is control itre ally evigne for t itre ally evigne for t icatio r to t d SD), s (EII EIIS (ivel. i CST, ing in ling sy ment Unit unit s (cram provide for t icatio r to t d SD), s (EII EIIS (ivel. i CST, ing in ling sy ment unit ine ovel. s (cram provide solution for t icatio r to t d s (control inter i	ing a click of celay hich is celay celay celay control is control is control is control is control is control is celay cel	BS c de né dem	

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LICENSEE EVEN		APPRENDED BUPTA		HO 3150 /36/97	8164	-		
PACILITY RAME (1)	DOCKEY WORKER (2)	LE	ER BUINE ER	(3)		I	PAG	8 (3)
		TEAR	380 809	11	REV			
PLANT HATCH, UNIT 1	05000321	91	001		0.0	4	OF.	8

A post-event review team observed that a secondary containment damper. 1741-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 15:0° CST and 15:10 CST the control roos 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 HFIC 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 begato 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 vater level again began to decrease. At approximately 15:35 CST, with ceator vater level at approximately 15 inches above instrument zero and decreasing slowly. RCIC was restarted. If was at this time that the licensed operator noriced that position indication had been lost on 1E51-F013. The operating crev concluded that the val & was only partially open sinc. 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 15:60 CST, reactor water level reached approximately 12.5 inches above instressive, 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 imminen. By approximately 15:67 CST, a reactor feed pump was returned to service, and water level was controlled thereafter using the normal reactor level control system.

LICENSEE GUENINGERIG		EPORT (LER)		10H AJPREXX2 0H6 RD 5190-8114 R0071585 : 4/30/92						
PLANT HATCH, UNIT 1		DOCEET WORSER (2)	and an and a second second second	R BUNGBER 15	in the state of th	1	PAG	E (3		
			TEAR	SEQ WON	REV	-				
PLANT	HATCH. UNIT 1	05000321	91	001	00	15	OF	8		
EXT		energia de la seconda de la compañía de la compañía La compañía de la comp	endanar is islen	al and a state where		-	in denine i	*****		
	CAUSE OF THE EVENT									
	The direct cause of the first rated thermal power. The roo remote power transmission lin 500. The failed current limi reaching phase 2 of PCB 500 w to clear the fault. The open which led to the scram.	t causes of the first so e and the failed current ting resistor prevented hich caus. ' the redundar	ram wer t limiti the ti ht break	e the fa ing resis > signal ter, PCB	iled tor in from 510, t	PCB o op				
	The cause of the failure of t mode was a failed speed contr recalibrate the controller, b recalibration. However, it s controller, due to the config successful control of HPCI in	oller. Post-event main out the controller would hould be noted that the uration of the control	tenance not ret failure	attempte tain its e mode of	d to the s	peed				
	The caule of the lost valve i valve actuator control power valve, preventing the valve f by the architect engineer and	circuit. This interrup rom being moved. The f	ted con use fai	trol powe lure was	t to t invest	he igai	red			
	The cause of the failure of d pneumatic actuator. It appea outside of the reactor builds conditions which fostered the resultant corrosion over time specifically devpoint, partic part of Georgia Power Company instrument air supply system results of the sampling met t .981. As part of the ongoing instrume " air quality, air o against the same standard.	ars that due to the loca ag, the damper was expo- condensition and accum i. It should be noted to ulate content, and oil i's response to Generic problems affecting safe the requirements ANSI/IS g Flant Hatch program for	tion of sed to ulation tat the content Letter ty rela A S7.3 r maint	this dam environme of moist air qual , hrs bee 88-14 re ted equip 1975, Res aining pr	per or ntal ure ar ity, n sam ardin; ment. iffirm oper	n the nd th pied The ed	e he as			
	BEBARTISTITTY INSIDETO INT. C.	TETT ACCECCATAT								
	REPORTABILITY ANALYSIS AND SA	AFELI ASSESSMENT								
	This event is reportable per actuation of the Reactor Pro- Safety Features (ESF) occurre 'ockout relay resulted in a turn resulted in a reactor so 50,73(a)(C)(v) because an even fulfillment of the safety fur consequences of an accident, caused the RPC1 system to the operators were required to the reactor water level.	tection System (KPS, EII ed. Specifically, tripp turbine trip above 30% r cram. This event is als ent occurred which could notion of a system which Specifically, a failed ip repeatedly due to ove	S Code ing of ated the to report have p is int HPCI s trspeed.	JC) and I a main thermal po- table pe- prevented ended to peed con with the	Engine cansfo wer, w r 10 C the mitig trolle e resu	ther lich FR ate l lt t	i in the	1		

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(1-41) LICENS	FEXANINATION	a betalen direction (LER)	REPORT (/51/92						
and the second	the second se	DOCKET BUNGER (2)		LES MUNIBER (5)					
FACILITY BARE (1)				VER DEC BURN ALV					
PLANT HATCH, UNIT 1		0 5 0 0 0 3 2 1	9.1	001	0.0	4 OF 8			

A post-event review team observed that a secondary containment damper, 1T61-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 file in the switchyard. The fire brigade responded, but found the fire had already been extinguished by a nember 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 BPIC 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 an designed on a RCIC trip signal. As decay heat caused reactor pressure to increase and the bypass valves opened to control reactor pressure, teactor 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 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 RFCI in the manual control mode and recovered reactor wessel water level. HPCI would have been restarted earlier to recover level, but operations personnel believed the restoration of redwater was imminent. By approximately 15:47 CST, a reactor feed pump was returned to service, and water level was controlled thereafter using the normal earlier level control system.

LICENSEE EXEMINATION		e niften renalrine cenechten OR7 (LER)					4/30/92	0104			
PLANT HATCH, UNIT 1		DOCKET MI THER (2)	1		-	15)	******	PAGE (5			
			YEAR		SEQ SU	-	REV	-	T		
LANT I	HATCH, UNIT 1	05000321	9 1		001	1	00	1.5	OF 8		
	CAUSE OF THE EVENT										
	The direct caule of the first or rated thermal power. The root of remote power transmission line a 500. The failed current limitic reaching phase 2 of PCB 500 which to clear the fault. The opening which led to the scram.	causes of the first s and the failed current ng resistor prevented ch caused the redunda	t limi the t nt brea	ere tir rie	e the ng res p sign er, PC	fai ist al B 5	led of in from 10, t	PCB o op			
	The cause of the failure of the mode was a failed speed control recalibrate the controller, but recalibration. However, it how controller, due to the configure successful control of MPCI in the	ier. Post-event main the controller would uld be noted that the ation of the control	tenanc not r failu	e i eti re	attem; ain it mode	s of	t to the s	peer			
	The cause of the lost valve ind valve actuator control power it valve, preventing the valve foo by the architect ingloeer and w	rouit. This interrug m being moved. The f	ted co use fa	nt 11	rol pr ure wi	ver ks	invest	he iga	ted		
	The cause of the sailure of dam pneumatic actuator. It appears outside of the remeter building conditions which fostered the c resultant corresion over time, specifically devpoint, particul part of Georgia Power Company's instrument air supply system pr results of the sampling met the 1981. As part of the ongoing P instrument air supply, air qua against the same standard.	that due to the loca , the damper was expr ondensition and cus It should be noted to ate content, and oil response to Generic oblems affecting safe requirements ANSI/I lant Hatch program for	tion o milatic hat the conter Letter thy rel GA S7.3 or main	if en en it, ent lat	this nvirm of mo air q has 18-14 ed eq 1975, iining	tam ime ist uul bee teg Rea pr	per of ntal ure a) ity. n sam ardin, ment. fficm oper	n th nd t pied E Th ed	e he as		
	REPORTABILITY ANALYSIS AND SAFE	TY ASSESSMENT									
	This event is reportable per 10 actuation of the Reactor Protec Safety Fear, as (ESf) occurred. lockout recay resulted in a tur- turn resulted in a teactor sore $5^0, 73(a)(3)(4)$ because an event fulfillment of the safety funct consequences of an accident. Is caused the HPCI system to trip operators were required to take	ction System (RPS, EI Speci' "ly, trip rbine tri, ve 30% im. This eva is al coccurred which coul tion of a system whic Specifically, a faile repeatedly due to ov	IS Code ping o rated so rep d have l is i d HPCI erspee	f i the property d.	IC) an a main ermal table revent ended peed o	d H tr per ed to th	ingine white 10 c the mitig trolle c rem	eroo (rme) (hie) (FR (ate ())	i in the		

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LICENSE CAPAL SETTE	LICENERE EXEMINATION (LER)						
FACILITY BASE (1)	POCEET BUMBER (2)	ma man	ER RUMBER (
PROFILITE BRACK (4)	MARKET BURDER (4)	TEAR	. REV	PAGE			
					1	11	
PLANT BATCH, UNIT 1	05000321	91	100.	0.0	6	OF 8	
The Reactor Protection System (RPS reactor stram to ensure the radioa cladding and pressure system bound consequences of transients and acc can result in an addition of posit pressure rise col. apses steam void stram prior to the Neutron Monitor it is required to provide a satisf limits. The high pressure scram is is adequate to previde overpressu the turbine stop value clorure scr described in this report, the RPS controlled by the turbine bypase view as maintained will below the vess the turbine stop value clorure scr described in this report, the RPS controlled by the turbine bypase view as maintained will below the vess tuel-clad temporature in the event causing a loss of coolant which dow reactor vessel. The Automatic Dep backup for the HPCI system. Upon view operable for the HPCI system Upon view operable Based upon the Unit 1 Fi loop of the CSS or the UPCI system for any ruppure of the nuclear system situation of the secondary conta airborne radioactive materilies, and elevated release of the building at basis fuel handling or loss of cool subsystems: the reactor building, main stack. In this event, secondar subsystems: the reactor building, main stack on nuclear satery. Since the it is concluded that the event coul- under other operating conditions.	ctive miterials ba ary, are maintaine idents. Closure o ive reacti .cy to s. Turbine stop w ing System or Reac actory margin to on n conjunction with rizing the pressur- am provides additi- atives alone. Conse- al design pressure of a small break - is not result in tr essurization System (DS) initiation, the essurization System (CS). Initiation the rest the Low Fressur- tray System (CS). I this event, due of rest than ance on the complete an inject , the ADS, iPCI sy hal Safety Analysi- can supply sufficient em boundary up to inment is to limit to provide a mean mos, here so that o ant accident (LOCA y containment dam signal. However, losed so that seco	rriers, d, and f f the in the core alve clo tor High ore then the pre- equently adequation in Reac equently adequation or ADS, e reactor e Coola CIIS Cod c a con rbine o ion int stem, a s Repor- ent coo and inc ground s for t ff-site) vill em cons eatment per 1T4 as pre- ndary c	such as to mitiga inbine st as the sure ini- pressure in- source ini- pressure re- source re- gin. In- tor press- ressuriz- tor press- ressuriz- troller in- verspeed of the re- nd CSS re- tor (FSAR) ling to to luding the level re- he contro- doses fi- be below ists of i System. 1-F043B f iously ne- ontainment had no a l power c	tuel te the op valv reactor tiates e; howe aulic lief sy y; howe sure va r press ed tc l oiler s ation of e JE) is tion sy n opera salfunc end ha ictor mained e the rea pe Desi cleases oiled, the lie herea and th ailed the li hree and th ailed the li hree and th ailed the li	res a sver, ster even ure instant ster tion d ic ster tion d ic ster tion d ic ster tion d ic ster tion d ic ster to f i ster i tion d ic ster i ster i ster i i ster i i ster i i i ster i i i ster i i i ster i i i ster i i i ster i i i ster i i i ster i i i ster i i i ster i i ster i i ster i i ster i ster i ster i ster i i ster i i ster i ster i ster i ster i ster i ster i ster i ster i ster i ster i ster i ster i i i ster i i i i i i i i i i i i i i i i i i i		

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	- Carlos and Carlos an	RECTIVE ACTIONS						
	Cor	rective actions for this	even' included:					
	1.	Repairing the fallen 230	WkV *ransmission line. Th	his act	tion is con	mplete	Ċ.	E
	ž.,	Repairing PCB 500. This	action is complete.					
	37		CI Pump Operability." T	ng the his ac	HPCI oper tion is co	abilit mplete	y te	51
 Replacing the failed juse in the control power circuit for IE51-F013. Thi action is complete. 							5	
	5.	Repairing the failed dam complete.	nper actuator for 1741-FO	43B.	This actio	n 15		
6. One additional secondary containment solation damper ectuator located outside the reactor building will be "sected during "%% 1991 Unit 1 out to determine if moisture-induced corresion is evident. The remaining similar dampers will be inspected if corresion is found. This action will be complete by 12/17/91.						outi		
	ADD	DITIONAL INFORMATION						
	 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 switchward led to reactor trips in the past two years. One event during this time frame was identified in which the MPCI system received a valid avtomatic 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 mauses of the injection system failures were different.							
	3.	Failed Components Ident	ification:					
		A. Haster Parts List N Manufacturer: Model Number: Type: Manufacturer Code: EllS System Code: Reportable to NFRDS Rowt Cause Code:	Voodward Go EG-M Electronic V75 BJ			c Pic)	tup	
		Ell'S Component Code						

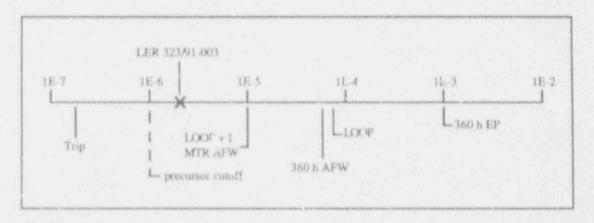
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TREES AND A CONTRACTOR OF A STREET AND A CONTRACTOR AND A	A consideration of the first sector of the sector	district.	and a second second	den administra		- Antonio
 B. Master Parts List Number: Manufacturer: Nodel Number: Type: Manufacturer Code: EIIS System Code: Reportable to NPRDS: Root Cause Code: EIIS Component Code: 	Bussman KTN.R-6 Fuse J569 BN No X FU	2				
C. Master Parts List Number: Manufacturer: Model Number: Type: Manufacturer Code: EIIS System Code: Reportable to NPRDS: Root Cause Code: EIIS Component Code:	1T41-F0438 Bettis Corpora 522C-SR-72 Air Operated I B237 BD No X DMP		Actualo	r		
D. Master Farts List Number: Manufacturer: Model Number: Type: Manufacturer Code: EIIS System Code: Reportable to NFRDS: Root Cause Code: EIIS Component Code:	None Unknown (unrea 132A12:0-32 Current Limiti Unknown FK No X BKR			ed resi	istor	× 2

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 2.1×10^{-6} . The relative significance of this event compared to other postulated events at Diablo Car you 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 locetly in preparation for entering cold shutdown. A procedure had been revised in 1988 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.

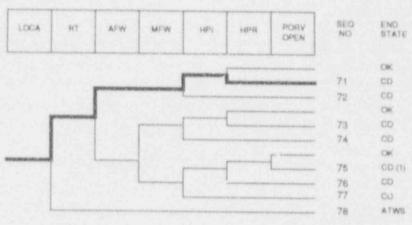
The CS system is also a two-train system that initially provides water from the reactor water storage tank (RWST) to two spray ring headers for containment pressure suppression following a LOCA. After the RWST is empty, CS flow is provided from the RHR system.

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 (ASr) 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 smallbreak 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.



(1) OK for Class D

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 Flant: Diable Canyon 2

AAVAILABILITY, DURATION= 6

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

trans LCOF LOCA	1,5£-03 6,8£~05 6,2£-06
SEQUENCE CONDITIONAL PROBABILITY SUMS	
End State/Initiator	Probability
TRANS LCOP LCCA	1.0£~68 3.6E~09 2.15⇒06
Total	2.1E-06
RTWS	
TRANS LOOP LOCA	0.08+00 0.430.0 0.480.0
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
71 loca -rafw -hpl HPR/-HPI	CD	2.18-06	1.56-01
** non-racevery credit for edited case			
SEQUENCE CONDITIONAL PROBABILITIES (SECTENCE ORDER) Sequence	End State	Prob	N Rec**
71 loca -rt -afw -hpi HPR/-HPI	cB	2.18-06	1,58-01

** non-reduvery 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:	111. 46/10.	38.81	pwibseal.omp
BRANCH MODEL:	c:\asp\1	99.91	diabio2.ell
PROBABILITY FILE:	. C2 \ A #25 . 1	98.91	pwr_ball.pro .

No Recovery Limit

Event Iduntiflar: 323/91-003.

BRANCH FREQUENCIES/PROBABILITIES

Branch	System.	Non-Recov	Opr Fail
Trans	2.58-04	1.02+00	
loop	2,0E-05	5.86-01	
loca	2.48-06	4.3E-01	
PE	2.85-04	1.28-01	
rt/loop	0,02+00	1,0E+00	
energ.power	5.48-04	B.0E-01	
afw	3.82-04	2.62-03	
afw/amerg.power	5.0E-02	3.42-01	
ntw	1.0E+CO	7.08-02	
porv.or.srv.chall	4.02-02	1,02+00	
porv.or.stv.reseat	3.08-02	1.18-02	
porv.or.srv.reseat/emerg.power	3.06-02	1.02+00	
seal.loca	3.28-01	1,08+00	
ep.recial)	6,58-01	1,02+00	
ep.rec	1.12-01	1.0R+00	
hpi	3.05-03	8,42-01	
hpl (f/b)	1.08-03	8.48-01	1.06-02
RER/~RPT	1.5E-04 > 1.0E+00	1,08:00 > 3,48-01	1,08~03
Branch Model: 1.09,2+opr			
Train 1 Cond Probi	1.02-02 > Unevallable		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
porv.open	1.05-02	1.02+00	4.05-04

* branch model file ** forced

Minariok 05-26-1952 10:46:03

Event Identifier: 323/91-003

TETAL (4) INADVERTENT ENTRIES INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW EVENT INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW EVENT INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW MEMORY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW MEMORY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW MEMORY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW MEMORY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW MEMORY INTO TECHNICAL SPECIFICATION 3.0.3 DUE TO PERSONNEL ERROR INADEQUATE PROCEDURE REVIEW OPENDING TO THE REVIEW MEMORY IN TO THE REVIEW OPENDING REPORT TO THE REQUIREMENTS OF 10 DIA OPENDING REPORT TO THE REQUIREMENTS OF 10 DIA OPENDING REPORT TO THE REQUIREMENT OF THE REPORT OF THE	ANI 7
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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 RHP sump 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 1-5 and reviewing all other "1" 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 proparation and review of procedure revisions.

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DIABLO CANYON UNIT 2	0 5 0 0 3 2 3 91 -0	013-010	2 104 8

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 (SP)(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.

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 8 (BE)(BP)(RVR)(V) and both containment spray (CS) pumps (BE)(P) were inoperable. RHR Valves 8982A and 8 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 coth of these instances, Unit 2 entered Technical Specification (TS) 3.0.3. In the first event, which occurred at 0535 PDT, Unit 2 entered 15 3.0.3 because the RHR Valves B982A 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 30.72(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

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	Surveillance Requir RMR Valves 8982A an (84) removed in Mod	d B be close	d with ;	5.2. Dower t	TS 4.5 o the	i.2 requi valve op	res that erators	
	There are two metho power to the RHR va of series contactor switches are locate room. Closing of t rapid restoration o are required.	Tve operator s (MCTR) 42- d on the ver he series co	s. 1'e 8982A an tiral ci ntactori	first nd B. ontrol s from	methor Series board the co	i require s contact in the c ontrol ro	s openin or (pgg) ontrol om permi	ng le its
	The second method r (BKR) locally. If be dispatched to cl 480V breakers is th after reaching Mode	the RHR valv ose the 480V me method for	es must breake	be opers. Op	erated ening	, an oper the valv	ator mu e operat	st tor
	Safety Evaluation F capability exist to control room. FSAI valves that must hi requirement is imp "Routine Shift Chec once every 12 hour contactors 42-8982/	o restore pow Cupdate Tables two power res Lemented by S Cks Required S, valves 898	er to t e 6.3-1 torable urveill by Lice i2A and	hese v 2 list from ance Ti nses."	alve o s valv the co est Pr STP	perators es 8982A rtrol roc ocedure (I-1A requ	from the and B a m. Thi STP) 1- tires th	s s 1A, at
	OP L-5 was revised revision was inser open the 480V valv Mode 4. Therefore TS 3.5.3.d, TS 3.6	ting Step 6.3 e operator be , OP 1-5 did	1.2, whi eakers not mee	ch req while t the	uired the pl requir	operators ant was s ements of	to loc till in	
	On September 1, 19 OP L-5 was perform	91, at 0535 (ed.	PDT, whi	le in	Mode 4	, Step 6	3.2 of	
	Previous Events: R	HR Valves 890	82A and	8				
	A review of operat indicated that the have had their cir previous occasions	RHR Valves I cuit breaker	8982A ar	d B fr	on the	contain	ment sua	(p)
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2. The root cause for Event 2. CS pumps being made inoperable in Mode 4, is personnel error, inattention to detail by the Senior

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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-S, and the operator issued the clearance prior to reaching that procedure step.

C. Contributory Cause:

The practice of pre-approving clearances for the refueling cutage contributed to Event 2. If the on-shift foreman had been asked th approve the clearance for deenergizing the CS pumps just before the clearance was processed, the request would have been rejected based on TS requirements.

Event 1: TS 3.5.3.d and TS 3.6.2.1 require an operable flow path capat's of taking suction from the containment sump during the recirculation phase of operation. Because the 480V breakers to the valves had been or ned locally (the series contactors were already open with closure pc." ble 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 collainment 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 Mcde 4, containment integrity would not have been compromised.

Since an operable flow path could have been established within an acceptable time eriod and containment integrity would not have been compromised. The health and safety to the public were not adversely affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

 Events 1 and 2: The RHP volves and CS pumps were restored to an operable condition.

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IV. Anat is he Event

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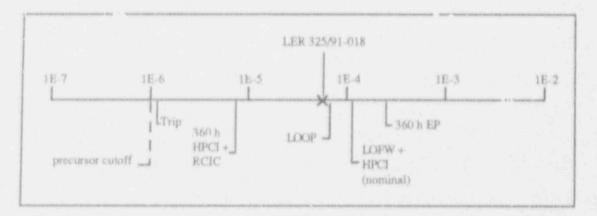
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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 x 10⁻⁵. The r, ative significance of this event compared to other postulated events at Brunswick is from 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 acturted 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-ofcoolant 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 inor trable 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 sauck-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.

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Dominant core damage sequence for LER 325/91-018

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BRANCH FREQUENCIES/PROBABILITIES

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On July 18. 1991. Unit 1 reactor was at 100% power when it acrammed as the result of a Main Steam Line Isolation signal, inadvertently generated during surveillance IMST-RSDP-210 for reactor water level transmitter B21-LT-N0268, 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.

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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-714 was almost complete and the reactor vessel level transmitter E21-LT-N026B was being returned to service. The level transmitter 821-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-NC26B-4 resulted in the pressure transient on the common instrument variable leg header, whose instruments feed both reactor protection divisions.

The 1-B21-LT-NO26B 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 'ransmitter 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 1 isolation command closed the Outboard Reactor water Cleanup Isolation Valve. The following : stems received start commands: CS. HPCI, RCIC, and the four EDC'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 Belief Valves operated as designed to control reactor pressure PCIS isolations and ECCS initiations occurred as designed.

Additional problems identified during the ever were:

A limit switch problem on the outboard MSIV 1-821-F0268 resulted in dual indication for two and one-half minutes after its closure.

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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 roct value closure.

6) 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 lets 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 $1/\sqrt{27/91}$)

6) Review the Scram event with appropriate instrumentation and Control (16C) personnel prior to the next performance of the $1/2\rm MST-RSDP21Q$ (Due 8/22/91)

7) Review industry data related to the instrument valve leakage during similar events. (Due 9/76/91)

8) Unit 2's B21-LT-ND26E values will be inspected for leaks during the next scheduled outsge. (Due 11/27/91)

9) Aring the next refueling outages the seven other 3-inch Anchor-Darling doubly-disc gate values 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 s-inch doubledisc gate values 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 metry of the four disc guides removed (to prevent possible foreign-object damage within the system), and the open limit switch reset to 6.4 so as to sold the degraded guide area where jauming 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 NFC1 oil pressure gauge has been isolated and placed under clearance pending replacement

EAFETY ASSESSMENT

The instrument header pressure transient event posed minimal safety significance since all systems performed : wir safety related functions.

The HPCI oil leak was of minimal safety significance as the 60 minutes between the sime the alarm would have come in and the system shutdown would have been adequate for Operations to prevent loss of the system by in estigating the cause and closing the gauge isolation valve. If the HPCI from had been inaccessible, HPCI would have been lost after approximately I hour and 20 minutes. As HPCI is a single train system and is not single failure proof the availability of the outomatic Depressurization System (ADS) with the low pressure ECOS extens would have assured adequate mafe shutdown capability for this failure mode. This failure is actually less significant than most HPCI failure modes in that 1' would allow significant HPCI operation prior to the actual loss of the system.

ARE FORM WAR LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			APPROVED DWE HILL STOCKTON EXPLAND, 42000 TETTINATED NUTLER IN THE RESIDENCE OF DECEMBER, VIETTIN, 1980 APPROVED THE RESIDENCE OF DECEMBER OF DECEMBER, VIETTIN, 1950 APPROVED THE STOCKTON TO THE RESIDENCE AND REPORTS MANAGEMENT DEMANDED TO THE RESIDENCE AND REPORTS MANAGEMENT DEMANDED TO THE RESIDENCE AND REPORTS MANAGEMENT DEMANDED TO SOLUTION AND RECENT AND RESIDENCE THE RESIDENCE OF MALE STOCKTON RESIDENCE THE RESIDENCE OF MALE SOLUTIONS				
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The failure of the Main Steagling Drain Inboard Isolation Valve 1-821-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 inshifty 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 shurdown. 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. Archor Darling has been notified of the problems we are having with this valve.

PREVIOUS SIMILAR EVERTS

Other instrument perturbations have been reported under LER's $1.90\cdot006$, $2.89\cdot017$, $1.87\cdot017$, and $2.86\cdot020$

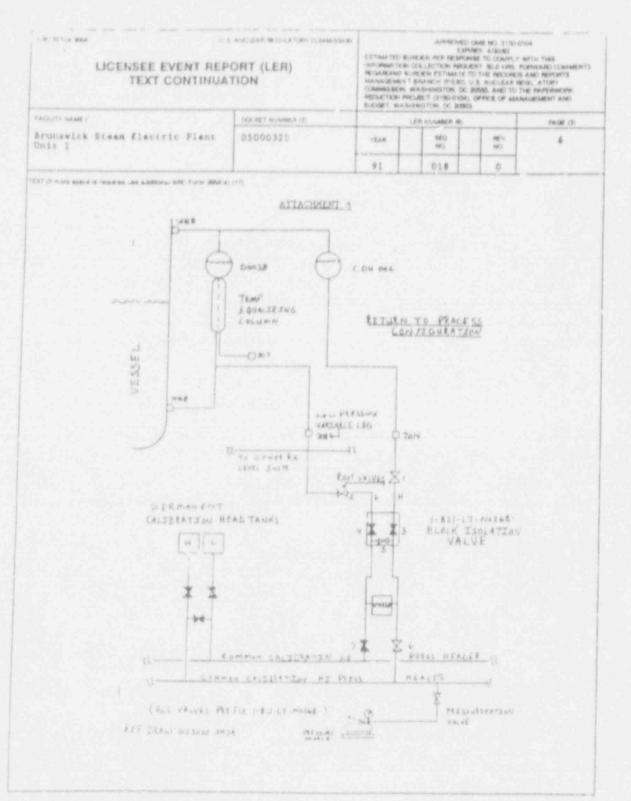
COMPONENT IDENTIFICATION

System/Component

EIIS Code

Primary Concainment Isolation Sy - r	38
Righ Pressure Coulant Intertion	8.1
Reactor Protection System	3.6
"mergency Diesel Generator	1.8
reactor Gore Isolstion Cooling System	BN
Residual Heat Removal/Low Pressure Coolant Intection	80
Core Spray	BM
Standby Gas Treatment System	2H */EV
Safety Relief Valve	- (B. V

* No EIIS System Identifier Found



ACCIDENT J"QUENCE PRECURSOR PROGRAM EVENT ANALYSIS

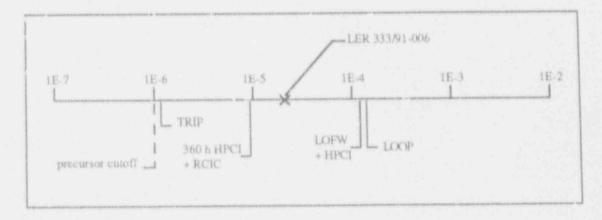
LEK No.:	333/91-006
Event Description:	Trip with both LPCI trains inoperable
Date of Event:	May 7, 1991
Plant:	Fitzpatrick

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 scattured 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, o ened 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/I PCI 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 sut. 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 rectared.

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 lowpressure 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.

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Dominant core damage sequence for LER 333/91-006

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CONDITIONAL ORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/91-006 Event Description: Trip with both LPCI trains and one RHE tr Event Dete: 05/07/91 Plant: Fitzpetrick	ain unaveilable
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NON-RECOVERABLE INITIATING EVENT PROMABILITIES	
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SEQUENCE CONDITIONAL PROBABILITIES (REQUENCE ORDER)

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Event Identifier: 333/91-006

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Description

NAT FORM BOLD

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 Testo. 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 19MOV-25A valve. RHR header pressure upstream of 10MOV-27A increased wish the space between 10MoV-"7A and 10MoV-25A was pressurized. These clservations indicated that or board 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.J.a. Performance of ST-2B on the RHR LPCI loop A was necessarily suspended.

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At 4:45 A.M., while perform normally closed LPCI inboar open fully and then failed switch tripped the power su completion of attempts to b were also unable to operate because ? e motor operator Both the A and B loops of t an inoperable condition due Technical Specification 3.5	d injection gate to fully close. upply to the oper both open and clo the valve using could not be man the LPCI mode of to one inoperab 5.A.6 requires th	valve 1 The mot ator mot se the valve the RHR ie valve at the	IOMOV-2 for ope for privalve. hual has aclutch system e in eactor	5B fai arator opera indwhee bed. a were ach loo r be p	now	in in
a cold condition within 24 inoperable. At 12:37 P.M. a reactor shu	hours whenever b utdown to the col	oth LPC	tion v	ystems as sta	are rted	
The emergency plan was init was notified by use of the 12:55 F.M. The main general transmission system (line) procedures, the reactor was approximately 15 percent p the shutdown cooling mode coolant temperature of les condition) was achieved at terminated at 4:00 A.M.	emergency notifi ator was disconne at 5:45 P.M. Ir s manually scram owel. RHR syster at 2:56 A.M. on P s than 212 degree 3:30 A.M. The N	cation acted fr accord and at 6 a A was May 8, 1 as fahre Unusual	system om the ance w :20 P. placed 991. nheit Event	(ENS) elect ith M. fro in se A reac (cold was fo	at rica m rvic tor rmal	l e in ly
At 9:55 A.M. a test determ of angle globe valve 10MOV minute (gpm). The RHR A 1 cooling to remove decay he 10MOV-25B. On May 12th at LPCI inboard injection gat	-27A was approximop continued to the second state of the second st	mately 5 be used tem nut s and po	,100 g for s was fo st-wor	allons hutdow und or k test	n	
Shutdown cooling was then loop at 1410 to permit inv valve 10MOV-27A. Inspecti 10MOV-27A found fracture of seat, disc, and disc guide from the system to facilit As of the date of this rep repairs are in progress.	vestigation of th lon of the intern of the valve stem e ribs. It was n tate internal mac	e seat 1 als of 4 and sev ecessary hining 4	leakage ingle g /ere da / to re ind wel	in R) lobe mage move ding	(R A valva to th the v repair	loop ne valve irs.
Cause						
Valve 10MOV-25B failed to force required to move the torque switch. This switc accordance with design. excessive friction between stem nut and the moving va	e valve stem whic ch then interrupt The cause of the n the mating acme	h in tu ed the excessi screw	rn trij motor j ve tori thread	pped t power que wa s of t	he m supp s he f	otor ly in ixed

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of the 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 is 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 step 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 pursonnel 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 (ICMOV-27) was added to the list of designated primary containment isolation valves. Both (cne 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 -37) are designated in each loop. One of there two valves remained operable in each of the two loops. Therefore, a double valve primary containment isolation function was always available and operable.

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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 torgue switch and thermal overload protection. The fully

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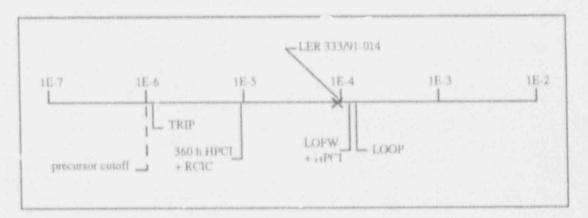
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:	333/91-014
Event Description:	Hydraulic pressure locking of two low-pressure ECCS injection
	valves
Date of Event:	August 5, 1991
Plant:	Fitznatrick

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 these, 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 hydraclic 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:

- Water trapped in the valve bonnet "expands" as a result of heating during normal plant start-up.
- Water trapped in the valve bonnet "expands" as a result of heating during a postulated high-energy line break.
- One side 2, 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 i is analysis.

In the RHR and CS systems there are testable check values between the reactor and the normally closed ist. alon values. Leakage part the check values will eventually place teactor 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 values following vessel depressuration 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 values shut.

After the valves lock shut, there is a finite period of time before the bonnet predecays to a level less than the maximum bonnet pressure the valve actuate to open the valve. This period of time depends on the leaver a of the broad of the disk seating surface the valve size, and the different tessure Lower bounet leak rates where esult in longer periods that the five will consider any of the shut position. Consider any of time period from LOCA initiation until the low-pressure ECCS injection valves the 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 'wo 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 use 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 intra-al between precursor reports), a l-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 LPC₁ values. It is possible that the value bonnets would depressurize prior to the need for these values 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 x 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 x 10⁻⁴ * [1.0 * 0.15 + 2.0 x 10⁻³] = 1.5 x 10⁻⁵.

A second sensitivity analysis was performed assuming all four ECCS valves were failed.

Analysis Lesults

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 smallbre is 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 values 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 s_{1} iences 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 x 10⁻⁵, about half of the nominal co. The one probability estimated for the event.

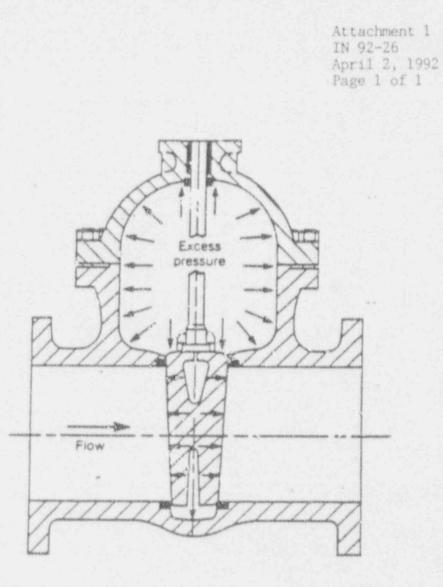
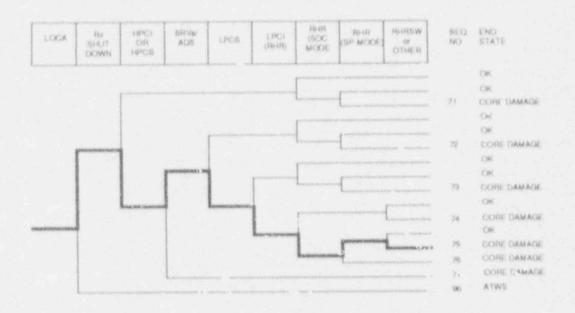


Figure 1. Hydraulic pressure locking phenomenon



Dominant fore damage sequence for LER 333/91-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

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1,05-01

Rount Identifier; Event Description; Vent Dete: Plant;	333/91-014 Low preseurs £COS valve hydrau 08/05/91 Fitspetrick	lically locked (LPCI failed)	
UNAVAILABILITY, DU	RATIL8- 6132		
RON-RECOVERABLE IN	TTIATING EVENY PROBABILITIES		
TYANS LIXIP LOCA		2.(E+50 3.6E-02 1.0E-02	
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End State/Ini	Liator	Probability	
TRANS LOOP LOCA		7,68-05 1,285-05 3,28-05	
Total		8,32-05	
ATWS.			
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Total		0.08+00	
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	Sequence	End State	Prob
/lpci -RHR(3	itdown hpc1 sev.ads LPCS LPC PCDOL)/LPC1,RNR,SDC1 RHESW		3,05-05
11 Liana -re,ar -fe/pos.trar	utdown pos/liana arw.chall/tr d RRR(SDC) zhr(spoudi)/zhr(sp	anaseram -srv.close CD	2.76-05
	When a start where drawn were and the		

loop samerg.power srx.shutdown srv.chall/loop.sc.am srv.cloae CD 7.38-06 4,18-02 loop *nmerg.power *rx.shutdown arv.chall/loop.*ac.am *arv.cloae CD
*hpci RHR'S*Ci rhr(spcool)/rhr(sdc)
lrana *rx.shutdown pcs/trans arv.chall/trans.*scram *srv.cloae CD
fw/pcs.trans *hpci RHP(SDC) rhr(spcool)/rhr(sdc)
loop *emerg.power *rx.shutdown arv.chall/loop.*acram srv.close CD
bpci *arv.ads LPCF _PCI(FHR)/LPCS rhr(sdc)/lpci *RHR(SPCOOL)/
LPC*_RHR(sDC) RHRSN 3.08-06 3.98-62 3.78-06 2.58-01 LPCT.RHR(SDC) RHRSN trans -rx.shutdown pos/tr-us srv.chall/trans.-scram srv.close CD fw/pcs.trans Apci -srv.ads LPCS LPCY(sHR)/LPCS rhr(sdc)/lpci -RHR(SPCOOL)/LPTI.RHR(SDC) RHRSM loca -rx.shutdown -hpci RHR/SDC) vhr(spcool)/rhr(sdc) vb trans x.shutdow pcs/trans rv.chall/rrans.-scram srv.close CD -fw/pos.trans RHR(SDC) rhr(spcool)/rhr(sdc) 26 2.5E-06 2.48-01

2,28-96 5.72-02 1.08-06 . DE-01

** non-recovery credit for edited mase

REQUENCE CONDITIONAL PROMABILITIES (SEQUENCE ORDER)

Event Identifier: 333/91-014

16 4 1

	Seguance	Frid State	Frob	B BEC**
-11	Lyana -rw.sh-idown pos/lyang sry.chall/transmo.sm -miw.close -fw/ges.tyany BHRIEDC1 fhr(specc1)/threadc)		2.78-05	1.08-01
53	trana -ra.eNudown pca/itais atv.chall/tranasCram -stv.closs fw/pcs.trana -hpc1 BHR(SDC) rhr(spcol)/rhr(sdc)		5,08-06	3,96-02
33	trans -rx,shutdown pus/trans siv.chall/transsuram siv.cluse -fx/pus.trans RAR(SDC) rhr(spccoll/thr(sdc)	CD.	1,08-06	1.08-01
26	Trans -rx.shutdown pos/trans arv.chall/transscram srv.close fw/pos.trans npmi -srv.ada LPCS LPCI(BHR)/LPCS chrisdol/lpci		8.56-0.6	2-45-01
40	-RHR(SPCCOC)/LPCI_RHR(SDC) RHRSW loop -omerg.power -rs.shutdown arv.chall/loopscram -srv.closs		7.,38-94	4,18-02
53	-hpcl RHR(SOC1 :rhr(spcool)/thr(add) loop -emerg.power =rx.shuldews arv.chall/loop +cram arv.close hpcl =arv.ads LPCU LPCI(RHC)/LPCS rhi(add)/lpci =RHR(SPCOOL)/		3.78-96	2.52-01
	LPC1,RHR(SDC) RH' : loca -rs,shutdown -npc1 RHR(SDC) thr(speck1)/thr(sdc)		2.20-04	5.78-02
	lous -rw.ebutdown hpc1 -arv.ads LPCS LFCI(RNR)/LP'S chr(sdc)	CD	3,08-05	3.56-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the auded 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:	- ci/asp/:	1989	Incineal.	comp.
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PROBABILITY FILE:	ci/sab/	1989	ther call.	pro.

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BRANCH FREQUENCIES/PROBABILITIES

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106a	3,35-06	5,02+01	
rg.ahuldown	3.05-05	1.0R+0.	
tx,shutdown/ep	3.58904	308400	
pos/trans	1.35001	1.08.400	
arv.chali/transaccam	1.05+00	1.02+00	
arv.chall/loop.~scram	1,08+00	1,091+00	
ary.close	3,68-62		
emerg.power	2,98-03	8,0E-01	
10.19C	1,68+01	1,02+00	
fw/phaitsana	4.68-01	3.42-01	
fw/pcs.loca	1,05+00	3.4R-61	
hps.1	2.98-02		
relo	6.02-02	7.02×01	
ord	1.08-02	1.04 00	1.05-62
srv.ada	3.78-03	7,18-01	
LPCS	3.0E-03 = 1.5E-01	3.46+01 > 1.06+00	
Branch Model: 1.0F.2			
Train 1 Cond Prob:	3.08-02 > 3.08+01		
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LPCI(RHR)/LPCS	1.06-03 5 1.08400	7,1E-01 x 1,0E+00	
Bearich Model 1.08'.2		ATTRACT AND ADDRESS AND ADDRESS ADDRES	
Train 1 Cond Prob:	1,00-02 > Failed		
Train 2 Cond Probi	1.0E-01 > Failed	and and the second s	
RIGR (SDC)	2,18-02 0 1,08+00	3.48-01	

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Event Identifier: 333/91-014

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Rianch Hodel: 3.06,2+aeroo Train) Cond From Train 2 Cond Probi Serial Component Frobi rhr(HuC)/~ipcl	03 3.0E-03 > Failed 3.0E-01 > Failed 2.0E-02 2.0E-02	3,46=01	1.08-01
the index / ipcl	1.08+00	1.02+00	1,08-03
thr (specal) / thr (sdc)	2,02-03	3,48-01	
thr (specel) / lpc1, thr (sdc)	2,08-03	3.4E-01	
NAME (SPC(XOL) / LPCI, RMR (SDC)	9,3%~\$2 > 2,08~03	1.05*00	
Branch Model: 1,0F.1			
Train 1 Cond Prob:	R.3E-02 > 2.0E-03		
风行方展	2.05-02 > 1.01+00	3.4E-01 > 1.0E+00	2,08-63
Branch Model: 3.08.1+opt			
Tieln 1 Cond Prob:	2.0E-02 > Falted		

* Dranch model fils ** forced

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	and repay valv of t at 1 detected to t	uly ven irs /e, the lock ugu irmi s sp this	17, ting to the Lim ed-n st ned ray fa	th in ito fot fot in ilu	991 he boa rqu or 199 be boa re	wi Resoutb ird cur i hy ird mec	th th idual oard LPCI MB-4 rent. he ro draul injec hanis	Heat Low Pr inject actuat ot cau ic loc tion v m. Al	t shut Remova ossure ion va or mot se of king o alves l four re sid	1 (RH Cool lve f or wa the a f the were valv	R) (BC ant Ir ailed s due ctuato valve detern es wen)] s ijec to to or r s bo nine	open open sust notor onnet ed to nodif	e f (L ain fa	ollow PCI) The f ed op ilure Both sust	(10g (BO) 'ailur berati a was LPCI ceptik	and
NUC Pac		7/0	09	11	01	38	}										

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LICENSEE EVI	ENT REPORT (LER) TEXT C	ONTINUATI	ON				FROVED C	NKE NO.		
UTY RAME IS	DOC.417 06.00075 (8)			-		82	TIRES 8/3	1.000		
JAMES A. FITZPATRICK	DOKA (1 RUNSET S I)				NAMES # 1				6-86 (3	8
		78.A	-	-1-	BURNAR	-	PHY ROA		11	
SUCLEAR POWER FLANT	0 5 0 0 0	11111 91	1.	10	11 1 3	-	010	112	OF	
T matrix stronge is responsed, say autofiliations $HP^{(*)}_{-}$. Appendix $HS_{+}(\eta_{1})$:	n anna ann an an an an an an an Anna Ann M	inder de la deservation de la deservat	-	and in	chicks	-	hindrein		Link	
EIIS Codes are in []										
Description										
The plant was shutdow primary contairment i Residual Heat Kemoval [BO] subsystems was f	isolation valves in 1 (RHR) [BO] Low Pr	each of	t 00	hela	two nt I	ir nj:	ndep: actic	ende on (nt LPC	:I)
On July 17, 1991, fol actuator problems with hydrostatic test of to outboard (10MOV-27B) hydrostatic test press test, the piping betw the system was initial service in the s'utdo	th the outboard LPG the piping between LPCI injection val ssure was 2100 +/-2 ween valves was dep ated in preparation	T inject the inbo lves was 15 psig. pressuri:	pe U	n d rf po	valv (10M orme n co A f	e, ov d. mp il	a -25B Thi leti l an) an e on c d ve	f t nt	
Approximately 9 to 10 had been filled to th attempted to open the the control room (non actuator remained end the motor actuator c	he inboard LPCI in e 24-inch flex wed rmal stroke time ap ergized for approx	jection ge gate poroxima lwately	val val tel	ve ve y	(10 120	he MC se	ope V-25 cond	rato B) 1 s).	rs ror Tł	s he
On August 5, 1991 an susceptibility of ctl completed. It detern shared by the LPCI is injection valves of could potentially pr Cooling System (ECCS the event was determ	her components to mined that the cau nboard valves in b the Core Spray (CS event the operatic) low pressure inj	the fail se was a oth locp) (BO) s h of all sction s	de de s a yst f ubs	a m asi and tem our sys	gn j gn j bot . 2 Emi	ni ch Che arg	sm w blem inbo pro ency	tha ard bler Cor	a. te	
Cause of Event										
On July 28, 1991, to the valve wedge disc performed to reertab of the July 17th Fyd performed whils a st As test pressure inc came from the affect strass on the valve the most dramatic ch the rate of pressuri 30 minutes, indicati test pressure of 210 Thirty minutes after	s resulted in moto lish the condition rostatic test. An rain gauge on the reased to 500 paig ad valve. At the stem diopped from ange during the te ration dropped to ng compression of 0 paig was held fo	r failur s that e other hy yoke of , it was same tim 62,000 t st. At zero for air in t r 10 min	e, xir th r, 85 a het	a epti i2 ppi er	spe ad a tati valve orten orten orten orten orten alve and	te te te te te te te te te te te te te t	l te est as m hat comp of. st p hat st p hat st p hat st p	st mpl was oni sou res Thi pres	ras eti tor nds siv sur Tar	on ed as e, ge

LICENSEE EVENT REPO	ORT (LER) TEXY CONTI		E RUCLEAR REGULATORY ODORODOD APPROVED OWN NO 3180-8104 EXTURES 201000
IN THE REPORT OF A DESCRIPTION OF A DESC	0006.0.41 HELENGER (2)	1.69 10.00050 1	e Fa52 (8
JAMES A. FIT, PATRICK		78-54 589 (L. 25-7) L 174/1428	the second se
NUCLEAR POWER PLANY	0 16 10 10 10 18 14	1 911 -01114	
RT of among special in recovering, one publishment calls, Herein ambit to 1721	and a set of the set of	Contraction and a starting of the	and and a star for the sector of the sector
valve from the control root locked-rotor current and th electrician monitoring line the stem packing gland and depressurization, valve por changed from closed to inte from the control room.	he circuit break e current. The air escapod. C sition indicatio	er was manual bonnet was ve coincident with on in the cont	lly opened by an inted through th the bonnet trol room
The root cause of the sust subsequent failure of the trapped between the wedges susceptible to hydrostatic	Limitorque SMB-4 of a flex wedge	actuator mo	tor was pressure
Analysis of Event			
The potential loss of abil inboard infection valves t reported under the provisi event where a single cause inoperative in a system des	o provide core to ons of 10 CFR 50 isulted in two	flooding capa 5.73(a)(2)(vi 5 independent	bility is i)(B) as an trains becomin
TY: RHR system is capable (e.g., shutdown cooling, 1 system consists of two ind a heat exchanger, and the accommodate each design fu was the S loop inboard (to inboard valve is a normall gate valve. The design di inboard injection valve su	ow pressure ECC ependent loops, associated valv notion. The va ward concainmen y closed, live- fferential pres	5, containmen each comprise as and piping lve involved t) LPCI inject loas packed, sure against	t cooling). Th ed of two rumps necessary to in this event tion valve. Th 24" flex-wedge
Following the determinatio pressure locking of the va consultant to determine th gate valves. Thrue scenar	lve, calculation impact on oth	ns were perfo er motor open	rmed by a ated, flex wedg
 Water trapped in heating during n 	h the valve bonn hormal plant sta	et "expands" rt-up.	as a result of
 Water trapped in heating during a 			
 One side of the valve leakage ar a loss of coolar 	nd then suddenly		
The analysis eliminated th (scenarios 1 and 2) as a c source (reactor) and peak HELB.	concern based up	or distance	from the heat

UCENSEE EVENT R	EPORT (LER) TEXT CONTIN	UATION APPROVED C	NAN BALL JIND - BING.
ACIUTY MARS ()	SHOKAST HUMBER (2)	LER HUMMERS IS INS	P.S.B.1 (2)
JAMES A. FITZPATRICE	And the second second	Teas Iscouter as Person	
FURLERS POWER PLANT	0 18 10 10 10 13 13 1	, 911 _ 011 4 _ 010	\$14 OF \$ 13

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 mide of the flex wedge disc. The wedge will then flex, allowing reactor pressure into the bonnet. Pressures on the order of 1,000 pmig could become trapped in the bonnets of all four low pressure ECCS injection valves (FHR and Corn Spray mystems) following vessel depressurization during a LOCA. Calculations taking into account the installed actuator mize and past Locar Leak Rate Test (LLRT, data showed that bonnet pressures in the range of 600 to 700 pmig would be sufficient to lock the affected valves shut, preventing low pressure ECCS injection.

After the values lock shut, there is a finite period of time where the bonnet pressure decays to a level less than the maximum bonnet pressure the value actuator can overcome to open the value. 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 'eak rate test data. Lower leak rates will result in longer periods that the value will be locked in the shut position. Considering the time period from LOCA initiation until the ECCS injection values receive their open signal, the analysis conservatively estimated that the pressure within the bonnets of two out of four low pressure ECCS injection values would have decayed within the capability of the value actuator. If the values had had extremely low local leak rates, there could have been no low pressure ECC3 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 plint start-up, to incorporate a bonnet went to the high pressure side of the valve.

Long-term corrective actions will be the following:

- 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.

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NUCLEAR POWER PLANY	0 6 0 8 0 3 3 3 3	911			015 00	
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Additional information						
Component: Component Identification: System: Functio : IEEE Function: NFRDS Component Code: Manufacturer: NFRDS Vendor Code: Model: Type: Sile: Pressire Motor Operator Type:	Flex Wedge Gate 10MOV-25A/B RHR LPCI Inboa d Inject Isolation INV & ISV VALVE POWELL PJ05 1902JWE Flex Wedge Gat 24-Inch 900 psig Limitorque SMB old style with	ion i e -4T	6 Prit	ary Cont	ainme	nt
Component: Component Identification: System: Function:	Design No Long Flex Wedge Gat 14MOV-12A/B Come Spray Inboard Inject	e Va	ive, M	otor Op	erated	
IEEE Function: NPRDS Component Code: Manufacturer: NPRDS Vendor Code: Model: Type: Size: Fressuro Motor Operator Type:	Containment Is INV and ISV VALVE VELAN V080 B16-2A5PS-24TS Flex Wedge Gat 10-Inch 900 psig Limitorque SMI	olat s				

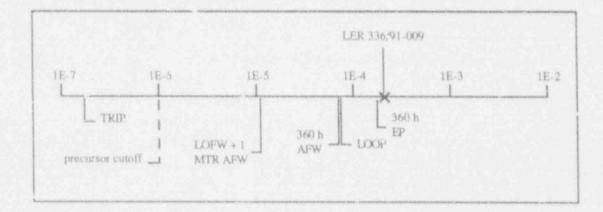
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 336/91-009 Both diesel generators unavailable and unit shutdown August 21, 1991 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 w.co., 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

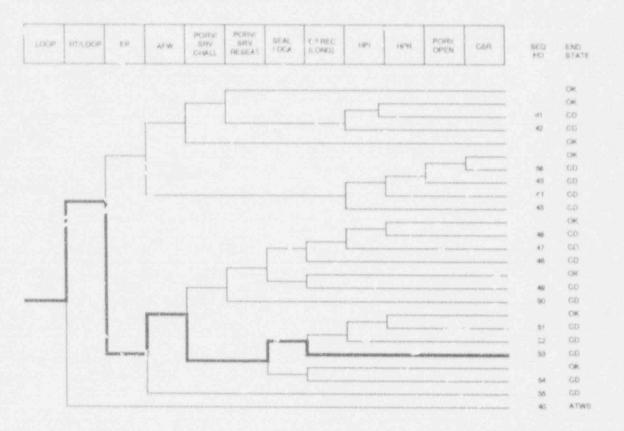
The Millstone 2 safety-related AC power system consists of two 4.16-kV buses, each supplied by an EDG rated at 2750 kW continuous duty. Each bus provides power to one service water pump, auxiliary reedwater pump, reactor building closed cooling water pump, high- and low-pressure safety injection pump, 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

B-341

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 336/01-009 Event Description: Both disast generators unavailable and unit shu Event Date: 08/21/91 Plant: Nillstone 2	tdo v
UNAVAILABILITY, CURATION- 360	
NOK-RECOVERABLE INITIATING EVENT PROBABILITIES	
12009	2,18-03
SEQUENCE CONSISTIONAL PROBABILITY SUMS	
End State/Infflator	Frobs Liney
a	
1.200	2.1.6-04
20tal	v.18+94
8.7W5	
1.000	0.06+00
15:41	0.08+00

REQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence		End State	Prob	S Rec**
the second se	op EMERG.POWER ~afw/ererg.powe	r spore.or.srv.chall	¢D.	9.35+05),3E-01
seal.loca 54 loop -rt/lo	ep.rec(#1) op EMEPG.PO.UN ~afw/emerg.powe	r -porv.or.srv.chall -		7,76-05	3,38-01
55 loop -rt, lo	ep.son op EMERG.POWER atw/emerg.powe	£	CD	3.68-05	1,18*01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROMABILITIES (SEQUENCE ORDER)

	Requence	End State	Prob	A Nec**
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.frv.ohall	CD	9,38-05	3,38-01
54	<pre>seal.loon ef rec(s)) loon =rt/loop EMERG.POMER =afw/emerg.power =porv.or.srv.chail =</pre>	-00	7.,78-05	3,38-01
55	meal.loca eD.rec loop ~rt/loop EMERG.POWeR afw/emerg.power	639	3,62+05	1,18-01

** non-recovery medit for edited cavi

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to follower >-sociated with an event. Parenthetical values indicate a reduction in *1sk compared to a aimilar perior without the existing failures.

SEDCENCE	MODELS	0.1	samp\1	98.93	DWK!	[Heal]	, 45 H B B
BRANCH E	206.5.1		(das/)	98.9	811	LathZ.	15.21
PROBABIL	ITY FILES	117	(asp))	989	DWT.	Bash	pro

Event Identifier: 336 91-009

B-342

No Recovery Unit

BRANCH PREQUENCIES/PROBABILITIES

Branch	System.	Non-Recov	Opt Fall
trans	4.08-04	1.06+00	
	1,85-05	3.32-01	
	2.42.006	4,38-01	
	2.80-04		
rt/160p	0.02.+00	1,01+00	
CREWE . FOWER	2,9E-03 > 1.02.00	8.02-01 > 1.02+00	
Branch Hodel: 1.OF.2			
Train) Cond Fruits	5.08-02 > Failed		
Train P. Cond Proby	5,77-02 > Failed		
atu	3.85-04	2,42-03	
afw/amerg.powar	5.08-02	3,40×01	
int w	Z.0E-01	3.48-01	
porv.or.arv.chall	2.08-02	1,07+00	
DOLV.OL.STV. FWRWAL	2,08-02	1.16-03	
porvior.ary.tesent/emerg.power -		1.0R+00	
seal.lona	6.02-02	1.02.00	
epress(al)	7,68+01		
WPL, KMC	4,05-02		
	5.0E-03	8,48-01	
hpi (17/k)	1,08-60	8,41-01	
DOTAL OPEN			4.38-04
hpr/shpi	1.5E-04	1.05+00	
CBE	2,56-03	3,42-01	
* branch model file			

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Event Idontifier: 336/91-009

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On August 21 control, while surveillance in the 13U unit Generator (D) reparalleled to that time.	being o in 1 h was out (G), the reload	operated diesel of serv operat the 12	i in p gene nice fi or op U D/	naraliel trator w or mau sened t 'G, but	with offsite on as being run t itenance. On he output brea errauc speed	cuits at o verify noung iker to control	2100 to op the err ternovi caused	KW load, erability w auc icsd s e the load t load swin	at the en hile 30 re wings on The get gs that p	d of dund the the the teven	tto one lant de 12U D or was ited re	e hos esel iesel ther load	ii geneti ng at	8107
With both em 13U D/G mai 1 and ½ hou	ntenant	e was a	iompi	leted a	ind the operat		the 13	U D/G wa	s de mons	trate	d saus	(açto	W YET	
signals with a with Technica of an operabi The second I	ddiciona il Specii lity tun MG was comuni comuni comuni	I instru fication on 8/2 declars theed u in at 1	menu requi 3/91 ed mi s acc 410 h	ation. itemenv at 05 operabl ordans hours u	is for one D/C bouts, the 1 e as a tends o e with Technis n 8/24/91, and	v of the being 30 D/3 if the re cal Speci 1 verifie	r 13U out of i outpu sverse shicasie id com	D/G was ser- ce - 1 n breaker power bip in Action pliance wi	periodical lowever, opened o and a un Statement h the act	dv ve duru n a t u do 1.3 B tor t	rified ng the revense wripos 1.1(d satems	in as perfi pov ver t) T ents (icorda ormar ret im 6 colt he ut of	ance nce ip

	LICENSEE EVENT REPORT (L TEXT CONTINUATION Millstone Nuclear Power Station Unit 2 mine state 4 minute use seminore NMC from bear Description of Event		Elson-arten der nersonnen ter ostennen verlich mit intermanisten sometichen resulter 800 Pins Forward continuents regelting berucen Astrinate Inter Nersonau eine Regelting berucen astrinate internet in-500 Pillis and a trei Regelting formen internet in-500 Pillis and a trei Regelting formen internet in-500 Pillis billisten and Kanagemeinen and bergelt Washington DC 20603 IEE Internet in Bergelting formen internet VEAN BECKERNISE INTERNET VEAN BECKERNISE INTERNET
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12.1	Description of Event	With the second second	dahatan kadén kadén kadén dén dén dén dén dén dén dén dén dén
	estatic load control, while being opera us one hour surveillance run. The fu- reduction diesel generator, the 13U a swings on the 12U Diesel Cenerator I The generator was then reparalleled to that prevented reloading at that time	ted in parallel with off esel generator was bein mit was out of service D/G), the operator ope Freidad the 12U D/G.	ower, the 12U diesel generator exhibited site circuits at 2190 KW load, at the end of g run to verify its operability while its for maintenance. On noting the erratic load med the output breaker to remove the load but erratic speed control caused load swings
	With both emergency D/Gs out of serv of the L3U D/G was demonstrated sati compliance with Technical Specificauo	stacionly within 1 and	
	control signals with additional in trume in accordance with Technical Specifica during the performance of an operabili opened on a reverse power trip. The power trip and a unit downpower to co	mation. The uperabilition requirements for a ty run on 8/23/91 at 0 second D/G was declar ild shutdown was romm (d) The unit reached i statements of Tech, at	cold shutdown at 1419 hours on 8/24/91, - tal Specifications 3.8 1.2 h (no core
	Cause of Eyeni		
	The cause of the load swings was interruling in the governor system of each D/s		oodward Governor EC+A electronic control
	Root Cause		
	Troubleshoosing was performed on bost to be errauc operation of the EG-A un		mor systems, which revealed the root cause
	The 13U D/Gs EG-A unit input and or loaded condition while paralleled with c signal was recorded as making a corresp	to grid. During observ	red load oscillations the EG A output
	changes. The "droop pot" should not i change in resistance in the "droup pot"	thange in resistance or will cause large load s	ntiometer as having large resistance value, ice an initial setting has been made. A wrigs, either positive or negative, while the the data obtained identifies the root cause
	The "droop por" is out of the circuit with this is failure or entatic operation would		on-parallel or "isochronous" mode, and vergency operation of the D/Os
	The EG-A and EGB-10C units from the factory text facility. Curing testing of the observed. Unfortunatel, the voltage sw valuable information was gained.	e EO-A une, unexpia-	and EO-A output voltage swings were

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41 0 × 619 8 - 89	LICENSEE EVENT REPORT (LE TEXT CONTINUATION	R)	ARPROVED ONE NO 3150-0104 E3 PRES 400 00 Estimated burden per response to comply write this intermation concerning resources (\$15 nm; Forward commences segarating bullan estimate to the Reports an Nepons Management Branch (2+30), 25 Nuclear Regulatory Commission, Washington DC 20555 and to the Pasee wors Republic on Review 13150-0104. Chicke of Management and Buogel (Vision office) 20550			
REGIST	1487A8 (1) /	DOCKET NUMBER (2)	ER NUSABER IS FAGE S			
	Millstone Nuclear Power Station Unit 2	0 5 0 0 0 0 3 3	MARCH MARCH			
EXTIN	nore space is replined use appropria held Form 3664					
	noted Initial's this contamination wa final report the vendor concluded the Milistone. This conclusion was based acconsistency between initial Indines a	of considered as a pos- of contamination was on the lack of any sci and linal reports does	a small amount of foreign material was sible cause of the erratic operation. In the not the cause of the load swings seen at oring of internal moving parts. This not alter the facts of the abnormalities seen in of the hydraulic oil that support the root.			
	have created the load swings. Other	nems checked and ein which and Relay (UPS)	ernor control system components which could minated were. Speed setting pot (motor 7. Generator Output Potential Transformers			
	Thus, the final root cause of load swi electronic govern it unit, or contamina	ngs on both diesel gen ation of the hydraulic (erators is erratic operation of the EG-A oil, or a combination of both conditions.			
Ш.	Analysis of Exent					
	paragraph 50 $73(a)(2)(i)$, the completion of a Specifications					
	There were no salety consequences as a result of this event since at all times the tinit was in co with Technical Specifications					
	The salety significance was minimal b available had it been called upon to p power.	recause the final review provide power in an er	is show the 13U D/G would have been mergency condition involving a loss of normal			
	Conscieve Action					
The corrective action taken was to replace the governor 1 131 D/Gs. Following replacement a full lest program wa of normal power (LNP) start, with sequenced loading of mode, followed by partial and full load rejection tests, fu runs at 2100 KW			conducted that subjected both D/Gs to a loss e generator while running in the isochronous			
	To preclude oil contamination as a c directed to add steps t flush the hyd	ause of a recurrence. draulic actuator unit as	the Maintenance Department has been part of the refueling maintenance effort			
	To preclude a similar re urrence, pla systems of a newer design. Peplacer outage	nn nave been initiated ment is anticipated to t	to upgrade the D/G controls with replacement be accomplished during the 1990 refuelting			
N. 1	Additional Information					
	Similar LERa None					
	EIIS EK - Emergency on-site p 63 - Governot (diese) gen W 290 - W oodward Governot	erator)				

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UCENSEE EVENT REPORT (LER) TEXT CONTINUATION	ANALYSIC/2015 (DAB No. 21%-2016) EXPERSION (S) Only Extension and the respective of powels with first intervention because an respective of powels with first intervention because the extension of the first sector conversion and applied by termination of the first sector and first transmission of the first sector of the first sector first transmission of the first sector of the first sector first transmission of the first sector of the first sector first transmission of the first sector of the first sector first transmission of the first sector of the first sector first transmission of the first sector of the first sector first sector and the sector transmission (first 50500)
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L mi 2. 0 5 0 0	0101018 911 01010 010 011 0P 011
(x) it many angle is the one agriculture of the plane (1);	
Quier	
Previous related evolus with observed load verify on August 13, 1989, and or April 7, 1980.	the 111 D/G were based in two cases on $MP_{\rm ex}^n$ ηn
During the Fall 1989 rehiering marage the EG-A unit	was replaced on the 12C D/G
Following load swingt observed 4/3/90, the governor a for drorp and speed on the Ex18-100 accustor units	control system was checked, and as a result, settings, sets adjusted, based on vendor recommendations.
Attachment MP2 Desel Generator Governor System	

1281 - Forth 1866-6 18-46 1/ 5 RESCURAN REQULATIONS COMMASSION EXPERIENCES # 00/02 nier per response to dom plantant request to 0 h LICENSEE EVENT REPORT (LER) TEX/ CONTINUATION Andreas Andreas Andreas Andreas Andreas Andreas Andreas PAGE () EACHTCH HARAS (1) ACKET HARMER 12 ETT PRIMARY NE VER PA Millione Nuclear Power Station Unit 2 01019 0 5 0 0 0 0 0 0 0 0 1 013 OF 013 TENT IN HORE BOARD IS TRUNCAL USE ADDITIONAL TABLE FORM (MARK & ATTACHMENT MPI DIESEL GENERATOR GOVERNOR SUSTEM SKETCH EGB-10C HYDRAULIC ACTUATOR UNIT DIESEL ENGINE FUEL RACK ELECTRONIC UNIT WOODWARD OOVERNOR FAIRBANKS-MORSE

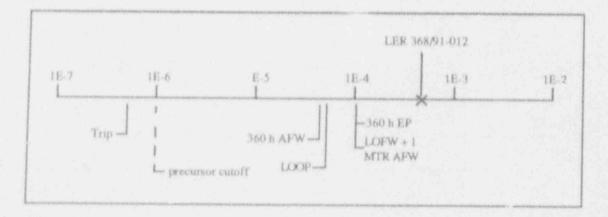
 $\begin{array}{c} \mathcal{D}_{\mathrm{s}}(\mathcal{D}) := \mathcal{D}_{\mathrm{s}}(\mathcal{D}) \\ (\tilde{K} - \tilde{K} \mathcal{D}) \end{array}$

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:368/91-012Event Description:Both normal service water trains fouled by debrisDate of Event:April 16, 1991Plant: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 scorce 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 x 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 spray, 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 safet, 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-po ver 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 4 CP 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 cil coolers, instrument and



IMAGE EVALUATION TEST TARGET (MT-3)

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service air compressors, and the reactor coolant pump (RCP) motors is assumed to result in an automatic or manual scram and loss of feat water (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 recover ... SW. This event tree is shown in Fig. 1. Successful alignment of the standby pump in the ECP was assumed to not result in a reactor tright (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 retief 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:

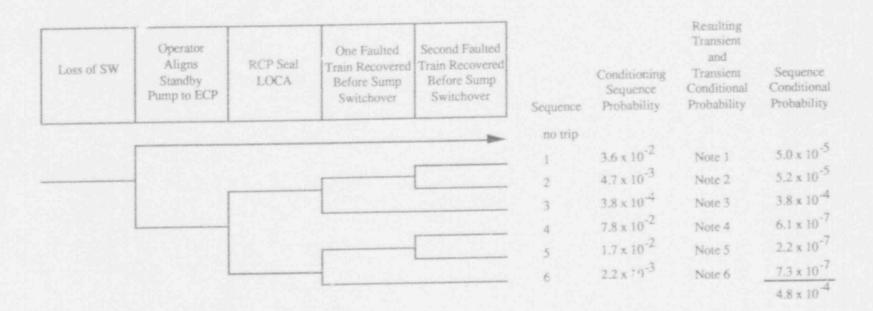
- a. The probability of the operator failing to correctly align the standby pump to the ECP was a sumed to be 0.12.
- b. The time required during the event to clean the first strainer (90 min) was assumed to consist of a 30-min preparation period and a 60-min time-to-repair after work orders were prepared, 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 $p_{1STR}(t)=e^{-.693(t/2.5)}$, 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. Beginding 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 \le similar to that used in the Accident Sequence Precursor (ASP) Program for model. 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:

 $p(seq.3) = p(opr fails to align standby pump to ECP) \times \int p_{isros}(t) \dots f_{st}(t) \times p_{isros}(t + 6|t) dt$

where $f_{SL}(t)$ is the probability density function for RCP seal LOCA and $p_{1STR}(t + 6 | t)$ 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 $p_{1STR}(t + 6 | t) = e^{-.693} (t+6.5) / e^{-.693(t-.5)}$, the probability for this sequence is $0.12 \times \int_{t}^{1.5} 0.68 \times e^{-.693(t+5.5)} dt = 3.8 \times 10^{-4}$.

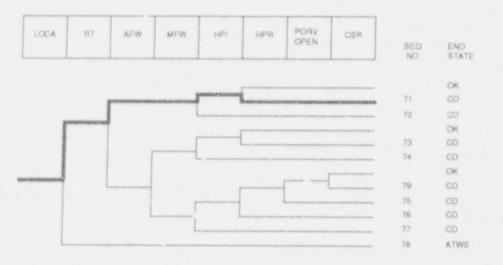
Analysis Results

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.



- 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 x 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 x 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 x 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 x 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 x 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: Rvett bescription: Evin. Date: Plant:	368/91-012 Both normal SW trains fouled (cond seg 04/16/91 ANO - Unit 2	ъ		
INITIATING EVENT				
NON-RECOVERABLE IN	ITIATING EVENT PROBABILITIES			
LOCA		1,08+00		
SECONNEL CONDITION	AL PROBABILITY SURS			
End State/Ini		Probability		
CD				
		1.48-05		
LOCA.		1.48-03		
Totel		1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1		
ATWS				
LOCA		3,48-05		
Totel		3.45-05		
SEQUENCE CONDITIO	NAL PROBABILITIES (PROBABILITY ORDER)			
	Sequence	End State	Prob	N Rec**
71 LOCA -rt -a 72 LOCA -rt -a	fw -hpi hpr/-hpi fw hpi	00 00	1,1E=03 2,5E=04	1.08+00 8.4E-01
78 LOCA rt		ATWS	3,45+05	1.28-01
** non-recovery c	redit for edited case			
SEQUENCE CONDITIO	NAL PROBABILITIES (SEQUENCE ORDER)			
	Sequence	End State	Prob	N Recht
71 LOCA -rt -a 72 LOCA -rt -a 78 LOCA rt	ifw =hpl hpr/=hpi fw hpl	CD CD ATWS	1,18-03 2,58-04 3,48-05	1,0E+00 8,4E-01 1,2E-0
** non-recovery (redit for edited case			
SEQUENCE MODEL: BRANCH MODEL: PROMABILITY FILE	c:\aap\1989\pwrgsesl.cmp c:\aap\1989\ano2.sll c:\aap\1989\pwr_b8ll.pro			
No Recovery Limi				
BRANCH FREQUENCI	ES/PROBABILITIES			
Branch	System	Non-Recov	Opt Fell	
trans	2.25-04	1.00+00		

Event Identifier: 368/91-012

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loop	1.60-05	3,62-01	
LOCA	2,48-06 > 2,48-06	4.3E-01 0 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.48-06		
15	2.85-04	1.26-01	
rtyloop	0.02+00	1.0E+00	
emerrg.power	2.92-03	8.02-01	
atw	1.38-03	2,65-01	
afw/emerg.power	5.0E-02	3.4E-01	
MPW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cond Frobi	2.0E-01 > Unavailable		
porv.or. rv.chall	2,02-02	1.08+50	
porv.or.srv.reseat	1.0E-02	1.18-02	
porv.or.srv.reseat/amerg.power	1.0E-02	1.0E+00	
seal.loca	4.02-02	1.0E+00	
ap.rec(s);	5,92-01	1.08+00	
ep.rec	2.11-02	1.0E+00	
hpi	3.05-04	8,48-01	
hp1(\$/b)	3.0E-04	8.48-01	52
porv.open	1.02-02	1.02+00	4,06-04
hpr/-hpi	1.56-04	1.0E+00	
0.81	2.08-03	9.48-01	

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Event Identifiet: 368/91-012

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Dates 04/16	normal SW trains fouled (cond seq 2			
INITIATING EVENT				
NON-RECOVERABLE INITIATI	NG EVENT PROBABILITIES			
LOCA		1,0E+00		
SEQUENCE CONCITIONAL PRO	MARILITY SUMS			
End State/Initiator		Probability		
CD				
LOCA		1,18+02		
		1,12+02		
Total		8-128 W.		
ATWS				
LOCA		3,4E-05		
Total		3.48-05		
SEQUENCE CONDITIONAL PR	OBABILITIES (PROBABILITY ORDER)			
	Sequence	End State	Prob	N Roc**
71 LOCA -rt -sfw -hp			1,16-02	1.0E+00
-78 LOCA rt.		A7W3	3.48-05	1.26-01
** non-recovery credit	for edited take			
	OBABILITIES (SEQUENCE ORDER)			
SEQUENCE CONCLETENT NO EN		End State	Prob	N Rec**
	Sequence	CD	1,18-02	GE+00
71 LOCA -rt -afw -hj 78 LOCA rt	1 HPR/HEI	ATWS	3.46-05	1.28-01
** non-recovery credit	for edited case			
BRANCH MODEL: C	r\asp\1989\pwrgseal.cmp r\asp\1989\pwrgseal.cmp r\asp\1989\pwr_ball.prc			
No Recovery Limit				
BRANCH FREQUENCIES/PRO	BABILITIES			
Branch	System	Non-Recov	Opr Fail	
trana Loop LOCA	2.2E-04 1.6E-05 2.4E-06 × 2.4E-06	1.08+00 3.68-01 4.38-01 > 1.08+00		

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Event Identifier: 368/91-012

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Branch Model: IN170R			
initiator Frequ	2.48-06		
FT	2,08-04	3,26-01	
rt/loop	0.01+00	1-06+00	
amerg.power	2,92-03	8,05-01	
ate	1.38-03	2.61-01	
alw/emarg.power	S.0R-02	3.4E-01	
MPW .	2,02-01 > 1,0E+00	3.4E+01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cund Prob:	2.02-01 > Unavailable		
porv.pr.arv.chall	2,02-02	1.0E+00	
porv.or.srv. essat	1.02-02	1.1E-02	
porv.or.stv.reseat/emerg.power	1.08-02	1.02.00	
seal.loca	4,010-02	1.05+00	
eputeo(ali	5,98-01	1.02+00	
ép.tec	2.18-02	1_02+00	
hpi	3.0E-04	8,46<0)	
hpl(t/h)	3.0E-08	8.48-01	1.08-02
porv.open	1.06+02	1.06+00	4,00-04
HPR/-HPI	1.58-04 + 1.08-02	1,02+00	
Branch Model: 1.0F.2			
Train 1 Cond P tobs	1.08-02		
Train 2 Cond robi	1.5%-02 > Unavailable		
	2,86-03 > 2,06-02	3.46-01	
Wranch Mov 11 1.0F.2			
Trein 1 Cond Prob:	2,08-02		
Train Cond Prob;	1.0E-01 > Unavailable		

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Event Identifier: 366/91-012

CONDITIONAL CONE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: Event Description: Event Date: Plant:	368/91-012 Both normal SW trains fouled (cond 04/16/91 ANO - Unit 2	1 90Q J)			
INITIATING EVEN					
NON RECOVERABLE IN	ITIATING EVENT PROBABILITIES				
LOCA		1.,0E+01			
SEQUENCE CONDITION	AL PROBABILITY SUMS				
End State/Ini	tistor	Probab	LIİSY		
ctp					
LOCK		1.05+0			
TOLAL		1,08+0	0		
ATKS					
LOCA		3.46-0	5.		
Total		3.48-0	5-1-1-1-1-1-1-1-1-1-1-1-1-1-1-1-1-1-1-1		
SEQUENCE CONDITION	AL PROPARILITIES (PROBABILITY ORD)	ER.)			
	Sequence		ED-1 State	Prob	N Rec**
71 LOCA -rt -a	(w -hpl HPR/-HPl		CD	1.08+00	1.08+00
78 LOCA IL			ATWS	3,48-05	1,22-01
** non-recovery c	redit for edited case				
SEQUENCE CONDITION	NAL PROBABILITIES (SEQUENCE ONDER)				
	Bequence		End State	Prob	N R&C**
71 LOCA -rt -a 78 LOCA rt	fw -hpi HPR/-HPT		CD ATWS	1.08+00 3.46-05	1,08+00 1,28-01
** non-recovery c	redit for edited case				
	c:\asp\1989\pwrgaeal.cmp c:\asp\1989\ano2.sll c:\asp\1989\pwr_bell.pro				
No Recovery Limit					
BRANCH FREQUENCIE	S/PROBABILITIES				
Branch	System	Non-Reco	v	Opr Fall	
trans loop LOCA	2,32-04 1,62-05 2,42-06 > 2,42-1	1.08+00 3.68-01 4.38-01	× 1.0£+00		

Event Identifiet: 368/91-012

Branch Models INITON			
Initiator Freq.	2.6E-06		
et	2 88-04	1.28-01	
st/loop	D.DE+0C	1,08+00	
emerg.power	2.98-03	8.05-01	
afw.	1,38-03	2.68-01	
als/wmaig.power	5.08-02	3.45-01	
NYW STREET	2.0E-01 > 1.0E+00	3.4R-01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cond Probi	2.0E-01 > Unavailable		
porv.or.arv.chall	2.08-02	1.08:+00	
	1.02-02	1.16-02	
porv.or.mrv.reseat	1.00-02	1.08+00	
porv.or.arv.reseat/emerg.power	4.02-02	1.UE+00	
anal.luca	5,92-01	1.02+00	
et:.rec(s1)		1.02+00	
ep.rec	2.18-02		
hpl	3.02-04		1,05-02
hp1(1/b)	3.02-04	B.4E-01	4.0E-04
pary.open	1,08-02	1,08.+00	8.00-08
HPR/-HPI	1,55-04 > 1,05+00	1.00+00	
Branch Moder: 1.OF.2			
Trein 1 Cond Prob:	1.08-07 > Unavailable		
Train 2 Cond Prob;	1,5E+02 > Unavailable		
CSR	2_01-03 > 1,01+00	3,42-01 > 1,0E+00	
Branch Model: 1.0F.2			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
Tealh 2 Cond Proba	1.08-01 > Unavailable		

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Event Identifier: 368/91-012

N Rec**

N RDC**

CONDITIONAL CORE DAMAGE PROJAG	ILITY CALCULATIONS	
Event Identifier: 368/91-012 Event Description: Both normal SW trains fouled (cond seq 4) Event Date: 04/16/91 Flant: ANO - Unit 2		
INITIATING EVENT		
NON-RECOVERABLE INITIATING EVENT PROBABILITIES		
TRANS	1,08+00	
SEQUENCE CONDITIONAL PROB/3. LITY SUME		
End State/Initiator	Probability	
TRANS	7,42-06	
Tutel	7,85-06	
ATHS		
TRANS.	3,46-05	
Total	3,48-55	
SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)	and inclusion	
-zequance	End State	Prob
18 trans vi	ATWS	3,46+05
** non-recovery credit for edited case		
SUQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)		
Requence	End State	Prob
18 trans it	ATHS	3,48-05
** non-recovery credit for edited case		
IEQUENCE MODEL: ci\asi\1989\pwrgsesl.cmp BRANCH MODEL: ci\asp\1989\and2.sll PROBABILITY FILE: ci\asp\1989\pwr_ball.pic		
No Recovery Limit		
BRANCH FREQUENCIES/PROBABILITIES		

Branch	System	Non-Recov	Opr Fall
trana Jaop Lock	2,2E-04 1,6E-05 2,4E-06 5 2,4E-06	1.0E+00 1.6E-01 4.3E-01 > 1.0E+00	
Branch Model: INITOR Initiator Freq:	2.48+06		

Event Identifier: 388/91-012

1.0E-02 4.0E-04

21	2.82-04	1,28-01
rt/loop	0,02+00	1.05+00
ene tg.power	2,8E-03	0.05-01
ntw	1,35-03	2,68-01
afw/emerg.power	5,08-02	3,46-01
H2'W	2.0E-01 > 1.0E+00	
Branch Model: 1.0P.1	**********	3.4E-01 > 1.0E+00
Train 1 Cond Prob:	2.0E=01 > Unavailable	
porv.oz.arv.chall	2.06-02	1.0E+00
porv.ot.arv.reseat	1.08-02	1,18-02
porv.or.arv.reseat/emerg.power	1,0E-02	1.02+00
seal, loca	4.0E-02	1.02+00
ep, zec(s1)	5,9E-01	1.02+00
BD. TOC	2,18-02	
hpl		1.0E+00
hpl(f/h)	3.0E-04	8,48-01
	3,08-04	8,45-01
porv.open	1.0E-02	1.0E+00
hpr/-hpi	1,58-04	1.08+00
cat	2.0E-03	3.42-01

* 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 seg 5) Event Date: 04/16/91 Flant: ANO - Onit 2				
INITIATING EVENT				
NON-RECOVERABLE INITIATING EVENT PROBABILITIES				
TRANS	1.05+0	0		
SEQUENCE CONDITIONAL PROBABILITY SUNJ				
End State/Initiator	Probab	11119		
ep				
TRANS	1,38-0	5		
Total	1,38-0	5		
ATWS				
TRANS	3.45-0	15		
Total	3.45-0	15		
SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)				
Sequence		End State	Prob	N Rec**
18 trans rt		ATWS	3.48-05	1.26-01
** non recovery credit for edited case				
SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)				
Sequence		End State	Prob	NRCSA
18 trans rt		ATWS	3.48-05	1,22-01
** non-recovery credit for edited case				
SEQUENCE MODEL: c:\asp\1989\pwrqaeal.cmp BRANCH WODEL: c:\asp\1989\ano2.sll PROB\31LITY FILE: c:\asp\1989\pwr_ball.pro				

No Recovery Limit

BRANCH PREQUENCIES/PROBABILITIES

Branch	iystem	Non-Recov
trans loop LOCA	2.22-04 1.62-05 2.42-06 > 2.42-06	1.0E+00 0.6E-01 4.3E-01 > 1.0E+00
Branch Model: INITOR		
Initiator Freq:	2.48-06	

Opr Fall

Evant Identifier: 369/91-012

1.0E-02 4.0E-04

8

21	2.86-04	1.26-01
rt/icop	0.05+00	1.00+00
emping.power	2,92-03	8.05-01
at w	1,35-03	2,62-01
afw/mmerg.power	5.0E=02	3,4E-01
MSTNI	£.0E-01 > 1.0E+00	3.46-01 > 1.05+00
Branch Modeli 1.0P.1		
Train 1 Cond Prob:	2.0E-01 > Unavaliable	
porv.or.srv.chall	2.08/-02	L, 0E+00
potv.or.arv.resoat	1.06-02	1.18-02
porv.or.wrv.reswat/emoty.power		1.08+00
seal.toca	4.02-02	1.02+00
0p. tes (NI)	5,98-01	1.06+80
ep.red	2.16-02	3,08+00
hpi	A.0E-04	0.48-01
hpi (f./b)	3,02-64	8,48-01
porv.open		1.02400
和论从了不知论了。	1.95-04 > 1.05-02	1,08+60
Branch Hodels 1.0F.2		
Ttain) Cond Probl		
Train 2 Cond Probi	1.5E-07 5 Unavailable	
CSA	2.02-03 > 2.02-02	3.48-01
Branch Model: 1.0F.2		
Train 1 Cond P. dr.		
Ttoin 2 Cond Crobs	1.02-01 > Dnavallable	

* branch model file ** forced

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Twent Identifier; 368/91-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

	368/91-012 Both nor:31 5W trains f 04/16/91 ANO - Unit 2	culed (cond seq 6)				
TRITIATING EVENT						
NUN-RECOVERABLE IN	ITIATING EVENT PROBABILI	1184				
TRANS			1.02+03			
SEQUENCE CONDITION	N. PROBABILITY SUMS					
End State/Init	llator		Propability			
TRANS			3,38-04			
TOLAL			3,38-04			
ATHS						
TRANS			3,45+05			
Total			3.48-05			
SEQUENCE CONDITION	AL PROBABILITIES (PROBAD	ALLITY ORDER)				
	Sequence		End (tinte.	Prob	N Rec**
18 trans rt			ATWS		3.45-03	1,28-01
** non-recovery cr	edit for edited case					
SEQUENCE CONDITION	AL PROBABILITIES (SEQUE)	NCE ORDER)				
	Sequence		Knd	State	Prob	N Rec**
19 trans rt			A785		3.85-05	1,28-01
** non-recovery or	edit for edited case					
SEQUENCE MODEL: BRANCI: MODEL: PROBABILITY FILE:	vi\aap\1988\pwrgamal v:\aap\1989\ano2.sll c:\aap\1989\pwr_bsll					
No Recovery Limit						
BRANCH FREQUENCIES	/PROBABILITIES					
Branch	System		Non-Kecov		Opr Fail	
trona loop LOCA Branch Model:			1.08*00 3.60-01 4.30-01 > 1.0	ne +00		
Initiator Freq	2,48-0	• • • • • • • • • • • • • • • • • • •				

event identifier: 368/91-012.

rt et/loop	2,82-04 0,02+00	1.20-01	
energ.power	2,95-03	8.02-03	
afw	1,3E-03	2.6E+01	
afw/emerg.power	5,02-02	3.48-01	
M2'W	2.08-01 × 1.08+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cond Prob:	2.0E-01 > Unevailable		
porv.or.srv.chsll	2,08-02	1,05+00	
porv.ot.srV.teset		1.16-02	
porv.or.srv.reseat/emerg.power	1,08+02	1.02.+00	
seal.loca	4,02-02	1,0E+00	
sp. rec(sl)	8 98-01	1,0E+00	
6D, 56C	2.18-02	1.06+00	
hpi	3.02-04	8.48-01	
npl(t/b)	3.06-04	8.48-01	1.06-02
perviopen	1.02-02	1.05+00	4.08-04
NFR/-HP1	1.5E-04 5 1.0E+00	1.0E+00	
Branch Hodel: 1.05.2			
Train 1 Cond Probi	1.0E=02 > Unavailable		
Train 2 Cond Prob:	1,56-02 > Unavailable		
CBR	2,05-03 > 1,05+00	3.48-03 > 1.08+00	
Branch Models 1.0F.2			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
Train 2 Cond Prob;	1.0E-01 > Dnavallable		
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* branch model file			
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Event Identifier: 368/91-012

NRC Form 366 (6~89) U.S. Nuclear Regulatory Conmission Approved CMB No. 3150-0104 Expires: 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1) Arkenses Naulear One, Ordt Two

DOCKET NUMBER (2) PAGE (3) 050000 3 6 8 10005

TITLE (4) Both Service Water Loope Declared Inoperable Due To Clagging Of Pump Discharge Strainers Caused By A Breakdawn In The Implementation Of Procedural Controls

EVENT DATE		1	LER NUMBER	(6)	REPORT	I DAD	(7)	COFER	FACILE	TIES	INVELVED (£1	
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EVEL		20.405(2)		50.36(c				0.73(a)(2)(v) 0.73(a)(2)(v)			Other (Sper	the sta	
10) 0000		20.405(a)		50.36(c			lower in the				Abstract be		
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ARSTRACT (Limit to 1400 spaces, i.e., approximitely fiftee 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 hypassing screens at the pump suctions and clogging discharge straigers. The traveling screens were being rotated for inspaction 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 ranced 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. Nucleur Regulatory Coescission Approved OMB No. 3150-0104 Expires: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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				Revision	
Arkansas Novlear One, Unit Two		Year	Number	Number:	
05000	3 6	8 9 1	0 1 2	0 0	0[2[OF]0]5

IXT (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 (Hode 2) with Reactor Coolant System (RCS) [AB] temperature at 545 degrees, pressure 2250 psis and power 8E-2. The traveling screen system for the Service Vater System (SW) [BI] was tagged out for meintenance activities.

B. Even* Det. iption.

On April 16, 1991 both SW loops were declared inoperable for approximation three minutes due to a breakdown in the implementation of procedural controls which resulted in a preventive maintenance (PH) 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 variable from the Emergency Cooling Fond (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 (GCW) (CC) huat exchangers. (CCW removes beat 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 rump.

Mechanical maintenance personnel were performing quarterly preventive maintenance on one — the traveling water screens at the SW intake. In order to obtain access to a part of the acrean 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 no mail cleaning spray (wash) being in operation.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET MUMBER (2)	LER NAMBER (6)	PACE (3)
		Sequential Revision	
Arkansas Nuclear Ope, Unit Two	Year	Nankoz Nankoz	
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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 nither 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 slarm 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 Fas 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 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 app.oximately 1752 hours. The standby pump was shifted to suppl, Loop II from the ECP to restore both loops to normal pressure and flow at 1813 hours. NRC Form 36'A (6-89)

U. S. Nuclear Regulatory Commission Approved CME No. 3150-0104 Expires: 4/30/92

LICENSER EVENT REPORT (LER) TEXT CONTEMUATION

FACILITY NAME (1)	LOOKET NUMBER	(2)		LER NUMBER	8 (6)		PACE (3)
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	0[5]0[0[0] 3]	6 8	9 1	- 0 1 2	-	0 0	040005

TEXT (If more space is required, use additional NAC Form Hood's) (17)

Other corrective actions include:

- 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 Mary 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.
- 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) U. S. Nuclear Regulatory Commission Approved CMB No. 3150-0104 Expires: 4/30/92

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	LIDCKET NUMBER	(2)		LER NUMBER	(6)	PAGE (3)
	1.			Sequent (a)	Revision	
Arkansas Nuclear One, Unit Two	1.000		Year	Nankar	Nation	
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TEXT (If more space is required, use additional NMC 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 ooth 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)(?)(vil).

G. Additional Information.

There have been no previous events of this nature reported as Licensee Event Reports at ANO.

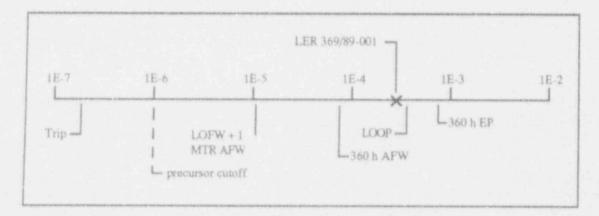
Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:369/91-001Event Description:Switchyard breaker test results in loss of offsite powerDate of Event:February 11, 1991Plant: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 follewed, and both diesel generators (DGs) started and loaded. An excessive cooldowr 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 is 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 S1 and automatic isolation of the MSIVs. RCS temperature and pressure then began rising until limited by operation of two PORVs (a

ird 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.

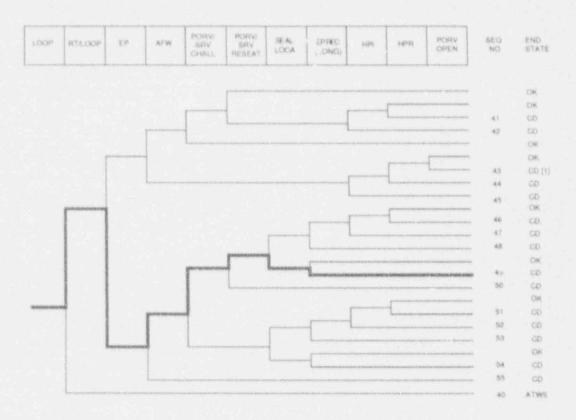
At McGuire, air is removed from the condenser by steam-jet air ejectors. This system might not be impacted by a loss-of-offsite power (LOOP). Condenser cooling is provided by the condenser circulating water system (CCW). The CCW system is crosstied between Units 1 and 2 via an 84-in. line. As power to 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 x 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 x 10⁻⁴.



(1) OK for Class D

Dominant core damage sequence for LER 369/91-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

ovent Identifier: 369/91-001 Sven. Description: Seitchyard breek Svent Date: 02/11/91 Plant: MoDulre 1	er teat reaults in a LOOP
INITIATING EVENT	
NON-RECOVERABLE INITIATING EVENT PR	OBABLLITIES
LEX III	3.02-33
SEQUENCE CONDITIONAL PROBABILITY SU	2.40
End Statu/Initiator	#robablili
LOOP	2.66-04
Total.	2.68-04
8793	
1009	0.00+00
Total	0,00+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob.	N Noc**
4.9	LCOP =rt/loop emerg.power =afe/emerg.power PORD/HR.SRV.CHALL =		2.36-04	2.4E-01
50	porv.or.srv.reseat/emerg.power =seal.loca NS.KCU LOOP =rt/loop emerg.power =afw/emerg.power PORV.OR.SRV.CHALL	CD	2,02-05	2,48-01
85	porv.or.srv.reseat/emorg.power LOOP ~rt/) op emorg.power siw/emorg.power		1.28-05	8.38-02

** 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.UR.SRV.URAS. porv.or.arv.remeat/emerg.power *aial.loca EP.AFC		2,35-04	2,48-01
50	LOOP -rt/loop emerg.power -afw/emerg.power PORV.OR.SRV.CHALL porv.or.srv.reseat/emerg.power		2.08-05	2,48-01
5.5	LOOP -rt/loop emerg.power afw/emerg.power		1,28-05	8,28-02

** non-recovery credit for edited case

SEQUENCE MODEL:	c:\asp\]	19891	perbasal.cmp
BRANCH MODEL:	c:\asp\:	9891	maguire.wll .
PROSABILITY FILE:	/gas/to	19891	per ball.pro

No Recovery Limit

BRANCH PREQUENCIES/PROBABILITIES

Event Identifier: 369/91-001

Branch	Syacen	Non-Repoy	Opr Fall
trana	4.38-04	1,06+00	
LOOP	1,68-05 > 1,88-05	3. ** ** Y C.0E-01	
Branch Model: INITOR			
Initiator Frequ	1,68-05		
1004	2,48-06	4,38-01	
15	2.85-04	1.2E-01	
rt/loop	0.05×00	1.05.400	
emeită "Dowe.	2.92-03	8,0E-01	
afw	3,88-04	2,68-01	
afu/emerg.power	5,08-02	3, 4P = 01	
mtw .	1.05:00	7,06-62	3,08-03
PORV, OR, SEV, CHALL	4.05+02 > 1.05+00	1,06+00	
Branch Model: 1.0F.1			
Train 1 Cond Probi	4.05-02 > 1.06+00		
porv.pr.srv.reseat	3.05+02	1.18-02	
porv.os "V.reseat/emerg.power	3.05-02	1,08+00	
seal, lbca	0.02+00	1,0E+00	
ep.rec(al)	0.08+00	1.08+60	
EP, REC	4.56-01 > 3.56-01	1.05+00	
Branch Model: 1.0F.1			
Train 1 Cond Frob:	4.55-01 × 3.55-01		
hp	1,05-03	8,65+01	
hpt (f/m)	2E-03	8,46+01	1.06-02
hpr/~hpl	1.6E-04	1.05+60	3.08-03
DOPV.BDMA		1.02+00	4.08-04
* branch model file			

At formed

Minarick 03-11-1992 12:32:35

Event identifier: 369/01-001

Guire Nuclear Station, Unit 3 (a) (b) (c)	Caused CLUTIES (1990 W foreauty) (1 ANEA CODS 7 0 (4	101361910F1 3 By An Inappropri x yep = DOCART W.WEERE 0151010101 0151010101
** A Unit 1 Resctor Trip Occurred Due to A Loss Of Offsite Power Action, A Management Deficiency, and An Equipment Failure ************************************	Caused ciuries (eve v foreerige () anes coos 7 0 4 3 4	1 By An Inappropria NVED 80 DOCATI NUMBER (0 15 0 10 0 1 1 0 15 0 10 0 1 1 0 15 10 10 0 1 0 10 0 0 1 0 10 0 1 0 10 0 0 1 0 0 0 1 0 0 0 0 1 0 0 0 1 0 0 0 0 1 0 0 0 1 0 0 1
SVENT GATE (6) LAR NUMBER (6) REPORT GATE (1) OTHER ARE 20 1 0 1 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 0 1 0 0 1 0 0 1 0 0 1 0 <t< td=""><td>и толоноці () Алел собя 7 <u>0 1</u>4 31 мам. 7 ас</td><td>DOCATT NO.WEEKSU 0 5 0 0 0 0 0 0 0 5 0 0 0 0 0 73.75 00 0 73.75 00 0 75.05 000 0 75.05 000 0 75.05 000 0 75.05 0000</td></t<>	и толоноці () Алел собя 7 <u>0 1</u> 4 31 мам. 7 ас	DOCATT NO.WEEKSU 0 5 0 0 0 0 0 0 0 5 0 0 0 0 0 73.75 00 0 73.75 00 0 75.05 000 0 75.05 000 0 75.05 000 0 75.05 0000
Z 1 1 9 1 9 1 9 1 -0 0 1 -0 0 0 3 2 3 9 1 operatives mode we 1 True ARPORY is subscripted publication to the Astochesters of is one 5 incention of the even of its mode we 1 True ARPORT is subscripted publication of the Astochesters of is one 5 incention we application of the astochest of the Astochesters of is one 5 incention we application of the Astochest of the Astochesters of is one 5 incention we application of the Astochest of the Astochesters of is one 5 incention we application of the Astochester of the Astochesters of the Astochester we application of the Astochesters of the Astoche	а толоноці () алка собя 7 0 4 3) мам.тас	0 15 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
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Desarting All Turing REPORT IS EUGNATIVED PURSUART TO THE REDUITEDANGED IN COMPANY OF IS CAR & Down in a series of in Marked in 1 0 0 0 00000 00 7500000 00 7500000 00 7500000000	ANEA CODA 7 0 4 30	12 71371800
ANDRE ME 1 0 0 400-16 20 400 MINING 20 400 MINING	ANEA CODA 7 0 4 30	Special Report
USAL 1 P 0 0 0 000 000000 00 000000000 00 000000	7 0 4 8	X OTTER Lances - Advances Anton and - Tasi UNC - Tasi Special Report TELEFNONE SUMMER 8 7 51 - 14 1 8
De selective de la contraction	7 0 4 8	Special Report
D Sipe, Chairman, McGuire Safety Review Group COMPLETE DAY THE LAR PORTAGE FOR THIS LER 121 COMPLETE DAY LINE FOR SACH COMPONENT FAILURE DESCRIPTION THIS REPORT 12 COMPLETE DAY LINE FOR SACH COMPONENT FAILURE DESCRIPTION THIS REPORT 12 COMPLETE DAY LINE FOR SACH COMPONENT FAILURES DESCRIPTION THIS REPORT 12 E STOTEW COMPONENT TURES DESCRIPTION THE REPORT 12 E STOTEW COMPONENT TURES DESCRIPTION TO 12 E STOTEW COMPONENT TURES	7 0 4 8	Special Report
D Sipe, Chairman, McGuire Safety Review Group COMPLETE DAR THE LEAST FOR THE LEAST FOR THE REPORT AS E STOTEW COMPONENT WARNERS OF TABLE COMPLETE DAR LINE FOR SACH COMPONENT FAILURS OF SCHARED IN THE REPORT AS A STOTEW COMPONENT WARNERS OF CAMPAGE AND CALSE DISTEM COMPONENT A STOTEW COMPONENT TURER FOR SACH STREETED INF	7 0 4 8	теленионе зомеен 8 7 5 4 1 8
D Sipe, Chairman, McGuire Safety Review Group COMPLETE DAS LINE FOR THE LEAD FOR THE CALLE DISCHARED IN THE REPORT IS E STOTEW COMPONENT MEMORY OF TOWARDS FOR THE DISCHARED IN THE REPORT IS A STOTEW COMPONENT MEMORY OF TOWARDS FOR THE DISCHARED IN THE REPORT IN A STOTEW COMPONENT MEMORY OF TOWARDS FOR THE DISCHARED IN THE REPORT IN A STOTEW COMPONENT MEMORY OF TOWARDS FOR THE	7 0 4 8	8 7 5 - 4 1 8
D Sipe, Chairmani, McGuire Safety Review Group сомясяте оняция соверсяте основонная селонования сациях отвежнаясо и тим явлоят из в system сомясимая междата соберся соберс	7 0 4 8	8 7 5 - 4 1 8
D Sipe, Chairmani, McGuire Safety Review Group сомясяте оняция соверсяте основонная селонования сациях отвежнаясо и тим явлоят из в system сомясимая междата соберся соберс	7 0 4 8	Interconstant of
COMPONENT FOR LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THE REPORT IS E SYSTEM COMPONENT MERUPAC TORING CONTROLS COMPONENT TORING CONFORMER	3i MANUTAC	Interconstant of
A STOTEM COMPONENT TURER TO ADROS CALLE PISTEM COMPONENT	илм. и ас товея	MERCH TABLE TO HERDS
negative state and a second	i. i. i. i. i. i.	
negative state and a second	L. L.L.	
negative state and a second	aken baadaa	
negative state and a second		MONTH DAY FEA
parama and a second	1×PECT8 1 /#M/35/	City
ES (1) van opengene EXPECTED SUBMISEDER DIE TEI Y NO	0416 10	
On February 11, 1991, A Unit 1 Reactor Trip occurred at 1355: the event, Unit 1 was operating in Mode 1 (Power Op : tion) a The Reactor was tripped by a Nuclear Instrumentation (NI) Pow Rate signal. The trip signal was initiated when offsite power was lost because a blackout occurred in the ' ' W switchyard. occur ed as a result of a failed relay in cu anction with a p modification test being performed on a newly added relay circu switchyard. Subsequent depres: ization of the Hain Steam (SI resulted in a Safety Injection (SI). An Unusual Event was de- due to Loss of Power and SI. The Technical Support Conter (T) activated as a conservative measure and TSC personnel made the notification to the NRC. A thorough "schnical review was per- event and, consequently, a decision will made by Station Manage concurrence of the NRC) to restart the Rescerch. Unit 1 was re 2 (Startup) operation on February 13, 1971, at approximately (event is issigned causes of Inapproprist) Action, Management I an Equip. Failure.	t 100% ver Rang r to th The N post uit in N) syst clared SC was e requi formed ement (eturned 0345.	power. ge Hi Flux he unit blackout the tem at 1420 s ired on the with i to Mode This

74175-386	LICENSEE EVENT REPO	ORT (LER) TEXT CONTIN	UATION	2.4	NICLEAR RELL APPROVED ON EXPRES & S14	4.50.7		
	et etc.	DUCKET NOMER UI		646 8 16 - 517 - 61 - 118 8	NF- 8-11-9 		+68 -5	
	McGuire Nuclear Station	0 16 10 10 10 13 1 6 19	9 1 1 0	1011	-010	12	0.0	1 8
12.1009.8	ner a squarke une enderson tille form MBA 2/172				4			
	EVALUATION:							
	Background							
	McGuire Nuclear Station consis equipment for the two units. 230 KV and 525 KV Switchyards	It functions in assoc	units and istion wit	the a h the	uxiliary McGuire			
	Each unit generates power at a through two half-size step-up Switchyard by overbead transmi switchyard, while Unit 2 is co of each unit is then delivered switchyard power circuit break configuration and transmission	trausformers [EllS:XJ ssion lines. Unit 1 nuected to the 525 KV into Duke's transmis ers [EllS:52] (PCB)	[MR] to the is connect / switchyar is on system in a breake	McGa ed ta d. 1 m thi	the 230 The output rough	- KV		
	Normal auxiliary power on each transformers (24 KV/6.9 KV) ea auxiliary transformer has two power to two sections of 6.9 K two other sections.	ch rated at 100 kilov secondary output wind	volt ampere lings, supp	is (K)	(A). East to real			
	The 230 KV and 525 KV switchya number of circuit breakers tha transmission system. The buse exchange between generators an isolate any section that may h buses in each switchyard, they bus. In addition to naming th a number, which aids in identi switchyards are used to connec- buses.	t connect the general s provide junction pr d the system. PCBs e faulted. To distin are designated as th t buses, each power fying the individual	tors [EIIS oints for t interrupt t nguish bets he red bus circuit bre breakers	GEN] the p (low seen and sker Rot	with th ower of power the two the yell is assi h	e and ow		
	The 525 KV and 230 KV switchya which permits power distribution	rds are connected th on between the two v	rough an a oltage lev	utotr els.	ansforme	r		
	Seven pairs of transmission li with the rest of the Duke syst Lines connect wich Harrisburg lines and the Schoonover lines The Blackburn lines feed the L Westport Lines tie with Marsha Ford Lines connert with Cowans	em. The Craighead L Tie Substation near tie with Riverbend ongview Tie Station 11 Steam Stations sw	ines and t Charlotte, Steam Stat near Hicko	he Me N.C. ions ry, N	ckleabur The No switchys C. The	e rua rd.		
	Fault Pressure Relaying [EIIS: as a supplement to the primary transformer wonding faults ber from the breakdown of the inse gases cause - rapid rise in th	/ protective relaying come severe, they pro clation [EIIS:1SL] wa	 When in iduce large iterials. 	terni amoi The e	d ints of p expanding	gase		
1.19.54 10	and the second	the second s	and some seal and			-		-

LICENSEE EVENT REP	ORT (LER) TEXT CONTIN	UATIO	N		1.0	HRUSSED	OME NO			or sale
CON NAME (1)	DOCK47 SUBMER (2)	- 44.8				Private -	ļ	74.	14 13	
McGuire Nuclear Station	0 15 10 10 10 13 1 61	9 911			1				arti	1
If more power a repro ter can adjustioner fulfit fame alled a 1.12		10101	-	alar.		hing have		-		-
pressure telays can sometimus protective relays can. Fault pressure relays are mour use a bellows [EIIS:BE] mechar	sted on the outside a	t = 1.00	ust	ormer	5 A	sing				
oil pressure. If the fault pressure relay(s) pressure rise on the insulatin will operate, through tripping) on the transformer 1g oil, indicating an	detects interp		h: gh windi	rat	e of fault	0			
These lockouts will clear the de-energizing the feeder break		by tota	11)	clea	ran	8 200				
A breaker failure relaying sch fault protection. It ensures breakers fail to trip when ini accomplished by opening all re switchyards.	isolation of the autitisted for a fault of	stransf anditio	0:	- r if This	th	e fee				
The directional distance phase protection of a transmission 1 transmission line for phase-to faults. This relay is directi- flow in one direction only. T line current flow with the bus quantity, or reference voltage faults within a certain distan- line impedance.	ine. It protects all -phase, three-phase, onal in that it will his direction is dete voltage. The bus vo . The directional di	three and tw respon rmined ltage stance	pha o-p d by is re	ses of hase-for o faul composi- the no lay de	f a lo- lt (ri) sn- ete	group curre ng th chang cts	nt e ing			
When directional distance relay is possible that these relays of operating voltage is usually or its associated circuits supp trip from this occurrence, an SOP is installed to supervise of	will pick up from los y due to the malfunct plying this voltage. instantaneous overcur	ion of To pr rent p	ent th eve has	only e volt nt an e rela	ag	The 1 e dev désir	oss ice able			
The directional distance phase (SOP) relay and its associated to initiate tripping. No tripp up, but the 85 relay and the SO	carrier (85) (LIIS)8 ping will take place	5] rel if the	84	must 1	18.3	picke	d ul	9		
The purpose of the Excore Instr monitor Reactor [EIIS:RCT] core trips and alarms [EIIS:ALM] for outputs of the scirce, intermed used to limit the maximum power ranges and are used as inputs t shutdown condition up to 120 pe provides power level indication	e leakage neutron flu r various phases of F fiate, and power rang r output of the React to monitor neutron fl ercent of full power.	x and eactor e dete- or with ux from The	gen Op cto hin a pow	erate eratic rs [E] their compl er rat	apj 15 15 etc	DET] The DET] cspec cd dete	art			

		LICENSEE EVENT R	EPORT (LER) TE	KT CONTINU	ATION		APPROVED DA		10.010	-
-	Md (1)	analisty in the second s	DOCKAY WUMPA	A (2)	-	ER NUMBER (4.08 (b)	-
					1848	REGULATION	ME V BRAN		TT	-
	Mettorian M	uclear Station		10131619	a sil.	Dinis.	0.10	S.,	OF1	
10		campanage Autor, Amore 2002,4 (c) (c) (c)	10 10 10 10	TATE LATE	P.1.11	-1 0 10 1a	I-le Tel	F	Terli	
		warm of abnormal g, and computing []			for rea	ote réc	ording,			
	Descripti	on of Event								
	operating test of a circuit i ties the autotrans autotrans conducted [EIIS:CL] trip_ing affected actu:tion is redund designed next zone yellow bu	ry 11, 1991, at ap at 100% power, Tr modification whic s a fault pressure 230KV switchyard t simulating a fault former to be deene with the feeder b circuitry was blo as a result of the downstream relay c of the sutotransf ant to the primary to clear a zone ar of protection in s. What follows i acd implementation	ansmission Dep b installed a relay switch o the 525KV sw pressure rela e the system of rgized because reakers to the cked on the fe test. Transministic ormer breaker of lockout scher cound a fault this case is is the sequence	artment pe new relay 63FPX on t vitchyard. ay trip of lispatcher s of system transform reder break nission per would have failure re se (which we even if the to open all e of events	rsonne circui he aut The s the sw would i load, er clo ers to sonnel compl clay sc vas blo : PCBs i that	<pre>l began t. The otrapsfo cope of itchyard not allo the tes sed. Th prevent failed etely bl heme. T cked) at tied to occurred</pre>	conductin relay rmer white the test: w the t was e trip co their to open ocked th his sche d is open. T the red	ch ing oil all e me he and		
	1)	At approximately iault pressure re appropriate termi	elay operation	by placing	g a jum	iper acri	880			
	2)	The associated lo and did not open because they were	the autotrans						d	
	3)	The breaker fails autotransformer fault was still j autofransformer	feeder breaker present that h	s remained ad not been	close	d and as	sumed the			
	-à)	The breaker fails clearing both re- switchyards.						PCBs		
	5)	At this point, l' their associated directly to outg Me.tlenburg Blac outgoing line is unit output.	"half" breake oing transmiss k, for Unit 11	ers which c sion tie li). (See pa	onnect nes. ge 18	the uni (Craight of 18.)	t bus li ad White Each	and		
	6)	At an unknown ti failed closed.	me before/dur	ing the eve	ent, di	stance	relay 211	LC		

talita comen Emili	LICENSEE EVENT RI	EPORT ILERI TEXT CO	NUNTINUATION		REGILAR REDU REPRESENTATION	8 40 X		
ACTO TO MANE IC		200311 NUMBER (2)			and the second s	-	408 0	-
			12.6.9	14 (0. 4 h V . 4 h Mpr #			T	-
HeGuire	Nuclear Station	0 18 10 10 10 13	6.9 8 . 1	0.00	0.0	1	orb	142
			CIT F I T	T. L. G.	L-L-IVI	1	Pure	-1
	the logic required.	lead line and elimin	the red and th current to CBS Thus, nated 1 of to	yellow i hrough i the PCI	us be line tripped			
73	The loss of the Gra current to be diver This caused an over	ted through PCB11 t	o the Meckli	caused enburg B	full loa Uack lin	d e		
8)	PCB11 tripped 0.2 s cleared the Mecklen connection of Unit site power to Unit	burg Black line. 7 1 to the grid resul	his was the	only re	maining			
9)	The unit had not red load current from Un auxiliaries. This is electrical distribut	nit I was subsequen induced a voltage t	tly redistri	buted t	o unit -			
10.)	Since the generator required by station Reactor Coolant (NC)	loads, frequency h	gan to rise	city th This	an increase	d		
m	The Nuclear Excore I Reactor power from I approximately 1 seco signal. The Reactor [EIIS TRB] trip at 1	00 percent to 106 p od and initiated a tripped at 1355:11	ercent powe high flux r	r in ate Read	tor Trip			
Pollowing and 1B st	the Reactor and Turb arted and began seque	ine Trips, Diesel (noing on blackout l	enerators () oad groups.	D/G) (E)	(15:DG) 1	A		
initiated Trip, whi performin	ater, the Control Roer emergency procedure 1 ch requires manually e g other actions to str jection (SI) [EIIS BG	EP/1/A/5000/01, Saf exercising the Reac abilize the unit.	ety lujectio tor Trip swi He also very	on or Re itches a	actor			
decreasing	temperature and Main g. NC system temperat d. The NC system was	ure was trending t	oward 557 de	grees F	ahrenhei	t		
below no l Reheaters Stage Rehe available.	(OPS) personnel real oad value. They stte (MSRs) [EIIS:MSR] and sters. They were uns Also, steam line dr his contributed to hi	mpted to reset the I remotely close va uccessful in this ain valves were op	Moisture Se lve ISM-15, attempt beca en and could	parator SM to S use was	econd no powe	r y		

5.63

H-3X	
12-26	

141 Farmi 14 9.441	LICENSEE EVENT REP	PORT (LER) TEXT CONTINU	ATIO	N		ANDULAN R ANDULU LANGES R	Det NO.		
ACTACING NO	AME TO THE REPORT OF THE REPORT	THE REPORT OF AND A PROPERTY OF			scutteren la			FAUR 18	-
			-648		21	No ver	ř.	11	
	McGuire Nuclear Station	0 10 10 10 10 13 1619	9.11		1010	6 1	6	(OF)	. 8
C. O. rais	growt it response, one problem with form \$86.4 at 112	and the second s		diament da	- they have	dire direction of the	-Anisher	i di sala	
	OPS personnel throttled the A the full closed position to 1 of manually closing valves 15 and 15P2, SM to Feedwater Pum minutes after the Reactor Tri reached	imit cooldovo. Also, t M-15 and 18P1, SM to Fe p Turbine 1B, when, at	hey i edwar 1412	vera ter , si	in th Pump 1 proxis	e proc urbine utelv	658 1A, 17		
	After the SI, a SM Isolation hain Steam Isolation Valves (the NC system and caused pres Power Operated Relief Valves did not lift due to being jum Pressurizer [EIIS:PZR] code s	MSIV) to close. This is sure and temperature to (PORV) INC-32 and IN - pered closed per work is	topp inc 16 op	ed 1 real ener	ieat re ie, and i. POB	smoval 1 NG sy EV 1NC=	from stem		
	Lower Containment [EIIS:NH] to to loss of containment ventil [EIIS:BC] doors to briefly op EP/1/A/S000/01 and entered pr Inside Containment. Containm	ation. This caused the en. OPS personnel the ocedure EP/1/A/S000/02	i low i exi . Hig	er ted h fi	ice con proces nergy	idenser lure Line Pr	eak		
	An Unusual Event was declared that all SI termination crite were met. The SI signal was	ria as described in pro	∕, OÞ scēdu	S p re	ersonn EP/0/A	el vers /5000/0	Tied 2		
	By 1435, power was fully rest 6.9 KV buses in the plant. S transferring loads from the D	hortly afterwards, OPS	pers	onn	el beg	8.0			
	The Technical Support Center activated as a conservative m with the Station Manager as E	seasure and subsequently	appör v ful	t C ly	enter activa	(OSC) v ted_at	ere 1503		
	TSC personnel determined that to enhance unit cooling by ve PORVs. The Main Condenser ha blackout.	ucing steam through th	e SM	SV9	tem at	mosphe:	ric .		
	By 1630, the unit was stabili shutdown in a routine man.er personnel to commence procedu buit Shutdown.	Subsequently, TSC pe	CRORT	sel.	direct	ed OPS			
	The OSC and TSC were deactive	ited at 1735.							
	The Station Manager called for prior to restarting the unit. Transmission Department person This technical review encompa	Many station groups, unnel participated in t	Desi his t	19.0	Engine	ering.	and		

	- 12	- 10	

		LICENSEE EVENT				COMPANY R.D.		
COLUMN RAME II			DOCKET NUMBER 10	provide the special	-24 10.66828.0			Alle in
				12.6.9	Add Jan Time	PULLINGER		11
	Julys N	ntiear Station	0 0 0 0 0 0 3 6	ALL NO.	1,010	0 1 0	à.	OFI
1 of most shares		national India Asian Addit at 1151			de de de se	4.4.4	-	di k
	*		chemistry samples were ta ts. This indicated React				a in	
	*		of Unit 1 Containment was o problems were found.	a perfoi	rmed by t	0P5		
	те. П		ing L partment and Mainte walked down the PZR PORV ound				céi:	
	*		er, ice bed, and doors we were determined to be unda		eyed by)	MES		
			ing Department personnel ument and determined ther tural damage.				re.	
		no evidence of	ycled the PZR PORV a numb high discharge pipe tempe /stem leakage through the	rature :	which wo			
	×		sing lower Containment Ven s direct#d by Work Request			ower sup	ply	
	. *		mance (PERF) personnel beg as rate trip signal.	ian perf	orming a	n evalua	tion	
			r blowdown walve 188-8 did ad functionally verified a				This	
			id Computer (OAC) was down ment and Electrical (IAE) AC to service.					
			reviewed Emergency Operat: ate the need for adding s ins.					
		Relay 21LC in Department per	the switchyard was repair sonnel.	ed by Tr	ansmiss	0B		
	1.6.	No other elect	rical problems were found					
			nd Volume Control (17) sy to be normal.	stem wa	(survey)	ed and a	11	
	fter ev quipmen	aluating the fac t problems ident	", associated with the ev ified, it was determined	ent and that it	correct was saf	ing all e and pr	uden	

dit Karn 18 142	LICENSEE EVENT REPO	ORT (LER) TEXT CONTIN	UATION	ULA NUCCEAN REGULAT APPROVED ONG NO EXPART ESTIM	
ADILITY N	586 (T)	DOK N ET RUSMBER ().		NUMBER IE	F8.01 135
			16.6.8	EDLENTIEL MESSAULA RUMER NUMER R	
	McGuire Nuclear Station	0 6 0 0 0 0 3 6	9911-	0 0 1 - 0 1 0 1	8 OF 1.8
11 11 1412	aparties at responses, une autobacente ArAC Auren 2002A (2717)	ine from den de rederieder gebernde meder ande	en al en alter er eller en alter	tendernal provident der eiter ander socher eite	
	to restart the Reactor. Start and Unit 1 was returned to Ope				
	Conclusion				
	A cause of Misunderstood Verty is assigned. Just prior to st Operating Center (AJC) and Tra autotransformer could be deem modification test within a sho Transmission Department policy soon as possible after they ar the equipment is safe. The Re policy and was anxious to comp contacted the AOC several time autotransformer and grant perm Relay Supervisor contacted the autotransformer from service. Operating Center (SJC) determi- taken out of service at that t discussion between the AOC and performing the test with the auto- confident that the Relay crew perform the test with the auto- unusual testing situation that reluctant to proceed. They has cleared before the end of the	art of the modificat nsmission personnel ergized long enough rt time of completin to test new devices e installed to prov lay crew performing lete the checkout. s that day and askes ission to proceed w AGC for permission The AGC in consult, ned that the autorr ime due to system 1 I Relay Supervisor f iutotransformer energiz they had not previ d hoped that the au day.	ion, Charl enticipate to perform ig the job i on operal ide maximum the test of The Relay d him to c ith the te to remove ation with ansformer oad condit ollowed. gized. They ously plan totransfor	lotte Area ed that the m a post . It is ting equipment as a assurance that was aware of this Supervisor lear the st. At 1200, the the System should not be ions. A They discussed e AOC was nd expertise to were faced with ned for and were mer could be	e e
	The Relay Supervisor was mindi energized) the downstream rela autotransformer from detecting during the test. He directed open the relay contacts so tha signal would actuate the relay lockout the autotransformer. brainstorming session on how t energized. The Relay crew tee their plan with the Relay Supe	iv logic must be blo g a fault and trippi the Relay crew pers at simulating a tran y logic but would no The Relay crew pers to perform the test chnicians researched	cked to pr ng the fee onnel to d sformer fa t open PCF onnel ther with the a the draws	event the eder breakers levelop a plan to mult pressure 3s 1, 3, 52, 53 t a held a autotransformer ings and reviewed	ю 1

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 is stify 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 Kelay 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

a ministral being attern conservation the factor man LICENSEE EVENT REPORT (LER) TEXT CONTINUATION 477401-11 048 NO 1180-0104 PAG LITY NAME OF an Accession in 144.0 McGuire Nuclear Station 0 0 0 0 0 0 3 0 9 9 1 TEV'S IF NOT APPER & REPART, use antitional Add. from MAX of CO. 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 Peficiency 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. Frior 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 fraining to determine the best methods for installing modifications and performing texts.

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NAS CONSISTERATION DESCRIPTION

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NAC ASIN MARK U.S. MLUCIAR PEDICLATIONY COMMERSED LICENSEE EVENT REPORT (LER) TEXT CONTINUATION AND DUCK ON BAIL OF UCHARA LUPINES 8-51-88 ACILITY NAME PAGE B TAP STOLETA No. March McGuire Nuclear Station 0 | 5 | 0 | 0 | 3 | 6 | 9 | 9 | 1 | --- 0 | 0 | 1 118 INT A man bann it in a man from man a stat 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 in 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 .rip setpoint (1200 Amps) of the SOP 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 switc'yard 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. PERY 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,

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 Plant OPS personnel responded correctly using appropriate procedures, and B-389

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8¢1(123	SAME III			DOCKET NUMBER (2)		-54.0	A REINARD R		-4.64	
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	cumulative no is 0.102 with	zzle u 7 sig	isàge factos d mificant safe	e usage factor for all Unit 1 ty (bjection & NRC notificat)	safet; vents	v injec The	tion eve	uts to d	The ate	
	24 months pri- which the cau Equipment Fai switchyard mo- in Problem In Transmission	or to se was lure w difica vestig depart	this event re an Inappropri- where Transmis- ttion work. H stion Report ment where wi	ence Program (vealed no ever iste Action, # sion Departmer lowever, two pr (PIR) 2-M89-02 itten compute (dered recurrit	ta in Manaj it peri eviou: 33 an ation	volving gement sonnel s event d 2.MRG	a React Deficien were per s were d ~0200 in	or Trip cy, or a forming ocumente	in. B	
	This event in	nst N	Auclear Plant	Reliability Da	ta sy	stem re	portable			
	There were no releases of r	perso adioac	nnel injurier tive material	, rediation en as a result o	pasur f thi	es, or s event	uncontro	lled		
	CORRECTIVE AC	TIONS:								
	limmediate:	1)	mitigation ;	el implemented procedures EP/), and EP/1/A/ sinment.	/A/50	00/01.	Safety 1	njection	01	
		-27	The OSC and	TSC were activ	ated					
		3)	Offsile power (essential t	er was restored ous).	to t	he unit	within	40 minut	es	
	Subsequent :	12	performed.	ent technical i This review re operly and the	veale	d that	the plan	it equips	est	
		2)	offsite jown policy required Control Room switchyard 1 station entry configuration the AOC Disp all work gro	switchyard work er system reli ires the AOC D a personnel of that could aff- ers a degraded on, the McGuiro patcher. This oups of increa d condition.	abilit (spatc any a set th elect will	y was i her to ctiviti e stati rical i rol Roi heights	mplement notify f ec in th ion. Also system on SRO w en the as	ted. Thi tcGuire we so, when ill notif wareness	s the y of	

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LIC	ENSEE	EVENT REPOR	T (LER) TEXT CONTIN	UATIO	N			40-42 DM	8 AG 3	 COMMUNE Spinore
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		to be within	mples of the NC sy normal parameters was not damaged.							
	4)	A survey of problems wer	Unit 1 Containment re found	was p	ert	ormed	and	0,0		
	5)	The ice cond problems we	denser ice bod, and re found.	doors	we	re sul	rvey	ed and	0.0	
	6)	temperature	seering Department spike in containme nammediate equipme	at and	i de	termin	bed	that		
	7)	the PZR POR	neering Department V and discharge pip age through the val	e and	det					
	8)	Relay 21LC personnel.	was repaired by Tra	nsmist	ion	depa	r Lase	nt.		
	9)	The unit se found.	condary side was su	rveye	i an	d no	prol	lems	vece	
	10)	ATTENTION a McGuire pla	placed on the switc ll circuits in this nt operation. Not ginning any work is	swith fy AO	chya C at	rd ca 382-	n a: 038;	ffect		
	11)	non-emergen	n Department person cy work in the swit rolling switchyard	chyar	d ur	itil a	0.01	oplete		
	12)		n Management perso riste personnel.	nnel r	evid	eved t	his	event		
Planned:	1)		nd PERF personnel e for the NI high					evalua	tio	n
	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.		on Department perso on test on the 63FP					the [nost.	
	ú)	setpoint for valves for	sign Engineering pe or acoustic monitor PZR PORV cycling e hould be changed.	ing of	th	e PZR	002	le safe	ety.	

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	McGuire Nuclear Station	0 18 0 0 0 3 0 9	9 1 1 - 0 0	1 - 0 0	13 00 1 18
	evaluat include analysi perform failure 6) General emergend	<pre>ssion Department personne ion of the failed 21LC re sending the relay to A. 1 s. They will also invest ed earlier to determine if of the relay. Office OPS personnel will cy plan exists to restore nt of a loss of both switc actor Trip with the plant initiated, D/Gs IA and IB on within 11 seconds (afte was well below the D/G ca rly, OPS personnel would revide instruction to ene effsite power was availabled.</pre>	I will conti lay contact. Brown Boveri igate other f this could I verify tha power to th hyards. being capab started, so r the load of pacity. If have referre rgize the 4 e to both ee	nue This may , Inc. for modification have caused t an adequate e station in le of le of the D/Gs had ed to 16 KV buses	
	Upon loss of power to the NC and the removal of residual NC system, sided by Auxiliar personnel were aware of this Adequate subcooling margin w Offsite power was restored w Approximately 17 minutes into pressure. Both NI pumps and started. Low steam line pres	pumps, coolant flow nece heat was maintained by na y Feedwater in the second and were monitoring subc- as always maintained durin ithin 40 minutes of the 10 o the event an S1 occurred 1 NV pump (1MV pump was a ssure resulted when a step	ssary for co tural circul ary system. onling parag ng the event oss of power d due to low already runn am header is	ation in the OPS weters.	
	valve remained partially oper steam usage on the secondary steam pressure and were in th leaks when the SI occurred. equipment or structural damag	side. OPS personnel were be process of securing ste It has been determined th ge as a result of the SI.	e aware of d cam usage an ast there wa	ecreasing d isolating s no	
	Pressurizer PORVs INC-32 and pressure at approximately 233 code safety valves were not c Pressurizer Relief Tank Ruptu	15 psig. The Pressurizer hallenged during the even	and Steam G it. Integri	enerator	

An Euusual Event was declared and the TSC was activated as a precaution 3 $^{-1}$ ase of the loss of offsite power and S1.

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27 ⁻ /	the VL at inspection equipment powered 1 expansion briefly a well below All Second and no movere no There we event.	r conta ir hand on was t or st by the s in ic as dess uw the ndary s uclear challes re no p th aud AL INFP	inment ling i perfor ructu D/Gs. wer cr gned. 3 psi) ssafet safet DRMATI vents: TR - PR -	t air temper inits trippi med and it cal damagt s The increa- ontainment. Maximum pr g setpoint t and accider y concerns (o fission pr nel injurier y of the pul ON:	ng off d bas been is a resu ised temp censure e for actua nt mitiga occurred coduct ba s or radi blic were t Recollect	urin, det. lt o erat. used sper tion as a rrie olog una	g the ermine f the ure re the l ience of co reso rs as ical ffect	los sd t SI. swul lce d wa onta pmer lt c a) rele	s o hat T ted Con s O inm if f t tesu tase	f p th hes in den .76 ent unc his it s a	ower. ere w e uni an a ser D psig spra tione inci of th s a r	A as ts ir ooi y, d is es is	visua no are no volumn s to o nich in is exp nt. T event	il Spen Sterr	ed s	
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	1510	510 The TD AFWP was stopped. (LB)										
	1513			n swapping lo i 4160 volt s								
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() tyre 2068 67	LICENSE	E EVENT RE	PORT (LER	TEXT CON	TINUA	TIO	N	51.8		14 8500 1480 (149 1481 (149	1. (10) 31		
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: 400/91-008 HPI unavailability for one refueling cycle because of inoperable miniflow lines April 3, 1991 Harris 1

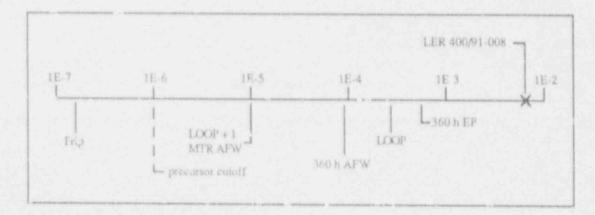
Summary.

Plant

Date of Event:

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 CS1Ps provide charging and reactor coolant pump seal injection flow during normal operation at Harris. Under accident conditions the CS1Ps 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 solution. On git 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 KWST.

During outage tosting, these reliest valves were both found to be damaged, along with associated piping. Relief valve ICS-755 failed to hold any pressure during bench testing, and ICS-744 lifted at 1100 psig. Piping upstream of valve ICS-755 was found to be cracked; this piping failed during testing. In addition, a weld indication was identified upstream of ICS-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 all mate 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 utnity 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 unevailability existed throughout the refueling cycle. To estimate the relative significance of the event within a 1-yr observation period (the interval between precarsor reports), a 1-yr unavailability period was utilized in the analysis (6132 h, assuming the plant was critical or at hot shutdown for 76% 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, bet which are not routine or involve substantial operator burden. (Use of SG depressurization and a P1 at 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 HPL.

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 x 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 ~1.3 x 10^{-4} without the use \sim SG depressurization, and 2.3 x 10^{-5} if SG depressurization and LPI were effective in providing core cooling.

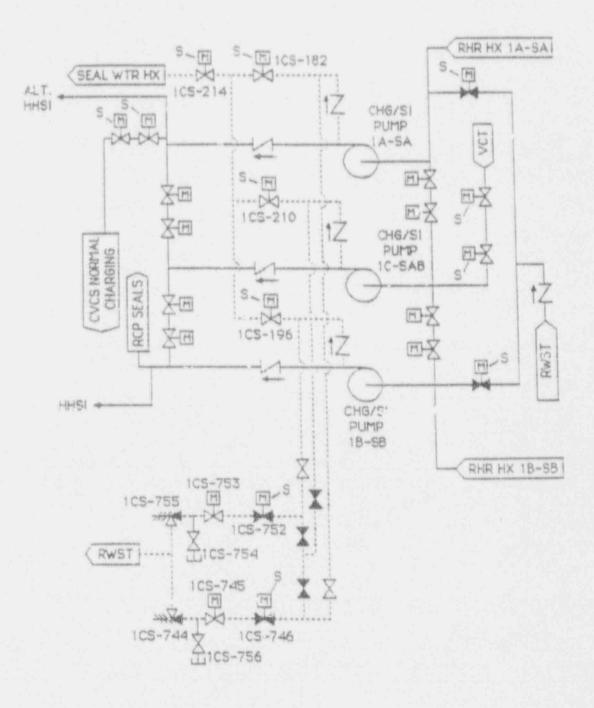
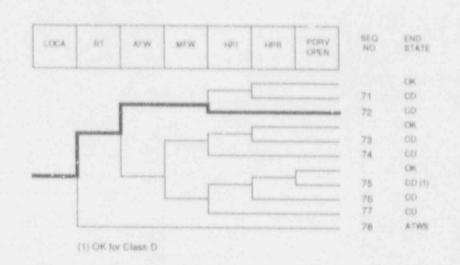


Fig. 1. Harris 1 charging/safety injection system



Dominant core damage sequence for LER 400/91-008

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 400/91-008 Event Description: HFI unavailable due to inoperable mini-flow lines Event Date: 04/03/91 Flant: Marris 1

UNAVAILABILITY, DURATION- 6132

NON-RECOVERABLE INITIATING EVENT PROBABILITIES.

TRANS LOOP LOCA	3,48.+05 5,36-02 6,38-03
SEQUENCE CONDITIONAL PROBABILITY SUMS	
End State/Initiator	Probabilit
TRANS LOOP LOCA	1,55-05 1,87-05 6,35-03
Total	6.38-03

TRANS LOOP LOOP LOOA 2.0E+00 2.0E+00 2.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End Slate	Prob	R.R.C
72 loca -rt -afw HPI		6,38-03	4.35+01
** non-recovery credit 'or edited case			
SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)			
Sequer de	End State	Prob	R Rec**

6,38-03 4,38-01

** non-recovery credit for edited case

72 loos ert eafs HPI

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:/ssp/l989/pwrbses/.cmp
BRANCH MODEL:	Cilaspilses/issils.sll
PROBABILITY FILE:	cilaspil089\pwr_ball.pro

No Recovery Limit

Event Identifler: 400/91-008

BRANCH PREQUENCIE /PROBABILITIES

Branch	Byaten	Non-Recov	Opt F#11
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loop	2.66-05	5.36-01	
Loca	2.48-04	6.36-03	
21 C	2,48-04	1,28-01	
rt/loop	0.08+00	1,08+00	
euse r.g., powerr	7,98-03	8.01-01	
ate	3,86-04	2,68-01	
afw/emerg.power	5,08-02	3,48-01	
RIW.	1,02+00	7.0E-02	1,08-03
purv.or.erv.ohall	4,08-02	1.0E+00	
pure.or.srv.reseat	2.06-02	1.18-02	
inry, or sty, reseat/emerg.; ower	2.01-02	1,08×00	
wesl.loca	2.78-01	1,02+00	
ep.two(ml)	5.76-01	1,06+00	
HU. THU	7.08-02	1,0E+00	
RPT	3.0E-04 > 1.0E+00	8.45-03 # 1.02+00	
REARCH MODELS 3:08.3			
Train 1 Cond Probi	1.0E+02 > Faile0		
Train 2 Cond Probi	1.0E-01 > Falled		
Train 3 Cond Probi	3.DE+01 > Falled		
HF1(F/B)	3.0E-04 > 1.0E+00	8,48-01 > 1,02+00	1.08-02
Branch Model: 1.00.3+opr			
Train) Cond Prob;	1.0E-07 > Failed		
Train 2 Cond Probi	1,0E-01 > .eiled		
Train à Cond Probi	3.0E=01 > Failed		
hpr/-hpl	3、为能一位者	1,02+00	1.08-03
/ DIV. DDON	1.08-02	1,08+50	4.08-04
* branch model file			
** forced			

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Event lientifler: 400/91-008

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This event is being reported in accordance with 10C(RS0.73(a)(2)(v) as an event that alone could have prevented the fulfillment of a safety function.

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EVENT DESCRIPTION:

On April 3, 1991, during the third refueling outage (BPO-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 cooditions, 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 actusted. After the secondary side of the steam generator is dry, the excess heat removal would end and the '25 would repressurize. 'to prevent CSIP failure from deadhead operation in this event, an alternate miniflow is plated into service when the normal miniflow is isolated (see Attachment 1). This alternate miniflow path is through relief valves (lCS-744 and lCS-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 ICS-754 and 1CS-756, immediately upstream of 1CS-755 and 1CS-744 respectively. Relief value 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 ICS-755 could not be determined on the available testing equipment because excessive valve seat leakage prevented pressurization. ICS-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 1C5-756 was repaired. Supports were designed and installed to prevent recurrence of this event. Based on the failure of 1CS=755, the other relief value in this system ($1CS=74\pi$) was selected for testing. The lift aetpoint of ICS=744 was determined to be 1100 psig, normal aetpoint 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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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, ICS-744 was tested in May 1989. At that time, the as found relief schoolnt was less than one percent below the acceptable range.

There have been no sigilar 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 romout 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 dOP-FRP-C.2, "Response to Degraded Core Cooling." This proceds e 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.

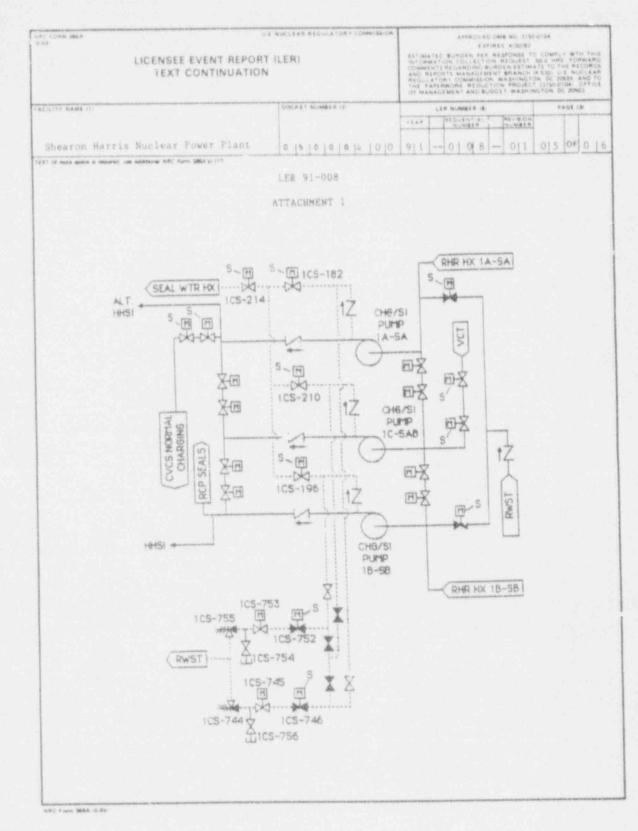
For a large break LOCA, if the CSIPs fail, LHSI Pumps would still function and would recover core cooling as decay heat production decreased. Potentially the operators would have detected CSIP runout prior to pump damage. Guidance on detecting potential CSIP runout is included in the EOP User's Guide and the indications of CSIP runout were included in operator training prior to Cyc's 2.

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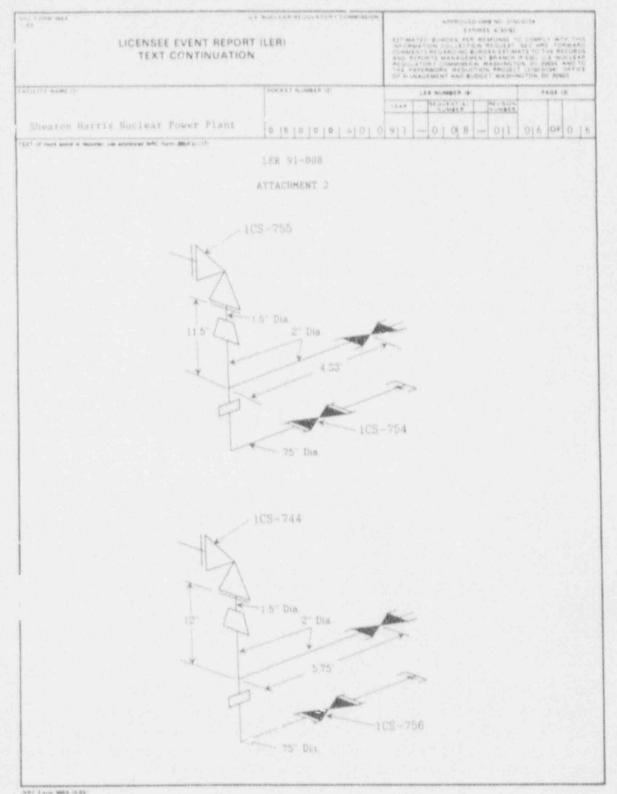
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÷.,	CTIVE ACTIONS:			
1)	The broken piping upstream or rewelding the line. The we repaired.	f test connection, Id indication upstr	1CS-754 was repair d by ream of 1CS-756 was also	
23	Supports were added to test conto prement future cracking.	unection lines upstr	ream 5, 108-754 and 108-756	
3)	Relief values ICS-744 and ICS- replaced prict to entry into Mo	755 are being rebuil ode 1.	lt and will be retested, or	
4)	Maintenance isstructions for and ICS-755) are being change and to vent the piping throu following installation, thereby	d to refill the pip ugh the relief velo	ping prior to installation vee by hydraulic pressure	
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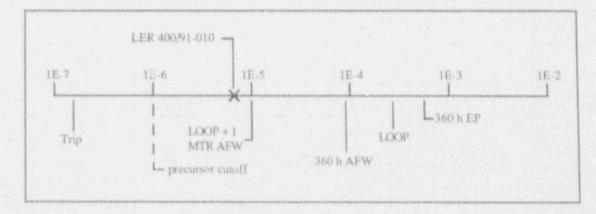
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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

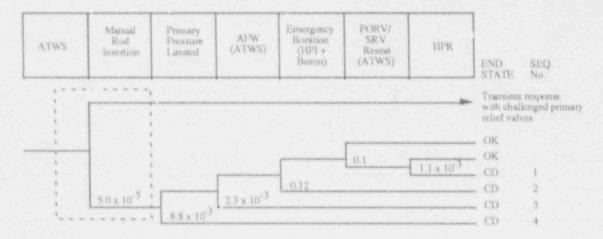
resu't of previous improper maintenance actions performed on the breaker. This type of failure, discussed in IEN 85-13, W stinghouse Technical Bulletin NSID-TB-85-16, and NUREG-1341 (*Regulatory Analysis for the Resolution of Generic Issue 115, Enhancement of the Reliability of the Westinghouse Solid 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 c neerning 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 wou..., ope 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 prever some 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)

Manual Rod Insertion

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.

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 "ail to manually trip) + $p(fail of both scram breakers) = 0.1 * 4.0 x 10^{-4} + 1.0 x 10^{-5} = 5.0 x 10^{-5}$.

Primary Pressure Limited

AFW (ATWS)

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 x 10⁻³ was assumed, based on information provided in the NUREG-1150 probabilistic risk assessment for Sequoyah.

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.

recirculation (HPR)

Failure of high-pressure A failure probability of 1.1 x 10-3 was used in the analysis, consistent with the nominal ASP model value for Harris.

5

Analysis Results

Based on the event tree model and branch probabilities described above, a conditional probability of subsequent core damage of 6.6 x 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.

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EVENT DESCRIPTION:

At 1553, 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-10056. 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-10056 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 hoard 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-70056. Reactor Coolant Flow Instrument (F-0415) Galibration. 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

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GAUSE: (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 brecker 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 Sefety 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 AFV 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).

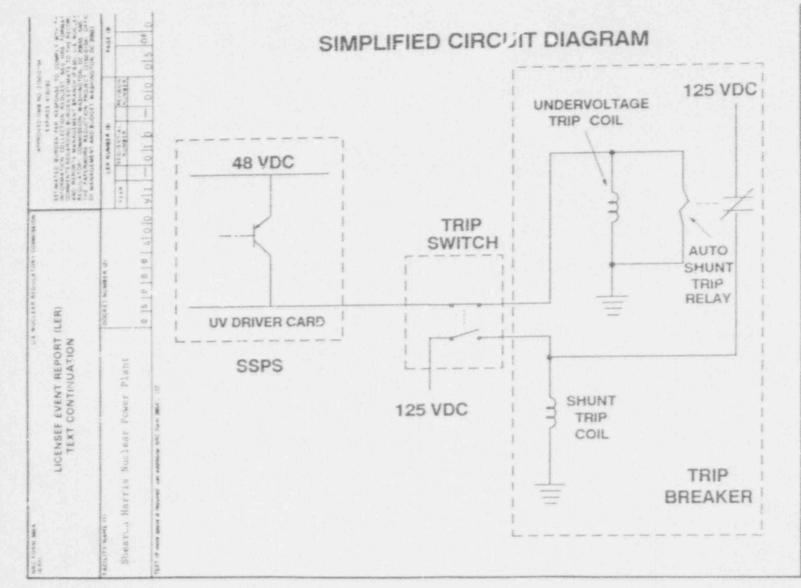
CORRECTIVE ACTIONS:

- 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.
- Replaced the failed undervoltage output driver card with a new fused card as recommended by Westinghouse Technical Bulletin NSID-TB-85-16.
- . Flaced non-fused undervoltage output driver carts on administrative hold and ordered additional fused undervoltage output driver cards.

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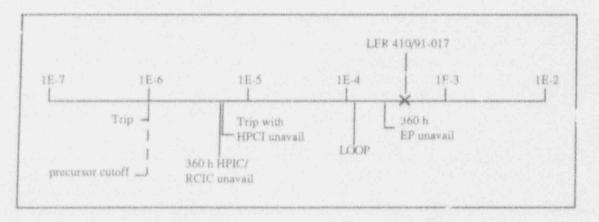
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

Event No.:410/91-017Event Description:Loss of five nonsafety uninterruptible power suppliesDate of Event:August 13, 1991Plant: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 trails 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 is 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 nonaally 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 . alves 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 " Λ " 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 till radiates "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 signids 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 one 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 nonrecovery 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
- 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 (FASS --- 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 IB

- 1. Digital memory module (DMM) --- UPS 1A backup
- Rod sequence control system (RSCS) UPS 1A backup
- 3. Rod withdrawal inhibit
- 4. Feedwater control system (FWCS)
- 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 IC

- 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.

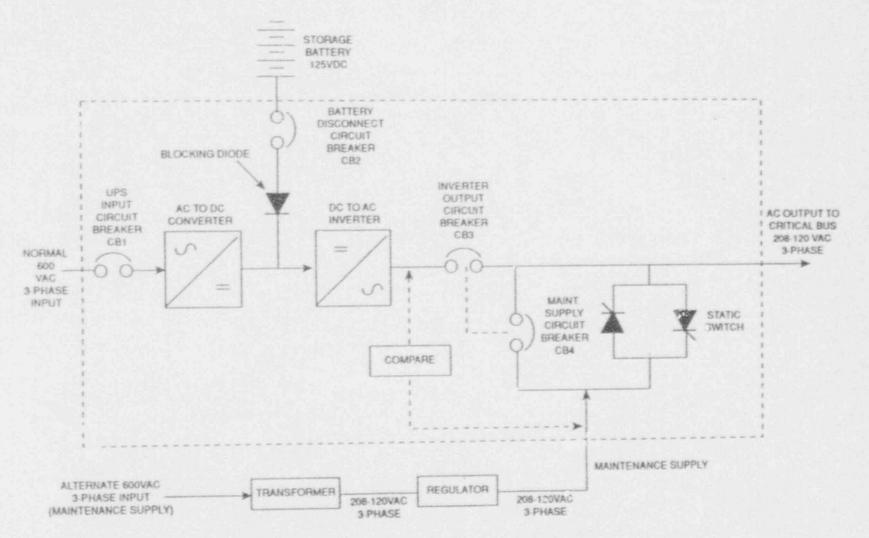


Fig. 1. Simplified electrical single line diagram for a 75-kVA 1-series UPS unit

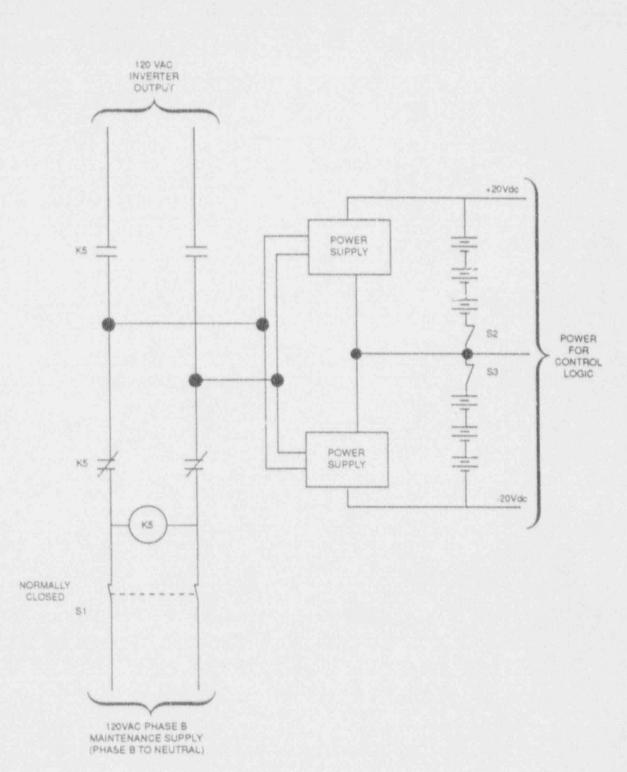


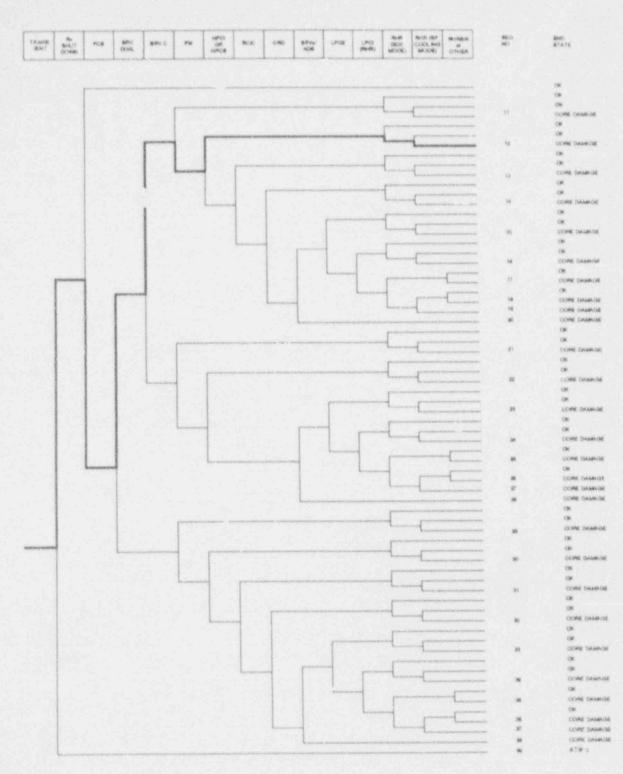
Fig. 2. Simplified diagram for UPS control logic power supply (shown at time of ev it)

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Dominant core damage sequence for LER 410/91-017

B-430

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier:	
Event Dates	Loss of five non-safety uninterruptible power supplies 08/13/81
Plants	Nine Mile Point 2

INITIATING EVERT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1,08+00
SEQUENCE CONDITIONAL PROBABILITY SUMS	
End State/Initiator	Probability
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THANS	3.06-04
Total	3.85-04
ATWE	
TRANS	3.05-05
Total	3.08-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence			End State	biop	N Rec**	
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20 trans -rs.sbut FW/PCs.TRANS		erv.chall/transscram	sr0,close	CD	4.88-05	4,18-02	
	down PCS/TRANS hpc1 RHR(SDC)	srv.chall/transscram RHR(SPCOOL)/RHR(SDC)	arv.close	CD	2.08-05	1.46-02	
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SEQUENCE CONDITIONAL	L PROBABILITIES	(SEQUENCE ORDER)					

		Seguence			End State	Prob	N Ruo +
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22	trans -Frnutdown	PCS/TRANS	RTV.chall/tranescrait RHR(SPCOOL)/RHR(SDC)	sty.close	CD	2.0E-05	1,46-02
28		PCS/TRANS	erv.chall/tranescram	scv.close	ĊĎ	4,88+05	4,18-02
9.9	trans rs.srutdown				ATWS	3,08-05	1.08+00

** non-recovery credit for edited case

SEQUENCE MODEL:	(01/085)	1989\hwrcseal.cmp
BRANCH MODEL:	/qas/10	1989\ninem12.all
PROBABILITY FILE:	calant)	1989\bwr cwll.ora

Event Identifiers 410/91-017

No Recovery Light

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trana	1.18-03	1,05+00	
loop	1.62-05	2.4E-01	
loca	3.3E-06	5,05-01	
rs.shutdown	3,02-05	1.0E+00	
rs.shutdown/ep	3.5E+04	1.08+00	
PCS/TRANS	1,72-01 > 1.02+00	1.05+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
arv.chall/tra sscram	1.0E+00	1,02+00	
arv.chall/loopacram	1,0E+00	1.02+00	
srv,close	5,96-02	1.08+00	
emerg.power	2,98-03	8.0E-01	
ep, sec	2.16-01	1.02+00	
FW/PCS_TRANS	2.98-01 > 1.08+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cond Prob:	2.9E-01 > Unavailable		
fw/pcs,loca	4.0E+02	3.4E-01	
hpc1	2.02-02	3.4E-01	
reie	6.05-02	7.06-01	
erd	1.08-02	1.08+00	1.05-02
SRV. ADS	3.7E-03 > 1.0E+00 **	7,18-01 > 1,28-01	1.0E-02 > 0.0E+00
Branch Model: 1.0F.1+op-			
Train 1 Cond Prob:	3.78-03		
lpes	2.02-02	3,4E-01	
LPCI(RHR)/LPCS	6.02-04 > 2.02-02	7.1E-01	
Blanch Model: 1.0F.3			
Train 1 Cond Probi	2.02-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
RHR (EDC)	2.38-02 > 4.98-02	3.4E=01 > 1.2E=01	1.08-03
Branch Model: 1.05.2+ser+op:			
Train 1 Cond Prob:	3,02-02		
Train 2 Cond Prob:	1.0E-01 > Unavailabl.		
Serial Component Prob:	2.0E-02		
rhr (sdc) /-lpc1	2.06-02	3,48-01	1.08-03
RHR (SDC) /LPCI	1,05+00 > 5,05+01	1.0E+00 > 1.2E-01	1,02-03
Branch Model: 1.0F.1+opr			
Train 1 Cond Prob:	1,08+00 > 5.08-01		
RRR (SPCOOL) / RHR (SDC)	2.0E+03 > 4.0E-01	3,48-01 > 1,28-01	
Branch Model: 1.0F.1			
Train 1 Cond Prob:	2.0E-03 > 4.0E-01		
RHR (SPCOOL) /-LPCT. RHR (SDC)	2,02-03 > 1,02-02	3.42-01 > 16-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-03 > 1.0E-02		
RHR (SPCOOL) /LPCI_RHR (SDC)	9.32-02 > 5.02-01	1.08+00 > 1.28-01	
Branch Model: 1,OF.1			
Train 1 Cond Prob:	9,31-02 > 5,0E-01		
thraw	2 02-02	3,42-01	0E=03

* branch model file ** forced

Minarick 05+30-1992

Event Identifier: 410/91-017

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1753 (4) R.V.83	Tran Cause	es Lo	er F 55 U	ault Cause f Annuncia	Lion Wh	or Scram at ich Led to Report Date	Dec 1	inter) aratig	ruptible on of a other	Power Su Site Area		y failu ergency		
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			1 89	ROBINITIES	-	BO TRUITION	OR THE		\$6.73ta1(21(x)		day.		a second s	
6.415									an ar an		18.1	PHONE NUM	(95 P	
ε. ς.	Tom	linso	m, s	upervisor	Reactor	Engineeri	ng, N	MP 2		3 1 1 5	3	4191	-1713	4
				COMPLETE	ONE LINE FOR	EACH COMPONENT	FAILURE	0440761#4	D IN THIS ARM	NRT (SBI			the second second	
CAUSE.	5+5*24	COMP	INENT	$\begin{array}{c} \kappa(a,A_{0,1}) \neq A_{0,1}\\ \tau_{i,1}(a,q,R) \end{array}$	NEPORTABLE TO APRUS		CAUSE	INCOME.	COMPONENT	MANUFRC TURER		NU NERDS		
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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 lated 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 7 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.

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NRC KORM MAA (6.89)	U.S. NUCLEER NELULATORY COMMISSION	8/PFROVED (SMX NO 1150-0104				
LICENSEE EVENT REP TEXT CONTINUAT	ESTIMATED BURDEN PEC REPORTS TO DOMMSY WITH THU INFORMATION CONCECTON REDUCEST BOD HER PORTMAR COMMENTS RECERDING BURDEN STIMATE TO THE RECEND AND REPORTS RECERDING BURDEN STIMATE TO THE RECEND AND REPORTS RECENTION FROM TO DESCRIPTION RECENT FOR TO DAMAGE AND RECENT AND TO THE RECENT FILL REPERPORT REDUCTION FROM TO DESCRIPTION OF MARKED RECENT BUDGET MARINESS RESERVANT					
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		VERA SECURATION MESSEON				
Nine Mile Point Unit 2	0 15 10 10 10 14 1 10	91_010	U12 OF 215			

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 ?"WS-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.

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CONTRACTOR		2.3	NUCLEAR REDUCATORY COMMISSION	APPENUVED DATE NO SIGODISE
		LICENSEE EVENT REPORT I TEXT CONTINUATION	LEA)	EXPLASE ALONG ESTIMATED BUILDER ALS REPORTED DIMEST WITH TH INFORMATED BUILDER ALS REPORTED TO DIMEST WITH TH INFORMATES BELANDING BUILDER STANATET. IN RECOM- AND REPORTS SKALADERING BUILDER IFS. DIMESTANDER ADDUCT ON REQUEST DIMENDED DIFFE UT MANAGEMENT AND BUILDET DIMENSION DE STRES DI MANAGEMENT AND BUILDET MASHINGTON DE STRES
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		C Unit 2 we extrine NRC form MBA (17)	0 0 0 0 0 0 4 1 0	91-0117-01003 012
		TION OF EVENT (cont.)		
0548	hours			
*	The Tran	main turbine tripped as a sformer.	result of an interna	I fault in the "B" Phase Main
*	resul		Reactor Recirculation	Valve (TCV) fast closure signals pump downshift to slow speed C-RPT) signal.
*	Turb	ne Bypass Valves opened t	o control reactor pre	ssure.
	Norn	al station power fast trans	ferred to reserve pow	ver.
*	Unin résp	te ruptible Power Supplies (active loads resulting in:	2VBB-UPS 1A-1D, 10	i) failed to provide power to their
	*	Loss of the plant Radio C	ommunication System	n (Radiax).
		Loss of Control Room and	iune ators.	
	*	Cooling Tower bypass value instrumentation (value ma		power to temperature monitoring tation reserve pr. Ser).
	•	Emergency Response Faci Recording System (GET)	lity (ERF) computer, G ARS). Gaseous Efflu	arameter Display System (SPDS), eneral Electric Transient Analysis ent Monitoring System (GEMS) ital Radiation Monitoring System
	*	Loss of plant GAltronics of	communication and p	aging system.
		Partial loss of the plant te	lephone system.	
	*	Loss of Balance of Plant (BOP) instrumentation	
	*	Locs of Essential Lighting	Inormal system light	ing remained operational).
		Non-safety relaxed Control	I Room recorders fai	led as is.

A MARINE

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FACILITY RAME (1)	EXCREMENT AND AND A TOP	LER BUILDER (B)	PAGE 18
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TEXT (2 mass space a reduced, one address $BR(-, c = MER(t))/T$			
L. DESCRIPTION OF EVENT (cont.)		
 Reactor Feedwater let 	vel control valves locked	up in the open position	6 - 1993 1993

- 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 automatin 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

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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 autumatic reactor scram had not yet occurred.

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LICENSEE EVENT REP TEXT CONTINUAT		4.51 Met. D. BUNKLER, SER. BERMUNST, N. COMBLER, K. BETTE, SAND DERUMAN, SAND, SER. SER. SER. STREAM, STREA
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Nine Mile Point Unit 2	0 16 10 10 10 14 1 10	9 1 - 0 1 7 - 0 0 0 5 OF 2 5
TERT of nova agains a menalist our additional ADU fairs MRA 371031		

L. 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.

Q556 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.

2000 bours

- Due to losu of Control Room annunciation with a plant transient in progress, the SSS at sumed 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.

LICENSEE EVENT REI TEXT CONTINUA		APPROVED DAME NO 3160 0104 \$470861 4.00%0 851 WATED BURDIAN FER REA 1900 10 COMMENT WITH THE MEDIAN TON DOLLATION
FACILITY NAME ())	DUCKEY WUNNER IS	LER NUMBER 16 PAGE (5)
Nir- Mile Point Unit 2	0 10 10 10 10 14 1 1 0	91 - 011 7 - 00 016 or 215
The stream is a requirement over another an ARC Form 300.4 (111)	an an an an Anna Anna Anna Anna Anna An	
- RESCRIPTION OF EVENT (con	(L.)	
0612 hours		
Nuclear Regulatory Comm	ission was notified via the	Emergency Notification System.
Q614 hours		
	to condensate storage tar	ystem realigned to full flow test nk). This line up leaves the ICS

0615 hours

- Reactor vessel water level reached Level 8 (202.3 inches).
- The Condensate Booster pumps were secured to limit the reautor 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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	LICENSEE EVENT REPORT (TEXT CONTINUATION	LERI	43/14 34/10 60488 44(1) 84/54 147 67/6	10 1 6 5 1946 A 10 9 7 1 6 10 9 7 1 6 10 9 7 1 10 10 9 7 10 10 9 7 10 10 9 7 10 10 9 7 10 10 br>10 10 10 10 10 10 10 10 10 10 10 1	RUMORA PE RUMORA PE PELOARDING TELOARDING TELOARDING RUMA PELO RUMA PELO RUMA PELO RUMA PELO	th H.E.S.F.	inteste its Inpakiti	 C. COMPLET And G. KRABA And G. KRABA And G. KRABA And G. KRABA C. C. BARAA C. C.	ALCO ALCO ALCO ALCO ALCO ALCO ALCO ALCO	11425 (c.R.).5 (c.R.)
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I. DESCI	RIPTION OF EVENT (cont.)									
0630 ho	urs									
six th	e full core display, when resto which had no indication. Ope e Rod Worth Minimizer (RWM) equence Control System (RSC)	rators also observed and that 15 rodr 1.	that	<u>arie</u>	rod ha	d no	indi	cation	on	
70	ywell unit cooler fans were r corded was 165 degrees Fat mained below 150 degrees Fa	venheit. The high								
0640 ho	MD8									
with th in a er th	andensate Booster Pump 2CN ithiu a band of 165 inches to 1 e Reactor Feedwater pump su e pressure across the valve (at the Turbine Building). The val result, reactor water level de itered Emergency Operating P e Reactor Feedwater pump by vel.	80 inches. Control I ction valves 2CNM- I SSS direction due t vs5 would not open creased to Level 3 rocedure N2 EOP-R	Room MOV8 o unk prech (159 PV C	ope I4A Idin 3 i)pe	and B and B vn radio og flow nches) rators f	atten with slops to th and subse	npte out e cal c le rai ope aqué	d to oj aqualiz onditio actor rators intly u	ing ing ans As re	1
0650 hc	Sur B									
P:	umpers were installed to by rocedure N2 EOP 6, "NMP2 E actor scram with a scram sign raining the scram discharge vo	OP Support Proced hal still present. Th	ure", is acti	atta	achmer was pe	nt 14 rton	h, to ned	reset to per	thi mit	0

0653 hours

rods had it been required.

- 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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LICENSEE EVENT REPOR TEXT CONTINUATIO		APPRICIAL CARE AS INCOMENTS AND A STATEMENT AND A STATEMENT AS AN AN A STATEMENT AS AN AN A STATEMENT AND A ST
FACTORY MARKET	DOCALL ROMALS D	LER BUILDERT IS FAUS IS -EAS LEADER IS RULES -EAS LEADER IS NUMBER
Nine Mile Point Vait 2	0 16 10 10 10 14 1 10	911-0117-000180+215
TAN' (R mania pasca a magament, and a spectrum RAC Rain, Mellol 5, 117)		
L. DESCRIPTIC N OF EVENT (cont.)		
0700 hours		
 Commenced minuel monitorin GEMS computers. 	ng of various plant efflu	ents due to the loss of DRMS and
0711 hours		
Plant process computer was	restored.	
Restarted the Division II Prim	ary Containment Hydro	igen/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 Decirculation System flow control valves were fully opened.

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CX - 14-14 (L)			

LICENSEE EVENT REF TEXT CONTINUA		APPENDICAL DAVE NO. 3150/0104 EXTERNAL AVAINTS EXTERNAL AVAINTS EXTERNAL AVAINTS EXTERNAL DAVE AVAINTS EXTERN
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Nine Mile Point Unit 2 References and a state of the last state of the	0 6 0 0 4 1 0	911 - 611 7-010 019 01 21
L. DESCRIPTION OF EVENT (cont	L.)	
0810 hours		
 RHR loops B and C were re 	turned to operable status.	
Q821 hours		
 The ADS inhibit was removing RP were removed, rastoring RP 		to automatic, and the jumpers
0834 hours		
 Verified that no adverse rad 	liological conditions existe	d on site.
0847 hours		
The Stack GEMS computer	was declared operable	
0857 hours		
 Initial reports from Offsite F normal at background levels 		fearns indicated readings were
0937 hours		
closed. Uperators de-ene	ergized the motor oper hnical Specifications and	AOV156 did not indicate fully ated injection shutoff valve declared ICS inoperable. (ICS antrol).
0950 hours		
		r sources. 2V88-UPS 1A & 18 herefore, they were left on their

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	LICENSEE EVENT REPOR TEXT CONTINUATION		B) MARA TORI DOL, ECTION RECEDUAT SUIT VAL FORMATI O'MMARAYA RIDATONO BUTCH STOLATS SUI VAL FORMATI O'MMARAYA RUDATONO BUTCH STOLATS TO THE RUDBOO BOD REDITS BREAKLAR OF BARACHI PERSON UN POLICER RUDULATORI COMMISSION READINGTON DE DESIGN OF FOIL DE REACHMENT ARC RUDOT REACHINGTON OF DESIGN. DE REACHMENT ARC RUDOT REACHINGTON OF DESIGN.
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	Mile Point Unit 2	0 16 0 0 0 0 413 0	0 9 1 - 0 1 7 - 0 0 10 0 2 5
1. 025	SCRIPTION OF EVENT (cont.)		
1000	hours		
•	the event (0548 hours). Of	perations Surveillance perability Test*, which	RVs had lifted at the beginning of Procedure N2-OSP-ISC-M@002, h is a test required by Technical ad by 1006 hours.
1020	hours		
	21/3B-UPS 1G was restored t	o its normal power su	ipply.
1031	hours		
	The Group 9 isolation was re	set	
1055	hours		
*		eactor water to the co	S-P1B was started and the system ondenser hotwell. This action was d reduce reactor water level.
1056	hours		
*	WCS isolated (Group 6 and 7 2WCS P18	' isolation) due to a hig	gh Deita Flow signal, tripping pump
1151	hours		
*	Operations Surveillance Proc Operability Test*, was comp		t@002, *Drywell Vacuum Breaker
1158	hours		
*	RHR loop *A* was secured 2RHS*P1A was secured.	d from the suppressi	on pool cooling mode and pump
1217	hours		
	Group 4 isolation, RHR samp	le and discharge to ra	dwaste isolation valves, was reset.

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NEC ZOAN MAR GAR	OF ADDIERS REDUCTION COMMUNICIES	APPROVED THAT HE STORE	127.00K
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L. 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 domineralizer 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.

1508 hours

Residual Heat Removal pump 2RHS*P1B was started in the shutdown cooling mode.

15' y 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.

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1943 hours

SED terminates the Site Area Emergency.

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	van antelenaar fell (Jaare 2004 v. 117) Politie (15. j. 12. j. 1			
II. CAUSE				
Transforme	ir Fault			
up Transfo differential the main g	rmer (2MTX-XM1B) which d and the overall unit different	eveloped an internal ial relays activated to ine. This resulted in	*B* Phase Main Generator Step- fault. The *B* Phase transformer isolate the fault by disconnecting a turbine trip causing a reactor p Valve closure.	
	an actual root cause of the f, will be submitted in a sup		cannot be suggested and when rt.	
UPS Failur	e			
UPS's (2V respective	BB-UPS1A, 1B, 1C, 1D, 1	and 1G) tripped res ation has been comp	in step up transformer, five Exide uiting in loss of power to their leted in accordance with Nuclear	ŕ
of a logic i on the ma maintenan below its t the mainte	nitiated trip. The failure of t sintenance power supply to ce power sup, y caused th rip setpoint, causing the uni	he "B" Phase Main T o all five UPS units e voltage on the UP ts to trip. Concurren	ide UPS units shutdown as sul ransformer caused a voltage c. The degraded voltage on thi S logic power supply to decreasi itly, the automatic load transfer to be degraded voltage conditions of	e e o
UPS is not supply. Th	designed to accommodate a	a degraded voltage co illowed the UPS logic	IPS units is improper design. The prodition of the maintenance power power supply voltage to decreas step-up Transformer fault.	61
•	The logic power supply is with the inverter output	normally energized f as a backup versus	rom the maintenance power supp inverter preferred.	lγ
•	Under degraded voltage on not actuate until the sup will cause the logic to tr	ply voltage has deci	ower supply switching circuit do eased to well below the level th	es at
C. C. P. de L	Consider and the process devices of an experimental probability of the second probability o second probability of the second probability of the			

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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 fest closure/Turbine Stop Valve closure) initiated from the "B" Phase Main Generator Stepup 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 W^S pump discharge value 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 fiashing 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 6 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 pocurred.

Group 9 Isolation

When the UPS failure occurred, GTS Effluent Monitor 2CTS-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 monual or automatic activation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS)*:

- Automatic reactor sciam.
- 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 linitiated at 1006 hours, complete 1151 bours). 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 workurs.

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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 discharga 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 (USA9, 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 Loed Rejection with bypass) 1070 psig vs. 1150 psig.
- Reactor water level as shown on both PAM recorders is slight' 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 1.-c. jired

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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 Sile 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 carrective actions include:

- The spare main transformer was connected to the "B" phase and pre-operational testing was completed.
- 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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1X.	CORRECTIVE ACTIONS (cont.)				
3.	The logic power supply for 21 inverter preferred with the magnetic sectors and the magnetic sectors and the sectors and the sectors are set of the sectors and the sectors are set of t) and 1G has been modified to be back-up.		
4.	All the UPS internal batteries	have been replaced.			
5.			t utilizes internal batteries. It was an any of these internal Catteries.		
6.	Changes have been incorport design deficiencies.	ated in the vendor man	ual to address the identified UPS		
7.	An evaluation is in progress to assess further UPS logic power supply modifications.				
8.	A replacement schedule for supplier recommendations an		nes is being developed based on lions.		
9.	Vvater Cleanup System", to	re-order the steps to	ng Procedure N2-OP-37, "Reactor assure system back pressure is Id cause system depressurization.		
<u>Y</u>	ADDITIONAL INFORMATION				
A.	Failed components:				
	Component description	 "B" phase output transi 			
	Ratings		degree Celsius rise,		
	Manufacturer	- McGraw Edi			
	Mark number	- 2MTX-XM18			
	Seriel number	- C-06607-5-2			
	Niagara Mohawk drawing Niagara Mohawk spec	EE-NO1A EO11A			
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V. ADDITIONAL INFORMATION (cont.)

Minute and the set Minute second		
Component description		Uninterruptible Power Supply
Ratings		75KVA, 60KW
Manufacturer	1.1	Exide Electronics Corporation
Mark Number		2V8B-UPS1A, 1B, 1C, 1D and 1G
Model Number		Mark II
Nagara Mohawk drawing		EE-OO1BH
Niagara Mohawk spec		EO35A

Previous similar events: none

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V. ADDITIONAL INFORMATION (cont.)

C. Identification of components referred to in this LER:

COMPONENT	IEEE 803 EIIS FUNCTION	IEEE 805 SYSTEM
Control Room Annunciation	N/A	1B
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	V8
Reactor Water Cleanup System	N/A	CE
B Phase Main Transformer	XFMR	EL.
Uninterruptible Power Supply	UJX	EE
Reactor Feedwater Pump	р	SJ
Condensate Pump	P	SD
Condensate Booster Pump	P	- SD
Residual Heat Removal Pump	Р	BO
Post Accident Monitoring Recorder	XR	IP .
Reactor Recirculation Pump	P	AD
Safety Relief Valves	RV	SB

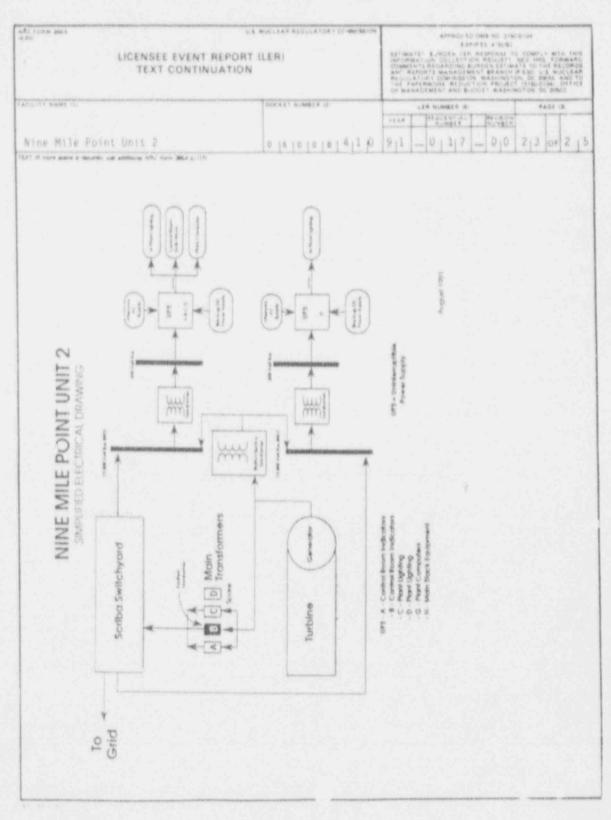
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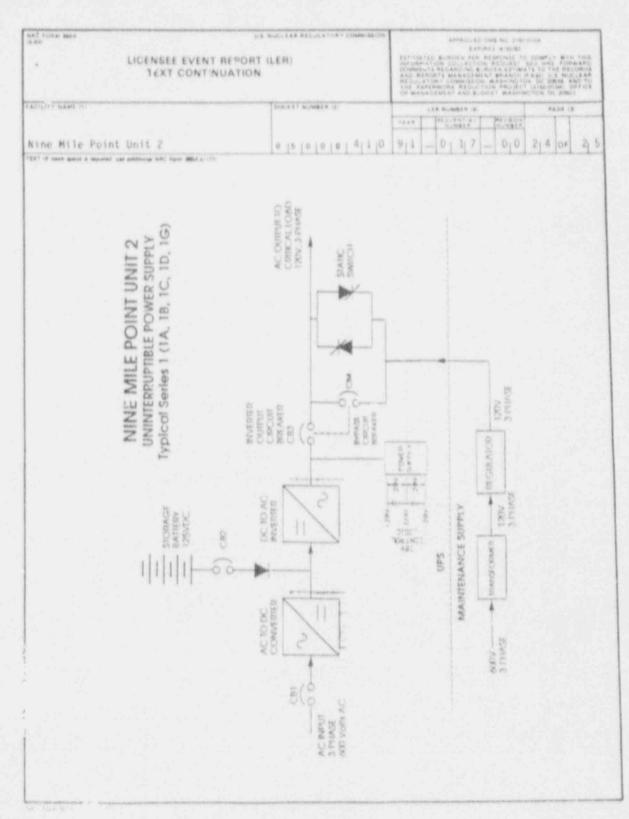
V. ADDITIONAL INFORMATION (cont.)

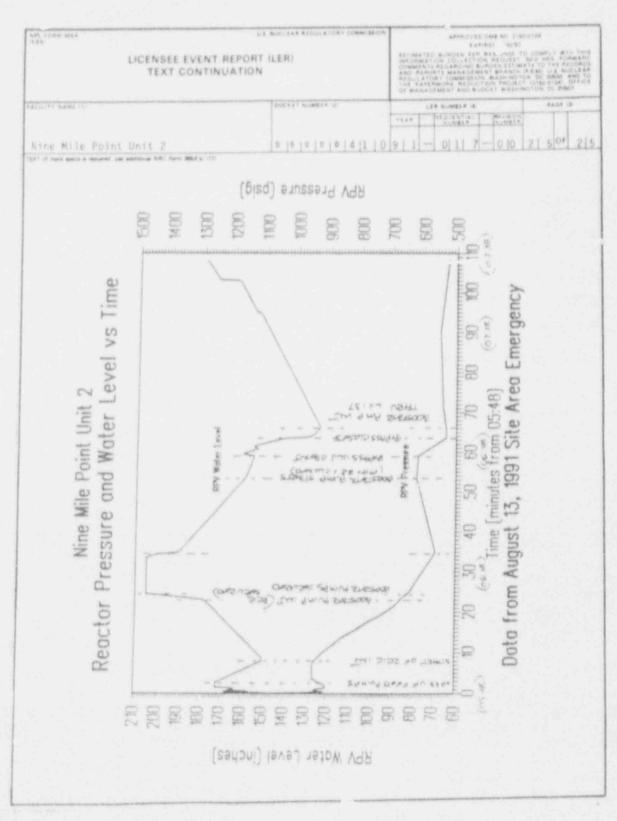
COMPONENT	IEEE 803 EIIS FUNCTION	IEEE 805 System ID
Plant Process Computer	CPU	ID
Alarm Typer	TTY	ID
Turbine Stop Valves	SHV	AT
Turbine Control Valves	FCV	AT
Turbine Bypass Valves	FCV	ال
Radio Leaky Wire	ANT	Fi
Cooling Tower Bypass Valve	V	KE
Feedwater Level Control Valves	LCV	SJ
Minimum Flow Valve	FCV	SJ/SD
Average Power Range Monitor Recorders	MTR	IG
Average Power Range Monitor Meters	PR	IG
Reactor Recirculation Flow Control Valve	FCV	DA
Condensate Storage Tank	ΤK	KA
Containment Vent and Purge Isolation Valve	15V	VB
Radiation Monitor	RIT	BH
Condenser Mechanical Air Removal Pump	Р	SH
Reactor Water Cleanup Pump	Р	BF
Drywell Vacuum Breaker	VACB	BF

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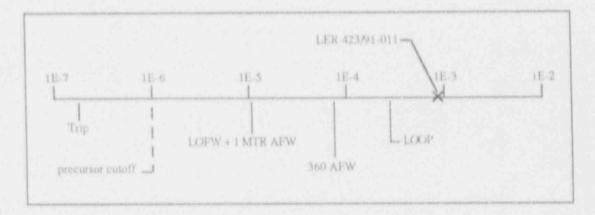
ACCIDE: T SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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 e-tuated 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 anavailability 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 assure a 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} .

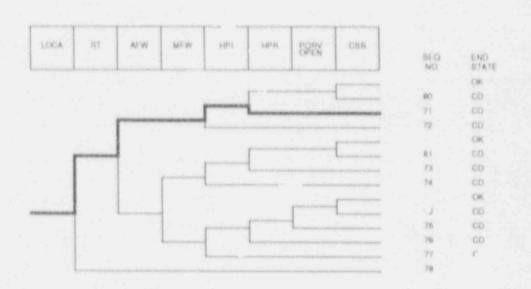
Note that while flow through the relief valves during injection would render the HPS1 ineffective (requiring the ch. ging pumps for injection), flow through the relief valves after sump switchover to his appressure recirculation (HPR) would result in loss of containment sump inventer and eventual failure of HPR. This situation could be detected through changes as 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

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B-461

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: Event Description; Event Dete: Fiant:	823/91-011 Both trains of HPEI unexai 04/10/91 Millatone 3	lable (CF# provide suc	(###)	
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7,48-04 6,38-05

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Noie: For unavailabil-ties, 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.

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PROBABILITY FILFS		/qas/	1999	pair.	Bull.	pro.

Event Identifier: 423/91-011

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BRANCH FREQUENCIES/PROBABILITIES

Hranch	System	Non-Recov	Opr Fail
ETANA	4.68-04	5,06+00	
1000	1,00-05	3,36-0;	
1004	2,42-06	4,38-01	
	2,08-04	1,28-01	
-1/loop	0.02+00	1.0E+00	
emerg.power	2,92-03	8,05-01	
atw	3,82-04	2,65-61	
afw/emerg.power	5,02-02	38-01	
MEM .	2,0E-01	3,48-0"	
porv.or.arv.chall	4,02-02	1,08+00	
porv.or.erv.reseat	2.02-02	1.18.+02	
porv.or.arv.reseat/smerg.nower	2,08-02	1.0E+00	
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ep.ret	1.52-01	1,02+00	
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Train 2 Cond Prot:	1.08-01		
porviopen	50-30.1	1.00+00	4,02-04
HPR/+HPI	1.58-04 > 1.58-04	1.02+00	1.0E-03 > 1.2E-01
Branch Model: 1.0F.2+opt	2130-224 N. 7150-54	4.190.799	TTAP-A3 & TTEP-A1
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* branch model tile ** forced

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	This event is being reported in accordar alone could have prevented the fulfilline consequences of an accident and 10CP caused two independent trains to becom consequences of an accident. An immed 10CFR30.72(b)(2)(ai)	nt of the safety funct R50 73(a)(2)(vit), at e moperable in a sing	ion of sys an even de system	ster c w t d	ms nei here i esigne	eded i sin d to	i o) pie o miti	mitig cause cause	ate the		an
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	When the event occurred, shift management declared the s Technical Specification action 3.0.3. The failed "A" stain r The temporary gagging device, previously installed on the " failures while investigating the lifting problems, was removed system was declared operable following the removal of the S.S.2 a was invoked. The system design pressure was teana "B" train relief valves was increased to 2250 psia from 176 analysis.	elief valve (3SIH*RV8853A) was gagged shut. B" train relief valve (3SIH*RV8853B) to limit d, and the "B" train of the safety injection gagging devices and Technical Specification lized and the setpoint of the "A" train and
	A test procedure was written, approved, and performed that surveillance procedure to duplicate the conditions that exist Instrumentation was installed on the safety injection system by the rels i valve. The testing verified that the pressure in pressure T, e test procedure verified that other combinatio subject the relief valves to pressures higher than their new	ed when the relief valve lifted to provide a trace of the actual pressure seen the system exceeded the relief valve setpoint ns of valve and pump manipulations did not
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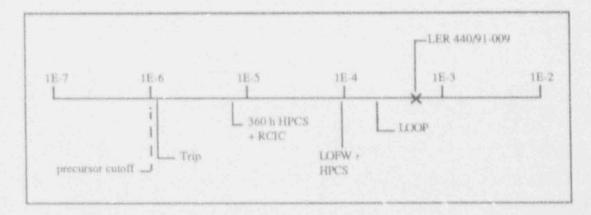
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 440/ Event Description: Two Date of Event: Mar Plant: Perr

440/91-009 Two EDGs inoperable March 14, 1991 Perry

Summary

Perry was operating at 160% 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 sh Clown 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.

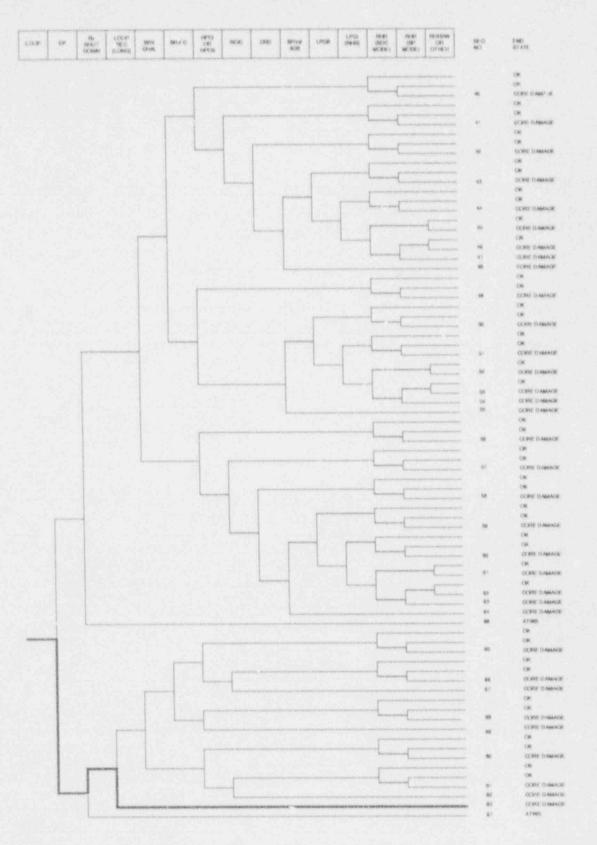
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Dominant core damage sequence for LER 440/91-009

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 440/91-009 Event Description: Two emergency diesel generators inoperable Event Dates: 03/14/91 Plant: Petry 1			
UNAVAILABILITY, DURATION- 360			
NON-RECOVERABLE INTELETING EVENT PROBABILITIES			
LOOP	8,16-03		
REQUENCE CONDITIONAL PROBABILITY SUMS			
End State/Initiator	Frobability		
LOOP	5,38-04		
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Total	0.06.+00		
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SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)			
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Note: For unavailabilities, conditional probability values are suded risk due to failures associated with an event. Parenthetl compared to a similar period without the existing failures,			
SEQUENCE MODEL: c:\asp\1989\bwccseal.omp BRANCH MODEL: c:\asp\1989\perry.sll PROBABILITY FILE: c:\asp\1989\bwr_call.pro			

HRANCH FREQUENCIES/PROBABILITIES

Branch	Systam	Non-Recov	Opr Fail
trans	7,78-04	1.08+00	

Event Identifier: 440/91-009

.oop	1.62-05	5.38-01	
1004	3.38×06	5,08-,1	
rs.shutdown	3,08<05	1.0E+00	
rx.shutdown/ep	3,58-04	1,0E+00	
pos/trans	1,76-01	1,05+00	
ar'.chall/trans.~acram	1.0E400	1.0E+00	
arv.ohall/loopacram	1.02+00	1,08+00	
srv.close	6,32-02	1.08+00	
EHERG.POWER	2,9E-03 > 1.0E+00	0.0E-01 > 1.0E+00	
Stanch Model: 1.OF.Z			
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Train 2 Cond Pretty	5.7E-02 > Failed		
ep.rec	1,72-01	1,02.+00	
fw/pca.trans	4,68-01	3,42-01	
fw/pos.loca	1.05+00	3,48-01	
hpc1	2,02-02	3,48-01	
reic	6,0E-02	7.08-01	
crd	1.0%-02	1.0E+D0	1.08-02
stV.ads	3,76-03	7.18-01	1.0E-02
lpos	2.0E+02	3.4E-01	
lpc1(rhr)/lpcs	6.0E-04	7,12-01	
tht (adc)	2.3E-02	3,48-01	1,06-03
chr(ade)/-lpc1	2.01-02	3,4E=01	1,06-03
thr (sdc) /lpci	1.0E+00	1,00+00	1.0E-09
thr empts all / thr (sdc)	2.08-03	3,48-01	
rhr(spoool)/~lpci.rhr(sde)	2.0E-03	3,4E-01	
chr(apucol)/lpci.r)r(ado)	9.38-02	1.02+00	
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1. 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 pravious monthly surveillance test. With the Division 2 DG inoperable, there was no diesol 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 Fressure Vessel [RPV] at saturated conditions at approximately 1040 psig.

11. DESCRIPTION OF EVENT

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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 I 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.

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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 KI parts were available from warehouse stock. Therefore, it was decided to obtain the required field contactor KI 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 mere transferred from the Division 4 DC at 1800. Fellowing inspection, installation, functional testing and one successful maintenance run to verify proper latching of field contactor KI, 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 2302.

III. CAUSE ANALYSIS

The root cause of the Division 2 DG failure was a failure of the field contactor KI (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 coll 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 coll 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 Kl 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 minutee

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every 31 days in accordance with Per- The root cause of the Division 1 D malfunction. After the successful synchronize the generator with the respond in the lower direction. E Division 1 DG governor controls af switch on the motor operated poten component. Based on the performan control in the lower direction fro malfunction was isolated to a small relays, the governor lower limits included visual inspection, cleani limit switches, verification of al testing. However, the conditions functioning during the surveilland troubleshooting. Although no cond speed control malfunction could be causing the event were corrected d tripping coil assembly from the Di Division 1 DG along with a new car	G surveillance test engine start, when grid, the manual g xtensive troublesho ter the engine was tiometer appeared t ice of automatic res m either local or t l portion of the ci witcl and associate eng and exercising a l terminations, and that prevented the e test could not be clusive cause of the identified, it is iuring these mainten tvision 2 DG was set	suspension was equip operators attempted overnor control fails oting was performed of shutdown. The lower o be the malfunction: et and the lack of me emote locations, the rouit that includes of wiring. Troublesh- ill accessible contac- is appropriate mainten governor speed contr e recreated during su believed that the co- nance activities. The rviced and reinstalle	ement to ed to on the limit ing anual two ooting ts and ance ol from bsequent nor nditions e d on the		
warehouse. Followup investigation determined prohibited synchronizing the Divis the DG to be declared inoperable, loads under accident conditions. Division I DG test was not conside capable of performing its intended provided power promptly to the eng- loss of offsite power occurred.	that the problem w sion 1 DG with the would not have pre Thus in accordance ered a valid failur d safety function.	ith frequency control preferred source and vented the DG from as with R.G. 1.108 c.2. e since the DG was fo The Division 1 DG co	, which required suming e.2, the illy puld have		
IV. SAFETY ANALYSIS					
The Standby Dicsel Generator System the Division 1, 2 and 3 Class IE 1 offsite power supplies. During th from two physically independent consite electrical distribution sy Spray System [BG] (HPCS) and its operable during this event. Upon Division 1 DC could not be determ	huses in the event he entire event, Cl ircuits from the tr stem. Additionally associated diesel g failure of the syr	of a loss of the red ass lE power was ava ansmission network t , the High Pressure generator were verifi- achronizing mechanism	undant ilable o the Core ec , the		

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demonstrate loading capabilities pe however, the Division 1 DG was capa voltage until it was further disabl repairs to the Division 2 DG. The both Division 1 and 2 DGs were inca their respective busses. Therefore because the loss of Division 1 and outside Updated Safety Analysis Rep scenatios.	ble of responding p led by the removal o total time was 11 h spable of responding t, the event is cons 2 backup power supp	roperly to a loss of f parts to expedite th ours and 55 minutes th to a loss of power th idered safety signifi- lies results in condi-	bus he hat o cant
Previous similar events with two or were identified in 15Rs 87-009, 89- caused by failures of the field con- mechanisms. Two previous plant even involving the field contactor K1. latching mechanism resulting from a failure of the Division 1 DG (refer 1990). The second event in December inadequate Periodic Test Instruction Division 1 contactor and the switch actions from this event, the Divis February 12, 1991 for similar dama, Subsequent to this inspection acti- contactor was verified by independen diesel generator on February 14, 1 on the Division 2 DG is, therefore the cause for malfunction.	-001, and 90-005. N Intactor K1 assembly ents documented in C The first occurrence aged grease. This r rence letter PY-CEI/ er, 1990 was due to on, resulting in an hing contact welded. ion 2 contactor was ge and found in sati vity, proper operation ent maintenance and 991. The failure di	one of these events w or the diesel governo ondition Reports occu e was due to a sticky esulted in a valid te NRR-1120L dated Janua performance of an open closing coil on As part of the corr inspected by work ord sfactory condition. on of the Division 2 surveillance runs of accovered on March 14,	ere r rred st ry 19, the ective er on the 1991
VI. CORRECTIVE ACTIONS			
Corrective actions previously iden have prevented this event from occ		ted would not be experi	ted to
The following corrective actions w	ere or will be comp	leted to prevent recu	rence;
 The Division 2 DG carrier asse for failure analysis. Conclus failure analysis will be evalu conjunction with the DG engine action(s) will be implemented 	ions and recommenia iated by the respons ering support group	tions as a result of 1 tble system engineer	the In
2. Notification of this even was General Motors EMD) on Ap il 4		Owners Groups (DeLav	al and

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3.	Implement design changes (DCP reliability of the field conta position and addition of an el- should prevent undetectable fa diesel generator to be inopera implemented on the Division 1	ctor (K1) by monito ectrical seal-in fo ilures of the field ble. These design	oring eature d brea	critical co . This der ker Kl caus	imponer ilgn c ilng t	hange	
1.4	Revise Periodic Maintenance In incorporate specific inspectio Division 1 and 2 field contact	n criteria and ser	Panel vice r	Maintenance equiremente	e" to s for	both	
5.	Revise Instrument Maintenance Maintenance" to incorporate ap both Division 1 and 2 governor	ecific inspection	and se	rator Gene rvice requ	ral iremen	its for	r
	s submittal satisfies the requi	rements of Technic	al Spe	cification	s 4.8.	1,1,3	

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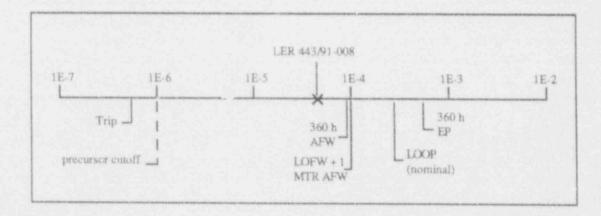
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No .: 443/91-008 Event Description: Date of Event: Plant:

Loss of offsite power June 27, 1991 Setbrook

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 decrees probability estimated for this event is 4.4×10^{-5} . The relative clenificance 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 piant 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.

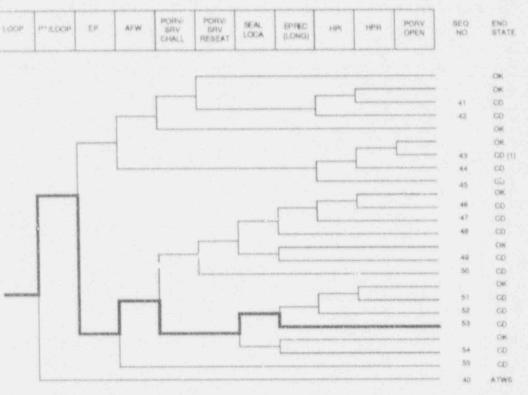
ASP Modeling Assumptions and Approach

The event has been modeled as a plant-centered LOOP. Probabilitics 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.



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Dominant core damage sequence for LER 443/91-008

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Date:	443/91-008 Loss of offeite power 06/27/91 Seabrook 1	
INITIATING EVENT		
NON-RECOVERABLE INT	TIATING EVENT AN BABILITIES	
LOUP		1.28-01
SEQUENCE CONDITIONA	L PROBABILITY SUMS	
End Stat /Init	lator	vrobability
cp		
LEXOP		4,42-05
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1.009		0.02+00
Total		0.02+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY OFDER)

sequence	End state	Prob	N Rec**
53 LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chail SEAL.LOCA EP.REC(SL)	CD	2,98-05	9.58-92
54 LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - BEAL.LOCA EP.REC	CD	9,58-06	9.5E-02
55 LDOP -rt/loop emerg.power afw/emerg.power 18 LOOP -rt/loop emerg.power ~afw/emerg.power porv.or.srv.chall ~ porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD CD	4.7£=05 1.2k=06	3.38-02 9.58-02

** non-recovery credit for edited case

BEQUENCY CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	1.28-06	
48 LXOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - CD porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	1.48-00	9,58+02
53 LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.wrv.chall CD SEAL.LOCA EP.REC(SL)	2.98-05	9,58-02
54 LOOP art/locp emerg.power afw/emerg.power aporv.or.arv.chall = CD SEAL.SOCA EP.REC	8.58+06	9,58-0,2
55 LOOP -rt/loop emerg.power afw/emerg.power CD	4,78-06	3.38~02

** non-recovery credit for edited case

SEQUENCE MODEL:	01	asp/1989/j.wcbseal.cm	Ø.
BRANCH MODEL:	1051	asp\1989\seabrook.sl	1
PROBABILITY FILE:	251	asp\1989\pwr ball.pr	

Event Identifier: 443/01-008

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opt Fail
trans	5.38-04	1,05+00	
LOOP	1.6E-05 > 1.6E-05	E.3E-01 > 1.2E-01	
Branch Modeli INITOR			
Initiator Freq:	1.68-05		
100a	2.42+06	4,38-01	
18 The Physics Physics Physics 1998	2.85-04	1,28-01	
rt/100p	0.08+00	1.02+00	
emerg.power	2,91-03	8,01=01	
afw	1.31-03	2,68-01	
afw/emetg.power	5,0E-02	3,48-01	
mfw	1,05+00	7.08-02	
porv.or.arv.chall	4.0E+02	1.02+00	
porv.or.srv.reseat	2.08-02	1,16-02	
porv.or.srv.reseat/emerg.power	2,08-02	1,02+00	
SEAL, LOCA	2,78-01 > 2,38-01	1,05+00	
Branch Model: 1.DF.1			
Train 1 Cond Prob:	2.78-01 > 2.38-01		
EP.REC(SL)	5.7E-01 > 4.8E-01	1.08/00	
Branch Model: 1.OF.1			
Train 1 Cond Probi	5,7E-01 > 4,8E-01		
EP, REC	7.05-02 > 4.35-02	1.08+00	
Branch Model: 1.0F 1			
Train 1 Cond Prob:	7,01-02 > 4,38-02		
hpt	1.0E-03	8,42-01	
hpi (c/b)	1,02-03	8.48-01	1.08-02
hpr/-hpi	1.55-04	1.08+00	1.02-03
porv.open	1.08-02	1,0E+00	4,08-04
		1.000000	4105-04
* branch mode) file			

* branch model file ** forced

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Event Identifier: 443/91-008

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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 switchys.d 345kV circuit breakers tripped open disconnecting the generator from the offsite distribution system.

The event occurred during the perform, ce 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 emergeacy 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 deexergization 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 lay will be reevaluated.

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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 transformed 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 'r high-high signal and subsequent feedwater isolation. Actual steam generator levels did not approach the high-higu 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 bases were re-energized from the offsite power sources beginning at 1:54 p.m. EDT with all bases 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

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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 break-r 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 bousing. 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:

- The relay housing for relay SOBF-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.
 -) 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.
 - 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.

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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 Fabreabelt and pressure of 2,235 psig.

This is the first event of this type at Seabrook Station.

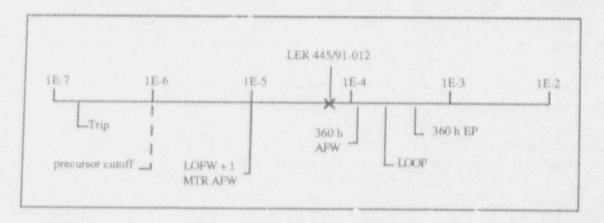
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

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 (S1) 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 by inavailable 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

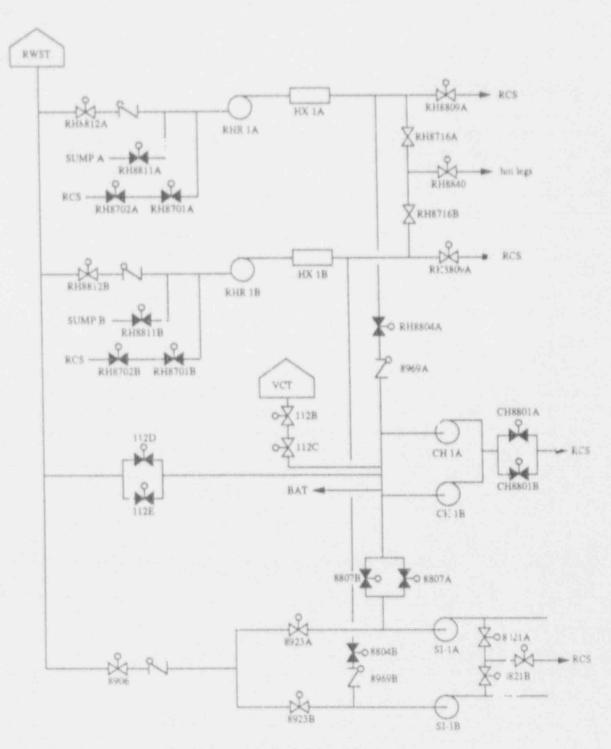
could migrate to the second SI pump during recirculation. A sensitivity analysis was performed to assess the impact of this possibility on event significance.

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 crossconnect in the pump suctions, then the significance of the event is much higher — 6.3×10^{-3} base. We 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 \$923A and \$923B) to the suction of S1 pump 1B.

LER 445/90-035 (documented in Appendix C to the 1990 precursor report) describes another event at Comatche 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.



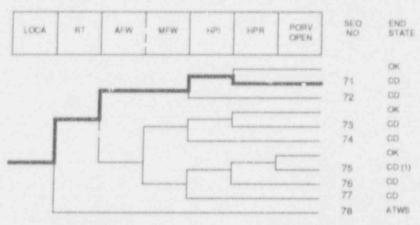
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Fig. 1. Comanche Peak Safety Injection Systems

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Dominant core damage sequence for LER 445/91-012

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CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

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** non-recovery credit for edited case

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

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Event Ident111et: 445/41-012

BRANCH FREQUENCIES/PROBABILLYIES

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Enclosure to TXX-91145

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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 Bonc 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.

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I. CESCRIPTION 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.

9

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. B-498

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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. THE METHOD OF DISCOVERY OF EACH COMPONENT OR SYSTEM FAILURE OR PROCEDURAL ERROR

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. B-499

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11.	02	MPONENT OR SYSTEM FAILURES			
	A,	EAILURE MODE, MECHANISM, AND EFF	ECT OF EACH FAILED		
		Not applicable - there were no component f	ailures associated with this event.		
	Β.	CAUSE OF EACH COMPONENT OR SYS	TEM FAILURE		
83		Not applicable - there were no component for	allures associated with this event.		
	C.	SYSTEMS OR SECONDARY FUNCTIONS FAILURE OF COMPONENTS WITH MULT			
		Not applicable - there were no component f	ailures associated with this event.		
	D,	FAILED COMPONENT INFORMATION			
		Not applicable - there were no component f	ailures associated with this event.		

III. ANALYSIS OF THE EVENT

Enclosure to TXX-91145

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 the archdered inoperable due to a failure.

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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.

	VENT REPORT (LER)	APPROVED CALE NO. SYSK-DYDA EXPIRES & VEXME EETIMATED BURKEN PER REPORTE TO DOMPLY WITH THE SHORMATIK COLLECTION RECKET KO HIS FORWARD COMMENTS REGARDS BURDEN ERTMATE TO THE RECORDS AND REPORTS MANAGEME STANCH (P.SEE, U.S. NUCLEAR RECKLATORY COMMENDER), WASHINGT CO. 20584, AND TO THE PAPERWORK RECKLICKN PROJECT (3150-01) OFFICE OF MANAGEMENT AND BURKET WASHINGTON, DC. 20505
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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.

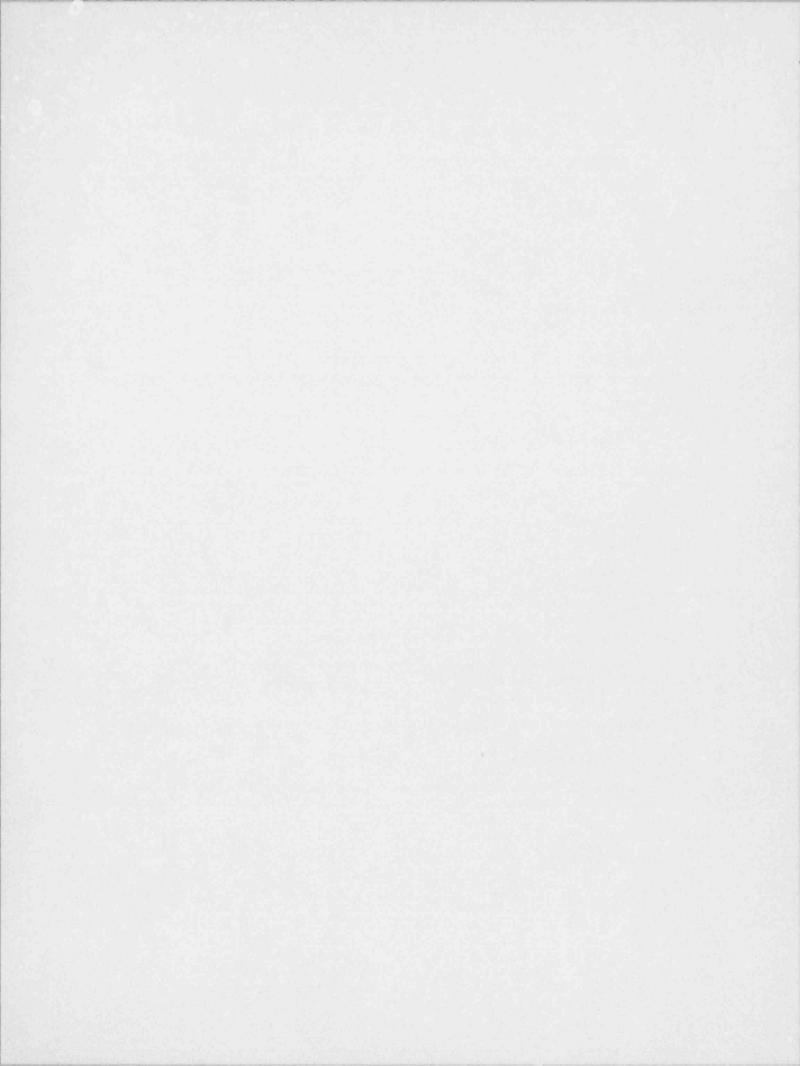
VI. PREVIOUS SIMILAR EVENTS

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 ultrasphic 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.

LER No.	Event Title	Plant Name	Page No.
255/91-017	Reactor coolant pump seal heat exchanger tube failure could result in loss of coolant outside containment	Palisades	C-5
260/91-013	Both containment airlock doors open at same time	Browns Ferry 2	C-12
269/91-028	Decay heat removal system operational problems	Oconee 1	C-25
287/91-002	Reactor coolant inventory loss at cold shutdown	Oconee 3	C-91
287/91-008	87,000 gal reactor coolant system leak	Oconee 3	C-105
293/91-005	Loss of one division of class 1E loads	Pilgrim	C-133
302/91-018	Engineered safeguards actuation inappropriately bypassed	Crystal River 3	C-147
327/91-020	Loss of fire protection system	Séquoyah 1	C-154
336/91-010	Reanalysis of main steam line break	Millstone 2	C-163
369/91-006	Potential failures in containment spray and air return	McGuire 1	C-171

Table C.1. Index of containment-related and other events

424/91-009	Instrumentation problems lead to RHR pump vortexing and loss of shutdown cooling during reactor cavity draindown	Vogtle 1	C-181
\$28/91-001	Reactor coolant pump seal heat exchanger tube failure could result in nonisolable loss of coolant outside containment	Palo Verde I	C-193

a

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: 255/91-017

Date of Event:

Reactor coolant pump seal heat exchanger tube failure could result in loss of coolant outside containment August 5, 1991 Palisades

Summary

Plant:

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 yould 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.

10.01 Farm. 200 U.S. MLRIEAR REGULATORY COMMINENCE LICENSEE EVENT REPORT (LER) -----PACILIT LABE IN DENCIR # 1 MILMORD # 121 VIOT IN 1 01 015 Falisades Plant 0 10 10 10 10 12 15 15 POTENTIAL INTER-SYSTEM LOCA WITHIN THE PRIMARY COOLANT FUMP 07168 FACILITIES BRVOLVED 80 FACILITI NAMES DOCKS NUMBER . ME VERTH BOATH DAY YEAR DOCKET MARERIA MONTH DRY RABY 18.6.8 N/A 0 | \$ | 0 | 0 | 0 | 0 0 9 11 0 51 01 1.8 91 9 ¥. 0 | 8 | 0 | 0 | 0 | N/A and more or respire of she GPS RATING 89 40114 20 405147 80 * \$4x (() (m) 71.713 ------00.26147737 -12.7154 PCHARE A. 80 JB 141121 10.730-1011-001 DTHER (Bench: in Adamari Banan and in Tari, NRC Form -----90 754(12)() -----22.000 to 111 bits ------Informational 30 .486.1x11114 \$6 7.36(10)/W M Thatters HERMIER DOAT ACT FOR THIS LER 118 11.16.465 TELEPHONE NUMBER TANTA SOL Cris T Hillman, Sr Licensing Engineer 64 116 7 6 4 1- 1 8 9 11 3 DOMAPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THE REPORT 11.0 PERCATAGLE TO WERCE CALLER STETEM MANUFAC TURER COMPONENT -----CAUSE MANUPAC TURER SPORTABLE TO NEMDS COMPONENT. NA. BUPPLEMECTAL REPORT EXPECTED ILE VBAR NONTH DAY REPROTED BURNISSION DATE 1151 TEL IN THE COMMON EXPECTED SUBACESION DATE. 410 ABSTRACT /Low'r in TADE genorie - a gagerosonara y Frigan A 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 specifies 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.

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EVENT DESCRIPTION

At 1000 hours on August 5, 1991, the plant was operating rt 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 (eak outside the containment building [NH]. This determination was based on Palisades specific calculations developed as a result of the review of Information Notice No. 60-54, "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 (CTW) 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 Byro: -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 Balisades.

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.

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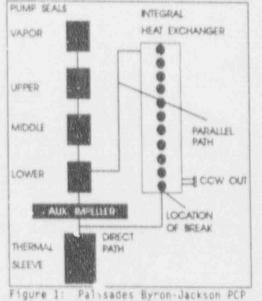
CAUSE OF THE EVENT

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 cirect 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. RETRAN (EPRI transient thermalhydraulic 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.



Integral Heat Exchanger

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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).
- 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 cholant 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-0956 and RV-0939. When a significantly larger relief valve replacing 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 deve oped 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 CCM 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.

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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 decradation 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 prenomenon 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 intersystem LOCA was in progress. The event described in 1N 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:

- 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 radiologic/l consequences analysis.
- Document the radiological consequences analysis for an inter-system LOCA within the PCP under current plant conditions.

ADDITIONAL INFORMATION

1442 XOA #844

No previous similar events have been reported in accordance with 10 CFR 50.73.

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:260/91-013Event Description:Both containment airlock doors open at same timeDate of Event:June 5, 1991Plant:Browns Ferry 2

Summary

Unauthorized personnel action resulted in disarming of the drywell airlock interlock and simultaneous opening of both the inner and outer air. ...k 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 incontainment 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 Fvent-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.

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The corrective apecialized tra Operations perso- personnel correc performed an in- to further enha- operational ati	e actions to address the specif- ining for plant personnel, pro- onnel are responsible for the o- ctive action in accordance with dependent review to identify ar- nce maintenance-related activit irudes. This review resulted i- mance pre-test briefings, and	ice of this event in edure enhancements to peration of the dryw TVA policy. In add eas in which improve ies and to reinforce n additional procedu	o ensure eli doors, and ition, TVA ments were prudent requisite re improvements,

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DESCRIPTION OF EVENT

On June 5, 1 i at approximately 024° hours a loss of primary containment integrity occurred when both drywell personnel mirlock 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, <u>System Thermal Expansion</u>, with reactor coolant system pressure at approximately 150 psig. Mechanical Maintenance craftamen were designated to operate the drywell airlock doors. These individuals were the assigned and qualified personnel to perform this tas!

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 i.e 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 craftsmen 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)(1).

ANALYSIS OF EVENT

A. Introduction

The safety significance of this event was svaluated acouming 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

Flant Operating Conditions Prior to the Primary Containment Breach Event

Reactor Status: Critical (1% Full Power SCRAM Setpoint: 15% Full Power Primary System Pressure: 150 FSIG Primary System Temperature: 365°F Decay Heat Load: c0.04% Full Power Fuel Fission Product Inventory: c1% of the Safriy 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 pafety. 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 con/sequences 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. Any yaim of Postulated Events

Design basis accidents and transients which could occur in the startup/hot shutdown condition and which challengs 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

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pool vis 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 RHZ and core spray pumps were available to automatically start and restore level. Finsion 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 \times 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 repult 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 isolstion 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 ft²) 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 aecondery 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 intogrity would have been maintained since the core would remain covered. Radiological dose offsite would be well below 10 CFK 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 assured 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 \times $10^{-5}\,.$

4. Loss of Coolant Accident - Large Break

In the unlikely event of a design basis pipe rup: are 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 automatical; 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 (ors open a significant amount of steam would be released into the secondary containment. Secondary containment would become pressurized and relief panels within the bui ing and on the refueling floor would actuate. Fuel cladding integrity would have been maintained due to the design response of the ECC3 systems. Radiological release, had it occurred, would be limited to ' ' * tivity in the reactor coolant which was small due to the low powe and lack of recent core power history.

Because fuel dam: - 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 t	emperatures in excess of environmental (qualification
temperat	ures utilizes r 10 CFE 50.49 analyses	for some areas of the
reactor	building, Although this reduces the cel	liability of the affected
equipmen	t, there is a high probability that a m	inimum complement of ECCS

equipment, there is a high probability that a minimum complement of ECCS equipment would remain capable 5, 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 'ts function and the event would not have resulted in a common π^{-1} is 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 ? 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 x 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 t' in 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 recore zed point below which critical cracks in intermediate (between terminal end points) pipe locations need not be postulated1. 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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U.S. MICLEAR REGULATORY COMMISSION Approved OMB No. HRC FORM 366A 164 Expires #/] : LICENSEE EVENT REPORT (LER) TEXT CONTINUATION DOCKET NUMBER (2) | LER NUMBER (6) | FACILITY NAME (1) PAGE (3) SEQUENTIAL | REVISION IYEAR L NUMBER 1 NUMBER | 10151C10101 21 6 01 9 11-- 0 1 1 3 1-- 0 1 1 01 7 0F 11 2 Browns Ferry Unit 2 TEXT (If more space is required, use additional NRC Form 366A's) (17) present during the event, and the probability of a design basis earthquake occurring in that four-hour timeframe was calculated to be 1.6 x 10^{-8} . This supports the conclusion that a critical crack was not credible during the event. Flant conditions were also not sufficient to cause catastrophic failure such as a double ended pipe ruptur 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 paig. 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 LEB 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 LBE approv. in conjunction with conservative leak rate menitoring limits used at some 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. ¹NRC 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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decay heat	ated effects on the environment are great, the low actual pressure and temperature safety systems.	tly limited by the low e, and the availability of
that: (1) required, the postul and (4) th break LOCA probabilit the conclu	asment of the safety significance of this the postulation of a double-ended guill (2) the evaluated events have a low prob- ation of critical cracks is not required e calculated offsite dose as the r-sult is well below 10 CFR 100 limits. Thus, y in conjunction with plant conditions d sion that this event had no actual or po- and safety of the public.	otine break is not ability of occurrence, (3) due to low stress levels, of a worst limiting lerge the low accident uring the event lead to
CAUSE OF EVENT		
Mechanical Mai work by disarm craftsman had this task. Ir allowing him t	of this event was an unauthorized person ntenance crafteman (utility, non-license aing the interlock on the drywell airlock received no direction from his superviso addition, the craftsman did not have we to perform this work. A contributing cau a taken by those in the direct area during	d) performed unauthorized . Prior to this act the or or the SOS to perform ritten authorization use of this event was the
PREVIOUS SIMI	LAP_EVENTS	
There have be	en no previous occurrences of loss of pr	imary containment integrity.
CORRECTIVE AC	TIONS	
	tion immediate corrective action was take primary containment integrity.	en by the SOS to
Corrective ac specifics of are provided	tions have been implemented in several a this event. The areas and their respect below.	reas to address the ive corrective action(s)
craftsman	mmunication - Without proper authorizati modified the assigned scope of work. T ailed to react to the unauthorized perso it.	he foreman and general
plant per	<u>Actions</u> - Plant management developed a y training package and conducted employe sonnel from June 7 through June 12, 1991 int description, plant personnel responsi	e training sessions for . These sessions provided
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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.

 Work Practices - The craftsman defeated the interlocks without proper authorization and work documentation as required by plant procedures.

<u>Corrective Action</u> - 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 shnual training program.

 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.

<u>Corrective Actions</u> - 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 sirlock 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.

NRC Form 366(6+89)

(5-69)	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)	
Corrective plant pers the effect training d plant's sa effectiven 5. Unauthoriz unauthoriz	required, use additional NRC Fore 3664'si (17) Actions - Training as discussed in ite onnel. Site Quality Assurance (QA) per iveness of this training. Based on the as provided in the Maintenance area. I epartment has enhanced its program on t fety barriers and the responsibility to ess. ed Personnel Action - The personnel inv ed work in violation of plant procedure Action - The arsonnel involved have i	formed surveys to determine the surveys, additional in addition, the site the requirements of the o maintain their volved performed es.
In addition, T identify areas maintenance-re	action in accordance with TVA policy. VA management performed an independent in which improvements may be prudent lated activities and to reinforce requ is review resulted in the development isted below.	review of the event to to further enhance isite operational
control, S System, co authorizat enhanced t in-progres during per hours) and work plann addition, be filled	Enhancements - The plant instruction g ite Director Standard Practice (SDSP) ntained adequate controls to ensure Op ion prior to commencing work. The pro o improve the process for notifying Op s work. Specifically, it has been enh formance of a work order (WO) any sign acope changes occur, the SOS and unit er's guide has also been improved to r for work that affects certain critical out and inserted in the front of the w tsmen of potential adverse impacts on	7.6, Maintenance Management erations notifications and cedure has, however, been erations of the status of anced to ensure that if ificant delays (over four operator are notified. The eflect this enhancement. In [systems, a "red sheet" must ork package as a flag to
during SOS Attachment individual was also e be carried requires t	overs - To ensure proper attendence an turnover meetings, General Operating A, <u>SOS Turnover Checklist</u> , was enhance s scheduled to attend the shift turnov nhanced to include a listing of power over into the oncoming shift. In add he listing of prejob briefings to ensu- briefing on the work activities/test	Instruction 300-1, ed to clearly identify the er. The turnover checklist secension tests that would lition, the checklist now ire the oncoming shift
were ident	- The site QA organization performed a lifted where Operations notifications w ealed that 12 of the WOs required mino	vere not being made. The

4FE Form 366(&-89)

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problems wo WOs were fo independent	and needed to be clo uld have resulted fro und to have adequate ly reviewed over 700 e, Procedure Change 2	<pre>m execution of the acope and work con of the procedures</pre>	se WOs. The res trols. QA also	mining
have been in procedural testing.	efines - To enhance t soued to test directo requirements for cond hese guidelines requi	rs to reemphasize ucting briefings f re that pretest br	compliance with or power ascens iefings be held	lon or the

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on the testing. shift during which the test is performed; that personnel direc OT 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.

- 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.
- Graft Qualification Training TVA is also evaluating the applicability of 6.1 a Peach Bottom type acreening and evaluation program for craft personnel. This includes the possibility of using craft acreening services provided by Edison Electric Institute (Power Plant Maintenance Positions Selection System).
- Power Ascension Test Review To ensure that support activities are completely specified and documented, TVA reviewed the power ascenator tests. Mineteen tests were reviewed; seven of which were improved.
- Shift Technical Advisor (STA) Training TVA reviewed the current STA training program, which includes senior reactor operator qualification, and 8. found it adequately covers primary containment requirements. Interviews with individual STAs found them knowledgeable of these requirements.
- Foreman Qualification Evaluation TVA will develop a acreening 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 > continuing supervisory training program which foremen will attend.

NRC Form 3564

FACILITY NAME (1)

Browns Farry Unit 2 TEXT (If more space is

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NRC Form 366(6-89)

ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

AIT No.: Event Description: Date of Event: Plant: 269/91-028 Decay heat removal system operational problems September 7 and September 19, 1991 Oconee 1

Summary

On September 7, 1991, approximately one month into a refueling outage, lowpressure 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

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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 , ondition 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 SOI MARIETTA ETREET, 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 Team Members: B. Desai Resident Inspector, RI! P. Doyle, NRR W. Lyon, Senior Reactor Engineer, NRR L. Mellen, Reactor Inspector, RII W. Orders, Senior Resident Inspector, RII Wiens, Project Manager, NRR . 01 Team Leader: GR. Crienjak; Chief Operational Programs Section

Division of Reactor Safety

Date Signed

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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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- Figure 1 Low Pressure Injection System Drawing
- Figure 2 Low Pressure Injection System Line up (September 19-20, 1991)
- Figure 3 Low Pressure Injection System (Switchover Mode)
- Figure 4 Operations Shift Organization Chart

- 1. INTRODUCTION AUGMENTED INSPECTION TIAM (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 ware 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 stention 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. Refer to Appendix C

11. Event Description

C .

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 ccoler 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 18 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 18 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.

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18 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).
- IA LPI train is secured by throttling lLP-12 and stopping IA 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 succion 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 Feactor 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 18 LPI pump is secured.
- Radiation protection notes that half the stud holes are - 1440 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 "ISA-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 IA 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 18 LPI pump (1400 gµm/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 sarlier 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, lodine, 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 Senticience, 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, 18 LPI cooler Low Pressure Service Water putlet 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 18 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, 18 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 (Lacovery)

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 IA 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 18 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 IA LPI train. During the start-up of the IA 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 ILP-17. The breaker for the IA LPI train discharge valve (ILP-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 IA LPI train, the valve, ILP-17, was open. The valve could very well have been closed.

At 1458 the 1A LPI train low flow statalurm 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 recay 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 cooldown 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 IB LPI decay heat cooler by observing flow indication on the newly installed controllers for valves ILPSW-251 and 252 (flow control v-lves 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 licansee 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 18 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 then 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.

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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 level 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 tr a loss of the system pump. The actual event was a mispusitioning of a valve, and neither procedure referred to the affected flow control valves (1175W-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 Restriction process, OP/O/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 VOIES testing. The two procedures were TT/1/1 /251/11, VOIES Test of LPI Header Motor Operating Valves, and

DP/1/A/1104/04, LPI System. The TT, 12.1.2 (1.V. step), required the operators to..." align the 18 LPI pump to the 18 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 tem temperature.

B. Operator Responsibilities

The responsibilities of the reactor operators and the senior reactor operator in the contro' 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 eptember 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 IA 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 inadeguate 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 values at Oconee unit 1, including ILPSW-251 and ILPSW-252. These two values 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 value controllers and manual loaders in the control room which operate such that the controlled values 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 elictropneumatic 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 setpoint and a continuous analog display of set-point and flowrate. 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. Postmodification 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 ILPSW-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 ILPSW-251 failed the stroke test, the Removal and Restoration form under which the work had been done

sared, and rework was done under the control of the 8.33 modification work procedure. As described previously, OP/O/A/1102/06, Removal and Restoration $r^{\,\rm T}$ Station Equipment, specifies "Removal and Pestorations 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 open stors 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

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 th LPSW-251 and LPSW-252 revealed no deficiencies with either troller 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,

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completed on September 2.

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 the 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 coulers. 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 engines, 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 pariod in the outage, contributed to the event.

All 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 "7" ealed 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 terred 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.

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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 holar: System heat-up event was initiated with the unplanned (for the involved operating shift) shifting from IA LPI train to 18 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 purp 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 lodine, 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.

6%

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 scent and tiso in any Technical Specification safety limits/requirements were exceeded.

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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."

Technici Specification 1.2.1 defines Cold Shutdown as:

"The reactor is in the cold shutdown condition when it is subcritical 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.
- 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/refueiing 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.

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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 "icensee's analysis indicated that LPI flow loss wow, occur at 15 hours with no operator action up 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 . sed 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 c 'age support wires and tubes to provide for co.tainment closure.

The operators had other options for stopping the heat-up, including:

- Re-initiation of Low Pressure Service Water flow.
- 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.
- Use of other pumps to transfer water from the borated water storage tank to the Reactor Coolant System.
- 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 28

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 sc. dule 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 unmonitoric reactor coolant system heat-up. Although these changes did not r se the event, the disruption in control room activities to complish 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.
 - 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 IB 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 Coclant 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 msig.
- 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 iniact 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 shuidown to Reactor Coolani System temperature of 250 degrees Fahrenheit and pressure of 310 psig. This was performed earlier by the day shift with the 1A High Pressure Injection pump operating. maintaining pressurizer level. The 18 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 18 High Pressure Injection pump bearing temperature during the pump performance run.

On Sentember

D. Event Initiation

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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 18 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 18 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 18 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.

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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 I om 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 iPI 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 Opc ator 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 tteps 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 applicab' - "essure 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 Wasie 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 .alve 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 Processre 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 Conirol 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 PI 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 seel supply filter replacement. Of these activities, the 1B Kigh 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 prooccupied. 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 All 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 All 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 prio: 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 Sonior 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 rvent 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 of ations may have been difficult unless LPI operation was termined 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 recalibratica. The licensee reported that no overpressurization of major system components occurred with respect to such criteria as allowable hydrostatic test pressure (heat exchangers), maximum code allowable pressure (piping), and decign 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 Cholant System/LPI system. The leak was contained within the aux liary 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 Jispatched non-licensed operators to check for reakage. 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 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 prossurization 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 rsight was not at a lavel 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, heatup 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:

- Implement enhanced controls of testing activities effecting valve posicioning.
- 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 (DATC) 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.

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- h. Perform a review and implement enhancements to integrate the planning, scheduling, and coordination of valve positioning activities during shutdown conditions.
- 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 interiw 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, Muclear Control Operator C. Little, Instrument and Electrical Manager H. Lowery, Oconee Safety Review Group, Chairman J. Mangum, Jr., Nuclear Control Operators, Unit ! 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

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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/1164/04	Low Pressure Injection System
OP/0/B/1106/33	Primary System Leak Identification
OP/182/1104/10	Low Pressure Service Water
IP/0/A/3001/011B	Testing Motor Operated Valves Using VOTES
TT/1/A/251/11	VOTES resting 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 Doonee 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

- Duke Power Company, "Outage Management Philosophy," Procedure 3.0, Rev 4, May 2, 1990.
- 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.
- "Duke Power Company, Oconee Nuclear Station, Integrated Scheduling Group," Section 1.0, "Introduction/Responsibilities," ISG Directive 1.0, Rev 9, February 18, 1991.
- *Duke Power Company, Oconee Nuclear Station, Integrated Scheduling Group, * Section 3.0, *Refueling Outages,* ISG Directive 3.0, Rev 7, May 22, 1989.
- 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.
- 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.

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- 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.
- "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.
- 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.
- "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

- "Design Engineering Department Operability Evaluation," Oconee Unit 1, PIR Number 1-091-0101, September 20, 1991.
- "Low Pressure Injection System," a lesson in the operations training program, OP-OC-PNS-LPI, Rev 5, October 1, 1990.
- "Controlling Procedure for Unit Startup," a lesson in the operations training program, OP-OC-CP-Oll, Rev 5, June 19, 1990.
- "Controlling Procedure for Unit Shutdown," a lesson in the operations training program, OP-OC-CP-O14, 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:

- 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.
- 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.
- 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.
- 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.
- 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.
- Evaluate management involvement during the Unit 1 event, the post event reviews, and the subsequent recovery.

- For each equipment malfunction or personnel error to the extent prictical, 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.
- Prepare a special inspection report documenting the results of the above activities within 30 days of inspection completion.

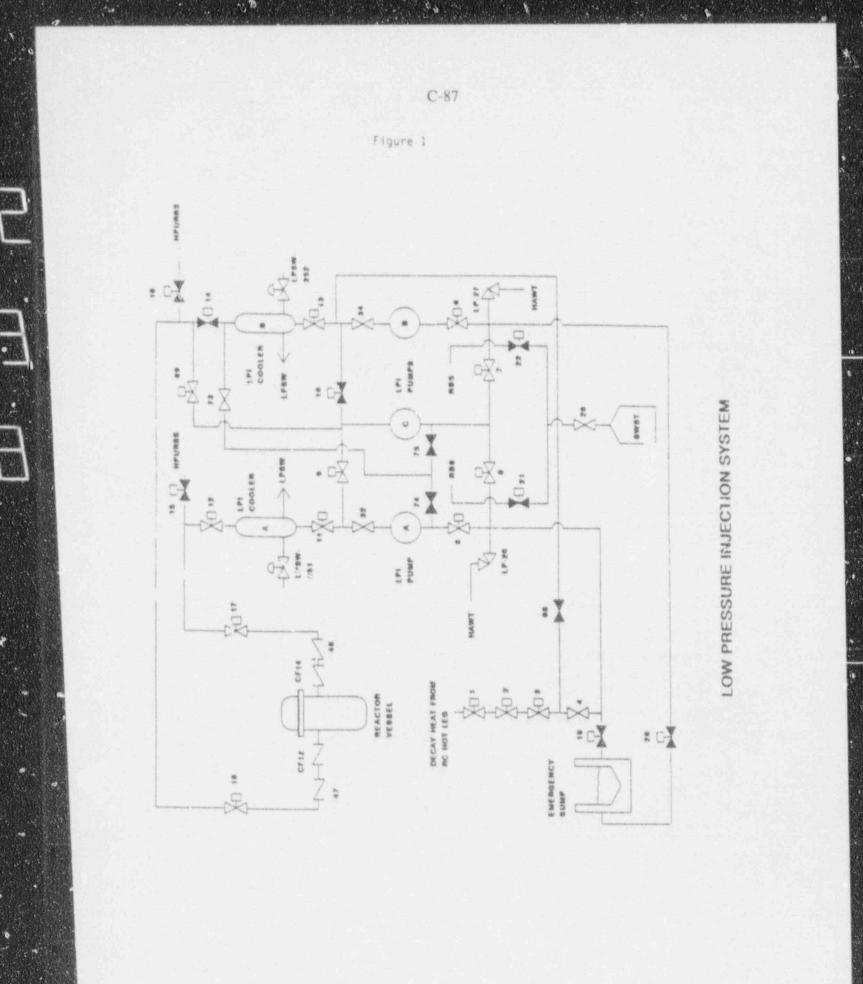
Appendix D

Acronyms

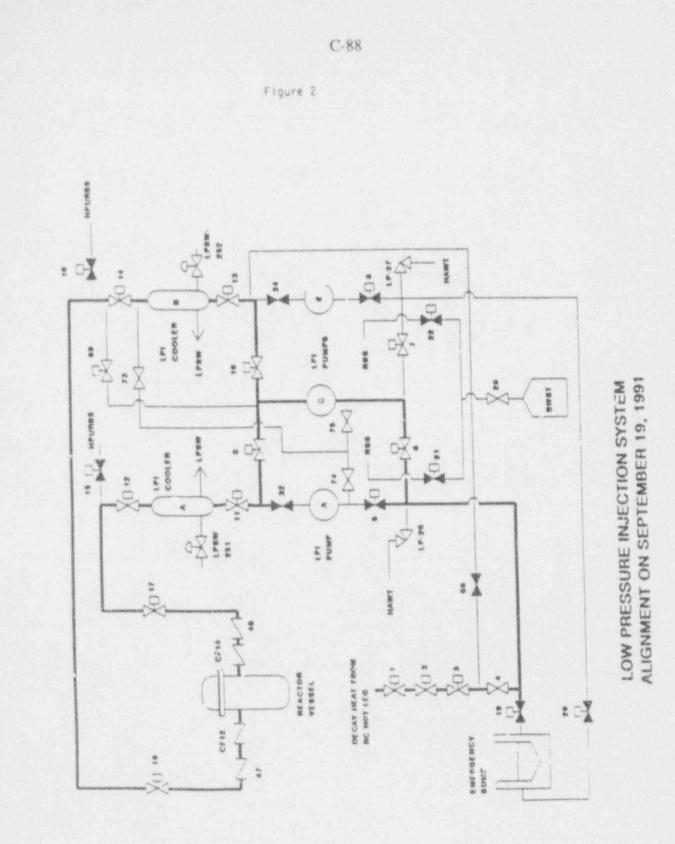
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AIT	Augmented Inspection Team
DPM	Disintegrations per Minute
IV	Independent Verification
LPI	Low Pressure Injection
NRC	Nuclear Regulatory Commission
TT	Temporary Test (Procedure)



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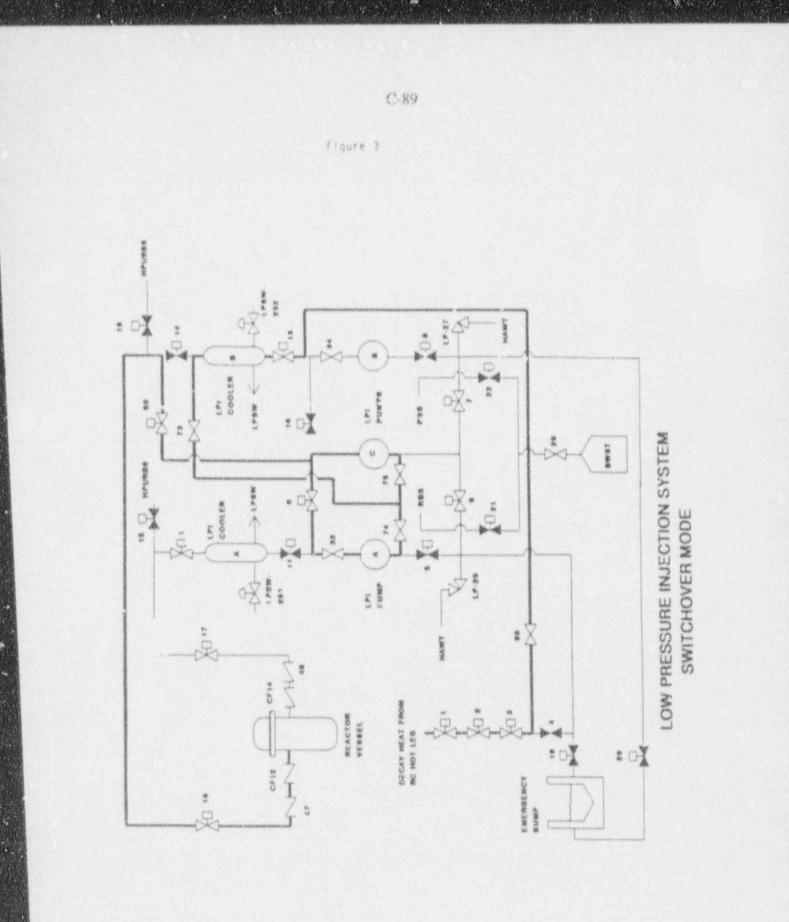
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Operations Shift Organization Chart (after 9/7/91 heat-up event)

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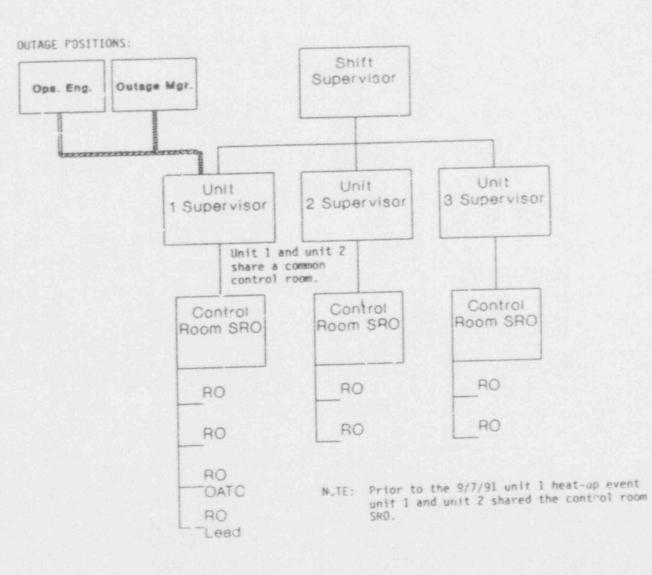


Figure 4

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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No: Event Description: Date of Event: Plant: 287/91-002 Reactor coolant inventory loss at cold shutdown March 8, 1991 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 — caked 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 reciosed 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 Cie 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 higr est 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.

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BACKGROUND

The Low Pressure Injection (LPI) (EIISIBP) system at Oconee is used to remove core decay heat during shutdown conditions. Three LPI pumps are available to take sumtion from the decay heat drop line which originates at the bottom of a Reactor Coolant System (RCS) (EIISIAB) reactor vessel discharge leg (hot leg). The point at which the decay heat drop line joins the hot leg is spproximately 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 Somp (RBES). The pumps discharge through either of two coolers to the resistor vessel.

Two sumps sxist 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 BBES 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 tics 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. 17-5 (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 5 hot leg and the BI 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 auction 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 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. Re 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/O/A/1800/105, "Reactor B liding Emergency Sump LPI Suction Line Flange Installation, Removal and Screen Inspection." The techniciane 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 auction pipe which is actually connected to 3LP-20 (RBES Train B to LPI Isolation Valve).

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At 0401 on February 23, 1901, Operations initiated FT/3/A/203/04, "LPI system Leskage". Enclosure 13.2. This procedure is designed to leak check the suction pipe from the RBES to 3LP-19 and value 3LP-19 itself and is required by Technical Specification 4.5.4. Low Pressure Injection System Leskage. The initial conditions pection of the procedure requires a verification that the blank flange is installed on the SLP-19 suction pipe and not installed on the 3LP-20 suction pipe. Reactor operator A (RO A) used the maintenance flange installation procedure (HF/0/A/1800/105) to verify that 3LP-19 had been blanked. A Men- licensed operator (MLO A) verified that a blank flange idd not exist on slip-20 using the handbritten markings on the wall. The leak theck portion of the procedure was performed. Although the required pressure was maintained, a smell leak was noticed on the flange itself. If 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- fly suction pipe. valve 3LP-19 was repacked under Work Request 579330. Due to the location of the valve and its surrounding enclosure, this job regured that the motor operator be removed during the task and then for suction pipe. Valve 3LP-19 was repacked under Work Request 579330. Due to the location of the valve 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 had flange level. This is above the reduced inventory action level and flange level. This is above the reduced inventory action level addressed by Generic Letter 86-17. Loss of Decay Heat Removal, which corresponds to 14 inches on LF-5. The LPI system was operating in the decay heat removal indee with the ALPI pump discharging through the 3B LPI header. The 3C LPI pump was available as was the 3M LPI header. The 3B LPI pump breaker was first "racked in". Core exit thermocouples had not yet been i			0 15 10 10 10 2	8 8 7	911 -	-0 0	12	-	010	013	GF	1]]
Technicians A. B and C asked the constol 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 J&E Technicians A and B. Unit Operations Engineer		System Leakage". Enclosure J check the suction pipe from and is required by Technica System Leakage. The initia requires a verification tha suction pipe and not instal Operator A (RO A) used the i (HP/O/A/1800/105) to verify licensed operator (NLO A) v 3LF-20 using the handwritte portion of the procedure wa was maintained. a small lea not realized that the test installed. After performance of the le 19 suction pipe valve 3LF- Due to the location of the required that the motor ope reinstalled. This was acco 5. 1991 while the reactor w On March 8. 1991, the Doome reactor vessel had been ref head and upper internals re System (RCS) was letween 76 Transmitter. This places the head flange level. This is addressed by Generic Letter corresponds to 14 inches of decay heat removal mode wit LFI header. The 3C LFI put The 3B LFI pump breaker was used if the breaker was fi not yet been inserted into following refueling. The Alarms (RIAS) (EIISII). R unit ventilation monitors out of service. The Reactor operating but a flow path prevent the Reactor Build compressed air during outa At approximately 0730 on M Technicians A. B and C ask to stroke valve 3LF-19. T procedure IF/O/A/3001/10. to check the valve operator reluctant to stroke the vei- installed flange that had Control Boom Supervisor d	13.2. This proce the RBES to 3LP 1 Specification of 1 conditions sec t the blank flam led on the 3LP-2 maintenance flam that 3LP-19 had erified that a b n markings on th s performed. Al k was noticed on was invalid sinc ak test portion 19 was repacked valve and it. st rator be removed mplished between was defueled and to e Unit 3 plant of fueled. The read moved. Water 14 is and 80 inches the level at slim a bove the redu r 88-17. Loss of h LT-5. The LPI th the 3A LPI pu po was available s removed in ". the core during unit 3 Reactor B eactor Building equi 0 Building Furges through the purch or Building equi 0 Building Furges through the purch of the Control 1 hey were using 5 "Maintenance of or limits. The show a detected d hecused the iob	edure -19 an 4.5.4. tion o ge is 0 suct ge is been lank f e wall the f e wall the f e wall the f r the f f f the f the f status ctor v evel i on LT- ced in Decay syste mp dis as we ervice fill izing f sulf contro under the f f under the f f f f f f f f f f f f f f f f f f f	is desi d value Low Pr f the c install ion pi tallat blanker lange flange (3/A/20 Work R ding en ng the uary 23 PI syst was as essel 1 n the r stallat was as essel 2 N the stallat was as essel 1 n the r stallat to the uary 23 PI syst was as essel 1 n the f 5. RCS below ' wentor ' Heat to re wat to re wat to re wat to re wat to re wat to re wat to re stall orque 1 1 Room the is that is the is	igned sources sources sources led of pe. p d. d n equiproces led of pe. p d. d n equiproces is sources addid n equiproces is sources addid n equiproces is sources is s	to 19 If duren the reference Not of in in in in in in in in in in	letse strenger the stronger with a stronger wi	<pre>k elf ction ction iLP-1' 'e st on ssure was ectly 3LP- 3D. is jo en March down the iure Leve vess ating s ba ocess ating s ating to s ha oces ha</pre>	9 bb n lel iB id sand et con		

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	A was concerned that the suct the value might lead to air b Injection (LPI) pump. The Co Engineer A jointly concluded leakage to the RBES would be would be secured prior to the gave permission to stroke the The Control Room Super-isor b	inding of the operat nirol Room Superviso that valve 312-19 co- negligible, and that valve stroke. The valve stroke. The valve.	ing L r and uld b the Contr is po	ow Pr Uni e st oper ol R int	reasur t Oper roked ating com Si he rea	t LF ipe	ions hat I pum rviso sted	p ř		
	that the I&E Technicians cont valve. I&E Technicians A and the control room. After Oper associated with valve JIF-19 breaker to 31F-19 and establi and B who were at the valve J Technician A began manually o	i H do not remember b ations removed the s l&E Technician C is ished communication w itself. At approxima	ein s s ith 1 itely	tion Lind	is ci Lgs ed at echni	th	e e			
	At 0848, the control room re- high alarm. Reactor Operator to 20 inches. At 0848:37 an received in the control room Level alarm. Control room p- verifying the LFI valve line	r B (RO B) noticed th Emergency Sump Level followed by a React ersonnel began invest	iat C1 L High Sr Ver	r-S h n ala nsel	iad de irm wa Ultra	SO:	ased lic			
	Radiation Frotection Special hatch, received a call from that reactor vessel water le Technician A (RFT A), assign Building (level of the top o purtable dose rate meter tha had increased to approximate flowr of the Reactor Buildin sent him back to evacuate th fourth floor down the stairw RPI A contacted personnel on their dosimetr, and personal abnormally high radiation fi not directly over the fuel t	personnel in the Rear vel was decreasing. ed to the third floor f the fuel transfer of t dose rates above to ly 8 Rem/hour. RPT of g and came to the pe a fourth floor and d ells and away from t the RB polar crane ratemeters that the eld. The workers in	ctor I Radii r of canal he fu A eva rsonn irect he fu and d y wer the	Auil: ation the I el tr cuato el tr el tr el tr e tern e no pola	ling s Prot Reacts bund w ransfe ed the atc t ransfe t ransfe t ransfe t ransfe t ransfe t ransfe t ransfe	tacit free	ting tion h A chal of A con t canal am were	hie		
	At approximately 0852 Operat procedure. RO B called RPS pussible leakage in the Reac Radiation Frotection had not loss of reactor vessel level due to a fluctuation in pump the Reactor Building Normal	A at the RB personne for Building and Was t heard of any leakag 1. At 0852.32 RO C s 1. amperage. At 0853.	l hat told e. th toppe 50 pu	ch t l tha wy w d th mpit	c inv t alt ere a e 3A	est hou war LP1	igate gii # of pump			
	At 0854 b) INE Techniciaus / 19	A and & completed mar	nually	ope	ning	va)	ve 31	¥		
	At 0856.30. values 3LP-21 at to LFI) were opened per the value breakers. The breake operation as a step in the 0857.21. values 3LP-21 and	Loss of LPI procedures had been opened to fuel transfer canal of	re afi o pres drain	vent proc	losin inadv redure	ger	the tent At	Ιγ		

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	that water from the Borat. the RCS.	ed Water Storage Tank ()	BWST)	was not r	efilling	2				
	1&E Technician C. after o 3LP-19 from the L.eaker a was cycled again electric were still unaware of the located in the Auxiliary page the I&E Technicians Operator B (NLO 8) to 3LP the valve just as I&E Tec time from the breaker. N valve 3LP-1 and leave it	t 0857:32. Between 085 ally from the breaker. effects of opening 3LP Building. The control without success and had -19 to have the valve c bnician C had closed th LO B informed 1&E Techn	9 and The -19 s room 1 sent losed e val	0901 valv I&E Techni ince the v had attemp Non-licer . NLO B t ve for the	e 3LP-19 cians alves a sted to sed eached second	9 re				
	RPS A had received a call basement that water was f inches near the RBES. At to RO A. He informed RO the increased dose rates Operations reopened 3LP-2 and 3LP-21 and 3LP-22 wer approximately 76 inches.	looding the floor and h 0901 RPS A called the A of the leakage in the above the fuel transfer 1 and 31P-22. Reactor	ad re contr Reac cana Vesse	ached six ol room an tor Build 1. At 09 1 level i	to twel nd spoke ing and 02:52 noreased					
	Operations vented the 3A BWST level had decreased temperature had risen fro Fabrenheit.	from 43.4 feet to 41.7	feet.	LPI Pum	p suction	on				
	Radiation Protection pers the continuors air sample 0940. Five additional or approximately two hours is collected on the Reactor system were also analyzed maximum permissible conce the Reactor Building at 1 who were in the Reactor F analyses performed and re maximum permissible organ personnel in the Reactor millirem. Spilled water (EIIS:WD) system where i of the Reactor Buildirg 5 Follow up investigation sump blank flinge had be not 3EP-19.	ers in the Reactor Buil illections were taken f later. Compensatory sa Building Purge system d. Results showed less entration of airborne c the time of this event. Building during the even esults were all less th n burden. The highest Euilding at the time o was pumped to the Liqu t was processed and rel basement was performed on the day of the event	ding t rom th mples and th than ontam SiX nt ha an 0. radia of the bid Wa eased after show	between 09 bese same which wer he Unit Vx 25 percer ination er of the s; d body bu 03 percen tion expor- spill wa ste Dispo . Decont it was d ed that t	12 and sampler e being int of th tisted i ixty peo rden t of the sure of s 40 sal aminatic he RBES	s on ple any m				
	The On-site Safety Revie of the incident. An Eme Commission (NRC) was com inspector was also notif	rgency Notification of pleteg per 10CFR50.72.	the N	luclear Re	quiator					
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temperatures could not have increased more than 23 degrees Fahrenheit. Graphs contained in the Loss of LFI 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 (LFI) 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 LFI pump used for forced cooling of the RCS was secured to prevent caritation. Furthermore, the loss of inventory lead to increased dose rate 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.

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 "3L>-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. FT/3/A/203/04. LPI System Leakage and a Performance procedure for stroking these valves. FT/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 Fipervisors indicate that the identification of ILP-19 and JLP-20 auction pipes have had to be researched during other cutages. 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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NALL FILMS SHARE OF NUCLERS BEFORE TORY COMMITMUM 1 APPROVED ON NO 3150-0104 5 x # 1 # 1 10 / 10 / 10 SERVES X3002 STIMATED RURDER TER REPORT TO COMPLY WITH THIS MYORMATION COLLECTION REDUGT NO HER FORWARD COMMENT RESERVENT REALOW RECOMP. AND REPORT MANAGEMENT REALOW IN SECURIT AND REPORT SMANAGEMENT REALOW IN SOUTH SECURIT AND REPORT SMANAGEMENT REALOW IN SOUTH SECURIT DIF RAFEMENTA RESULCTION REDUCT () 50 0164 (24 C) MANAGEMENT AND SOUGET RESEMENT ROAD CODES: MANAGEMENT RESULCTION REDUCT () 50 0164 (24 C) MANAGEMENT () 50 0164 (24 C) MANAGEMENT RESULCTION REDUCT () 50 0164 (24 C) MANAGEMENT () 50 LICENSEE EVENT REPORT (LER) TEXT CONTINUATION FACILITY NAME DINCKST NUMBER 12 LAR NUMBER IS PAG7 18 -248 SEGUENT AL At ville In United in 0 16 10 10 12 18 7 9 1 - 0 10 12 - 0 10 0 7 OF 1 1 Oconee Nuclear Station, Unit 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 E ilding and would have properly identified the component. Fiping layout diagrams exist that could have been consulted which give the correct physical locations of the suction pipes. 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 L&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 wes inevitable. However, the magnitude of the loss may have been significantly lower if proper communication existed between the Control Room Supervisor and L&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.

Radiation Protection personnel quicki, 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

personnel was proper. Operations quickly secured the operating LFI pump when indications of cavitation were observed. The appropriate actions

The response to the event by Operations and Radiation Protection

were taken to isolate the leak and restore reactor vessel level

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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AF/A/1700/07 loss of LFL will be revised on all three Occure 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 Frotection (RP) personnel stressing the incortance of communication with the control room if RP frees that an erea evacuation is warranted but has not occurred.

SAFETY ANALYSIS

10.00

The rapid loss of Reactor Coolant System (RCS) inventory presented two challenges to nuclear safety. I) a loss of core decay heat Lemoval ability and 21 an increase in dose rates in the Reactor Building.

The ability to remove cure lecay heat using formed cooling was lost for 18.5 minutes. Core temperatures increased an estimated 20 degrees Fahrenheit to approximately 117 degrees Fahrenheit in this time. This is well below the amount required to Segin RCS boiling in the core. Core boiling would lead to further loss of RCS inventory and eventual core uncovery and damage. Touke 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 lies of Low Pressure Injection (15. procedule. The leas was inclated by closing valve 31F=15. Borated water from the Borated Water Storage Tank (BWST) was used to removely is removel level. The LPI pump was vented and returned to cervice.

If 31P-19 could not have been closed, the BWST could still have been able to flood the core. Operation of values on the LPI suction header (317-6 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 is the Reactor Building basement via the open 3LF-19 or by isolating the decay heat drop line using isolation velves 3LF-1 or 3LFthe vater would have been allowed to fill the fuel transfer canal. Once BWST incentory was depleted, forced cooling could have been established by allowing the LFT pumps to take suction from the Reactor Building Emergency Sump (REES).

Although containment closure did not exist during this event. Operations Engineering staff has stated that containment closure could have been a tablished within one hour. Haintenance on Reactor Building penetration valves were acheduled in such a manner that only one side of a penetration had work scheduled at a time. The Reactor Building Furge flow path could have been isolated by either of two remotely operated values. Both the personnel hatch and eguipment 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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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.:287/91-008Event Description:87,000 gal reactor cooling system leakEvent Date:November 23, 1991Plant: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 approximetely 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 storege 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 ir invel. 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 coatrolled 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 an 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).

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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 mren. hyroid) 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.

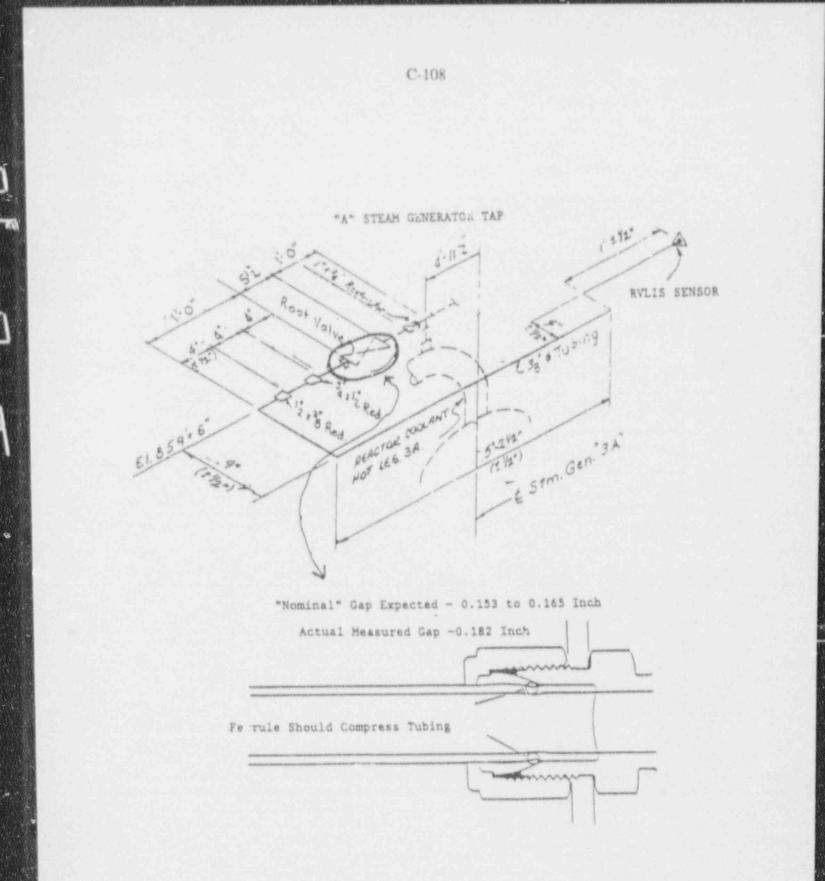


Fig. 1. Failed tubing configuration

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BACKGROUND

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The Reactor Protective System (RPS) [EIIS:30] is a safety related system The which monitors parameters related to the safe operation of the plant. RFS 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] Fump discharge pressure. The RPS logic requires that pressure twitches 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 cooldeave and depressure being either too high or too low. cooldown and depressurization to cold shutdown, the RFS normal RCS pressure trips can be can be bypassed and a lower high "ressure trip setpoint imposed to limit pressure excursions.

The Integrated Control System (ICS) [KIID.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) [ETIS: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 dema d 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 'hrough four are safety rods, used to provide shaping groups. Groups one through four are safety hos, 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:ROC] 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 ir a group reaches its out limit switch.

The High Pressure Injection (HPI) System [E115:BQ] controls the Reactor Coolant System (RCS) [EIIS:AB] inventory, provides the seal water for the Reactor Coolant Fumps [EIIS:F], and recirculates RCS letdown for water quality maintenance and reactor coolant boric acid concentration control The HF: 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 neveral differential pressure transmitters. Four of these transmitters are connected to the four redundant channe's of the RPS. A fifth transmitter provides the normal input to the ICS.

EVENT DESCRIPTION

On November 23, 1991, Oconee Unit 3 was operating at 100 % Full Fower (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 & 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 Lime, they received a fire alarm from a detector [EITS.IC] located inside the reactor containment building (RR) [EITS.NN]. CRO & checked for a spurious alarm by resetting the fire alarm and observed that it elarmed again. The CROS notified the Unit Supervisor and Control Room Senior Reactor Operator (CRSRO) that a problem existed. CRO & also attempted to visually inspect the RB using a video camera installed inside the RB at one end of the r fueling canal and a monitor adjacent to the control room. However, the image was so foggy that CRO & assumed that the camera was eiths" 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 (HFI) 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 AF/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 [EII9:11] 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 soutdown. 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% FF. 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% FF.

Throughout the event, the CROS made additions to the LDST from the Bleed Huldup 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% FF 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 (MFWF B) in manual and began to reduce its demand. Apparently. FDWF 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 MFWF B output was reduced. FDWF 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 MFWF B up.

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the contiol system reacted to match total ferdwater flow to total feedwater demand by reducing MFWP A demand and output. The oscillation also resulted in feedwater header low pressure a arms, iou Main Steam pressure slarms, and opening of turbine by-past 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 NEWF A apparently reached the trip setpoint und 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:si) 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 pressnrizer 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 1084 psig, according to the Transient Monitor [EIIS:10]. 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 reedwater pumps do not trip due to low discharge pressure, so both pumps continued to run until CRO & manually tripped MFWP &. The emergency feedwater system [EIIS:EA] was not actuated after the trip.

At 0340 hours, leidown was re-establish d at 20 . s.

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 stmosphere contained radioactive lodine at 2 times maximum permissible concentration (hPC) and Noble gases at 407 MPC.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

At about 0400 hours, the video camera in containment was used to exacine the area. It showed a significant amount of steam rising from the "A" Steam Generator cavity. The steam was condensing on virtually will 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. Flans were made to initiate boron addition to raise boron concentration for long term shutdown margin considerations.

At 0520 hours, the Engineered Safeguards (ES) (EliSiJE) 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 RFS Actuation

Step 2.1 of Enclosure 4.2 in the shutdown procedure specified that the turbine bypass values (TBVs) [EIIS:50] were to be placed in Manual. The TBVs are used to control main steam pressure and, therefore, the saturation temperature in the team generator, which, in turn, controls the RCS temperature. However, CRO & had been controlling pressure by using the ICS turbine header pressu; 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 byp-seed. At 0613 hours, the Emergency Peedwater pumps were placed in Manual.

At 0622 hours, RCS pressure was 1660 psig and temperature was 526 F. At 0633 hours, the RFS 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 performed 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 resot, 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 I25 paig to raise the suturation 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 comperature and pressure increasing again. CRO A stated that he concentrated on RCS temperature and Lurbine 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 RFS. The CRD breakers opened but, since all control rods were stready 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 eset 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, airboing ioding 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 mource 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.

207 O Parker Hannifin Company (Parker), manufacturer of the fitting, was contacted and provided a range of "nominal" values for the makeup gap between the bex on the fitting and the end of the nut. The Parker spokeeperson 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 Freesure Injection Systems. This inspection included 455 fittings (264 Pirker 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 retightening, 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 ase.

The release data is summarized on Attachment C. Final calculations will be included in the Semi-annual Effluent 1 port.

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Monitoring in accordance with the Fuel Reliability Frogram 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 microcurics/milliliter dose equivalent fodine, compared to Unit 1 levels of approximately 0.01 microcuries/milliliter dose equivalent fodine.

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 score. 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 Fower administrative limits.

CONCLUSIONS.

A. RCS Leak

It is concluded, based on the investigation performed by Oconee Engineering and Bablock and Wilcox. that the initiating cause of the leak in this event was improper installation of the fitting. Specifically, the fitting but was not fully tightened. Therefore, a contributing cause of Inappropriate Action. (Improper Artion. Action chosen was proper but execution failed because an action tas performed with insufficient provision), is assigned. However, the room 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 he installed in accordance with the manufacturer's instructions.

Both Swegelock 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 2/16 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 Ocones. No similar device or inspection criteria was referenced in Parker installation instructions.

According to the craft (echnician 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 essembly into the Reacto: 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 sisted that the line was inspected in accordance with the QC menual 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 subjection during three subsequent refueling outages without my indication of fleakage. 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 of " it 3 after the event found that approximately 28 % of the fittings in loted did not meet the manufacturer's guidelines. This indicates that "skill of the craft" was not adequate to assure that the manufacture is 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 steps pressure and feedwater flow at low power conditions after placing a Mein Feedwater pump (MFWF B) in manual to shutdown the pump. This rost 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 recorocd immediately prior to the trip revealed that steam pressure and feedwater demand were out of phase and limit cycling before MFWF 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 clausic 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 unanges 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 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 twerall 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 contect buffers require menual reset. contact buffers on MFWF B were apparently actuated when CRO A manually ran back the demand to 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 MFWF B, the system responded by reducing demind for MFWF A, which was still in Automatic. When MFWP A discharge pressure reached the setpoint, the associated contact suffers actuated and satisfied the logic in the RP5. The Emergency Feedwater pumps are also actuated by indicated low discharge pressure on both HFWFs, 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 trap. These checks found that one switch in each actuation channel of the Emergency Feedwater actuation logic was slightly out of the procedule calibration tolerance on the low side. Therefore, MFWF discharge pressure could fall low enough to actuate the RPS sw thes, 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. Inedvertent RPS Actuation

It is concluded that the root cause of the inadvertent actuation of the Reactor Protective System (RFS) 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 supervisico.

It is noted that the procedures in use. OF/3/A/1102/10, "Unit Shutdown" Enclosure 4.2, and OF/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. Oconep has not had a history of leaks due to leak ng "ompression 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 oumps, the RFS had been calibrated to trip the unit 1 fonly 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 LEP 269/90-06.

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The unplanned actuation of the RFS 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 actistion portion of this event, CRBRO 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 Farker Hamilfin Company model 12-3/4 ZHEW2-S5, has been determined to be NPRDS reportable.

CORRECTIVE ACTIONS

Immediate

1. Operators began a controlled unit shutdown.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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.

Following the Unit trip. Operations stabilized the unit a d continued shutting down to cold shutdown.

Subsequent

The root value, tubing, and associated fittings on both the "A" and "B" Steam Generator RVLIS impulse lines were replaced with new components.

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.

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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US HUCLEAR REGULATORY COMMERSION APPROS 10 0648 400 3180 6104 8 849858 8/50/92 ЕРТИМАТЕР АУЛОВИИ ГЕЙ ЛЕКОРОНИЕ ТО ИНСОМААТИОН СОСLЕСТИОН ЛЕОИНЕТ ТО ОБМИБАТЕ В САМОНИЕ ОБИСОН ЕТТИМАТ АНО ЛЕОИНТЕ МАЛИОВЕНСТ ВИЛИСТ НО ЛЕОИТЕ МАЛИОВЕНСТ ВИЛИСТ ТО ТИК ТАЛЕЛИВОЛТ МЕРИСТИОН ЛЕОЛЕТ ОТ МАЛАЛЕВИИТ ОСОМАТЕЛЯТ. LICENSEE EVENT REPORT (LER) TEXT CONTINUATION DOICH ST RUMANER U LEA HLAMESP IS REDUKETIKL MUVIER N YEAR. 0 5 0 0 0 0 2 8 7 9,1 8:010 0 0 1 6 or 2 14 Oconee Nuclear Station "E?" (if many passo is response, and adultment fully farm \$884.5) (17) 5. The calibration of the Main Feedwater Pump low mischarge 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. Flanned 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. All compression fittings on tubing c. meeted 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.

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 LCS 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 inapprov 'e action and less than adequate ; supervision will be counselled.

9. Operations procedures will be evaluated for enhancements. Specifically, additional "-ondition 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

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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 eppropriately to minimize the release. The total releases were increased due to the relatively high amount of failed fuel (estimated at B rods) which existed in the core prior to the event. Since there are 177 fuel assemblies and each assemble has 208 rods, eight leais 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 Fr^o functioned as designed.

The inadvertent actuation of the FFS after resetting the Control Rod Drive (CRU) breakers had minor safely 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 app imately 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 Bypess 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 Farker 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:

- Parkar does not consider the gap dimension to be a critical 1.3 parameter,
- the fittings were all tightened as much as appeared feasible to highly experienced instrument technicians.
- these fittings have been in place for years without leaking. and
- one of the fittings most out of the nominal range was removed 4) 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 reanalyzed, including the affect on the connected instrumentation. A summary of the results of this analysis follows:

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 RFS channels and would cause a reactor trip on Flux/Flow/Imbalence. 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 RFS 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.

Problem fittings were found which could affect pressure indication to Engineered Safequards Channel B RCS pressure and RFS Channel B RCS pressure. A failure on this line could result in actuation of ES and

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RFS Channels B. Neither system would actuate solely due to actuation of only one channel.

1. Problem fittings were found on one of two level control transmitters which control Emergency Feedwater flow into the "B" Steam Generator "G B). The affected transmitter shares an impulse line with animitters for Startup. Operate, and Full Range level indications on SG B. Redundan' 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, 'f a LOC? occurred after the instrument failure, the open tubing would provide a leak path out of containment.

4. Problem fitting: 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 alaim 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 P2K 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, FZR instrument failure scenarios are frequently used in Operator training, and the Operators are trained to recognize these failure modes

One problem fitting was found on a transmitter for HPI Nozzle Warming Flow, which provides indication only.

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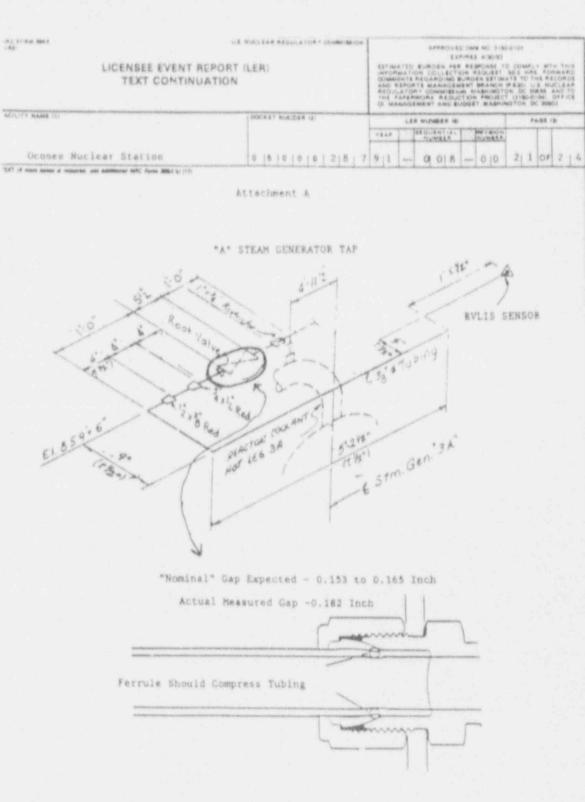
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The instruments connected to the RCS would result in system leakage, but, due to the size of the tubing, the leakage would remain within the capability of a single HPI pump to provide makeup. The HPI Nozzle Warming Flow instrument is located outside 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 rther 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. Full, immore, 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 B

List of Equipment Inspected

Environmentally Qualified Transmitters- 4 of 11 opened and visually inspected. No evidence of water intrusion was found.

Lavironmentally Qualified Valves- 8 of 8 Target Rock solenoid valves were cycle tested successfully.

Value Operators - Inspected 26 Limitorque limit switch housings for water.

Fire Detectors- 21 of 22 checked out good. Replaced bad une.

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 roa position indication tube cables, found no sign of moisture intrusion.

Pressurizer heaters- inspected two junction boxes and meggered 3 cables. No defects found.

Incore inscruments- 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

k-actor Coolant Pump Motors- performed High Pot Test on 2 of 4 pumps. Scaually inspected instrument terminals on 2 of 4 pumps. Changed oil on 1A2 pump (both oil pots) affor water found in upper oil pot.

Cranes- Visually inspected polar crane. Control Rod Drive crane, and fuel handling bridges.

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Attachment D

Contamination Survey Results

AREA	CONTAMINATION	ISOTOPIC
A Steam Generator Cavity	24 K cpm 127 mred	Co-58 71% Cr-51 11%
P Steam Generator Cavity	44 K cpm 42 mrad	Co-58 58% I-131 13% Cs-137 6% Cs-134 5%
Basement West Side	(10,000 mrad) 873 mrad	Co-58 36% 1-131 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%
lst 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% Ce-137 26% Cs-134 13% I-131 9%
3rd Floor	18 K cpm 156 mrad (1487 mrad)	Nb-95 9% I-131 4%
4th Floor	20 K cpm 46 mrad	
Polar Crane	90 mrad (182 mrad)	

NOTE: Readings indicate high "typical" readings in general area. Parentheses indicate readings at localized hot $s_{\rm b}$ is within general area.

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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.; Event Description: Date of Event: Plant: 293/91-005 Loss of one division of class 1E loads March 15, 1991 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 in operable. 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

Or 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 sorveillance 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 (PBCCW) 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 resided 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 the stime period is ~116 h.)

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ABSTRACT						
On March 25, 1991 at O610 hours, the Emergency Diesel inoperable, a loss of AC power to Train 'B' component actuations of portions of the Primary Containment and Isolation Control Systems occurred during a Technical surveillance test of the EDG R'.	ts of safety sys d Secondary Cont	tems, and ainment				
The cause for the event was a failure of the automation the EDG 'B' that was fully loaded on its safety bus a voltage regulator was manufactured by the Basler Elec SVR01A0_92B1B, serial number 9047500105. The affects were re-energized and returned to normal service by M The EDG 'B' voltage regulator was replaced and the EL with satisfactory results. The surveillance was comp approximately 0915 hours. The failure of the AVR was AVR magnetic amplifier due to low insulation resistant its production failure and returned materials data in isolated occurrence. This event occurred during power operation wells at reactor mode selector switch was in the RUN position	at the time of t ctric Company, w ed safety system March 25, 1991 a DG 'B' was surve pleted on March s caused by the nice. A manufact ndicated the fai	the event. The odel number components t 2100 hours. 111ance tested 28, 1991 at failure of the urer search of lure was an tor power. The				
The tor mode shreetor switch was in the hom position pressure was 1036 psig with the RV water temperature This report is submitted in accordanc, with 10 CFR Si (a)(2)(v)(0), and this event posed no threat to the p	ot 548 degrees 0.73 subparts (a	Fahrenheit. ()(2)(iv) and				
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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 manu/acturer'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). Bus A5 and A6 supply power to essential loads required during normal operations and Linormal operational transients and accidents. Buses A1, A2, A3, A4 supply power to other station auxiliaries during planned operations. Power is d) tributed to the six A160 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 (CRO) 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 486 VAC power to Bus B1. Similarly, Bus A6 feeds 4160 VAC power to the motors of the CRD pump 'B', RH' 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 sw'ng 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 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 AS and A6. The diagram does not depict feeder breakers A801 (152-801) and A802 (152-802) that are located on the Elaskout 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 wire closed, the Startup Transformer (Sull) 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 Sulveillance", soliton 8.2. The event occurred while the EDG 'B' was fully loaded at approximately 2600 KK and synchronized to Bus A6 in parallel with the Unit Auxiliary Transformer, after being loaded for approximately 15 minutes.

EVENT DESCRIPTION

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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 A160 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 foad center Bus B2 and its related loads:

- Turbine Building Closed Cooling Water (TBCCW) System Loop 18' pump (P-1108)
- 480 VAC MCC-814 including:
 - 125 VDC Battery charger 'B'. The 125 VDC Battery 'B' was subsequently al'gned 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 So) at 0641 nours.

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	•	Standby Gas Treatment System (SGTS and exhaust fan (VIX-2108). This be Inoperable.	
	,	Control Room High Efficiency Air F Train 'B' air inlet filter heater CRHEAFS Train 'B' to be inoperable	(VCRF+101B). This caused the
	*	High Pressure Coolant Injection CH containment isolation valve MO-230	PCI) turbine exhaust vacuum 11-34.
	•	Reactor Building Closed Cooling Wa pumps (P-202D/E/F). This caused t Loop 'B' to be inoperable. The Ri then cross-tied at Obil hours.	the Containment Cooling System
		RECCH System Loop 'B' heat exchange	ger discharge valve (MO-3806)
	٠	Salt Service Water (SSN) System La also caused the Containment Cooli Inoperable	oca 'B' pumps (P-2080/E). This ng System Loop 'B' to be
	*	Diesel Fuel OII Transfer System	B' pomp (P-141B)
	*	Reactor Feedpump 'B' auxiliary of	1-pump (P=1528)
		Batlery Room 'B' exhaust fan UVER	=1038)
		TBCCK System Loop 'B' heat exchan	ger discharge valve (MO-3805)
	480	VAC MCC-B18 Including:	
		EDG 'B' auxiliary panel (C-104A)	
	*	EOG 'B' compartment supply fan (V (VEX-214B)	SF-2088) and exhaust fan
	×	Orywell Train 'B' unit coolers (V VAC-206A2782)	/AC-201A2/B2/C2/D2/F2/F2 and
	٠	HFCI compartment unit coolers (V/ HFCI System to be administrative in standby service.	
	*	RHR/Core Spray compartment '8' u	off coolers (VAC-2040/0)
	*	CRD compartment train '6' unit u	soler (VAC-2018)
	,	fore Spray (oop 'B' valves (NG-1 caused the Core Shray Loop 'B' t	400-3848248258). This o be invperable.

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	RHR Loop 'B' Sup Drywell Spray va bypass valve (MO (MO-1001-188)	lves (MO-1001-23B at -1001-16B), pumps m This caused the RHR	on valves (HO-1001-78/D), nd -268), Heat Exchanger Inimum flow valve Loop 'B' to be inoperable d Drywell Spray modes.				
	RCIC turbine.ste	am supply isolation	valve (MO-1301-16)				
•	block valve (MO- (MO-1001-368), 5 This also caused	1001-34B), Suppress uppression Chamber	ng/Suppression Chamber Spray ion Pool Cooling valve Spray valve (MO-1001-378). o be inoperable for the 1 Spray modes.				
•	RHR Loop 'B' Shu This caused the related Shutdown	utdown Cooling suction valves (MC-1001-43B/D). RHR Loop 'B' to be inoperable for the nonsafety j n Cooling mode.					
	Standby Liguid (introl (SBLC) Syste	m pump 'B' (*-2078)				
*	RBCCW valves:						
	* MO-4010A/8	(RHR Loop 'B' heat	exchanger isolation)				
	 MO-4009A/B isolation) 	(RBCCW Lonps 'A'/'B	' non-essential loads				
		rywell Trains 'A'/'B 'B' coolers return l	and Recirculation System ine isolation)				
	• MO-4083 (RI	BCCH Loop 'B' heat e	xchanger bypass)				
	Power supply (Y	7) for the following					
	 Suppression (Panel C-1) 		nd temperature monitoring				
	 MCC-B18 al units (VCC 	r conditioning units -203A/8)	(VRC-203A/S) and condenser				
	* MCC-Bis fa	n/damper control (Pa	nel (-249)				
*	This resulted 1 set/pump 'B'	n a lockout and trip The speed of the MG	illiary oil pumps (P-225A/B). s of the recirculation MG set/pump 'A' was then proximately 30 percent.				
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		 Suppression Chamber Train '3' cir. 	culating fan (VEX-2078)
		 Reactor Water Cleanup (RWCU) Syst (P-204B) 	em recirculation pump '8'
		 CRHEAFS Train 'B' supply fan (VSF CRHEAFS Train 'B' to be inoperabl 	
		 Safeguard 120 VAC Train 'B' (Cont Y41) 	rol Power Supply-Panels ¥4 and
		 480 VAC HCC-B2B including: 	
		 Main Stack Dilution Fan 'A' (VSF- 	-206A)
		 Main Stack Ellution Air Heaters 	'A' and 'B'
		• Main Stack Exhaust Fan (Vik-209)	
		• Electric Unit Heaters (VFUH-201A	/B/C)
re Col	ays lo	of safeguard 120 VAC Train 'B' power from cated in Panel C-942 resulted in actuation int Isolation Control System (PCIS) and Rea (BIS).	s of portions of the Primary
Th	PCIS	actuation resulted in the following respon	ises:
	•	The Train 'B' Primary Containment System (isolation valves that were open closed aut	
	*	The inboard and outboard PCS Group 3/RHR 5 closed position, remained closed.	system isolation valves, in the
	*	The outboard PCS Group F/RWCU System isold in the open position, closed automatically	
Th	e REIS	actuation resulted in the following respon	nses:
	٠	The Train 'B' Secondary Containment System and exhaust ventilation dampers, in the or automatically.	m (SCS)/Reactor Building supply pen position, closed
	•	The SCS/SGTS Train 'B' exhaust fan (VEX-2 de-energized. The SCS/SGTS Train 'A' ech a utility licensed operator to maintain a Reactor Building	aust fan was started manually by

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Failure and Malfunction Riport 91-97 was written to document the event. The NRC Operations Center was notified in accordance with (O CFR 50.72 subparts (b)(2)(11) and (b)(2)(11) 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 LCCs was not invoked because the LCOs were terminated by 2300 hours on March 25, 1/91 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' autor coltage regulator (AVR) that occurred during the surveillance test (8.9.1) while EDG 'B' was loaded on Bus Ac. The voltage regulator was manufactured by the Basler Electric Company. model number SV. 11 382818, serial number 9047500105. The cause for the failure of the AVR was the failure of the AVR magnetic amplifier (11) 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 '3' 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, 11ke 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

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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 185-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 remainer closed as designed.

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fall	spec ure ied ti	' engine of EDG B'. igned and was the r ut relay actuated an ium to the sudden ic inat _ Tected the EDG he EDG 'B' overspeed	G 'B' output breaker / The overspeed trip result of the actuation ad tripped feeder breat bad reduction and the G 'B' engine governor relay (OSR) to actual rip of breaker A609 (occurred a on of lucko ker A605 t automatic control. te the EDG	it approxim but relay 1 to Bus A6, voltage re The oversp 'B' shutdo	ately 109 86-A6. the EDG ' gulator eed cond! own relay	i0 ihen B'			
CORR	LECTIV	VE ACTION								
			rveillance tested in factory results on Ka				.2.7			
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The	falle	owing actions were to	aken prior to re-ener	gizing Bus	A6:					
	•	The cause for the a	ctuation of lockout r	elay 186-A	6 wa* Iden	tified.				
	•		in accordince with p ctory as-found result		.M.3-4, °1	nsulation				
	•	9), "Reset of Lock-	6 was reset in accore Out Relays and Protec ppickimately 1400 hou	ti.e Relay			lev.			
	*	Bus A6 was re-energ	ized on March 25, 199	0 at 1413	hours.					
	•	primary and seconda	(152-608) to transfo ry sides (4160 VAC/48 nce with procedure 3	O VAC) of	transforme	r X-22 w	ere			
	*		(152-608) was closed re-energized by appro				and			
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C-142

LICENSEE EVENT REPORT TEXT CONTINUATION	ΑΡΥΝΟΥΤΟ ΟΛΤΕ ΝΟ ΤΟ ΕΧΡΙΠΟΙ Α ΟΛΟΙΑ ΑΝΤΟ ΤΟ ΕΧΡΙΠΟΙ ΑΝΟΙΑ ΤΗΝ ΠΙΑΡΟΝΙ ΤΟ ΟΛΟΙΑΤΙΟΝ ΠΟΙΑΡΟΝΑ ΤΟ ΤΟ ΑΝΟΙΑ ΤΟ ΟΛΟΙΑΤΙΟΝ ΤΟ ΑΝΟΙΑΤΙΟΝ ΠΙΑΡΟΝΑ ΤΟ ΟΛΟΙΑΤΙΟΝ ΤΟ ΑΝΟΙΑΤΙΟΝΙ ΤΗ ΤΗΝΟΛΟ ΤΗ ΤΑΛΙΟΝΤΟ ΤΟ ΑΝΟΙΑΤΙΟΝΙ ΤΗ ΤΗΝΟΛΟ ΟΓ ΜΑΝΑΟΙΑΜΈΝΕ ΑΝΟΙΒΟΙΟΙΕΤ ΜΑΙΟ ΟΓ ΜΑΝΑΟΙΑΜΈΝΕ ΑΝΟΙΒΟΙΟΕΤΕ ΜΑΙΟ	TO LOWPLY WITH THIS BUD WITH FORMARIC FATE TO THE RECORDS OF SIGN & NUTLEAR ON DO 20055 AND TO	
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EDG 'A' was surveillance tested in completed with satisfactory results the event), March 26, 1991 at 0703 The following actions were taken pr	accordance with prov s on March 25, 1991 s hours, and March 27	at 0502 hours (just pr , 1991 at 0558 hours.	
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The EDG 'B' was tested in accordance satisfactory results. The test beg hours. The LCO for EDG 'B' was ten hours.	can on March 28, 199	1 at approximatel: 061	15 1y 0915
Temporary Modification 91-22 (Rev. Essentially, the modification prov RHw/Shutdown Cooling suction line de-energized. This action was tak implementation was not necessary by (via Panel Y4) on March 25, 1991 at	ided for energizing isolation valves whi en as a contingency ecause 120 VAC power	the circuit that confr le Panels Y4 and C-942 measure and its	rols the 2 were

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PREVENTIVE ACTION

8/ August 1896-4 41 (197)

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 bad 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.

Pi edure 2.1.12.1 (currently Rev. 8), "Emergency Dierol Generator Daily Su illance", is performed to record critical EDG 'A' and 'B' parameters including room, emperature. 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 F', a pressure water for core r 'ing. In the unlikely event the RCIC System became inoperable while the HPCI Syst 's not available, an automatic (or manual) actuation of the ADS would reduce Rea. 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.

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This report is submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the FCIS and RBIC 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)(0) 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 unide tifiable period of time. The potentionmeter was cleaned and the cover was installed. The potentiometer is physically separate from the voltage regulator.

ENJRGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

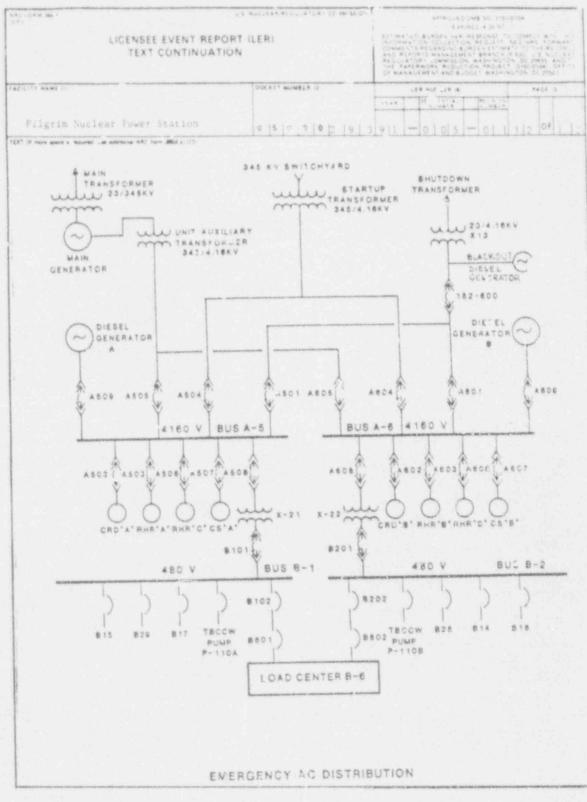
COMPONENTS Amplifier (L1) AMP Breaker (152-605) BXR Bus (A5) 80 Regulator (Voltage Regulator) RG Relay, Locking Cut (186-5, 186-A6) Transformer 86 XEMR

SYSTEMS

Comprisent Soling System (RBCCW/TBCCW)	CC
Control Complex Environmental Control System (CRHEAF5)	VI
Control Red Drive (CRO) System	AA
Core Spray System	BM
Emergency Cosite Power Supply System (EDG)	EK.
Engineered Safety Features Accuation System (PCIS/RBIS)	36
Essential Service Water System (SSW)	81
High Pre-sure Coolant Injection (HPCI) System	8J
Low Voltage Power System - Class 11	ED
Medium Power System - Class IE	EB
Reactor Core Isolation Cooling (RCIC) System	BN
Reactor Recirculation System	CA
Reactor W-ter Cleanup (RWCU) System	35
Residual Heat Removal (RHR) System	80
Standby Gus Treatment System (SGTS)	BR
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Even.: Plant: 302/91-018 Engineered safeguards actuation inappropriately bypassed December 8, 1991 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 begai. 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 consurizer 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.

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CRYSTAL RIVER UNIT 3 (CR-3)	0 0 0 0 0 0 0 0 0	VEAR EXELUTION MEURICAL MEURICAL 9 1 0 1 8 0 0	

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 D247, 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 [1L] 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 manu ily bypass automatic High Pressure Injection (HPI) [80] 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.

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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 [A8,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 E5 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 compcunded 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,

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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 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. It us 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 REV-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

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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 Regualification Training. Administrative guidance has been developed to provide direction for the appropriate bypassing of ES actuation signals.

PREVIOUS SIMILAR EVENTS

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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, 10
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.

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On July 22, 1991, Mode 1, Limiting all fire protects inoperable. The fire hoses within affected, consti- were declared in water system hear positioned valv	3 spaces, i.e., approximately f at 2115 Eastern dayligh Conditions for Operation on spray and sprinkler s require, action provision one hour could not be o tuting operations prohibi- operable as the result of ders. The loss of header a that were manipulated d iscovery of the incorrect	t time (EDT). (LCOs) 3.7.1 ystems and ho ns to establ omplied with ted by techn a loss of p pressure wa buring fire p ly positione	, with Units 1 and 11.2 and 3.7.11.4 ose stations were ish fire watches a because all plant ical specification ressure in all fin s the result of in ump testing on the d valves, actions	2 operating in were entered when declared and route backup areas were is. These system to suppression icorrectly afternoon of were promptly

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Mode i (100 percent reactor por per square inch gauge [paig], i fire protection spray and sprin Code KF] were declared inopera system [EJIS Code KF] headers. the action provisions of Limit could not be complied with hec	ern daylight time (EDT), with Units I and 2 operating in wer, reactor coolant system [RCS] pressure at 2,235 pounds and RCS average temperature at 578 degrees Fabrenbeit, the nkier systems [FIIS Code KP] and fire hose stations [EIIS 51e when pressure was lost in the fire suppression water Although significant firewatch coverage was in effect, ing Conditions for Operation (LCOs) 1.7.11.2 and 3.7.11.4 ause of the scope and cause of the inoperable systems, prohibited by technical specifications (TSs).
Performance Test," and SI-73.4 inappropriate personnel action open flow path from the fire s discharges into the intake for suppression water system was s at 2115 EOT on July 22. At th backup system required by Acti meet flow rate and pressure re in Special Report 91-04, dated Because of the luck of system	eillance Instruction (SI) 73.2, "Fire Pump 18-8 , "Fire Pump 28-8 Performance Test," on July 22, 1991, is vesulted in an incorrect valve alignment that created an suppression water system headers to a test drain, which easy. Consequently, header pressure for the fire subsequently lost, and the system was declared inoperable to this event, the system was being considered the on 5.1 of 100 3.7.11.1 because of the inability to fully equirements. This condition was previously reported to NRC 1 May 20, 1991, and LES 50-327/91009, dated June 5, 1991. pressure, the spray and sprinkler systems required by se stations required by 100 3.7.11.4 were also declared y 22.
responsible for American Socie ('AUD A') was assigned to perf	July 22, a dayshift assistant unit operator (AUD) c^{-1} of Mechanical Engineers (ASME) Section XI, testing $C_{\rm e}$ SI-73.2. AUD A was also assigned to be the SI-73.2 block were encountered with the ultrasonic flow instrument est completion was delayed.
testing ('AUG B') was assigned B1-73.4. AUD B was also assigned logged in the S1-73.4 test in	evening shift AUO responsible for ASME. Section X1. d to astist in the completion of 51+73.2 and to perform gned as the SI-73.4 test director. A pretest briefing was g at 1500 EDT. However: SI-73.4 had not been approved for shift operations supervisor (ASOS).
all A and all A restored the period on this value alignmen verifier. Before taking the	e data collecting portion of SI-73.2 was completed and system to its normal lineup. Allo a served as the first 1, and A^{\prime} is served as the second person and independent B^{\prime} -73.2 parkage to the main control room (MCR) for review, over of the test and system status.
oprissicalian (ARRID) ayatam ta p	ID A and ATU 0 began aligning the high pressure fire erform 51-16.4. The AUOA completed selected partinos of that might have alerted the MCR to the changes being made line.

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Sequoyah Nuclear Plant Unit 1		A NUMBER NUMBER

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S1-73.4 involves the positioning of eight values. The purpose of these value manipulations is to isolato the pump being tested from the rest of the system and to provide a test flow path. The AUOS placed seven of the eight values in the required position. One value, 2-26-575, "Auxiliary Building HFFF Supply Value," was left open. S1-73.4 requires 2-26-575 to be shut. AUO A and AUO B did stut values 1-26-550, "FP Strainer "niet isolation Value," and 1-26-553, "FP strainer out at isolation Value," isolating the No. 1 HFFF strainer. Additionally, the fire on test header isolation value, 0-26-859, was opened. With the HFFF system 1 is isolap, a direct path from the 28-8 fire pump to the 10 inch test discharge value was established.

The AUOs intentionally did not follow the steps of 51-73.4. They were trying to save time by lining up for 51-73.4 before the results of 51-73.2 were reviewed and approved. However, they realized that the 18-8 fire pump was technically inoperable until 51-73.2was complete. They believed that by leaving 2-26-575 open, a flow path for the Unit 2 fire pumps would be available until 51-73.4 was actually started. This deviation was not authorized. This alignment was not documented in the configuration log or in the 51-73.4 package.

The two AUGs took the SI-73.2 and SI-73.4 packages to the MCR. The AUGs delivered the SI-73.2 package to the Unit 1 ASOS and informed him that they were "set up" frr SI-73.4. The ASOS interpreted this to mean that the test equipment was inst-field. The ASOS wanted Technical Support personnel to verify that the test results were satisfactory and directed the AUGs "not to start SI-73.4." The ASOS meant that no valve 14 ups were to be performed.

At approximately 1730 EDT, the No. 2 HFFF strainer high differential pressure alarm was received in the MCR. AUO B was sent to the pumping station to 7 estigate. AUO B reported bacs to the MCR that the No. 1 strainer was isolated. ... 0 B did not report that he had earlier isolated the No. 1 HFFF strainer with AUO A as part of the SI-73.4 valve alignment. The unit operator directed AUC B to unisolate the No. 1 HFFF strainer.

The ASOS checked the configuration log and the S1-73.2 and S1-73.4 mackages to decermine if the abnormal alignment of the No. 1 strainer was a result of the... tests. The abnormal alignment was not documented. The ASUS questioned the ALO 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 S1-73.4.

The gradual loss of system pressure was first noted at approximately 1800 EDT on July 32 at the direction of the MCR, the turbine building #30 began monitoring the turbin building EPFF header pressure. Efforts were initiated to locate and isolate the cause the depressurfication. The shift operations supervisor contacled 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 purp test header isolation value was checked. The value was found to be in the open position at 11k0 EDT and was subsequently closed as part of the recovery actions.

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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 it 2334 EDT. Safety-related areas of the plant had fire protection coverage avaluance at this time. At 0109 EDT on July 23, system pressure was being maintained normal, and the fire suppression water system was aligned for normal service. 1008 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 2-26-375 and 0-26-7. (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 couse of this event was the failure of AUDs A and B to follow approved plant procedures. The failure of the AUDs to follow Site Standard Practice (SSP) 8.1, 'Conduct of Testing,' directly led to this event. The AUDs were the designated test directors for these test evaluations. They violated the requirements of SP-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 sequer... test performance. If these sections had been followed, the unsurhorized value alignment would not have then made and/or the MCR could have better mitigated the consequences.

An additional example of failing to follow procedures was the AUOs' noncompliance with S1-13.4. Specifically, valve 2-26-575 was not closed as required by Step 16 of Section 5.2 of S1-73.4. Several other steps in S1-73.4 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 Allos, and an evaluation of their performance has led to the contlusion that the performance problems described shove are isolated to the two AUGs specifically involved, and are not a reflection of their tick with AUO performance in general.

Poor communications used by personnel wish contributed to this event. The use of informal ferminology associated with the status of the surveillance testing inhibited the NCE sollity to determine actual plant configuration. If the AUOs and the MCE personnal 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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was degraded for configuration or 40 minutes (app elapsed while th TS 3.7.11.1 act capabilities if	r approximately the RF:P system roximately 1600 the HPFP system p ion 5.1 allows 2 the system becc	5 hours and 35 minutes m was not recognized fo EDT to 2140 EDT). Appr messure was begraded wi 14 hours to reestablish	ailed above, corrective actions
with the action coverage was in fire barrier or provided covera continuous wats truck was conne compensatory de NFFF fire pump detection and/o have bien dispu- been detected in numps on low s	provisions of 1 effect at the detection requi- ge for all acce- h was posted at cted to the KFF asure was in p- power leads. 1 in firewatches w itched according v any of severa- viton pressure.	LCOS 3.7.11.7 and 3.7.11 time of the event as con- irements. (Roving hour) ssible arear of the cont- thr diesel generator by P system yard piping as ach because of concerns f a fire had occurred du- ould have alerted Opera- ly. The reduced HPFP s i indications: includin- observed low pressure m	systems precluded full compliance .4; however, extensive firewatch pensatory measures for unrelated y watches were in effect, which rol and auxiliary buildings, and a ilding.) Additionally, a pumper a compensatory measure. This of potential degradation of the aring this period, in-service tions, and a fire brigade would ystem pressure and flow meld have g star: signals to the n m fire no flow from sprinklers o hoses, rations could have them is. Inted

antions of the system to divert flow to the area of the fire. In parallel to these Actions 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 rause of the loss of pressure, as was cone. Accilons caparity would have been available chrough the use of contracted missic pumpers. This would provide the ability to route independent holes or to sugment its system fire. The compartmentalized configuration of the plant, and the use of portable time extinguishers, could have provided the ability to privile your containment of the fire while exact testimation was configura-

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TEXT (11 more space is resurred, use additional NEC form 1664's) (17) ANALYSIS OF EVENT

Areas of the plant protected by carbon dioxide suppression systems, (i.e., computer room, auxiliary instrument rooms, diesel generator rooms, fuel all pump rooms, and diesel generator electrical board rooms) were not effected by the loss of HPFP system water pressure.

The loss of MPFF system pressure also impacted the system's ability to provide emergency feedwater to the RCS steam generators under flood conditions, as described in UFSAE, Section 9.5.1. However, due to the relatively short duration of this event compared to the flood notification and preparation time described in UFSAE, 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 result 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 home stations to be declared inoperable.

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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 336/91-010 Reanalysis of main steam line break Octobe: 18, 1991 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 p ug and 427°F, respectively. The Millstone 2 contair ment 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 esc. nated in NUREG-1150 for a similar containment c sign indicates that uncertainty remains regarding containment survivability under the limiting MSLB conditions.

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ASP Modeling Assumptions and Approach

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This event has not been modeled as an accident sequence precursor.

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Description of Logar

On October 18, 1991, at 1505 hours, with the plant in Mode 1 at 100° power, a reportability determination was inside concerning a reanabati of "4 main steam line break event inside the convintiment. The re-analysis has shown that the v implicing made for the existing (1979) main steam line break analysis were non-conversitive with escillable of power level, break size, and single active failure. Using more restrictive atsumptions, design units for containment pressure and temperator could be exceeded.

The easing (1979) man, seam line break analysis assumes a postulated double-ended (h 3 h^2) break of the notio seam line between the sceam generator outlet and the sieron line flow restrictor at line zero power, with the worst single active failure being a failure of a diesel generator and the resultant loss of une-hill of the emergetic; safeguards leatures with b reduce containment pressure (1 containment spiral spiral point) and 2 sumanment at recirculation fails). The peak containment pressure and temperature for this analysis is gliedicted to be 47 paig and 274°T.

It has been deservined that the limiting commitment pressure and temperature are attained by postulating a disible-ended break of the main mean line between the tream generator order and the steam line. How restrictor at full power, with the single acrice failure being a failure of the main freedomic regularing value of the affected mean generator to close. This analysis also assumed operator acriems is secure feedwater to the affected mean generator of close. This analysis also assumed operator because to ender the feedwater to the affected mean generator of 10 minutes following the teactor usin. These results exceed containment design remover and temperature .

An immediate report was m. To the NRC and the unit immediately commenced an orderic downpower to approximately. We power (Mode 2) by plant operators. The existing main steam line break analysis remote salid for Mode 2 operation. No automatic or manual salety systems were required to respond during the event.

CAUSE OF LYCH

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The root cause of the evens has been determined to be an incorrect assumption, made in the FSAR multism, that the timbing condition, for the containment response due to a Main Steam Line Break (MSLB), was het zero prover. This incorrect assumption was based upon the judgement due to a hot sero prover the steam generators contain the largest inventors 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 imming.

As a result of the planned mean 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 boochmark new steam generator and containment models. During the benchmarking of the current steam generators, it was discovered that the first zero power conduction size may be benchmark new steam generators. It was discovered that the first zero power conduction size may be benchmark new steams.

The peak containment temperature is highly dependent on the moliture cativolar that occurs from the break. Musicure (arryinger is important in that while a significant ministure carryinger the containment temperature will be binded to the saturation remperature corresponding to the containment pressure. It no ministure carryinger occurs and pure steam is discharged, superfloating will occur and containment temperature will not be limited to the saturation temperature.

At his zero prover, the large steam generator manners will assure that monitore carryiner and tactur for must break tizes. However, at full power, will the reduced investors, monitor carryiner is not predicted to occur. Thus, for peak containment temperature, the billion of solution shall be full provided.

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la tr tr b	troughout the transient. Thus, at zero iffed open condition. However, at full intuition of the event and thus would b equilating valve failure, the feedwater a etween full power and hol zero power ontainment would he full power with a	power e subi ddittor Thus	i th sect n wr i, th	e mai to a f suld n e limi	i ter allec kire ung	ediki liop (hat con	nier en i n ol duu	tegi toni tsei tsei	the the	ini ini nas	vak Wit fier umu	ve v h a enco un s	ma ma 6 in mas	id b in i ini	e or eedw ((a))	en a aler nver	a an anns	
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ת עע גע גע גע גע גע גע גע גע גע גע גע גע	In response to an NRC request for info nade on December 21, 1979, the desp he additional mass releases to the com SAR case and shown to have no impa- tude was amired at only assessing the u- ssumptions were not reevaluated. This compution Engineering. This analysis normation requested in the L&E Bolle nade in December 1979, it was assume therefore, no new analysis was perform he NRC on October 7, 1965. The nor- ne tereword to evaluate the impact of	n bas ainme ict on ipaci was s was s was s was s was s un 80 red tha red to record	is at the of t app of the of the of the of the of the	eamlin hue to peak he ne oried inied issued is ana e Buil nive a	ie b aux con a au by e io th i in i in i in i in i in i in i in i i	reak iliar tami nom valu se S Feb A ptd	ari s fe mer tauc tauc RC rua als Sali stis	edw edw i pr inin ns c ob o su ns l were	s w ale lati lati lati lati lati lati lati lati	as on e b iuai iuai iuai ot e	reev addin and system the as vi- tion disco	alu ion i ne ie N res Rej iver	aled wer the (55) (95) sim pon pon	i ir e an e or S ve 0.5 illar id to wa	the dded are gina indo ince to the to the stee	ana to t Sinc L FS the Bul eive	lysis he AR ique leun d In	

It should be recognized that in determining the cause of this event, reliance has been placed upon the available documentation for the abelian and evaluations performed in the 1914-1980 time period. Because these evaluations were performed over ten years ago, not all of the documentation has been retrieved. However, from he 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.

U Analysis of Event

This event is being reported in accordance with 10CFR50.73(a)(2)(ii)(B), which requires the eponing of any event or condition that results in the nuclear power plant being in a condition outside the design basis of the plant.

The salest consequences of this event are the potential overpressurization of the containment with subsequent damage to the containment structure and salest related equipment required for safe shutdown of the plant from a postulate. MSLB event The safety consequences are minimal, however, upon consideration of containment design margins, salety related equipment qualifications, and standard post trip operator actions.

In considering the sales consequences of this even the following items were addressed

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Price 1 (1000) Price 1 (10000) Price 1 (10000) Pri	i 01110 0 0 0. 0F 0 m consists of a presidential gried by a massive reinforced contre- pressure of 54 psig, and was tested of a design pressure of 54 psig. The combinations, including the case will of a design pressure of 54 psig. The combinations, including the case will of 1 psig. The code requires that errorability of the structure at the tion 9 1 1) becomented by many sources recently structure has been found to be 2 m- ident Risks. An Assessment for fine pical contaminent structures. Includ is a design pressure of 4° psig. The active was around 100 psig (a factor english being higher than as amed, ation of structural behavior during even performed for Midboute 2, but
 Unit 2. If a 1 a 1 a 1 a 1 a 1 a 1 a 1 a 1 a 1 a	1 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
 (a) Containment Structural Integrits The Millione 2 containment services and dome connected to and support foundation slab. The containment and dome connected to and support foundation slab. The containment and dome connected to and support foundation slab. The containment and dome connected to and support for a provide test of the service /li>	read by a massive reinitiated control pressure of 54 psig, and easi letted esign method was used to design the of a design pressure of 54 psig. The combinations, including the case of s 81 psig. The code requires that ervicability of the structure at the tion 9 (11) ocumented by many sources recently structure has been found to be 2 to ident Risks. An Assessment for Fire pical containment structures. Includ is a design pressure of 4° psig. The acity was around 100 psig (a factor englis being higher than as amed, ation of structural behavior during eco performed for Midboute 2, but
 for Containment Structural Integrity. The Millistice 2 container reinforced concrete cylinder and dome connected to and sup foundation slab. The containment was designed for an internate 52 psig during the structure in a cyrity test. The working arress containment structure was checked for factored loads and loa a 1.5 hoad factor on the design pressure, which corresponds "strength be adequate to support the factore for carrow load cases, including the cases los found there expands of excited loads and hoa as isolated been be attured." (ACL-318-71) commentary Sections for which are expanded and the generat, the anticipated ublinate capacity of a committee of 5 times design pressure. SLREG-1150 enuled "Severe AdV 5 Nurthear Power Plants," studies the ublinate capacity of a committee of 5 times design pressure. SLREG-1150 enuled "Severe AdV 5 Nurthear Power Plants," studies the ublinate capacity of a committee of a containment, we evaluation determined that a lower bound on the ublinate capacity of a containment we evaluate the anticipated there are a detailed with the must be a detailed with the set of the containment of the sublation details for the design has of the containment structure whet factored 1 has a lower bound dismate capacity of a containment structure whether the distore 2 containment we was a detailed with the Millistone 2 containment we want factored 1 how a substantiate share the containment with the containment structure and the design has a structure and the containment structure are beyond the design has a substantiate share the structure. the Equipment Qualification. The electrical equipment if the fully of 2.5 PCF and pressure of 54 psig. For a full power MSLB with no successite feedwater to base termined there equipment we have determined that equipment required to have temained to the	read by a massive reinitiated control pressure of 54 psig, and easi letted esign method was used to design the of a design pressure of 54 psig. The combinations, including the case of s 81 psig. The code requires that ervicability of the structure at the tion 9 (11) ocumented by many sources recently structure has been found to be 2 to ident Risks. An Assessment for Fire pical containment structures. Includ is a design pressure of 4° psig. The acity was around 100 psig (a factor englis being higher than as amed, ation of structural behavior during eco performed for Midboute 2, but
 In general, the anticipated utilinate capacity of a comainment 2.5 inness design pressure. St REG-1150 enuled "Severe Ad U.S. Nuclear Power Plants." studies the utimate capacity of in this study was 22mm, which is a prestressed containment, we evaluation determined that a lower bound on the utimate capacity of a containment determined that a lower bound on the utimate capacity of design basis events. A similar detailed study is a containment we evaluation determined that a lower bound on the utimate capacity of design basis events. A similar detailed study has not same factors which contribute to a lower bound distinct capacity with the moment of the Millstone 2 containment is a lower bound distinct capacity of the Millstone 2 containment can support the factored 1 load cases are beyond the design basis of the containment straining capability of the structure. th Equipment Quelification. The electrical equipment in the offits, ing all MSL B events has been qualified to 10CFR16 a trom 324°F to 448°F and pressure ranging from 70 to 127°F. Although this temperature and pressure standards are a full power MSLB with no summatic feedwater Bolaic feedwater for 10 minutes, the predicted peak somainment of 27°F. Although this temperature and pressure would have eqciptionent we have determined that equipment required to base temained uperable. 	structure has been from to be a fi- ident Risks. An Assessment for five pual contaminent structures. Includ in a design pressure of 4° psig. The acity was around 100 psig (a factor englis being higher than as arned, ation of structural behavior during een performed for Millsone 2, bus
fulls, mg all MSLB exerts has been qualified to D0CFR10 a from 224°F to 448°F and pressures ranging from 70 is 127 qualification profile for this equipment was based on a LOC 284°F and pressure of 54 play. For a full power MSLB with no automatic feedwater Bolatic feedwater for 10 minutes, the predicted peak containment p 27°F. Although this temperature and pressure would have equipment, we have determined that equipment required to have remained operable.	ad case and beyond. These postulari actives but within the overall load
Leedwater for 10 minutes, the predicted peak containment p Q7*F. Although this temperature and pressure would have equipment, we have determined that equipment required to have cemained operable. Thereis analysis has shown for the predicted short datation.	nequirements with temperatures king
Thermal analysis has shown for the predicted short duration	concerned the qualification of country
conditions that the sortace temperature of salets related equipmentative of the partial steam pressure in containment. There exercise this the SRC in STREG 0581, arrapraph 1.2(5), have been a momber of vendor ten results which have also possible partial steam pressure of the containment during 14.7 ps., i.e., the initial partial atmospheric air pressure, the analysis. The resulting maximum steam temperature during predicted to be 322° F. As this remperature, all of the requirements and the qualificable.	prineral will not true above the anutral is method of analysis hat been UREG 0510 and NUREG (511. The emonstrated due terromerium The he accident is estimated by subtraction is the absolute pressure of she accident we ahave NSLB accident is thus ed safe shurdown equipment in
The preduced MSLB accident pressure at 93 psic is shelfn some of the safe attandown equipment in containment. The equipment is 'to psic In general electrical equipment is to buinder than higher pressure. The following equipment has pressure conducta	higher than the qualification pressure owest qualification pressure of the

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N Corrective Action

A Justification for Continued Operation (JCO) was developed to allow the plant to return to power operation by stationing a dedicated reactor operation to close the main feedwater block values 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 value to close on the affected steam generator. This analyse assumed operator action to close the main feedwater block values within 15 seconds following the reactor trip with a 10 second closure time of the silve. The peak containment pressure and temperature for this case is predicted to be 54 psig and 413°F. This JCO documents N/ECO evaluation of operator actions following a reactor trip, feedwater block value operation under postulated accident conditions, containment succural integrity, and equipment environmental qualification. Diagnostic testing of the motor operated main feedwater block values was performed in accordance with established procedures developed under the Northeast Cultures 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 all remain below the design basis value for all main seam line break events. Although the design basis value for all main seam line break events. Although the design basis value for all main seam line break events. Although the value for MSLB temperature pack events the containment qualification temperature of 289°F. Given this puschcation for success the containment qualification temperature of provides reasonable assurance that with the actions of a maximum saturated seam temperature of 289°F. Given this puschcation for success the containment qualification temperature of 289°F. Given this puschcation for success the containment qualification temperature of the required safe shuidown equiptive distable based on a maximum saturated seam temperature of the equiptive size distable based on a maximum saturated

As pan of the JCO, short term corrective hardware changes are being developed to automatically close the main leedwater block valves given a Containment Isolation Actuation Signal (CLAS). The current schedule is to have these short term hardware changes installed a close by November 30, 1991. Permanent long term hardware and selpoint changes will be performed during the 1992 retur¹ to outoge. Following these changes, the predicted MSLB leak containment pressure and temperature with be equal to or less than 54 psig and 413°F, therefore, the required safe shutdown electrical equipment will remain outoffable.

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

Additional Information

There were no failed components during this event

Similar LERs 77-23, 80-05, 83-07, 85-01 and 86-10

Main Feedwater Regulating Valves

Manufacturer	Copes-Vuican
Model	$p_{\rm er}_{\rm 2000}$ (2) Angle
Sire	14 inch 900#
EDS Code	\$)-1,CV-C635
Main Freuwater Block Values	
Manufacturer	Ctane
X1()(dg)	L-900 Gane
Sire	18 mch 400#
ETIS Code	$\{J_{i+1}\}_{i=1}^{N} \subset h \geq 1$

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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: Date of Event: Plant: 369/91-006 Potential failures in containment spray and air return February 15, 1991 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 tocuroalation 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 storar tank; when this supply is exhausted, water is recirculated from the containment sumr, the suph 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 *»* 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 0.55 psig, the systems restart, and much 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 m intained by the available containment . 37ay (ND system) [actually a possible alignment of the RHR systera]." (Ne a: Brackess, "[]", 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 die 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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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 Sprry (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) personnal, 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.

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EVALUATION.

Background

The VX [EIIS:8B] system is designed to rapidly return wir 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 wir 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 als. Ontains two 100 percent rapacity hydrogen skimmer [EIIS:SKR] fans, each wich a capacity of 3,000 cfm. A normally closed, motor operated valve [EIIS:V] on the hydrogen skimmer header prevents the sic flow from hypassing the ice condenser during initial blowdown. It remains closed vitil the end of initial blowdown. After initial blowdown, a start permiss related a Phase B. Containment isolation at 3 sig. (Sp) signal open the valve coincident with Cont inment 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 Reat Removal System (ND) [EIIS:RP]. The NS system is actuated by an 5p 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 Safely Features System (ESF) and is provided to prevent exceeding the negative design pressure of the Containment structure. The systems permissive and tensination features are redundant and are accomplished by independent pressure switches [EIIS-PS] which provide

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interlocks to prohibit Co skimmer Ian operation whe system is designed such t opray or Containment air it allow Containment opra operation which not requir	n Containment) hat no single (return and hyd) by or Containment	pressure is be failure can pr rogen skimmer nt air return	elow 0.35 psig revent proper fan initiatio and hydrogen	. The Containment n nor can skimmer fan	

hydrogen skimmer and air return fan operation is actomatically terminated upon pressure deray to 0 35 psig, thereby, controlling Containment pressure.

operability Evaluation for FIK 0+M91+0032 states, in parts

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 Spsignal, 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 those 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 at MEVNs 2417 and 2418. The designed operator associated with the first action will ensure that the design function of the air return fans (stret 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.

Pased 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 ("S) 3.6.5.6 states that two independent Containment Air Return and Nydrogen Skimmer systems shall be operable in Modes 1, 2 (Startun), 3 (Not Standby), and 4 (Not Stotdown). With one Containment Air Return and Nydrogen 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 3.0.1.

IB 3.0.) 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, an applicable, in

a. At least Hot Standby within the next 6 hours,

b. At least Hot Shutdown within the following 6 hours, and

. At least Cold S* . town 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 [EllS:MO] could exceed the specified cycling duty after an automatic (auto) actuation. This rendered the VX system inoperable on both bnits. 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 rucling duty. However, DE personnel did determine that since the NS system pump, would complete their design function prior to any postulated motor damage, they did not present a problem from a safety or operability contern. Therefore, the OE would focus on the VX system. However, a resolution to the dead heading problem is being pursued by DL personnel.

To prevent the VX system fans and damper/valve motors from exceeding their c; 'e duty it would be necessary to wanually 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, Emerginty 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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	This event has been assigned a simulticipated environmental interpolation of the fans and dampers damper/valve motors had not been botors were designed to cycle a slso known that during a LOCA. Containment. However, this infand cycle duty) was generated by system several years prior to recognized that the interaction cycle duty of the affected moto exceeding the cycle duty of a m failure. Motors are designed to within a certain time frame (cy application. When a motor is smore than its full load rated correate a rotating magnetic field itself with. This inrush of containing caused by exceeding the motor exceeding the motor exceeding the motor exceeding the second se	eraction. The int with the cycle dut n previously evalua and the cycle duty f there will be press ormation (Containme y different design o this event. At t between the Contai rs could present a notor presents the p o start and stop a cle duty) depending tarted, it pulls ag urrent, because the d which the rotor 4 mirent generates exe its design capacit tof a break down in recover heating.	eractio y of th ted. T or each ure flu nt pres groups hat tim nment e problem cessibil certain t on the proximus static static cessive ty for n the in	n betwee e fan ar he fans is know ctuation sure flu when den e, it wo nvironme t, The j ity of i number sir part itely 7 mary or y amounts cycle du nsulatio	n the and damp en. It i is in ictuation igning t is not ent and t problem s equipment of times icular to 9 time stator a of heat if, if r n, short	s he he with coils lign uns	
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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 wit in 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 70 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 alter, yte method for controlling hydrogen pockets would have been available. The Hydrogen Mitigation System (ERM) 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 ERM 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).

Duying the time the VX system was inoperable, there were to 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.

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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: 424/91-009

Instrumentation problems lead to RHR pump vortexing and loss of shutdown cooling during reactor cavity draindown October 26, 1991 Vogtle 1

Plant:

Date of Event:

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 ar ⁴ 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 draindows 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 mir. 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 sufficiently. Shutdown coeling was unavailable for a total of about 50 min, during which time the RCS temperators.

ASP Modeling Assumptions, Approach, and Results

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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.

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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 bead. 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 shurdown 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 rem-ined 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 18 minutes from the time the 1B pump started showing indication of vortexing, and full shutdown cooling was reescablished 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 50.7% (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 c the residual heat removal (RHR) safety function of the RHR system.

B. UNIT STATUS AT TIME OF EVENT

Unit 1 was s. it 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 Trai 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 lead flange level) to allow the reinstallation of the reactor vessel head. (Note: Unit 1 "mid-loop" elevation is 187 ft and reduced invent_ry 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 Seat 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

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the pravious 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 temoved during each set wing outage. Based on his understanding, the APO proneeded 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 IB RHR pump was operation provide rec. culation shutdown cooling at a flowrate of approximation of gal/min. At 1848 EDT, the night shift unit shift supervisor (USS) aved the day shift US3 in vactor cavity water shift supervisor (USS) level was not d to be . . . elevation of app-skimatily ... ft as indicated by the pressurizer cold calibrated level indicator ('...'-4.2). At 1930 EDT, a night shift plant equipment operator (PEO) arrive. it f. Unit 1 containment to relieve the day shift APO who was part in the tygon tube "... "ontrol room reserved that level was ap ... lwately 207 ft. This WAS' sight glass being monitored should be coming on scale 204 to level indication could be observed in the sight glass as get. how 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 scopped while the problem was investigated. The PFO and the APO then proc .ded 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 PEJ and the PO 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 concrol 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 1' el 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 ALBO6 D03. "Accumulator 04 Ri/Lo Level," was received in the Unit 1 control room. This annunciator was part of a recently added modification to provide a temporary RuS high level alarm (satpoint 192 ft 6 in) during refueling operations. On receiving the annunciator, the control room reactor operator observed level indicator

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117-957 to be at top of scale (100 percent) and tapped on the indicator This caused 111-957 level indication to drop to 60 percent (i.e., 190 ft 9 The draindown was stopped by realigning the A RHR pump so that it in). temnorarily recirculated to the RCS. The PEO performing the sight glass watch was directed to visually wrify 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 111-957 indicated level. The I&C foreman indicated that the reference leg for 111-957 might need to be filled. Therefore, it was decided that 111-957 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 IB RHR pump, indicating that vortaxing or cavitation of the pump was occurring. Operator action was taken as directed by Abnormal Oper-ting Procedure 18019-C. *Loss of Residual Heat Removal.* to close the discharge valves for the 18 RHR pump, putting the 18 RHR pump on miniflow. Motor current readings for the 18 RHR pump stabilized; however, discharge pressure remained low. At this time, 117-957 was observed to be at approximately 30 percent (i.e., 188 ft 3 in) and narrow range instrument LLI-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 IA RHR pump was then shut down and its suction was realigned to the At approximately 2239 EDT, the 1A RHR pump was restarted and operated RWST . 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 18 RHR pump began to show some improvement and a recirculation cooling flow of approximately 350 gal/min was recatabilished. At approximately 224% EDT, the 1A RHR pump discharge valves were closed. placing the LA RHR pump on miniflow. The LA RHR pump such in was realigned to the RCS and leakage through the discharge valve provide, a recirculation cooling flow of approximately 350 gal/min. At this time, an attempt was made to increase the recirculation cooling flow of the 18 RHR pump However, after increasing flow to approximately 2600 gal/min, indications of vortexing c cavitation were again observed. The 18 RHR pump flow was reduced to 1800 gal/min and the pump operated satisfactorily with noindication of vortexing or cavitation. (Note: A subsequent review of compute, 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. There ure, 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 arght 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 18 RHR pump. The 18 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 tim- the sight glass was put in service. The clearance for the sight glass was released and the opper isulation valve was opened it was slad discovered that a HEFA filter .nit was conn+ via a flexible duct, to the opening where the pressurizer safety valve had been removed. At the sime 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 of: an' a vent wort on the unit was opened to relieve the vacuum on the pressurizer.

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 reducad inventory operations provides level indication based on differential pressure as measured between the hot legs of RCS loops 1 and 4 ap; the pressurizer (for the level transmitters) and between the intermediate leg of RCS loop 1 and the pressurizet (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 reach as 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 explaint why it also presented a false high indication of level.

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The root cause of the event was procedure in dequacy. Procedures for reducing RCS level during refueling operations provide sufficient ateps 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, admit strative 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 annualizor or the cause for the ensuing "low" level indication of LLI-957. Had troubleshooting or . 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 LLI-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 confirmed the temporary tygon tube and visual level indications. On this basis, they delayed troubleshooting of LLI-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 tensive training the operators had received on industry events involving is of RHR. This included training and simulator scenarios on oper is response to a loss of RHR during the requalification training segment provide 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 18 RHR p shutdown cooling for approxima flow was not reestablished unt indications of vortexing and a computer data indicates that conditions for approximately 1 the pump experienced vortexing vortexing occurs, it causes al cause the pump performance to to the pump such as would be e enough air is introduced into pump to become air bound and to possible to overheat and subse operation of the 18 RHR pump to the pump, vibration measure characteristic curve were sati- no indication of pump damage for the pump was reperformed degradation of the 18 RHR pump. For the 1A RHR pump, operator degradation of the pump. Aft 18 RHR pump, control room ope contingency actions provided included operator action take the RCS draindown vis the 1A	the ly 16 minutes and 11 approximately 50 11 ingestion. Will the pump was operate 3 minutes, all avai- 3 tot did not experi- 17 to enter the suct decrease but will no expected should cavi- the suction of the the pump flow to sto- outently damage the inder these conditions ments and comparison isfactorily completed on November 1, 199 The results of the p had occurred action was effective a to is educe the flow RHR pump, and reali- tatanding of the ev- obser 26, 1891, that nto ieduce the flow RHR pump, and reali- tata which even. Indicated way have start a to used This manifes essure and flow flow ulfillment of the F Notification pure starts	full minut e a su d at c lable ence c tion b vot nec listic pump ons wa on wite ed or 91, ch e IST ve in tions propri such a c (b)/2 ch wert i chec to enc sted i ther t chec to enc sted i ther t chec t c sted f t c hec t c sted f t c hec t c sted f t c hec t c sted f t c hec t c sted f t c sted f t c hec t c sted f t c hec t c sted f t sted sted f t c sted f t sted sted sted sted sted sted sted ste	recl tes e ubseq or ne data cavit f the cession of the ben ben to the the the the the the the the the the	reula ifter juent iar ne i indi tation pump arliy cur will flow e to ve ca e pump ber 2 servi irmed ber 2 servi irmed rentir rortes y pen c. B RHS p time t did i). 1 t seva sibie bortl f in nat ch on of CFR 5	tic the tree catone	on cov e fir -lew low te th When This use d wevers to erns d dan 1991 -est iat no g for he his ump. p to a t rep ever, bls t r for he t for he t for he he he he he he he he he he	olir st of at will is the is the is the is the stor the stor the stor the stor the stor R	li ge f s at th T) s e s e to t iot. ild	

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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 sir ingestion for the 1A RHR purp 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 a: the time of the event was 0.1022 E8 Stu/hr. A subsequent review of RHR heat exchanges inlet temperature data suggest. that the RCS actually experienced an average heatup of 19 F (i.e., 88 F to 107 F), which is reasonable considering the may mum 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 uncover, 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 conclided that the ivent 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.

CORRECTIVE ACTIONS

- 1. All procedures used for draindown of the reactor vessel will be reviewed to ensure sufficient steps are in luded 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)
- Administrative controls will by revised to ensure appropriate reviews and documentation for the strachment of HEPA filter units to plant equipment. This revision is expected by January 17, 1992.

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та н 4 6 	C CONERATING PLANT - UNIT 1 The reduced inventory RCS procedural or hardware mod single vent path. This re 1992. Shift personnel involved 1 disciplined and counseled maintaining awareness of p investigating problems/inv A case study will be devel and will be presented to remphasize lessons 'serned establishing an adequate r been taken for the problem event: 'to 'sportance of 's sight g in service: an turnovers, and briefings. March 1, 1992 The modification status s enhancements to make modi Operations staff. Revisi to be complete by January Abnormal Operating Proceed Westinghouse Abnormal Res Operating At Mid-Loop Com actions I'r scopping a SP indications of vortexing is expected to be completed March I. INFORMATION Failed Components Idential None.	level instrumentati iffications to reduc view is expected to regarding "he need plant configuration consistencies noted loped by the person the Operations staff from the event, into vent path, the propusation utilizing procedura nd the need for app The case study is ystem will be revie fication status mor ons to the program. 21, 1992. uure 18019.C will be ponse Guidelite ARG diftions." to evalua is pump cavitation is by December 30, 1	on will e common be common for add status during wel invo f The cluding or steps chat our l guida. repriate expects wed for e resdil as necs review 1, "Lo te the ions to are obs	be revien n mode ef plete by cpriately itional e and for major evo lved in t case stud that and that and that and that and that and that and to be p possible iy availal essary, a ed agains as of RHR adequacy take aft	wed for fects of January mphasis lutions. he event tance cl uid have ing the lacing bl acting bl acting bl actions. oresented ble to to the spect of spect er	a 15, 15, on c c d by he ted		
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ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: Event Description: 528/-1-001

Reactor cool: it pump seal heat exchanger tube failur, ould result in non-isolable loss of coolant ou side containment. January 10, 1991 Palo Verde 1

Summary

Plant:

Date of Event:

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 ioxpressure application, the NCWS containment isolation valves could w_i 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 radiolo_b cal 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 wis not modeled as an accident sequence precursor.

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MAR 0.3 1991 LICENSEE EVENT REPORT (LER)		ОНЕ НО. 1160 стан НЕЗ КОНТО НЕЗ КОНТО НО ПО НО ПО НЕЗ КОНТО НО ПО НЕЗ КОНТО НО ПО НО ПО НЕЗ КОНТО НО ПО НЕЗ КОНТО НО ПО НО ПО НО ПО НО ПО НО ПО НО ПО НО ПО НО ПО НО ПО НО ПО НО НО НО НО НО НО НО НО НО Н
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At approximately 1500 MST on January 10, were in MODE 1 (POWER OPERATION) at approximately 1500 MST on January 10, were in MODE 1 (POWER OPERATION) at approximately the Engineering determined that a postulated high pressure seal cooler could result in outside containment. A conservative eva- on assumptions used in the Standard Revis the Exclusion Area Boundary cumulative the limits. An evaluation based on existing be a small fraction of 10CFR100 limits. The cause was that a tube rupture in the considered in the original plant design. Immediate corrective actions were taken 10CFR100 limits would not be exceeded as 2) monitor the Nuclear Cooling Water Sys seal cooler leak A design change is be postulated event described in this LER completed in Units 1, 2, and 3 by July 1 No ; & similar events have been rep	simutely 100 percent po preak in a Reactor Cool a reactor coolant syst uation of this postulat w Fian (MUREG 0800) det yrold dose could exceed RCS activity showed than seal cooler and its eff of 1) monitor RCS activ a rewilt of this postul es to provide early der ng developed to mitigat The dosign change is ex 33.	wer when P ^{UNGS} ant Pump (RCP) em (RCS) leak ed event based ermined that lOCFRIOO t doses would ett was not ity to ensure ated event and ection of a e the pected to be
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1.		CRIPTION OF WHAT OCCU	REED:				
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		At approximately 15 2, and 3 were in MC percent power	mately 1500 MST on Jenuary 10, 1091, Pelo Verde Units 1, ere in MODE 1 (POWER OPERATION) at approximately 100 wer				
	ø.	Reportable Event De of Major Occurrence	escription (Including	Dates and Approxima	te limes		
		Event Classificatio	ion: A condition that was outside the design tests of the plant.				
		determined that w (RCP)(P)(AB) high in a reactor cools building (NH). A based on the assum (SRP) determined r thyroid dose could postulated event b would be a small f	500 MST on January 10 postulated briak'in t pressure seal cooler nt system (RCS)(AB) 1 conservative evaluati ptions used in NUREG 'hat the Exclusion Are exceed 10CFR100 limits seed on existing RCS raction of 10CFR100 1 costulated event would	he Fractor Goolant ((SEAL)/GLR)(AB) coul ark outside the Cont on of this postulate 0800, Standard revie a Boundary (EAB) cum ts. An evaluation of activity showed that imits. The evaluation	ump d result ainment d event w Flan wlative of this doses on also		
		information Notice Component Cooling post-lated scenari RCF seal cooler - Nuclear Cosling Wa potential existed failure could resu entering the low y the RCS hakage wi between the impel between the impel between the bear in the bearing sleevy housing. This is via the seal coole	on based on the recome 84-54. "Potential O- Vater Ny - 2." PVNGS to in a double a be could result in our ater System (NCWS) (CC for a leskage path our out in high pressure, out flow from the RC ler hub and bearing a ng sleeve and stop se e, and through drille akage would then proc er inlet valve (ISV)(ablished past the jou ve (ISV)(AB).	repressurization of Engineering identif ended guillotine br- repressurization of and therefore, the itside of Containmen high temperature RC ture NCWS piping. M P body through clear leeve, through a cle al, into a flow pass d clearances in the end to the RCP seal AB). A parallel flo	ied a ak of a the t This S fluid ost of ances arauce age in RCP seal cooler wpath		

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	indicate the initial guilloting break of t per second (lbm/kec) (ISV)(CC) are not day pressures that could the tube failure is p povential release pay tank pressure relief (NF) noof. This reli gauge (psig)] dischar Auxiliary Building re the caps ity of the p the singu tank (l5 pr In addition to the all coolec tube rupture of RCP seels of the aff w uld be diverted to the seal housing wou the RCP seel housing	leasings flow rate t the tube would be ap Lince NCWS contain signed to isolate or result from this RC postulated to flow 1 th outside Containment valve (TK)(RV)(CC) isf valve [set at 1 rges to an open star oof. Since the maging ressure relief valve sig) could be exceed hove, a postulated of may simultaneously acted purp because of the break and any 1d be evaruated via However, this de sequences of this p	catastrophic high pre initiate degradation cooling and lutricati residual fluid remain the auxiliary impell gradation does not in osculated event since	d wass is inst from og a surge lding och he xceeds re of ssure of the of the ing flow ing in er in crease	
	water to numerous he The NEWS is constant (MON)(1L) which alar water act.vity reach	at exchangers that ly monitored by an ms in the Control R es a maximum preset f detecting RCS in-	a which provides cool contain radioactive w on-line radiation mon dom (NA) when the coo level. The radiatio leakage of 0.08 gallo leak begins.	ater. Itor ling	
	using postulated des reactor coolant leak spiking fectors, rea percent failed fuel SRP for Chapter 15 F thyroid dose could e	ign basis condition age rate and accide actor coolant activi and no operator act SAR analysi] indic sceed 10GFR1C limi sting conditions at a small fraction of		itInuous odine : one : the : the : ive An :B dose	

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the original design of a Manufacturing, Installat seal coolers described Safety Analysis Report Report for Palo Verde we detected by a combination high surge tank level so Once leakage is detected cooler isolation valves seal cooler and its sub	the plant (SALP C tion Error'. The in the Combustion (CESSAR) and the as that any leak on of the NCWS re witches which all d it would be is The possibili sequent effoct o	Cause Code 3: Design, a design basis of the RCP n engineering Standard NRC Safety Evaluation age from the RCS would be adiation menitors and the arm in the Control Room, olated using the RCP seal ty of a tube rupture in the n the NCWS was not
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		No unusual chara poor lighting) c	ecteristics of the contributed is thi t was not a rosult (s.	s postulate	d event. The	ie, heat,		
	Ĵ.	Safety System Re	es, ones					
		Not applicable vere necessary.	there were no sa	fety system	responses and	nane		
	К.	Falled Component	C Information:					
		Not applicable	no component fai	lures were	involved.			
11.	ASS	ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:						
	and pro val sga smo RCS val	operating procedure: Control Room perion nel 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 scal cooler could not be isolated, the RCS would be depressurized to allow the NCWS containment isolation valves to be closed to isolate the leak.						
	pos Thi to lod per ass as, for wit tag	A conservative evaluation of the radiological consequences of a postulated guilloting bleak of the RCP seal cooler tubing was performed. This evaluation used a constant, continuous reactor conlant leakage rate to the atmosphere of 58 lbm/sec and accident dose parameters (i.e., loding spiking factors, reactor coolant activities corresponding to one percent failed fuel, no operator action to isolate the reak, etc.) assumed in the SRP for Chap or 15 socident analyses. The evaluation assumed all of the leakage was released to atmosphere and took no credit for ioding partitioning factors. This evaluation indicates the EAB cumulative down would exceed IOCFRIOO limits for dose to the shyroid within 30 minutes of the postulated event. If ioding partitioning factors, flasting and time dependent leakage ware considered in this chalves, the results would be iess than IOCFRIOO limits.						
	A 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 indime spiking factor of 60, indime 131 dose equivalent concentration of 6.0E-2 microcuries per milliviter (uci/ml) and eight foiled fuel pins, all based on actual worst case date for							

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			VERS SECONTAL RECEVUES		
Р	alo Verde Unit 1	0 5 0 0 0 5 2 8	1911 - loid 1-ioid	016 01 018	
Ст [*] // лини жиси и т	PVNGS Units 1, 2, and 3. rate to the atmosphere of leak rate due to system de partition factor, and acci- conservatively used. This conservatively used. This consequences which are a hour cumulative thyroid d Zone (LPZ) 24 hour cumula The 30 day Control Room to The potential leak was al criteria. If a leak ware unidentified mechanism. stable crack up to a leak crack size was determined Leak Before Break (LBB.MR Wall Cracked Pipes Under during normal operation a "Evaluation of Potential factor of safety of two to leakage crack size. The	58 lbm/sec (i.e., epressurization), r ident (SEP specifie s evaluation result small fraction of 1 one would be 10.2 H rive thyroid dose was cal so evaluated based to develop by some he low stresses in trace of approximal using the methodo (C) Analysis Method Axial Plus Bending on 1 a safe shutdown for Pipe Breaks." to the critical cra resulting leak rat	nuous reactor coolant 1 no credit taken for re no operator action, no ed) Chi/Q values were ted in radiological 10CFR100 limits. The E kem and the Low Populat would be less than 13 E loulated to be 1.9 Rem. on leak before break e preexisting flaw or the piping 1 d resul tely 1.3 gpm. This st logy of NUREG/CR-4572 ' for Circumferential T Loads," which include earthquake. NUREG 10 requires the applicati ick size to arrive at a te including this safet	eak duced AB 2 tion tem tem *NRC hrough- s loads 61 on of a y	
	factor is 0.8 gpm. Recoy breaking. NUREG 1061 requ capable of detecting a 1 expected from the leakag 0.08 gpm. On-line radia capable of detecting lead	lires that the leak eak equivalent to o e crack size. In t tion monitoring and	detection system used one tenth of the leak r this case that value wo d chemical sampling are	ate uld be	
	An evaluation of the rad the high pressure seal c break criteria. This ev 1.3 gpm to conservativel analyses. The evaluation to one percent failed fur species of 0.01, and acc this scenario, the radio limits. The EAB 2 hour 1.7E-5 Rem and the LP2 8 5 Rem.	ooler tubing was pe aluation was based y bound the maximum n assumed reactor of el, a partition fac ident Chi/Q values logical consequence cumulative thyroid	erformed based on leak on a constant leak rat stable crack size lea coolant activity course rtor coefficient for le The results show that es are well below 10CFT dose would be approxim	before te of ak rate tponding odine at for R100 mately	
	Due to uncertainties in factor, P"NGS will monit levels. If these values equivalent, EAB doses wi taken if required. With doses will be limited to The double ended guillo	for PCS I-131 dose s exceed a level of (11 be resvaluated n the activity at o b a small fraction	equivalent concentrati 3E-1 ucl/c2 RCS 1-131 and additional actions r below this level, of of 10CFR100 limits	dose will be	

D. WERL		EVENT REPORT ONTINUATION	NUCLER REGULATORY COMPLEXION	$\label{eq:constraints} \begin{array}{c} Advanced to resolve and the resolved to a set of the resolved and the resolved$	
(FLITT NAME FIL			THICK FT ALONG S.M. (2)	LEAR PLANGER (E) PAOR (E) 11 A.R. NL2 DURAY (A) PL1 S (D) 11 A.R. NL2 DURAY (A) PL1 S (D)	
	lo Verde Unit		0 0 0 0 0 0 5 2 8		
	the spectrum RCP seal cool the amallest square feet, bounds all b bounding for	of break siz ler would cor break size e and does not reak sizes le this postula	es for a small brea respond to a break valuated for small result in fuel fa: as than 0.02 square ted event. Enjed p	g fuel failure by examining k LOCA. A failure of the size of 0.0043 square feet. bres. LOCA analysis is 0.02 lu: The break size for . and is considered r chis analysis, the RCP uld not result in fuel	
	makeup water inventory de Technical Sp 600,000 gall	for this pos mand was dete ecification 3 ons, based on Therefore, t	tulated event was e rained to be approx .1.2.6 specifies a	RWT)(TK)(BP) to provide valuated and the RWT imately 487.600 gallons minimum RWT inventory of sperature of 565 degrees adequate for this	
	consequences using SRP ap of this post radiological small leakag on the appli	Based on these evaluations, it is concluded that although the consequences of a postulated guillotine bleak of the seal cooler tubing using SRP specified parameters exceeds regulatory limits, an evaluation of this postulated event using existing PVNCS data demonstrates radiological consequences below IOCFRIOO 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 IOCFRIOO limits.			
111.	CORRECTIVE A	CTION			
	A. Imondia	te.			
	Juetifi	cation for Co	intinued Operations	nt were evaluated and a (JCO) was developed and 1. dated January 18, 1991)	
	a timel applica	y fashion the bls in Modes	following compensation	tory measures (only OPERATION through hu.	
	1.	been changed at least even 6) operable. 0.08 gpm and 1f RU-6 is on	to provide for back by 14 hours with the This method will a also provide a con-	occurrence procedures have kup grab samples to be taken e NCWS radiation monitor (RU- detect in-leakage lower than firmation of RU-6 operation hemistry samples will be	

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	2.	checistry samp.	.ng procedure have s be taken quickly	esponse procedure and been revised to requir to identify the source		
	3.	product activit the NCWS) or a manual sampling activity, an or SHUTDOWN) will shutdown to mor of the leakage. If RCS in-leaka to be the source sampling shall least every 5 h	y (indicative of Re radiation monitor s detects short live derly plant shutdow commence. Sampling ditor the leakage at ge through the seal s, the plant will r continue. Manual r bouts to ensure that	tts short lived fission sactor Coolant Leakage slarm is received and ed fission product en to Mode 5 (COLD g will continue during nd to determine the sou l cooler is determined not be shutnown and samples will be taken a t no R ~ Isakage in the adjution monitor due to	nto Tot	
	4.	RCS 1-131 dose monitored. If	and activity. equivalent concent these values excee	ration levels will be d a level of 25-1 uci/o e doses will be resval		
			actions will be ta			
В	Asti	on to Frevent Reco	arrence			
	desc	ribed in this LER	- Implementation o	tigate the postulated of this design change is and 3 by July 1993.	event s	
1V. P	REVIOUS	SIMILAR EVENTS:				
	o previo O.FR50		have been reported	t in accordance with		

NRC Form Date & 12.45

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Appendix D

POTENTIALLY SIGNIFICANT EVENTS THAT WERE CONSIDERED IMPRACTICAL TO ANALYZE

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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 1-5° 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 apply re-

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 (245/9)-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 circuit. 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 (S1)/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 or surred since 1982. The battery cell terminal post seals were inadequately designed and did not allow for corrotion 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 (285/91-008). 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 LV. A 1988 analysis that specified the degraded voltage set, oints 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 deepergized 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-C75). Design documents could not be located that would demonstrate the capability of the EDG combustion air engine exhaust and room ventilation systems to with tand 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 fits dampers for modification work restanted 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 conduct not embedded in concrete, susceptible to fire at Fitzpatrick (333/91-023). A portion of a fety division 1 MCC feeder cable conduit was found not to be embedded in concrete, as it as 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 coole is discharges into the train A ESW and KHRSW 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 (333/91-332). 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 sajety 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 sit. lation 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 excerd hardware limits and delay reactor trip at Catawba 1 (413/91-009). The gain setting corresponding to the average reprior 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 tast 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-rula ed 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

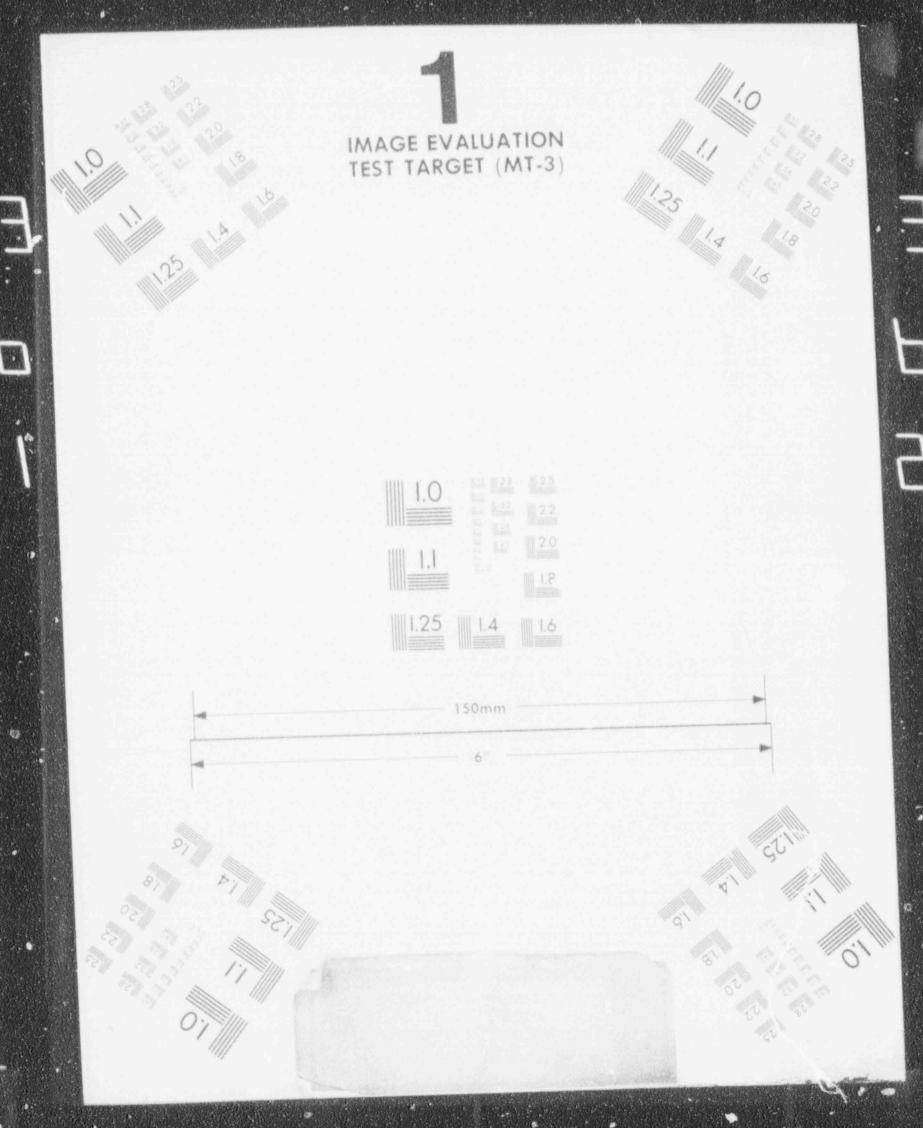
boron dilution accident due to a delayed reactor trip.

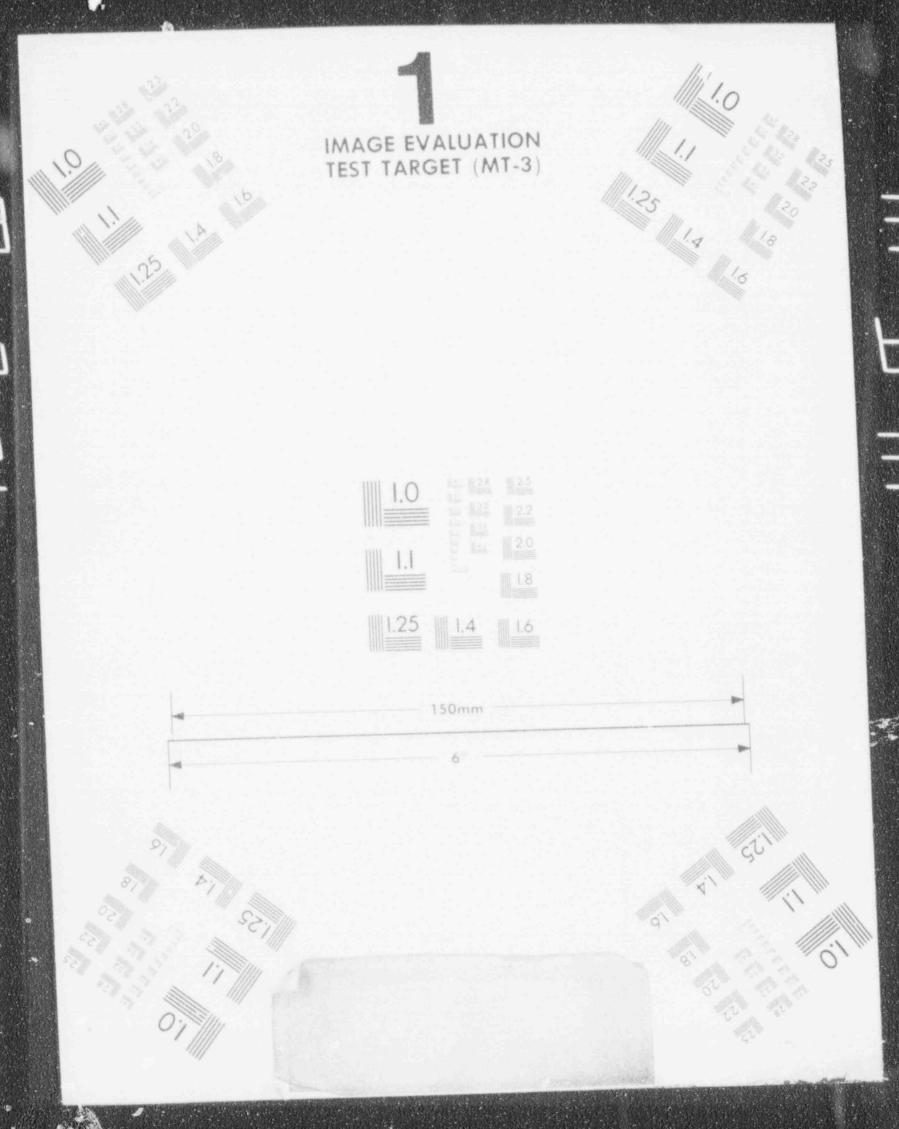
Mispositioned SI throttle valve caused inoperability of both SI pumps at Callaway I (483/91-003). The SI cold leg injection throttle valve had been mispositioned for over 2 yr. This condition would have caused the SI flow upper limit of 655 gpm to be exceeded, rendering both SI trains inoperable. Calculations by the utility determined that the maximum flow rate would be 706 gpm with the recirculation line open and throttle valve mispositioned.

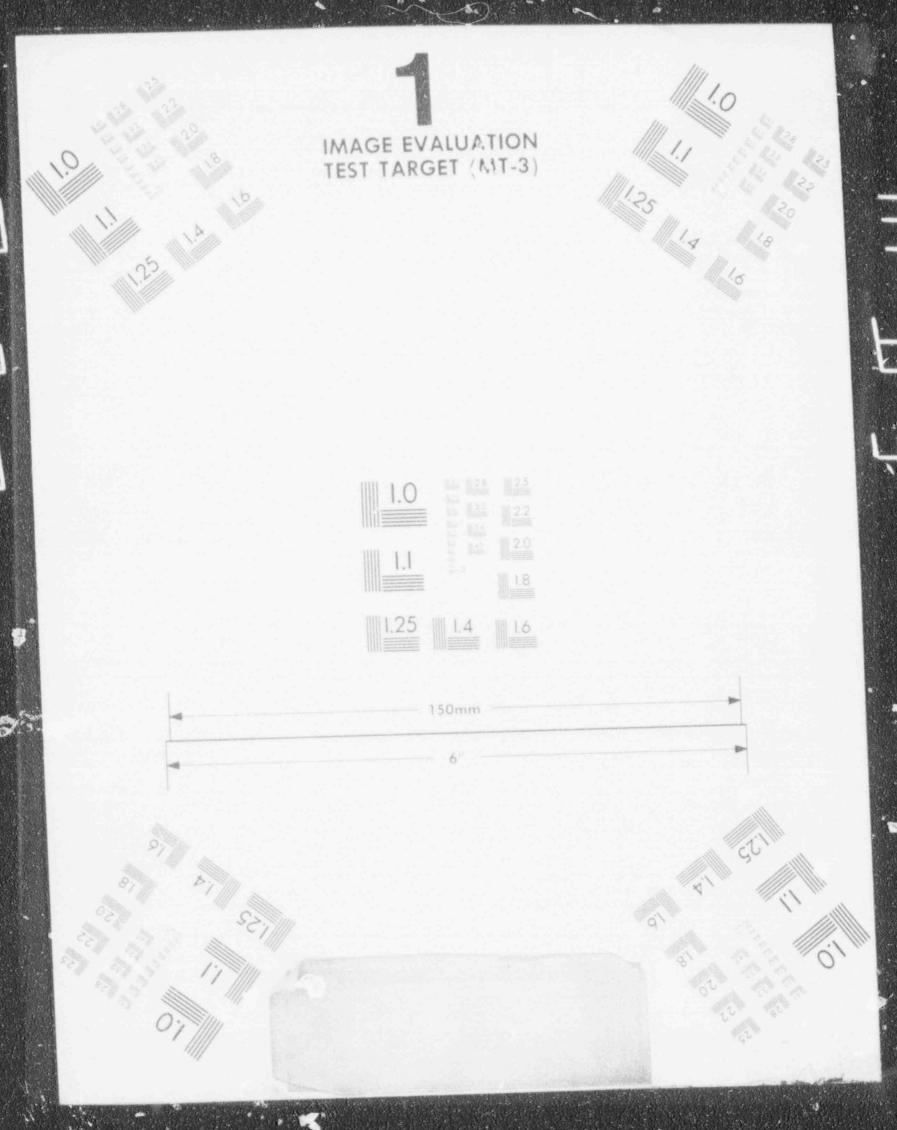
Normal soom cooling not adequate for engineered safety features (ESF) pump room loads at Palo Verde 1 (528/91-007). Normal room cooling system cooling to various ESF pump rooms is not adequate to meet essential cooling loads because it is not 100% redundant to some components served by the essential 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.

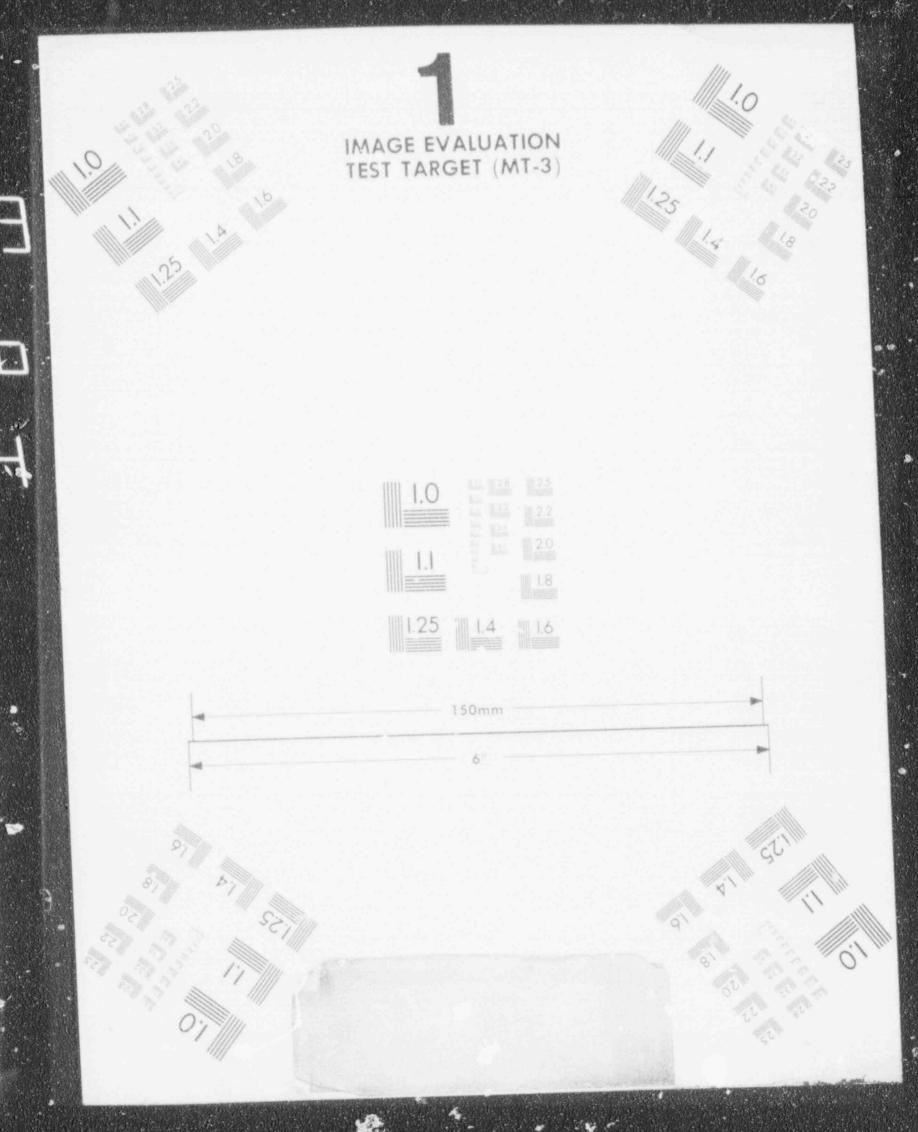
Design basis fire in control room could result in RCS leakage exceeding makeup at Palo Verde 1 (528/91-008). A design basis Appendix R fire in the control room could result in loss of reactor coolant pump (RCP) seal cooling. This in turn, could result in RCP seal damage, which may result in RCS leakage in excess of avail: ble 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 couil 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.









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