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Vol. 22

Precursors to Potential Severe Core Damage Accidents: 1994 A Status Report

Appendix I

Prepared by
R. J. Belles, J. W. Cletcher, D. A. Copinger, B. W. Dolan, J. W. Minarick, L. N. Vanden Heuvel

Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

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NUREG/CR–4674
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Vol. 22

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Appendix I

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Prepared by
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Washington, DC 20555–0001
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Previous Reports in Series

1. J. W. Minarick and C. A. Kukielka, Union Carbide Corp., Nuclear Div., Oak Ridge Natl. Lab.; and Science Applications, Inc., *Precursors to Potential Severe Core Damage Accidents: 1969-1979, A Status Report,* USNRC Report NUREG/CR-2497 (ORNL/NSIC-18/V1 and V2), June 1982.
2. W. B. Cottrell, J. W. Minarick, P. N. Austin, E. W. Hagen, and J. D. Harris, Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; and Science Applications International Corp., *Precursors to Potential Severe Core Damage Accidents: 1980-81, A Status Report,* USNRC Report NUREG/CR-3591, Vols. 1 and 2 (ORNL/NSIC-217/V1 and V2), July 1984.
3. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1985, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 1 and 2, December 1986.
4. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1984, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 3 and 4, May 1987.
5. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1986, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 5 and 6, May 1988.
6. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1987, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 7 and 8, July 1989.
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8. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1989, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 11 and 12, August 1990.
9. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab.; Science Applications International Corp.; and Professional Analysis, Inc., *Precursors to Potential Severe Core Damage Accidents: 1990, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 13 and 14, August 1991.
10. J. W. Minarick et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab., and Science Applications International Corp., *Precursors to Potential Severe Core Damage Accidents: 1991, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 15 and 16, September 1992.
11. D. A. Copinger et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab., and Science Applications International Corp., *Precursors to Potential Severe Core Damage Accidents: 1992, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 17 and 18, December 1993.
12. L. N. Vanden Heuvel et al., Martin Marietta Energy Systems, Inc., Oak Ridge Natl. Lab., and Science Applications International Corp., *Precursors to Potential Severe Core Damage Accidents: 1993, A Status Report,* USNRC Report NUREG/CR-4674 (ORNL/NOAC-232), Vols. 19 and 20, September 1994.

ABSTRACT

Nine operational events that affected eleven commercial light-water reactors (LWRs) during 1994 and that are considered to be precursors to potential severe core damage are described. All these events had conditional probabilities of subsequent severe core damage greater than or equal to 1.0×10^{-6}. These events were identified by computer-screening the 1994 licensee event reports from commercial LWRs to identify those that could be potential precursors. Candidate precursors were then selected and evaluated in a process similar to that used in previous assessments. Selected events underwent engineering evaluation that identified, analyzed, and documented the precursors. Other events designated by the Nuclear Regulatory Commission (NRC) also underwent a similar evaluation. Finally, documented precursors were submitted for review by licensees and NRC headquarters and regional offices to ensure that the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work, which evaluated 1969-1981 and 1984-1993 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for events. This document is bound in two volumes: Vol. 21 contains the main report and Appendices A-H; Vol. 22 contains Appendix I.

Contents

Previous Reports in Series ii

Abstract iii

Preface vii

Foreword ix

Acknowledgments xi

1. Introduction 1-1

1.1 Background 1-1

1.2 Current Process 1-1

2. Selection Criteria and Quantification 2-1

2.1 Accident Sequence Precursor Selection Criteria 2-1

2.1.1 Precursors 2-1

2.1.2 Potentially Significant Events Considered Impractical to Analyze 2-4

2.1.3 Containment-Related Events 2-4

2.1.4 "Interesting" Events 2-4

2.2 Precursor Quantification 2-4

2.3 Review of Precursor Documentation 2-5

2.4 Precursor Documentation Format 2-5

2.5 Potential Sources of Error 2-7

3. Results 3-1

3.1 Tabulation of Precursor Events 3-1

3.1.1 Potentially Significant Events That Were Impractical to Analyze 3-4

3.1.2 Containment-Related Events 3-4

3.1.3 "Interesting" Events 3-4

3.2 Important Precursors 3-4

3.2.1 Wolf Creek, RCS Blows Down to Refueling Water Storage Tank During Hot Shutdown 3-4

3.2.2 Haddam Neck, Power Operated Relief Valves and Vital 480-V ac Bus Degraded 3-6

3.3 Number of Precursors Identified 3-8

3.4 Insights 3-8

4. Glossary 4-1

5. References 5-1

Appendices

Appendix A: ASP Calculational Methodology A.1-1

Appendix B: ASP Models B.1-1

Appendix C: At-Power Precursors C.1-1

Appendix D: Shutdown Precursors D.1-1

Appendix E: Potentially Significant Events Considered Impractical to Analyze E.1-1

Appendix F: Containment-Related Events F.1-1

Appendix G: "Interesting" Events G.1-1

Appendix H: Resolution of Comments on the Preliminary 1994 ASP Analyses H.1-1

Appendix I: License Event Reports and Augmented Inspection Team Reports Cited in Appendices C–G I.1-1

List of Figures

Figure 2.1 ASP analysis process. 2-3

Figure 2.2 ASP review process. 2-6

List of Tables

Table 3.1 At-power precursors involving unavailabilities sorted by plant 3-2

Table 3.2 At-power precursors involving initiating events sorted by plant 3-2

Table 3.3 Shutdown precursors involving initiating events sorted by plant 3-2

Table 3.4 At-power precursors involving unavailabilities sorted by conditional core damage probability 3-3

Table 3.5 At-power precursors involving initiating events sorted by conditional core damage probability 3-3

Table 3.6 Shutdown precursors involving initiating events sorted by conditional core damage probability 3-3

Table 3.7 Number of precursors by year 3-8

Table 3.8 Number of precursors by event type 3-9

PREFACE

The Accident Sequence Precursor (ASP) Program was established by the Nuclear Operations Analysis Center at Oak Ridge National Laboratory (ORNL) in the summer of 1979. The first major report of that program was published in June 1982 and received extensive review. Twelve reports documenting the review of operational events for precursors have been published in this program (see Chap. 5). These reports describe events that occurred from 1969 through 1993, excluding 1982 and 1983. They have been completed on a yearly basis since 1987.

The current effort was undertaken on behalf of the Office for Analysis and Evaluation of Operational Data of the Nuclear Regulatory Commission (NRC). The NRC Project Manager is P. D. O'Reilly.

The methodology developed and utilized in the ASP Program permits a reasonable estimate of the significance of operational events, including observed human and system interactions. The present effort for 1994 is a continuation of the assessment undertaken in the previous reports for operational events that occurred in 1969-1981 and 1984-1993.

The preliminary analyses of the 1994 events were sent for review to NRC staff and licensees for those plants for which potential ASP events were identified. This is similar to the review process used for the 1992 and 1993 events. In addition, the 1994 events were also independently reviewed as part of NRC's policy regarding probabilistic risk assessment (PRA) activities. All comments were evaluated, and analyses were revised as appropriate.

Reanalyses typically focused on and gave credit for equipment and procedures that provided additional protection against core damage. These additional features were beyond what was normally included in ASP analyses of events prior to 1992. Therefore, comparing and trending analysis results from prior years is more difficult because analysis results before 1992 may have been different if additional information had been solicited from the licensees and incorporated.

For 1994 the total number of precursors identified is less than that of past years. This is due at least in part to incorporating feedback on equipment, systems, procedures, etc., such that events initially identified as potential precursors with a conditional core damage probability somewhat greater than 10^{-6} were reanalyzed resulting in a value less than 10^{-6}, which is the threshold for rejection. In addition, new models were used for the analysis of 1994 events. These models utilize ASP class-based event trees and plant-specific linked fault trees. The models are based on previous work performed by ORNL. The models were converted into the Integrated Reliability and Risk Analysis System software by the Idaho National Engineering Laboratory. These new models, which obviously influence the calculation of conditional core damage probabilities for events, represent another factor for consideration when comparing results for 1994 with those from previous years.

The operational events selected in the ASP Program form a unique data base of historical system failures, multiple losses of redundancy, and infrequent core damage initiators. These events are useful in identifying significant weaknesses in design and operation, for trends analysis concerning industry performance and the impact of regulatory actions, and for PRA-related information.

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FOREWORD

This report provides the results of the review and evaluation of 1994 operational experience data by the Nuclear Regulatory Commission's ongoing Accident Sequence Precursor (ASP) Program. The ASP Program provides a safety significance perspective of nuclear plant operational experience. The program uses probabilistic risk assessment (PRA) techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include initiators, degradations of plant conditions, and safety equipment failures that could increase the probability of postulated accident sequences.

The primary objective of the ASP Program is to systematically evaluate U.S. nuclear plant operating experience to identify, document, and rank those operating events which were most significant in terms of the potential for inadequate core cooling and core damage. In addition, the program has the following secondary objectives: (1) to categorize the precursor events for plant specific and generic implications, (2) to provide a measure which can be used to trend nuclear plant core damage risk, and (3) to provide a partial check on PRA-predicted dominant core damage scenarios.

This year marked the completion of the initial development of improvements in the methods used for the ASP analysis of operational events. The ASP analyses of 1994 operational experience were performed using the staff's recently developed simplified, plant-specific, train-level models for analyzing operational events. These models are based on the staff's Integrated Reliability and Risk Analysis System (IRRAS), which uses fault tree linking techniques to quantify accident sequences.

In recent years, licensees of U.S. nuclear plants have added safety equipment and have improved plant and emergency operating procedures. Some of these changes, particularly those involving use of alternate equipment or recovery actions in response to specific accident scenarios, can have a significant effect on the calculated conditional core damage probabilities for certain accident sequences. In keeping with established practice, the 1994 preliminary ASP analyses were transmitted to the pertinent nuclear plant licensees and to the NRC staff for review. The licensees were requested to review and comment on the technical adequacy of the analyses, including the depiction of their plant equipment and equipment capabilities. Each of the review comments received from licensees and the NRC staff was evaluated for reasonableness and pertinence to the ASP analysis in an attempt to use realistic values. All of the preliminary precursor events were reviewed, and the conditional core damage probability calculations were reised where appropriate. The objective of this review process was to provide as realistic an analysis of the significance of the event as possible. In addition, consistent with the recommendations of the NRC's interoffice PRA Working Group, each of the analyses has been independently peer reviewed. This review provided a quality check of the analysis, ensured consistency with the ASP analysis guidelines, and verified the adequacy of the modeling approach and appropriateness of the assumptions used in the analysis.

The total number of precursors (9) identified for 1994 is less than last year. The two most important precursor events for 1994 consisted of an intersystem loss-of-coolant accident (LOCA) which occurred at a PWR during shutdown, and the unavailability of both pressurizer power-operated relief valves (PORVs) for an extended period of time, which was discovered at another PWR.

Charles E. Rossi, Director
Safety Programs Division
Office for Analysis and Evaluation
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*On loan from the Japan Atomic Energy Research Institute.

Appendix I:

License Event Reports and Augmented Inspection Team Reports Cited in Appendices C–G

I.1 Introduction

This appendix contains the Licensee Event Reports (LERs), Augmented Inspection Team Reports (AITs), and routine NRC Inspection Reports (IRs) that are cited in Appendices C–G. The documents are ordered by docket number. The associated plant, associated event type, document title, and page number are included in Table I.1.

Table I.1. LERs, AITs, and Inspection Reports Referenced in Appendices C–G

Document	Plant	Event Type	Document Title	Page
LER 213/94-004	Haddam Neck	At power precursor	Automatic 480 Volt Bus Transfer Failure Due to Circuit Breaker Malfunction	I.2-1
LER 213/94-005		At power precursor	Pressurizer PORVs Failed to Fully Stroke Open During Testing	I.3-1
LER 213/94-007		At power precursor	Potential for Radiological Release During Post LOCA Sump Recirculation	I.4-1
LER 213/94-012		Impractical	Potential Loss of Service Water Due to Flood Induced Strainer Fouling	I.5-1
LER 213/94-013		At power precursor	HPSI Pump Discharge Relief Valve Setpoint Found Low	I.6-1
IR 213/94-03		At power precursor	Inspection Report 50-213/94-03 Related to Pressurizer Power Operated Relief Valve Failures and MCC-5 ABT	I.7-1
LER 219/94-010	Oyster Creek	Impractical	Reactor Shutdown Commenced Due to Loss of Both Containment Spray Systems Due to Biological Plugging	I.8-1
LER 237/94-004	Dresden 2	Impractical	High Pressure Coolant Injection System Steam Drain Line Isolation Valves Installed Backwards Due to Construction Error	I.9-1
LER 237/94-006		Impractical	Unit 2 Shutdown Cooling Pump Motors Did Not Have Relay Setting Orders Reviewed Prior to Motor Installations Due to Inadequate Work Practices	I.10-1
LER 237/94-018		At power precursor	Potential Trip of Motor Control Centers Due to Improper Feed Breaker Settings	I.11-1
LER 237/94-021		At power precursor	HPCI Turbine Tripped on High Exhaust Pressure Due to a Failed Exhaust Check Valve	I.12-1
LER 245/94-015	Millstone 1	Interesting	RPV Draindown and Drywell Spray Event	I.13-1
249/94-S01, NRC IN 94-42	Dresden 3	Impractical	Cracking in the Lower Region of the Core Shroud in Boiling -Water Reactors	I.14-1
LER 250/94-005	Turkey Point 3	At power precursor	Design Defect in Safeguards Bus Sequencer Test Logic Places Both Units Outside the Design Basis	I.15-1

Table I.1. LERs, AITs, and Inspection Reports Referenced in Appendices C–G (cont.)

Document	Plant	Event Type	Document Title	Page
254/94-S01, NRC IN 94-42	Quad Cities 1	Impractical	Cracking in the Lower Region of the Core Shroud in Boiling-Water Reactors	I.16-1
LER 255/94-008	Palisades	Impractical	Lack of Separation or Isolation Between 1E and Non-1E Circuits	I.17-1
LER 255/94-014		Impractical	Potential Sump Blockage From Signs, Adhesive Labels, and Tape	I.18-1
LER 266/94-002	Point Beach 1	At power precursor	Inoperability of Both Emergency Diesel Generators	I.19-1
LER 269/94-004	Oconee 1	Interesting	Post-Accident Core Cooling Technically Inoperable Due to a Design Deficiency	I.20-1
LER 271/94-002	Vermont Yankee	Impractical	Alternate Cooling System Water Temperature Greater Than Design Basis During Warm Weather Circ Water System Operation Due to Inadequate Analysis of the Alternate Cooling System	I.21-1
LER 272/94-007	Salem 1	Interesting	Reactor Trip From 25% Power/Two Safety Injections, Manually Initiated Main Steam Isolation, and Discretionary Declaration of Alert	I.22-1
AIT 272/94-80		Interesting	Augmented Inspection Team (AIT) Report 272/94-80 and 311/94-80 Related to Plant Trip and SI Actuations	I.23-1
LER 275/94-020	Diablo Canyon 1	Interesting	Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage That Resulted from an Electrical System Disturbance External to the PG&E System	I.24-1
LER 293/94-004	Pilgrim	Impractical	Automatic Closing of the Reactor Core Isolation Cooling System Turbine Steam Supply Isolation Valves Due to High Steam Flow Signal During Surveillance Testing	I.25-1
LER 295/94-003	Zion 1	Interesting	Containment Pressure Sensing Lines Were Inadvertently Capped During Containment Closeout	I.26-1
LER 295/94-011		Impractical	Violation of the 10CFR50 Appendix R Analysis Separation Criteria in Fire Zone 18.6.A-1	I.27-1
LER 298/94-010	Cooper	Interesting	Closure of Shutdown Cooling Suction Isolation Valves While Warming the Residual Heat Removal System Due to Leakage Through the Minimum Flow Valve	I.28-1

Table I.1. LERs, AITs, and Inspection Reports Referenced in Appendices C–G (cont.)

Document	Plant	Event Type	Document Title	Page
LER 304/94-002	Zion 2	At power precursor	Exceeded Limiting Condition for Operation 3.7.2. Action E for Placing Unit in Mode 4 with a Turbine-Driven and Motor-Driven AFW Pump Inoperable	I.29-1
LER 318/94-001	Calvert Cliffs 2	At power precursor	Reactor Trip Due to Opening of 13.8 Kilovolt Feeder Breaker	I.30-1
LER 324/94-008	Brunswick 2	Interesting	Dispatcher Switching Evolution Results in Loss-of-offsite Power to Unit 2	I.31-1
LER 336/94-040	Millstone 2	Containment	Ventilation Design Deficiency Affecting Enclosure Building Integrity	I.32-1
LER 366/94-003	Hatch 2	Interesting	Fuse Actuation Results in ESF Actuation and Interruption in Shutdown Cooling Flow	I.33-1
LER 382/94-004	Waterford 3	Impractical	Degraded CCW Heat Exchanger Discovered While Shutdown, Due to Biological Fouling	I.34-1
LER 454/94-003	Byron 1 and 2	Impractical	Auxiliary Feedwater Isolation Valve Exposure to Potentially Harsh Environment Due to Flood Seal Removal	I.35-1
LER 458/94-023	River Bend	At power precursor	Reactor Scram Due to Spurious Signals from Undamped Rosemount Model 1153 Transmitters	I.36-1
AIT 458/94-20		At power precursor	Augmented Inspection Team (AIT) Report 458/94-20 Related to Reactor Trip	I.37-1
IR 482/94-18	Wolf Creek	Shutdown precursor	Inspection Report 50-482/94-18 Related to the Draindown Event of September 17, 1994	I.38-1
LER 482/94-013		Shutdown precursor	Personnel Error Resulted in an Unanticipated Loss of Reactor Coolant Level	I.39-1
LER 529/94-002	Palo Verde 2	Interesting	Reactor Trip Caused by Personnel Error	I.40-1

AIT = NRC Augmented Inspection Team Report
LER = Licensee Event Report
IR = NRC Inspection Report

Appendix I

LER No. 213/94-004
Haddam Neck

NRC Form 366 (4-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Haddam Neck

DOCKET NUMBER (2): 0 5 0 0 0 2 1 3

PAGE (3): 1 OF 0 6

TITLE (4): Automatic 480 Volt Bus Transfer Failure Due to Circuit Breaker Malfunction

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	1 6	9 4	9 4	0 0 4	0 1	0 5	2 6	9 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME: B. McKenna, Engineer

TELEPHONE NUMBER: AREA CODE 2 0 3 — 2 6 7 1 - 1 2 5 5 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
B	E I K	1 5 1 2	W 1 2 0	Y							

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE)

X NO

EXPECTED SUBMISSION DATE (15): MONTH / DAY / YEAR

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

ABSTRACT

On February 16, 1994, at 0130 hours with the plant shut down in mode 5 (cold shutdown) for Service Water piping repairs, performance of special test ST 11.7-126 "Functional Test Of MCC-5 Automatic Bus Transfer (ABT)" was unsatisfactorily completed when the 480 volt bus 6 feed to Motor Control Center (MCC) 5 circuit breaker 11C failed to close. The cause of the failure has been identified to be an out - of- position mechanical retaining device mounted on the manual operating shaft of the bus 6 11C breaker. This device being out of its normal position allowed the shaft to travel further than designed into the breaker operating mechanism causing the breaker to malfunction upon receiving a close signal. Corrective action consisted of replacing the breaker's manual operating mechanism and modifying the ABT scheme to minimize challenges to the breaker operation. The condition leading to the transfer failure had very likely existed for a time period in excess of the 72 hour Action Statement in Technical Specification 3.8.3.1.2 and thus is reportable under 10CFR50.73(a)(2)(i)(B) as a condition prohibited by the plant's Technical Specifications. This Supplemental Report provides the results of the root cause evaluation and the long term corrective action.

NRC Form 366 (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 4	— 0 1	0 2 OF 0 6

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

BACKGROUND INFORMATION

The Motor Control Center (MCC) 5 Automatic Bus Transfer (ABT) circuit provides power to MCC-5 from either of two 480 volt AC power sources (EIIS Code: EK) (see Figure 1). MCC-5 is normally aligned so that bus 5 (Train 'A') provides power to MCC-5 via circuit breaker 9C. If for any reason bus 5 becomes de-energized the ABT scheme (see Figure 2) will transfer the feed for MCC-5 to bus 6 (Train 'B') via the 11C breaker. Upon restoration of bus 5 power the ABT scheme will then transfer the feed for MCC-5 back to bus 5 (the preferred supply). During the refueling outage of May to July 1993, an ABT failure was experienced. A root cause investigation performed following that failure was inconclusive yet a component, the 52X relay, common to both ABT circuit breakers (EIIS Code: 52) was determined to be the most suspect. These components were replaced on both the bus 5 9C breaker and bus 6 11C breaker. Connecticut Yankee (CY) committed to perform on- line testing of the 52X relay associated with the ABT. All testing on the bus 5 supply to MCC-5 has been successful since start-up from the 1993 refueling outage in July 1993. CY also committed to perform a functional test of the MCC-5 ABT whenever the plant entered Mode 5 (Cold Shutdown). The current shutdown for service water pipe repairs afforded an opportunity to perform this functional test.

EVENT DESCRIPTION

On February 16, 1994, at 0130 hours, with the plant shut down, in mode 5 (cold shutdown), a failure of the MCC-5 Automatic Bus Transfer scheme, while under test was experienced. Operations personnel were performing ST 11.7-126 "Functional Test Of MCC-5 Automatic Bus Transfer (ABT)". This test includes the sequential tripping of the 480 volt bus 5 (4851) and then the bus 6 (4961) feeder breakers. The bus 5 feeder breaker, 4851 was tripped and the ABT switched, i.e., bus 5 9C breaker opened and the bus 6 11C breaker closed, providing power to MCC-5 from bus 6. The bus 5 feeder breaker 4851 was then closed and the ABT successfully switched back powering MCC-5 from bus 5 once again. Bus 5 loads were restored in preparation of the second section of the test. When the preferred source selector switch (SS43) was selected from position 1 to position 2 in order to select bus 6 as the preferred source the bus 5 9C breaker tripped but the bus 6 11C breaker did not close. This left MCC-5 and all its associated loads de-energized. The operator manually closed the bus 5 9C breaker. This restored power to MCC-5 and its associated loads. The test was terminated at this point

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 4	— 0 1	0 3 OF 0 6

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

CAUSE OF THE EVENT

The cause of the bus 6 11C breaker to not close when position 2 was selected on the SS43 switch has been determined to be due to a mechanical problem within the breaker operating mechanism. A snap retaining ring was discovered approximately a half inch away from its mounting slot. This allowed the manual operating shaft to move further into the breaker than designed. It was able to travel far enough into the breaker that it interfered with the trip bar and actually maintained the breaker in the tripped position. When the breaker was called upon to close it would close and immediately trip. Performance of a root cause evaluation to determine all the circumstances that led to the MCC-5 ABT failure, including an assessment of the previous root cause evaluation was completed. The root cause of the ABT failures was confirmed to be an out-of-position retaining ring on the breaker closing handle operating shaft. Although it could not be determined how the retaining ring came out of position the most likely cause was that during breaker maintenance the retaining ring was moved out of position to lubricate the shaft and may not have been correctly re-installed. An assessment of the June 27, 1993 event found the previous root cause report to be comprehensive given the intermittent nature of the failure. The conclusive determination of the root cause of the recent failure was facilitated by the repeatability of the failure on demand.

SAFETY ASSESSMENT

This event is reportable under 10CFR50.73(a)(2)(i)(B) since a condition existed prohibited by the plant's Technical Specifications. Technical Specification 3.8.3.1.2 requires MCC-5 to be energized and capable of automatically obtaining power from 480 volt busses 5 and 6 in Modes 1, 2, 3 and 4. This condition had most likely existed for a time in excess of the 72 hour ACTION statement of Specification 3.8.3.1.2. MCC-5 and the associated Automatic Bus Transfer (ABT) are required to provide power to Emergency Core Cooling System (ECCS) valves needed to mitigate the consequences of design basis accidents with the failure of emergency diesel generator EG-2A. A postulated single failure of the ABT could render the ECCS inoperable. Throughout Cycle 18 the preferred power source selector switch SS43 for MCC-5 has been in the position whereby bus 5 would be the preferred power source. Having SS43 in the bus 5 position has ensured that the ABT would return to bus 5 (if energized) in the event of a failure of the bus 6 supply breaker (11C). All testing thus far on the bus 5 supply to MCC-5 has been successful. The safety function of MCC-5 would still be provided through bus 5. In addition, both emergency diesel generators were available had there been a loss of off-site power to bus 1 and 2.

NRC FORM 366A (9-83)

*U.S.GPO:1988-0-6 1-538/455

NRC Form 366A (9-83)

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U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 4	— 0 1	0 4 OF 0 6

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

Emergency diesel generator EG-2A would restore power to bus 5 and the ABT would provide power to MCC-5 from bus 5. There are also emergency operating procedures in place to restore power to MCC-5 and associated loads as required. Based on the above the safety significance of this event is minimal.

CORRECTIVE ACTION

Initial corrective action included the following:

1. Replacement of bus 6 breaker 11C manual operating mechanism.

2. Verification of position and condition of other breakers' manual operating shaft retaining devices.

3. Implementation of a modification to eliminate the preferred source selector switch SS43 and redesign the MCC-5 ABT scheme to block the trip of the normal feed bus 5 9C breaker on a total loss of AC power to minimize challenges to breaker operation.

Long term corrective action will include the revision of all appropriate preventive maintenance procedures for Westinghouse type DB breakers to include verification that the retaining ring is securely in place.

ADDITIONAL INFORMATION

Component	Manufacturer	Model/Part Number
Circuit Breaker	Westinghouse	Model No. DB-25
Operating Mechanism	Westinghouse	Part No. 405D804B07

This Supplemental Report is being issued to provide the results of the root cause evaluation and the long term corrective action.

PREVIOUS SIMILAR EVENTS

MCC-5 ABT failure during the 1993 refueling outage (June 27, 1993).

NRC Form 366A (9-83)

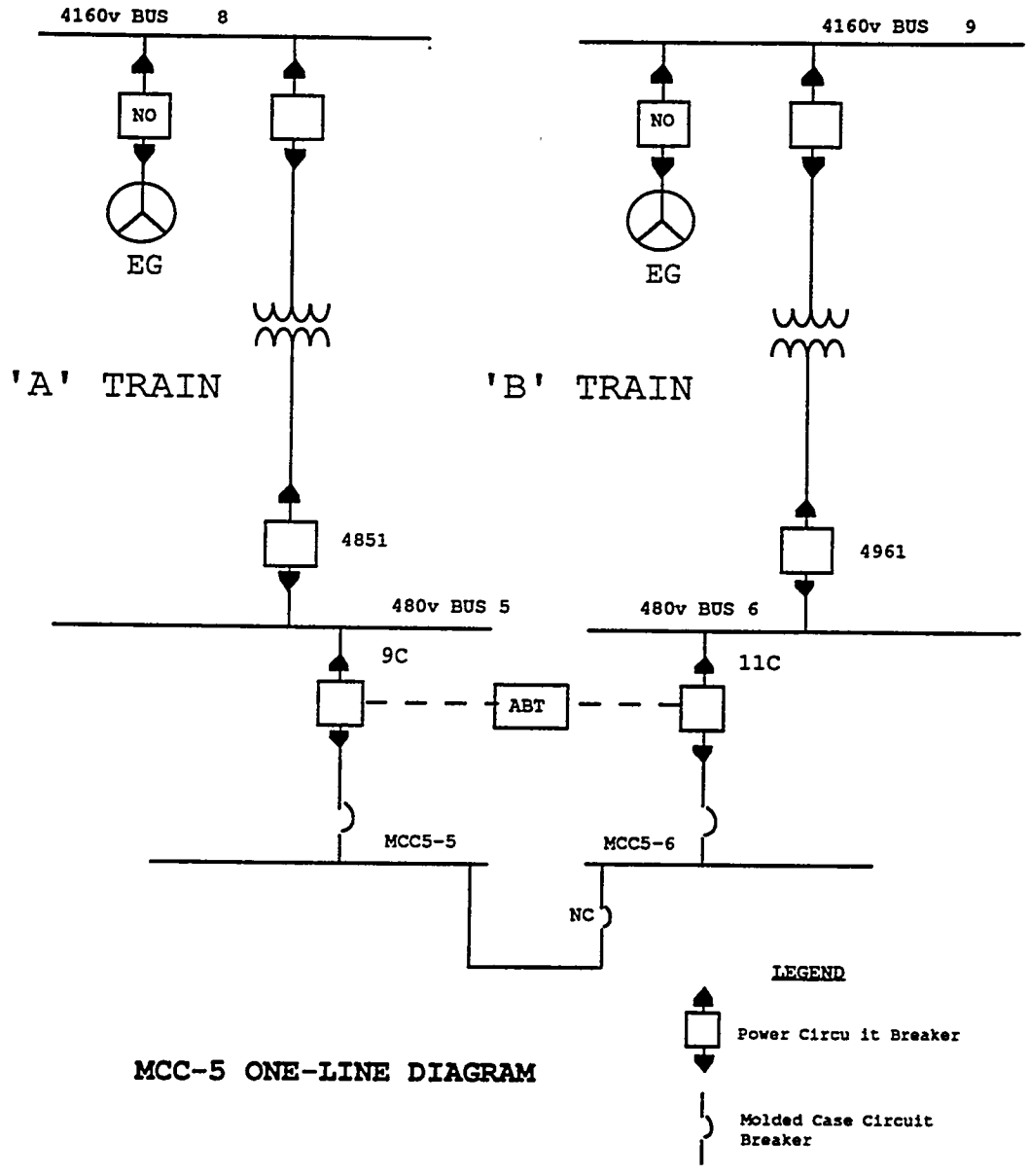
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 4	— 0 1	0 5 OF 0 6

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

FIGURE 1



MCC-5 ONE-LINE DIAGRAM

NRC FORM 366A (9-83)

NRC Form 366A (9-83)

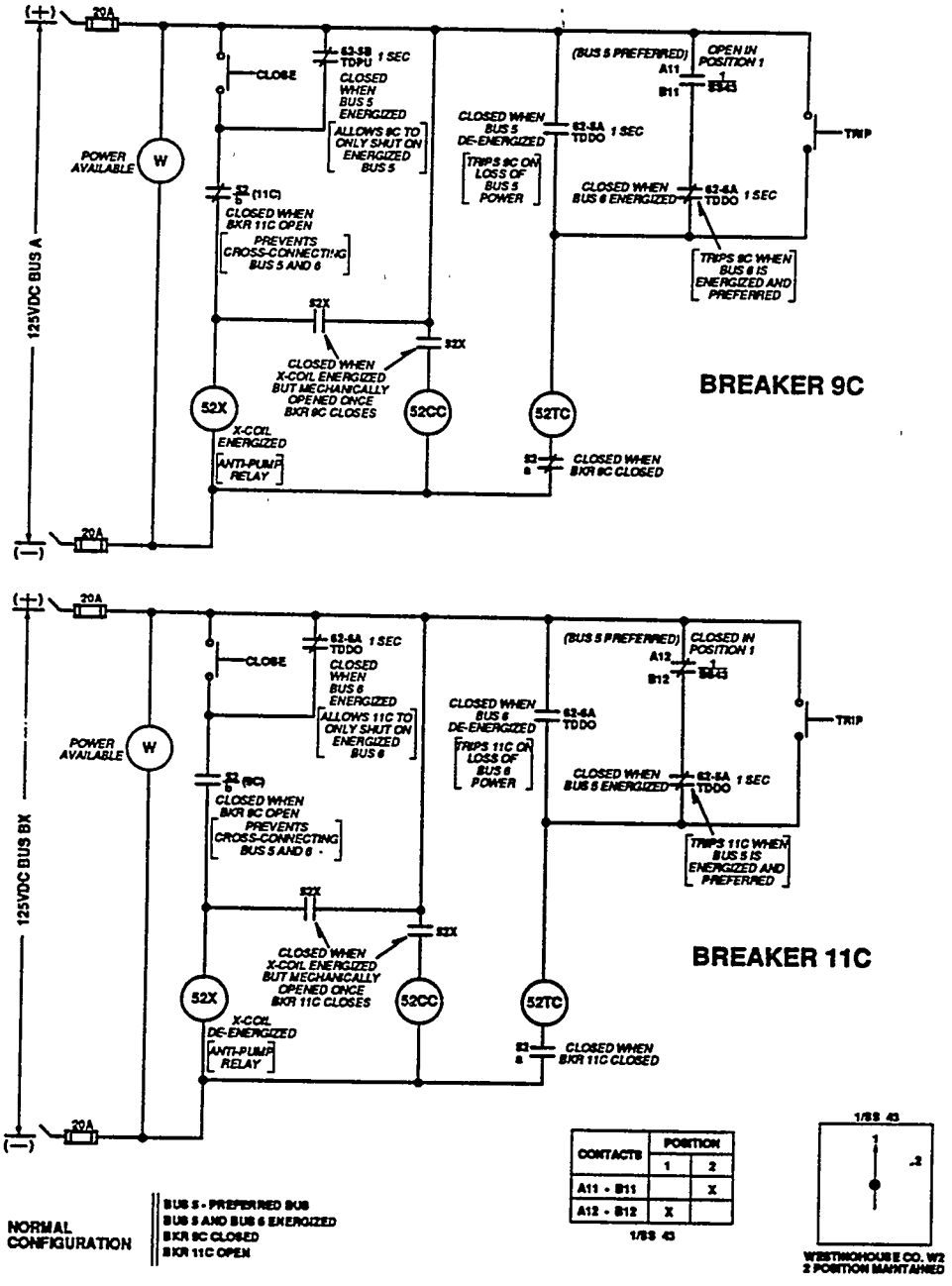
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	0 0 4	0 1	0 6 OF 0 6

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

FIGURE 2



NRC FORM 366A
19-83.

★U.S.GPO:1986-0-4 :-538/455

LER No. 213/94-005
Haddam Neck

NRC Form 366 (4-63)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Haddam Neck

DOCKET NUMBER (2): 0 5 0 0 0 2 1 3

PAGE (3): 1 OF 0 5

TITLE (4): Pressurizer PORVs Failed to Fully Stroke Open During Testing

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	1 9	9 4	9 4	- 0 0 5	- 0 0	0 3	1 8	9 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0 0

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME: M. F. Marino, Systems Engineering

TELEPHONE NUMBER: AREA CODE 2 0 3 - 2 6 7 - 2 5 1 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	A B	I R V	C 6 3 5	N					

SUPPLEMENTAL REPORT EXPECTED (14)

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

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

ABSTRACT

On February 19, 1994 at 1345 hours, with the plant in Mode 5 (Cold Shutdown) while performing a stroke test of the pressurizer Pilot-Operated Relief Valves (PORVs) it was determined that the valves would not fully open. The problem was traced to a leak in the diaphragm assembly of the PORVs (PR-AOV-568 & 570). This leak was caused by improper assembly of the diaphragm in the actuator due to incomplete communication between the manufacturer and the licensee. Both PORV diaphragms were replaced during the 1993 refueling outage with a new style. Corrective action consisted of replacing the new style diaphragms with the original material which had no history of this kind of failure. It is not known how long the PORVs had been inoperable prior to this surveillance, but it is believed to have been longer than the ACTION time allowed. Therefore, this event is reportable under 10CFR50.73(a)(2)(i)(B), since it resulted in a condition prohibited by the plant's Technical Specifications. It is also reportable under 10CFR50.73(a)(2)(v)(D) and 50.73(a)(2)(vii) as a common mode failure.

NRC Form 366 (9-83)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 5	— 0 0	0 2 OF 0 5

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

BACKGROUND INFORMATION

The primary purpose of the pressurizer Pilot Operated Relief Valves (PORVs) (EIIS Code: AB) is to limit Reactor Coolant System (RCS) pressure to below the pressurizer safety valve setpoint, thus limiting the operating frequency of the code safety valves. The PORVs open automatically on two out of three high pressurizer pressure signals. The air operated pressurizer PORVs (PR-AOV-568 and 570) receive their air supply from the containment control air system (EIIS Code: LD) and an air accumulator. The control room operators have the ability to open either PORV manually to establish a "bleed" path for use in the "feed-and-bleed" method of core cooling ("feed" via safety injection and "bleed" via the PORVs). This is required when the steam generators are not available for decay heat removal.

The control air system includes a 107 gallon emergency air accumulator to support PORV operation for the "feed-and-bleed" method of core cooling in the event of a failure of both non-safety related containment air compressors. The air supply lines which lead to the PORVs (Figure 1) are each provided with a pressure regulator (CA-PRV-836A & B)(EIIS Code: LD). These regulators reduce the air pressure being supplied from 120 psig to 85 psig.

The portion of the containment control air system that supplies air to the PORVs from the accumulator serves a safety related function. It is isolated from the remainder of the containment control air system by two safety related check valves.

EVENT DESCRIPTION

On February 19, 1994, at 1345 hours, with the plant in Mode 5 (Cold Shutdown) for a maintenance outage, while performing Surveillance 5.7-112, "Inservice Testing of Power Operated Relief Valves PR-AOV-568 and 570 and Associated SOVs", both PORVs failed to fully open. This surveillance verifies the ability to fully stroke and the time to stroke the PORVs in accordance with Technical Specification 4.4.4.1 and 4.4.4.6. Since the PORVs were last tested during the 1993 refueling outage, ending July 1993, the actual time of failure is unknown but is conservatively estimated to have been longer than allowed by the Technical Specification ACTION statement. Investigation of the failure revealed two problems:

1) Both PORV diaphragms leaked between the cover and the diaphragm.
2) The air regulators supplying both PORVs were set too low (77.3 PSIG and 75.1 versus the required 85 PSIG). The air regulator problem is secondary and would not alone have caused the failures.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 5	— 0 0	0 3 OF 0 5

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

CAUSE OF THE EVENT

The leaking diaphragms were caused by loose diaphragm cover bolts. Both PORV diaphragms were replaced during the 1993 refueling outage with a new style. The principle change was the substitution of a longer lasting material (EPDM) for the old Buna-N material. The manufacturer also changed the shape of the diaphragm somewhat although this was never communicated to the licensee. This change resulted in some difficulty installing the diaphragm. To overcome this a commonly used lubricant (Moly 55) was applied to aid installation. The PORVs were subsequently re-tested satisfactorily. Subsequent to the February 1994 failures an in-depth discussion with the manufacturer on the possible causes for failure revealed several aids to overcome installation problems. The most significant was the use of a sealant around the diaphragm's bolt circle. It is believed that the presence of lubricant instead of the sealant allowed some extrusion of the diaphragm from between the base and cover and away from the bolt holes. This extrusion also led to small tears at several diaphragm bolt holes, allowing the bolts to loosen over time.

The cause of this event was incomplete communication between the manufacturer and the licensee.

SAFETY ASSESSMENT

This event is reportable under 10CFR50.73(a)(2)(i)(B) since it resulted in a condition prohibited by the plant's Technical Specifications. It is also reportable under 10CFR50.73(a)(2)(v)(D) and 50.73(a)(2)(vii) as a common mode failure.

The operation of the pressurizer PORVs (PR-AOV-568 and 570) during a design basis accident is not required to prevent the violation of the pressure and temperature safety limits. In post-small break LOCA conditions the HPSI recirculation line back to the RWST is isolated and it is assumed that the PORVs are opened to ensure that the HPSI pumps are not dead headed. In this event the valves would open and perform their intended function for a short period of time. However, the air leakage would have resulted in the eventual loss of air and closure of the PORVs. The closure of the PORVs would result in the loss of forced flow and core cooling would occur by natural circulation. The safety significance of the event is low since, for a small break LOCA, charging flow would continue to supply coolant to the core. For large break LOCAs, the system pressure would be low enough to allow for recirculation using the HPSI pumps.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 5	— 0 0	0 4 OF 0 5

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

The operation of these valves is also required for a beyond design basis feed and bleed type accident (when the steam generators are unavailable to remove core decay heat). Although the use of the main and auxiliary feedwater systems is the primary and preferred method of safe shutdown, feed and bleed remains limiting to meeting the Probabilistic Risk Assessment (PRA) core melt frequency goal and is credited as an available safe shutdown method for the following applications:

1. Loss of main and auxiliary feedwater
2. High energy pipe breaks
3. Internally generated missile
4. Tornado missiles/wind protection

The eventual loss of air to the PORVs results in an increase in the core melt frequency.

CORRECTIVE ACTION

Corrective actions that have been completed relating to this event include the following:

1. Significant extrusion of the diaphragms was noted, raising questions as to the long term adequacy of this new style. Therefore, the new style diaphragms were replaced with the original Buna-N material which had no history of this kind of failure.

2. Discussions were conducted with the vendor regarding the incomplete communications issue.

3. The PORV air regulators were replaced.

ADDITIONAL INFORMATION

System	Component	Manufacturer	Model Number
LD	Air Regulator	ITT Conoflow (I208)	GFH25XT2365G
AB	PORV diaphragm	Copes-Vulcan (C635)	264331

PREVIOUS SIMILAR EVENTS

LER 93-007-00

NRC Form 366A (9-83)

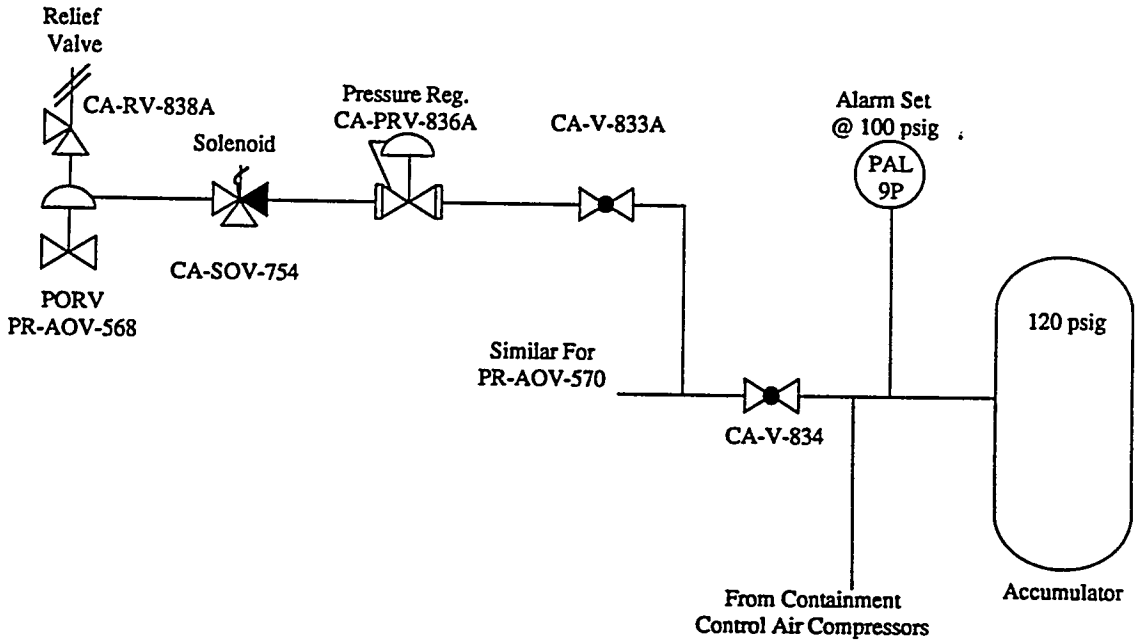
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 0 5	— 0 0	0 5 OF 0 5

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

Figure 1



NRC FORM 366A (9-83)

*U.S.GPO.1988-0-624-538/455

Appendix I

LER No. 213/94-007
Haddam Neck

ACCESSION #: 9404130172
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Haddam Neck

DOCKET NUMBER: 05000213

TITLE: Potential for Radiological Release During Post LOCA Sump Recirculation

EVENT DATE: 03/08/94 LER #: 94-007-00 REPORT DATE: 04/05/94

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 5 POWER LEVEL: 000

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

LICENSEE CONTACT FOR THIS LER:
NAME: J. Majewski, Senior Engineer TELEPHONE: (203) 267-2556

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

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On March 8, 1994, at approximately 1320 hours, with the plant in Mode 5 (cold shutdown), it was determined that the potential existed to lift a relief valve in the Chemical and Volume Control System (CVCS) during the performance of the emergency response procedure to establish containment sump recirculation following a Loss of Coolant Accident (LOCA). This in turn could cause another relief valve to lift in the Radioactive Waste Gas System which discharges to the environment via the plant stack. If such an event were to occur, radiological dose consequences could be more severe than previously predicted. The cause of this condition was a failure to recognize the full potential adverse impacts of a change to an emergency response procedure during the review of the procedure change in 1990. Corrective action involved revising the affected emergency response procedure to eliminate the potential overpressure condition. Also, in October, 1991 the station procedure addressing the preparation, change, and review of emergency response procedures was revised to provide for a more rigorous technical review of new or changed procedures than had existed previously.

END OF ABSTRACT

BACKGROUND INFORMATION

Several systems can be used at the Haddam Neck plant for containment sump recirculation following a Loss of Coolant Accident (LOCA) (see Figure 1). Namely, the Residual Heat Removal (RHR) system (EIIS code BP), the High Pressure Safety Injection (HPSI) system (EIIS Code BQ), and the charging portion of the Chemical and Volume Control system (CVCS) (EIIS Code CB). After the Refueling Water Storage Tank has been emptied to a specified low level during the injection phase, the RHR pumps and heat exchangers are then used to remove water accumulated in the containment sump and discharge it back to the RCS via the Charging and/or HPSI system.

The Charging system consists of three pumps in parallel (two moderate capacity centrifugal and one low capacity positive displacement) which discharge into a common header. Suction can be supplied from the Volume Control Tank (VCT), the Refueling Water Storage Tank (RWST), or the discharge of the RHR pumps and heat exchangers via either of two parallel motor operated valves (RH-MOV-33A and 33B). The discharge header splits into two paths, one provides Reactor Coolant Pump seal water supply and the other provides RCS makeup supply via the charging header to the RCS loop two cold leg. The discharge of the positive displacement pump is equipped with a relief valve (CH-RV-280) which is designed to protect the downstream piping and components from overpressure if the discharge flow path were to be isolated with the positive displacement pump in operation.

CH-RV-280 relieves to the Primary Drains Tank (PDT) in the radioactive waste gas system (EIIS Code:WE). The PDT is a 7500 gallon tank that receives waste water containing dissolved hydrogen or fission gases from various reactor plant sources Liquid in the PDT is pumped by one of two parallel pumps through a filter and a heater to the degasifier where it is sprayed through nozzles causing the heated liquid to flash thereby releasing the dissolved gasses. The degasified liquid is pumped through a cooler either to the CVCS or to outdoor storage tanks for eventual release offsite. The gases stripped from the liquid are cooled to condense any steam and are then routed to the waste gas surge tank. The waste gas surge tank receives radioactive waste gases from various sources including the gas space of the PDT. Collected gases are compressed by one of two parallel compressors and stored in three waste gas decay tanks for eventual release off site. The waste gas surge tank is protected against overpressure by an air operated valve actuated by a pressure switch at 14 psig and also by a spring loaded relief valve set at 20 psig. Both of these valves relieve directly to the environment via the plant stack.

TEXT

Overpressure protection for each of the three waste gas decay tanks is provided by an air operated valve actuated by a pressure switch at 215 psig and a spring loaded relief valve set at 225 psig. Both of these valves relieve directly to the environment via the plant stack.

EVENT DESCRIPTION

On March 8, 1994, at approximately 1320 hours, with the plant in Mode 5 (cold shutdown), an engineering evaluation determined that the potential existed to lift a relief valve in the Chemical and Volume Control System (CVCS) during the performance of the emergency response procedure to establish containment sump recirculation following a Loss of Coolant Accident (LOCA). Emergency response procedure ES-1.3, "Transfer to Sump Recirculation" provides for the use of the RHR, Charging, and HPSI pumps for sump recirculation if offsite power is available to the emergency buses. The RHR pumps are aligned to take suction from the containment sump and discharge to the suction of the charging pumps. One charging pump is checked to be running or is started and the flow control valves and motor operated isolation valves on the charging header are checked to be open. Flow from the sump to the RCS is then initiated by opening the RHR to Charging pump suction motor operated isolation valves (RH-MOV-33A and 33B). The charging pump suction is then isolated from the VCT and the RWST. If RCS pressure is less than 1500 psig, actions are then taken to align the discharge of the RHR pumps to the suction of the HPSI pumps. After this alignment is completed, the motor operated isolation valves on the charging header (CH-MOV-292B&C) are closed and one HPSI pump is started. The charging header isolation valves are closed to prevent excessive flow and runout of the RHR pumps once the HPSI pumps are started. The charging pump is left running to inject water through the RCP seals.

The reduced charging pump flow resulting from the closure of the charging header isolation valves when combined with the discharge pressure from the RHR pumps results in a charging pump discharge pressure in excess of the lift setpoint of CH-RV-280. CH-RV-280 has a lift setpoint of 2735 psig +/- 3% (2653 to 2817 psig). The charging pump discharge pressure during such an event was estimated to be approximately 2658 psig, which slightly exceeds the lowest allowable lift setpoint value for CH-RV-280. CH-RV-280 has a rated capacity of 30 gpm (the maximum flow rate of the positive displacement charging pump) at an accumulated pressure of 3300 psig. Thus, at a pressure very close to the lift setpoint, the flow rate would be expected to be much less than 30 gpm.

TEXT PAGE 4 OF 07

SAFETY ASSESSMENT

The potential to lift CH-RV-280 during post LOCA sump recirculation is reportable under 10 CFR 50.73 (a)(2)(v)(C) as a condition that alone could have prevented the fulfillment of the safety function of a system that is needed to control the release of radioactive material.

This event is only potentially significant following a large break LOCA in which significant core damage has occurred. If CH-RV-280 were to lift during sump recirculation using the charging pumps, there would be a slight reduction in the total coolant injection flow. As much as 30 gpm could be potentially lost, although much less than this would actually be expected as discussed above. Thus, the effect of CH-RV-280 lifting on the ability to maintain core cooling is insignificant.

A second concern with the potential to lift CH-RV-280 during post LOCA sump recirculation would be the increase in system leakage outside containment, that could result in an increase in calculated offsite dose consequences. The radiological consequence analysis for large break LOCA assumes a total system leakage of 3 liters per hour, which is significantly less than what could potentially be released. However, CH-RV-280 is downstream of the RHR heat exchangers and the temperature of the recirculated coolant leaked at this point would be less than 200 degrees (F). At this temperature, no flashing of the coolant will occur and the primary mechanism for iodine to become airborne will not be present. Thus, the actual airborne iodine fraction would be significantly less than assumed in the Final Safety Analysis Report (FSAR) radiological analysis. There is the possibility that the coolant released to the plant stack could leak out onto the ground and eventually get offsite. It would take a substantial amount of time for a leak of this magnitude to reach the site boundary and could reasonably be expected to be discovered by radiation monitoring surveys conducted during an accident. Based on the above, the actual safety significance is judged to be moderate.

CORRECTIVE ACTION

Corrective action involved revising emergency response procedure ES-1.3 to eliminate the potential overpressure condition by stopping the running charging pump prior to starting the HPSI pump. A review of the sump recirculation flow path was performed to determine if there were any other system relief valves that could potentially lift during performance of ES-1.3 and none were found.

TEXT

Relief flow from CH-RV-280 would cause the level in the PDT to increase, eventually starting an automatic degasifier cycle to process the water in the PDT. The PDT, degasifier, and waste gas systems would cycle on and off automatically to process the input to the PDT provided that steam is available to heat the degasifier feedwater. Unavailability of process steam would result in the failure of the PDT pumps to start since a temperature switch on the degasifier necessary for PDT pump start would not be actuated. PDT level would continue to increase. Eventually, the PDT and waste gas surge tank would become filled to capacity. Pressure up to this point has been controlled by the automatic starting and stopping of the waste gas compressors. Eventually, the suction lines for the waste gas compressors would be filled with water. If the temperature of the water is 125 degrees (F) or greater, the compressors will trip on high suction temperature. It is also possible that the compressors may trip on overload. Either of these two conditions will result in waste gas surge tank pressure reaching the setpoint of the relief valves and a radiological release to the environment via the plant stack. If the compressors continue to run, the waste gas decay tanks would eventually fill and be pressurized. Automatic alignment to the next unpressurized tank would occur until all three tanks had been pressurized. Pressure in the last tank would continue to increase to the lift setpoint of the relief valves also resulting in a radiological release to the environment via the plant stack.

Indications and alarms for the PDT, waste gas surge tank, degasifier, and waste gas compressors are provided locally on a control panel in the primary auxiliary building. However, radiological conditions in this building during sump recirculation may not permit monitoring of this control panel. Radiation monitoring for the plant stack which is displayed in the control room would provide the control room operators with information on a release in progress. This information alone, however, would not be sufficient to allow diagnosis and mitigation of such a release.

CAUSE OF THE EVENT

The cause of this condition was a failure to recognize the full potential adverse impacts of a change to emergency response procedure ES-1.3 during the review of the change in 1990. The alignment for sump recirculation using a combination of HPSI and Charging pumps was added to procedure ES-1.3 in April, 1990 following modifications to the HPSI pump suction lines which added valves to accomplish the alignment of the RHR pump discharge to the suction of the HPSI pumps.

TEXT PAGE 6 OF 07

Also, in October, 1991 the station procedure (ACP 1.2-6.13, "Emergency Response Procedure Generation Guidelines" which addresses the preparation, change, and review of emergency response procedures was revised to provide for a more rigorous technical review of new or changed procedures than had existed previously.

ADDITIONAL INFORMATION
N/A
PREVIOUS SIMILAR EVENTS
LER 90-011-00

Appendix I

LER No. 213/94-012
Haddam Neck

NRC Form 366
(4 83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	1 OF 0 4

TITLE (4)

Potential Loss of Service Water Due to Flood Induced Strainer Fouling

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 4	2 8	9 4	9 4	0 1 2	0 0	0 5	2 6	9 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
1	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
1 0 0	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
	20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
S. Weyland, Senior Engineer	AREA CODE 2 0 3 2 6 7 - 2 5 5 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

ABSTRACT

On April 28, 1994, at 1230 hours, with the plant in Mode 1 at 100 percent power, a previously unidentified external flooding scenario was discovered which has the potential to incapacitate the service water (SW) system at a river flood elevation less than that which was assumed in the design analysis. Under this newly discovered scenario, a flood at slightly above site grade elevation would enter the plant's intake structure and completely flood the lower level. This would prohibit personnel from entering the lower level to clean the SW pump discharge strainers. It is further postulated that river debris could clog the SW strainers to the point that the SW pumps are not capable of delivering sufficient flow. The cause of this condition was the apparent lack of recognition of the potential need to clean SW strainers during floods. Corrective action consisted of providing the operating shifts with alternatives for mitigating this event and incorporating appropriate changes into plant procedures. This event is reportable under 10CFR50.73(a)(2)(v)(D) as a condition that alone could have prevented the fulfillment of the safety function of a system needed to mitigate the consequences of an accident.

NRC Form 366
(9 83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 2	— 0 0	0 2 OF 0 4

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

BACKGROUND INFORMATION

The Updated Final Safety Analysis Report (UFSAR) Section 2.4.2 discusses the potential for flooding at the Haddam Neck site. This section states that the probable maximum flood (PMF) at the site is elevation 39.5' MSL. UFSAR Section 3.4.1 provides a discussion of the flood protection features at Haddam Neck. It states that structures and components required for safe shutdown of the plant are protected from external floods to an elevation of 30' 0" MSL (grade level is approximately 21' MSL). Floods in excess of 30' are of very low probability and procedures have been written and temporary equipment is available on site to maintain the plant in a safe condition for floods in excess of elevation 30'.

During the period of April 4, 1994 to May 6, 1994, the Service Water Operational Performance Inspection (SWOPI) was conducted to verify the ability of the service water system (EIIS Code: BI) to meet its design basis. One of the items which the inspectors postulated was a flood slightly in excess of grade elevation. This assumed flood would enter the intake structure (EIIS Code: MK) and flood its lower level by means of a stairwell. Two service water pumps (EIIS Code: P) are protected to elevation 30' 0" by means of fiberglass cans placed around the pump motors upon warning of impending site flooding. However, flooding of the lower level of the intake would make the service water discharge strainers (EIIS Code: STR) inaccessible for cleaning by normal means.

EVENT DESCRIPTION

On April 28, 1994, at 1230 hours, with the plant in Mode 1 at 100 percent power, a previously unidentified external flooding scenario was discovered which has the potential to incapacitate the service water (SW) system at a river flood elevation less than that which was assumed in the UFSAR. Under this newly discovered scenario, a flood at slightly above grade elevation (approximate el. 21' MSL) would enter the plant's intake structure and completely flood the lower level. This would prohibit personnel from entering the lower level to clean the service water pump discharge strainers. It is further postulated that river debris could clog the SW strainers to the point that the service water pumps are not capable of delivering sufficient flow to maintain vital functions (Emergency Diesel Generator cooling and Residual Heat Removal).

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 2	— 0 0	0 3 OF 0 4

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

Although it is believed that the service water system will remain operable for some time after the intake lower level is flooded and may remain operable throughout the entire flood, it cannot conclusively be shown that the service water system will remain operable. This condition has therefore been conservatively judged to be reportable.

CAUSE OF THE EVENT

The cause of this event was the apparent lack of recognition of the potential need to clean the service water strainers during floods. The methods and hardware modifications for coping with flooding conditions were evaluated during the Systematic Evaluation Program (SEP).

SAFETY ASSESSMENT

This event is reportable under 10CFR50.73(a)(2)(v)(D) as a condition that alone could have prevented the fulfillment of the safety function of a system needed to mitigate the consequences of an accident.

Abnormal Operating Procedure AOP 3.2-24 requires a plant shutdown prior to the flood arriving at the plant site. Therefore, required service water flow to maintain the plant in a safe condition is greatly reduced. All non essential Service Water loads will be isolated (Service Water to the diesels and to the Component Cooling Water (CCW) heat exchangers would be the only requirements during this scenario). Also, the diesel cooling requirement will be lessened due to the light loading of the diesel (when compared to design basis LOCA loading) and reactor heat loads rejected to service water through the Residual Heat Removal (RHR) and CCW systems will be greatly reduced from those experienced immediately after reactor shutdown.

Because of the reduced Service Water flow requirement in this scenario, the Service Water System would remain operable with considerably greater strainer clogging than would be permitted during power operation. It is estimated that a total service water flow of approximately 2000 GPM would be sufficient to maintain the plant in a safe condition (runout for a single Service Water pump is about 7000 GPM). It is therefore highly probable that Service Water would be available to provide its limited cooling requirements for a substantial period of time after the flood. In the event that the Service Water strainers clog and Service Water is not able to remove the required heat load, divers may be used to clean the clogged strainers.

NRC FORM 366A

★U.S.GPO.1986-0-6 1-538/455

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 2	— 0 0	0 4 OF 0 4

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

Additionally, throttle valves on the downstream side of the diesel generator and CCW heat exchanger could also be opened as the strainers clog to partially compensate for strainer blockage.

The actions to be taken to assure plant safety, assuming Service Water System failure due to strainer clogging, involved changes to AOP 3.2-24. Specifically, a gas driven pump will be set up on the mid level of the Turbine Building and suction will be taken from the Demineralized Water Storage Tank (DWST) or the Condensate Storage Tank (CST) to provide cooling water to the depressurized steam generators. In addition, the Primary Water Storage Tank (PWST) and the Recycle Primary Water Storage Tank (RPWST) can be used as backup sources of water. As a last resort flood water can be supplied to the gas driven pump.

Based on the above, the overall safety significance of this postulated scenario is minimal.

CORRECTIVE ACTIONS

The operating crews were briefed of the postulated scenario on April 28, 1994. Several potential alternatives to mitigate this unlikely event, including use of the portable gas driven pump, were discussed.

Plant procedure AOP 3.2-24 "Flooding of the Connecticut River" was enhanced to ensure that appropriate actions, as discussed above, are taken to maintain the plant in a safe condition during a postulated flood of a lower elevation.

ADDITIONAL INFORMATION

None.

PREVIOUS SIMILAR EVENTS

None.

LER No. 213/94-013
Haddam Neck

NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	1 OF 0 6

TITLE (4)

HPSI Pump Discharge Relief Valve Setpoint Found Low

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

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (Check one or more of the following) (11)			
1	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 1 0 0	20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
	20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE
W. Forrestt, Engineering Systems	2 1 0 8 6 7 - 2 5 5 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

ABSTRACT

On May 5, 1994, at 1630 hours, with the plant in Mode 1, at 100 percent power, the High Pressure Safety Injection (HPSI) common discharge header relief valve was found to be lifting during the performance of a routine surveillance procedure. The relief valve was found to be lifting when 'B' HPSI pump was operating, however it did not open when the "A" HPSI pump was operating. Lifting of the relief valve during the injection phase of a LOCA and its subsequent failure to reseat during sump recirculation would result in a discharge of contaminated sump water back to the refueling water storage tank and the potential for an unacceptable radiological release. The apparent cause of this event is setpoint drift coupled with the proximity of normal operating pressure to the relief valve setpoint. Short term corrective action consisted of removing the 'B' HPSI pump from service, increasing the allowable system header pressure along with the relief valve setpoint and returning the pump to service within 28 hours. Long term corrective action involves increasing the testing frequency of the relief valve (5 years to each refueling) and evaluating the feasibility of a further increase in allowable system pressure.

NRC Form 366
(9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 3	— 0 0	0 2 OF 0 6

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

BACKGROUND INFORMATION

The rated capacity of relief valve (EIIS Code: RV) SI-RV-870 is 35 gpm which discharges to the refueling water storage tank (RWST). Its purpose is to protect the High Pressure Safety Injection (HPSI) (EIIS Code: BQ) discharge piping (rated for 1500 psig) from Reactor Coolant System (RCS) (EIIS Code: AB) back leakage (at 2000 psig) through four 3" injection lines, each containing a normally closed motor operated valve and check valve in series (see Figure 1). Historically both HPSI pumps (EIIS Code: P) have operated with discharge pressures of 1400-1450 psig. However, as a result of overhauling the 'B' HPSI pump during the last refueling outage (ending mid July '93), the discharge pressure increased from 1440 psig to approximately 1500 psig. During subsequent startup testing, it was found that the relief valve was lifting when the 'B' Pump was operated. This testing was performed in Mode 4 (hot shutdown) to verify HPSI Pump operability prior to placing the pumps in service. The valve was removed and adjusted to lift at 1540 psig. Prior to placing the system in service the 'B' Pump was again operated with SI-RV-870 at the revised lift point to confirm the valve did not lift.

EVENT DESCRIPTION

On May 5, 1994, at 1630 hours, with the plant in Mode 1, at 100 percent power, the HPSI common discharge header relief valve SI-RV-870 was found to be lifting while performing surveillance procedure SUR 5.7 - 145A "Quarterly Inservice Testing of A & B HPSI pumps, and Non-Return Valves SI-NRV-921 and 922". The discharge pressure of the HPSI pumps during testing is 1460 psig and 1510 psig for pumps 'A' and 'B', respectively. While operating 'B' HPSI pump in accordance with this surveillance, abnormally high flows were detected via an ultrasonic flow device used to verify adequate pump recirculation flow. This condition was determined to be the result of SI-RV-870 lifting, and it only existed while the stronger 'B' Pump was operating. Subsequent relief valve closure was verified by obtaining normal flows while running the 'A' Pump.

The failure of SI-RV-870 to reseat after opening in a Small Break LOCA, would introduce an unanalyzed flow diversion of up to 35 gpm. This is considered negligible as both pumps would deliver much more coolant than assumed by Safety Analysis using degraded pump curves. However, if a LOCA occurred coupled with a SI-RV-870 failure to reclose, the potential exists during the sump recirculation phase for highly contaminated reactor coolant to be diverted to the atmospherically vented (RWST).

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 3	— 0 0	0 3 OF 0 6

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

CAUSE OF THE EVENT

The cause of this event is attributed to the slightly higher shutoff head of the 'B' HPSI pump (1510 psig versus 1460 psig for the 'A' pump) coupled with a drifting of the relief valve setpoint in the downward direction.

SAFETY ASSESSMENT

This event is reportable under 10CFR50.73(a)(2)(v) as a condition that alone could have prevented the fulfillment of the safety function of a system needed to control the release of radioactive material.

Once SI-RV-870 was found to be lifting, it became considered an active component (while previously being considered a passive component) which would need to reseat prior to entering sump recirculation. This new postulated single active failure would introduce an unanalyzed post LOCA condition. However, as described below, the valve is fully expected (under all accident scenarios) to reseat prior to entering sump recirculation.

The lifting of the HPSI discharge relief valve during the injection phase of a Loss of Coolant Accident (LOCA) and its subsequent failure to reclose during sump recirculation would result in a discharge of contaminated sump water back to the RWST and the potential for an unacceptable radiological release. However, in the 'as found' condition and subsequent testing, SI-RV-870 demonstrated repeatability while fully reseating after each lift. Therefore, it's considered unlikely that the valve would fail to reseat.

During the recirculation phase of a LOCA a Residual Heat Removal (RHR) pump discharges to the suction of a HPSI pump. If both pumps were running near shutoff there would be the potential to lift the HPSI discharge relief valve. However, in all liklihood, for a small break LOCA a plant cooldown would be commenced and HPSI would be terminated before sump recirculation is initiated. If RCS pressure is above 1500 psig when it is time to enter sump recirculation, Emergency Response Procedure ES 1.3, "Transfer to Sump Recirculation" directs the operator to enter sump recirculation using a charging pump aligned to the RHR pump discharge, thereby precluding a challenge to the HPSI discharge relief valve. This procedure also directs the operator to open a pressurizer pilot operated relief valve (PORV) prior to starting a HPSI pump during entry into sump recirculation.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 3	— 0 0	0 4 OF 0 6

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

This action rapidly decreases RCS pressure so that the HPSI and RHR pumps will run out on their pump curves and not challenge the HPSI relief valve.

Finally, an open relief valve would also represent a diversion path for ECCS coolant away from the core and back to the RWST. However, the single active failure in this scenario would be the failure of SI-RV-870 to reseat. Therefore, the flow diversion during the injection phase is negligible as both HPSI pumps would be available to provide sufficient delivery.

The significance of potentially sending 32 gpm of sump recirculation water to the atmospherically vented RWST is minimized for several reasons. The sump water will not contain significant noble gas activity, and since the temperature of the diverted sump water and RWST water are low enough that any leakage into the RWST will remain in the liquid phase, it is not expected that any significant offsite dose consequences will result from radioactive iodines or particulates in the diverted flow.

Furthermore, the most likely scenario of SI-RV-870 opening is the Small Break LOCA, and this scenario has been analyzed to introduce less fuel failure than the scenario bounded by the Large Break LOCA.

Based upon the discussion above, the overall safety significance of this event is low.

CORRECTIVE ACTION

In order to prevent the relief valve from opening during the injection phase of the Emergency Core Cooling System (ECCS), the control switch for the "B" HPSI pump was placed in Trip Pull Out (TPO) in order to prevent an automatic start on a Safety Injection Actuation Signal. This resulted in the "B" HPSI pump being declared inoperable and entry into a 72 hour Action statement. The maximum allowable operating pressure was increased to 1600 psig by completing a previously ongoing technical evaluation (initiated after the lifting event during start-up). A special test was then satisfactorily performed to raise the relief valve setting (in place) to 1565 psig using a hydrostatic pump, and the 'B' HPSI pump was placed back in service within 28 hours. The testing / maintenance frequency of the relief valve will be increased from once every five years to every refueling outage. Additionally, measures to further increase allowable header pressure will be investigated along with a possible modification to allow for on line removal / adjustment of SI-RV-870.

NRC Form 366A (5-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 3	— 0 0	0 5 OF 0 6

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

ADDITIONAL INFORMATION

None

PREVIOUS SIMILAR EVENTS

LER 94-007-00 Potential for Radiological Release During Post LOCA Sump Recirculation

NRC Form 366A (9-83)

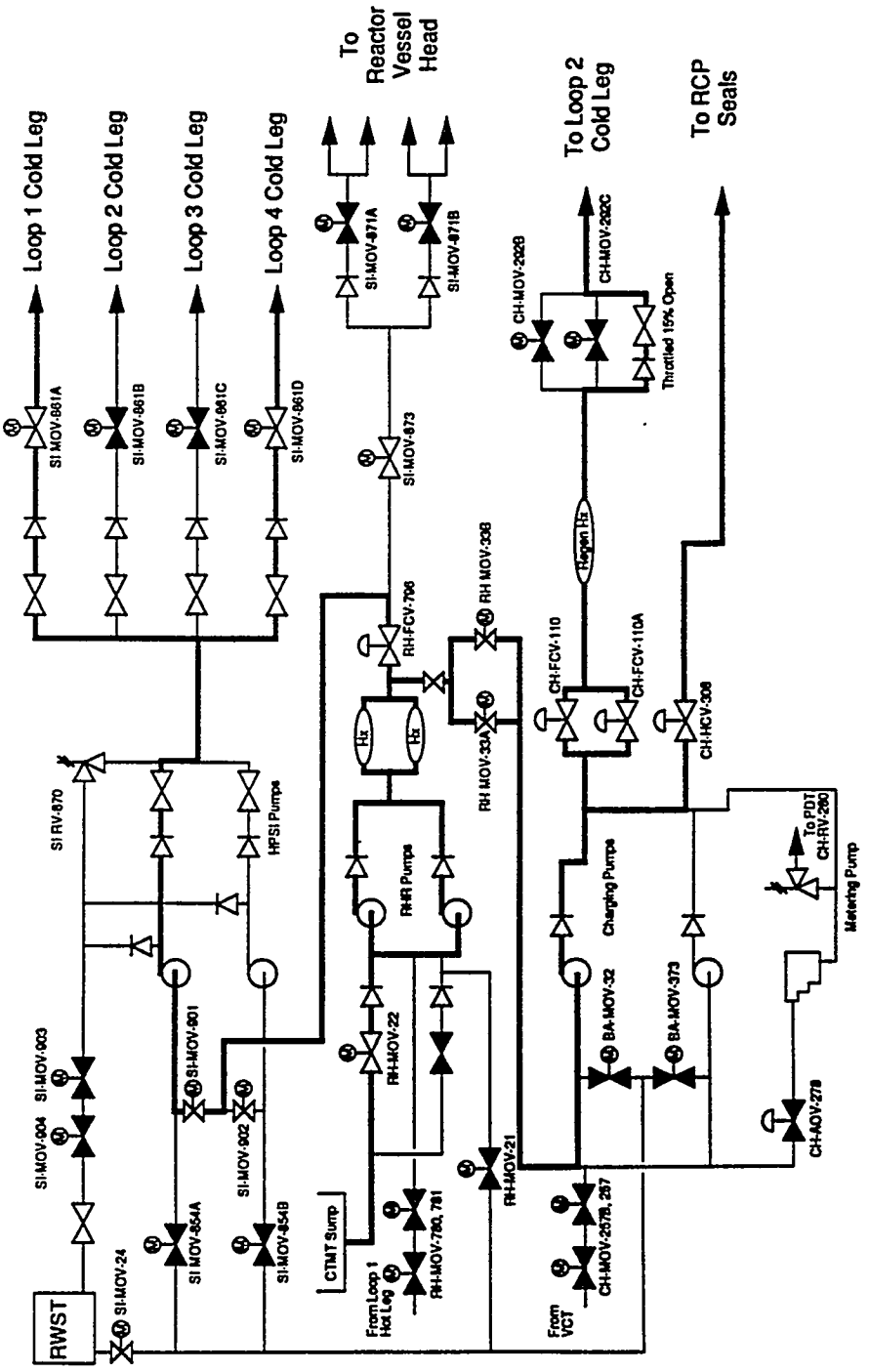
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 4	— 0 1 3	— 0 0	0 6 OF 0 6

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

Figure 1



NRC FORM 366A (9-83)

*U.S.GPO 1986-0-[illegible] -538/455

Appendix I

Inspection Report 213/94-03
Haddam Neck

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/ Report No.	50-213/94-03
License No.	DPR-61
Licensee:	Connecticut Yankee Atomic Power Company (CYAPCo) P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Plant
Location:	Haddam Neck, Connecticut
Dates:	January 16 to February 26, 1994
Inspectors:	William J. Raymond, Senior Resident Inspector Peter J. Habighorst, Resident Inspector Suresh Chaudhary, Senior Reactor Engineer
Approved by:	Lawrence T. Doerflein, Chief Reactor Projects Section 4A 4/7/94 Date

Areas Inspected: NRC resident inspection of plant operations, outage activities, maintenance, engineering and technical support and plant support activities.

Results: See Executive Summary

EXECUTIVE SUMMARY
HADDAM NECK PLANT INSPECTION 50-213/94-03

Plant Operations

Plant operators performed very well during this period responding to transient conditions, completing an orderly shutdown to cold shutdown, and implementing controls to minimize shutdown risks. The operators also provided good support to engineering to identify all service water system stagnant legs. The compensatory measures to address degraded service water piping were appropriate and thorough. A licensed senior reactor operator demonstrated excellent knowledge of the plant configuration and procedures by his recognition of a potential vulnerability when in the sump recirculation mode of reactor cooling following postulated accidents.

Maintenance

Maintenance investigations following the failure of both pressurizer PORVs on February 19 were good. The root cause determination for the failures, and the actions to improve the PORV air system is an unresolved item **(UNR 94-03-01)**. The use of mechanical restraining bars while testing the main steam trip valves will be reviewed on a subsequent inspection **(IFI 94-03-02)**. The licensee promptly investigated the operability of the main steam safety valves following the receipt of test information from the vendor. Although an acceptable method was developed to test the installed valves, the decision to not test the valves with the plant operating at power reflects a conservative safety ethic. Some main steam safety relief pilot valves failed when tested during cold shutdown plant conditions. The causal analysis was not complete at the end of the inspection period. Future NRC inspection will review the CYAPCo's root cause analysis and the corrective actions **(UNR 94-03-03)**.

CYAPCo staff performed well investigating the failure of the MCC-5 automatic bus transfer (ABT) during this inspection period. This item is considered unresolved pending the completion of the root cause investigation of the failure, and the implementation of corrective actions **(UNR 94-03-04)**. CYAPCo management and engineering did not aggressively pursue indications of corrosion induced degradation in service water piping, and had lost the initiative in resolving this problem prior to substantial NRC involvement on the issue. This item is considered open pending the completion of actions to replace degraded SW piping, and to address the root cause for the corrosion **(UNR 94-03-05)**.

Engineering and Technical Support

The discovery of silt and macrofouling in the service water supplies to the RHR heat exchangers revealed an inadequacy in CYAPCo's actions in response to NRC Generic Letter 89-13. This is an inspector follow item **(IFI 94-03-06)**.

Executive Summary

CYAPCo's identified discrepancies between the of "as-built" conditions for the low pressure safety injection system and the original piping specification. The deviations from the specifications were acceptable. This item is open pending the completion of actions to assure the accuracy of plant design basis information used for engineering evaluations (IFI 94-03-07).

Plant Support

Radiological controls were well implemented. Actions to investigate and correct an unsecured gate providing access to a locked high radiation area were prompt and thorough. The security officer who discovered the unsecured gate during a routine tour demonstrated good attention to detail and regard for radiological controls. Licensee measures to control and monitor radiological releases while purging the containment were good. Licensee actions during contract negotiations with the security force were thorough.

TABLE OF CONTENTS

EXECUTIVE SUMMARY ii

TABLE OF CONTENTS iv

1.0 SUMMARY OF FACILITY ACTIVITIES 1

2.0 PLANT OPERATIONS (71707 and 93702) 1
2.1 Operational Safety Verification 1
2.2 Plant Shutdown - Unusual Event 2
2.3 Service Water System Stagnant Line Verification and Alignment for Isolation 3
2.4 Compensatory Measures for a Postulated Service Water System Line Break 4
2.5 Power Reduction Due to Loss of Generator Cooling 4
2.6 Shutdown Operations 5
2.7 Charging System Valve Leakage 6

3.0 MAINTENANCE (61726 and 62703) 6
3.1 Maintenance Observations 6
3.1.1 Failure of the Pressurizer Power Operated Relief Valves 7
3.2 Surveillance Observations 10
3.3 Main Steam Safety Relief Valve Testing 11
3.4 MCC-5 ABT Testing 13
3.5 Examination and Replacement of Service Water Piping 18

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707) 28
4.1 Loose Sediment in Service Water Line to Residual Heat Removal (RHR) Heat Exchanger 28
4.2 Improper Pipe Flanges on the Low Pressure Safety Injection System . . . 30
4.3 Modification to MCC-5 32

5.0 PLANT SUPPORT (40500, 71707, 90712, and 92701) 33
5.1 Radiological Controls 33
5.1.1 Locked High Radiation Controls 33
5.1.2 Containment Purge Operations 34
5.2 Plant Operations Review Committee 34
5.3 Follow-up of Previous Inspection Findings 35
5.4 Union Negotiation Contingency Plans (IP 92709) 36

6.0 MEETINGS 36
6.1 Exit Meetings 36
6.2 Meeting with Local Officials 37

Table of Contents

ATTACHMENTS

ATTACHMENT A - EDG SERVICE WATER EVENTS SUMMARY

FIGURES

FIGURE 1 - MCC 5 ABT SCHEMATIC DIAGRAM
FIGURE 2 - ABT LOGIC DIAGRAM
FIGURE 3 - VIEW DB-25 BREAKER
FIGURE 4 - CROSS SECTIONAL VIEW DB-15/25 BREAKER
FIGURE 5 - VIEW OF DB-25 BREAKER OPERATING MECHANISM
FIGURE 6 - SERVICE WATER SUPPLE TO EMERGENCY DIESEL GENERATORS

Note: The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

The plant was operating at 100% full power at the start of the period on January 16. On January 20, plant load was reduced to 85% at 4:40 p.m. due to fluctuating temperatures on the main generator hydrogen coolers. The load reduction was stopped after finding the temperature controller for control valve SW-TCV-1711 had failed. The valve was placed in manual control and temperatures returned to normal. Plant load was increased to 100% on at 7:15 p.m.

The plant continued operating at 100% power until February 12, when both service water system headers to the emergency diesel generators were declared inoperable. An Unusual Event was declared due to the Technical Specification required shutdown. The plant was in cold shutdown at 6:10 p.m. on February 13, commencing an anticipated 55 day outage. The plant remained shutdown at the end of the period. The major work in progress included: activities to inspect and replace service water system piping, replacement of the seal on the #1 reactor coolant pump, painting the reactor cavity, and replacement of the coolers for containment air recirculation fans #2 and #3.

2.0 PLANT OPERATIONS (71707 and 93702)

In addition to normal utility working hours, the inspectors routinely conducted the review of plant operations during portions of backshifts (evening shifts) and deep backshifts (weekend and night shifts). Inspection coverage was provided for fifty five hours during backshifts and forty five hours during deep backshifts.

2.1 Operational Safety Verification

This inspection consisted of selective examinations of control room activities, operability reviews of engineered safety feature systems, plant tours, review of the problem identification systems, and attendance at periodic planning meetings. Control room reviews consisted of verification of staffing, operator procedural adherence, operator cognizance of control room alarms, control of technical specification limiting conditions of operation, and electrical distribution verifications. Administrative control procedure (ACP) - 1.0-23, "Operations Department Shift Staffing Requirements," identifies the minimum staffing requirements. During the inspection period, the inspectors verified these requirements were met.

The inspectors reviewed the onsite electrical distribution system to verify proper electrical line-up of the emergency core cooling pumps and valves, the emergency diesel generators, radiation monitors, and various engineered safety feature equipment. The inspectors also verified valve lineups, position of locked manual valves, power supplies, and flow paths for the high pressure safety injection system, the low pressure safety injection system, the containment air recirculation system, the service water system, and the emergency diesel generators. No deficiencies were noted.

Bypass jumpers were reviewed against the requirements of ACP 1.2-13.1, "Jumper, Lifted Lead, and Bypass Control," with emphasis on proper installation and the content of the safety evaluations. The inspector reviewed all jumpers for age, and verified that Plant Operations Review Committee (PORC) evaluations were completed to disposition longstanding evaluations. The jumpers reviewed were found to be in accordance with administrative requirements.

Log-Keeping and Turnovers

The inspectors reviewed control room logs, night order logs, plant information report logs, and crew turnover sheets. No discrepancies or unsatisfactory conditions were noted. The inspectors observed crew shift turnovers and determined they were satisfactory, with the shift supervisor controlling the turnover. Plant conditions and evolutions in progress were discussed with all members of the crew. The information exchanged was accurate. During attendance at daily planning meetings the inspector noted discussions were held which identified maintenance and surveillance activities in progress. The inspectors conducted periodic plant tours in the primary auxiliary building, turbine building, and intake structures. The inspectors noted plant housekeeping was satisfactory.

2.2 Plant Shutdown - Unusual Event

With the plant operating at 100% full power on February 12, plant workers prepared two welds in the service water system for ultrasonic (UT) examination. The UT exam was planned to better characterize degradation caused by corrosion in two welds in the service water supply piping to the emergency diesel generators (EDGs). While grinding the crown of weld #22, the weld began to weep through a pin hole sized defect. The leaky weld was on the upstream side of the isolation valve for the 'A' EDG supply header, was not isolable from the main SW header, and thus potentially affected the supply to the 'B' EDG as well. Although the weld still had structural integrity and both supply lines to the diesels were functional, the licensee declared both service water system headers inoperable.

The loss of two service water headers exceeded the minimum requirements for the SW system specified in Technical Specification (TS) 3.7.3. The licensee entered the action statement for TS 3.0.3 at 9:50 a.m. and began a controlled shutdown. An Unusual Event emergency was declared due to a shutdown required by the TS, which required that the plant be placed in Mode 5 (cold shutdown) within 36 hours. The reactor entered Mode 3 (reactor subcritical) at 3:23 p.m. on February 12, and Mode 5 at 6:10 p.m. on February 13, at which time the Unusual Event was terminated.

The resident inspector responded to the plant and observed control room operators implement normal operating procedure (NOP) 2.2-1, "Changing Plant Load." During the plant downpower, the inspector observed steam generator blowdown radiation monitor response, conformance with selected technical specification limiting conditions of operations, emergency

core cooling alignments, offsite power availability and reactor coolant pump seal flow. The inspector observed appropriate controls. The inspector followed the shutdown activities through termination of the event.

The licensee actions to repair the leaky weld and to address degraded piping in the service water system to are described in Section 3.5 of this report. The degraded conditions will be addressed prior to returning the plant to power operation. The inspector identified no inadequacies in the licensee actions to meet the technical specification requirements. The inspector determined the plant operators performed well in completing the orderly plant shutdown.

2.3 Service Water System Stagnant Line Verification and Alignment for Isolation

On February 2, the licensee began a systematic review to identify stagnant lines in the service water (SW) system. This effort was part of the review to identify the scope of the service water system piping and welds potentially degraded by corrosion. The CYAPCo review was performed by a senior reactor operator. The inspector independently reviewed the licensee's service water piping and instrument drawings, normal operating procedure valve line-up and plant walkdowns to verify stagnant lines within the service water system.

The lines identified by the licensee were consistent with the list developed by the inspector. Thirteen areas were identified not including the service water supply to the emergency diesel generators. The areas include both safety and non-safety related portions of the system. The areas were:

- Manual screenwash line from SW pump discharge (North and South headers)
- Diesel Fire Pump discharge to service water pump discharge header
- SW to control room, chemistry lab and office building air conditioning units
- Fire header to turbine lube oil cooler
- Standby lube oil cooler supply and return
- Lube oil cooler Bypass line
- Exciter cooler inlet Kinney Filter Bypass
- Exciter cooler outlet Throttle Valve
- Generator hydrogen cooler outlet bypass
- Waste Liquid Evaporator Overhead Condenser
- Adam Filter Bypass Motor-operated Valves
- Component Cooling Water Stand-by Heat Exchanger
- 'B' Spent Fuel Pit Heat Exchanger inlet and outlet lines

The inspector reviewed CYAPCo's selection criteria and the system alignment necessary for components to be considered stagnant. The inspector found CYAPCo's review was complete and thorough.

2.4 Compensatory Measures for a Postulated Service Water System Line Break

On February 4, CYAPCo made changes to enhance existing procedures, trained operators and pre-staged materials to align fire water to the emergency diesel generators. CYAPCo developed an operability determination for the service water system that accounted for potentially degraded conditions in SW system welds and piping. The operability determination was discussed with the NRC staff on February 3. The operability determination was not rejected by the NRC; however, some questions and concerns were raised by the staff. The compensatory measures were meant to provide alternate means to provide EDG cooling upon loss of the SW headers, and not to compensate for an inoperable SW system.

The inspector verified procedure changes to abnormal operating procedure (AOP) 3.2-5, "Natural Disasters," and AOP 3.2-19, "Loss of Service Water." AOP 3.2-5 was altered to refer operators to AOP 3.2-19 upon a postulated natural disaster. The inspector observed the training of operator crews pursuant to lesson plan CY-OP-LORT-93-5-L93502. The training made the operators aware of the service water pipe degradation, and the actions necessary to isolate and compensate for a postulated failure of the piping.

The inspector verified the licensee actions to pre-stage materials needed to align a supply of cooling water to the emergency diesel generators from the fire water system. This included the placement of three lengths of 50 foot reels of fire hose at the north door for each generator room. The inspector verified that 100 feet of hose was sufficient to reach from the diesel to either of two fire hydrants located in the yard. The inspector verified the presence of tools in a fire hose station needed to complete the connections. The plans included coordination with plant security to assure prompt access to the diesels.

The inspector determined the licensee was thorough in defining the compensatory measures to provide an alternate means of EDG cooling, and the measures were properly implemented.

2.5 Power Reduction Due to Loss of Generator Cooling

During routine operations at full power on January 20, the temperature controller for the generator hydrogen cooler failed at 4:30 p.m. The reactor operators noted increasing temperatures on the generator, and received alarms on "hydrogen hot gas temperature" and "hydrogen stator temperature." The shift supervisor directed the operators to start an immediate plant load reduction and dispatched the nuclear side operator (NSO) to investigate the status of the generator cooling.

The NSO determined that service water temperature control valve SW-TCV-1711 had failed to the closed position. The NSO was directed by control room operators to take manual control and to open the TCV. This action was completed to restore cooling to the generator, and once generator temperatures had stabilized, the operators stopped the load reduction at 85% full power. Licensee investigation determined that the temperature controller had failed to 87 degrees (°) Fahrenheit (F), which provided a false indication that the generator was overcooled,

causing the TCV to go to the closed position. After assuring generator cooling was stable in manual control, plant operators began a power increase at 4:45 p.m. to return the plant to full power operation. The temperature control valve was left in manual, a trouble report was written to effect repairs, and a plant information report was initiated.

The inspector reviewed plant status from the control room and at the hydrogen cooling station in the turbine building. The inspector noted the operator closely monitored the limits in the abnormal operating procedures which require that the turbine be tripped when stator temperature reaches 176° F, and generator differential temperature reaches 14.4° F. The temperatures reached during the transient were 172° F and 11.8° F, respectively. The inspector determined the plant operators performed very well, and in a timely fashion, in responding to the degraded cooling conditions. The inspector had no further comments in this area.

2.6 Shutdown Operations

The inspector reviewed plant operations during the load reduction on February 12 and after the plant was placed in cold shutdown. The review included the licensee actions to minimize shutdown risk. The shutdown risk assessment was completed for the service water (SW) outage schedule, once the full work scope was established. The licensee established controls for key safety functions (decay heat removal, reactor inventory, power availability, reactivity control, containment and support systems) and set up a status board in the control room to track changes to in service equipment. The status of essential equipment was summarized in the daily "plan of the day" for consideration by plant management and staff during the planning meetings. Contingency plans were established in the emergency and abnormal operating procedures.

The outage occurred because the licensee declared both service water headers inoperable due to corrosion induced degradation. The inoperable service water system impacted the operability of the diesel generators, which rely on the SW system for cooling. The emergency diesel generators were considered functional (when the associated SW headers were in service), but not "technical specification operable". SW headers were removed from service sequentially to allow for pipe inspections and replacement. The licensee's shutdown risk controls included assurance that the alternate diesel was functional and unaffected by the construction activities whenever one diesel was out of service for the pipe replacement. The licensee assured that at least three class 1E power supplies (one diesel plus two off site lines) were operable at all times. In addition, the licensee obtained a portable, trailer mounted air cooled diesel. The temporary diesel was set up at the site and made available to the operators to power shutdown cooling loads.

The inspector reviewed operator actions to implement shutdown risk controls during daily reviews of plant status and operations. The inspector identified no inadequacies with the licensee's plans. The inspector concluded the licensee's implementation of shutdown risk controls was a strength.

2.7 Charging System Valve Leakage

The inspector reviewed actions by plant operators on February 14 to identify and correct apparent leakage by valves in the charging (CHG) system. Actions were in progress to align the charging and residual heat removal systems to supply cooling water to the reactor coolant pump seals. Seal cooling was being established for shutdown operations in accordance with NOP 2.6-1A, "Mode 5 or Mode 6 RCP Seal Water Supply." The operators noted an unexpected increase in the level in the volume control tank (VCT), which was not in the valve lineup boundary for the intended seal cooling. The leak rate was determined to be about 5 gallons per minute. The leak was secured by closing CHG system valves 276 and 267, while investigations continued.

Subsequent investigations determined that charging valve CH-TV-334 was not fully closed even though it was in the closed position. The trip valve was a boundary valve in the lineup to establish seal cooling. Leakage past this valve on February 14 would allow seal injection water to enter the VCT. As corrective action, a work order was implemented to exercise and reset the stroke for the valve. The valve was satisfactorily leak tested following the repair. Seal cooling for shutdown operations was subsequently established without further problems.

The work control supervisor (a licensed senior reactor operator) initiated plant information report (PIR) 94-025 for this issue due to a plant safety issue identified by his review of the as found charging system conditions. The supervisor demonstrated good integrated system knowledge by recognizing that the charging system boundary valve leakage had implications when plant emergency systems were aligned to the sump recirculation mode in the post accident condition. The same charging system boundary valve leakage would exist while implementing emergency procedures ES-1.3, "Transfer to Sump Recirculation," and ES-1.4, "Transfer to Two Path Recirculation," following a postulated loss of coolant accident. The inspector noted the leak path would be isolable in the post accident mode.

Licensee review of this issue was in progress at the end of the inspection period. The PIR was assigned to plant engineering to evaluate the issue and recommend follow up actions. The inspector had no further comment on this matter at the present time. Licensee actions on PIRs are reviewed during routine inspection of plant operations.

3.0 MAINTENANCE (61726 and 62703)

3.1 Maintenance Observations

The inspectors observed various corrective and preventive maintenance activities for compliance with procedures, plant technical specifications, and applicable codes and standards. The inspectors also verified appropriate quality services division (QSD) involvement, appropriate use of safety tags, proper equipment alignment and use of jumpers, adequate radiological and fire prevention controls, appropriate personnel qualifications, and adequate post-maintenance testing. Portions of activities that were reviewed included:

- AWO 94-0969, Investigate EG2B Supply Pipe Welds
- AWO 94-0077, Replace Pipe Elbow in EG2B Supply Line
- AWO 94-0065, Replace 'A' AFW Pump Hydraulic Hose
- AWO 94-0071, Replace 'A' AFW Pump Discharge Relief Valve
- AWO 94-0089, Hydrostatic Test of Service Water Piping

The inspector did not identify any deficiencies with the observed maintenance activities.

3.1.1 Failure of the Pressurizer Power Operated Relief Valves

On February 19, during cold shutdown plant conditions, CYAPCo identified that both pressurizer power operated relief valves (PORVs) failed to fully stroke open during scheduled surveillance testing. Surveillance test SUR 5.7-112, "Inservice Testing of Power Operated Relief Valves PR-AOV-568 and PR-AOV-570 and associated SOV's," is written to demonstrate operability each cold shutdown of valve opening times for valves PR-AOV-568 and PR-AOV-570. Both valves opened to approximately 50% during the surveillance.

Upon discovery of the failures, CYAPCo reported the event to the NRC pursuant to 10 CFR 50.72(b)(2)(iii)(D) as a condition that alone could have prevented the fulfillment of the safety function of systems necessary to mitigate the consequences of an accident. The valves are credited in the emergency operating procedures as an alternate means to cooldown the reactor coolant system (feed and bleed mode) following a postulated steam generator tube rupture, and as a flow path in the alternate heat sink function for certain post accident conditions. The PORVs are not relied upon in the present plant mode (cold shutdown). Another set of spring loaded relief valves are used for the LTOP function while in cold shutdown.

SUR 5.7-112 implements the technical specifications surveillance requirements 4.0.5, 4.4.4.1, and 4.4.4.6. During the surveillance, each PORV is stroked through one complete cycle of travel, the air and control power is manually transferred from the normal to the emergency power and air supplies, and the valves are operated through another complete cycle of travel. The valve's design basis and technical specification basis is to open within 15 seconds, and to close within 2 seconds. The in-service test acceptance criteria opening time varies between 1.8 to 7.0 seconds depending on the valve; each valve is required to close in less than 2 seconds.

System Description

The primary purpose of the pressurizer PORVs is to limit reactor coolant system pressure to below the pressurizer safety valve setpoint, thus limiting the operating frequency of the safety valves. The control room operators have the ability to open either PORV manually to establish a "bleed" path for use in the "feed-and-bleed" method of core cooling. The inspector noted in emergency operating procedure E-0, "Reactor Trip or Safety Injection," step 15 that if secondary heat removal is inadequate due to insufficient auxiliary feedwater flow, operators are directed

to functional recovery procedure FR-H.1. This procedure discusses the use of the PORV's as a method for core cooling. The PORV's may also be used to reduce reactor coolant system pressure during a postulated steam generator tube rupture.

The pressurizer PORVs receive an air supply from the containment control air system and an air accumulator. The 107 gallon emergency air accumulator supports PORV operation for "feed-and-bleed" core cooling in the event of a failure of both non-safety related containment air compressors. The air supply lines which lead to the PORVs are each provided with a pressure regulator (CA-PRV-836A & B). The regulators reduce the air pressure supplied from the containment air system at a nominal pressure of 120 psig to 85 psig. An air relief valve (CA-RV-838A & B) is provided on each PORV operator to protect it from overpressurization in the event that the regulator fails open. The relief valves are set to open at 100 psig (maximum design operating pressure of the PORV diaphragms).

The feed-and-bleed method of core heat removal is important in the Haddam Neck probabilistic risk assessment (PRA) core melt frequency goal and is credited as an available safe shutdown method for loss of main and auxiliary feedwater, high-energy pipe breaks, internally generated missiles, and tornado missile/wind protection. The design of the PORV's is to remain operable for thirty hours, with a total of four valve strokes during feed-and-bleed scenarios.

Maintenance History

The inspector reviewed the past performance of the PORV's and the pressure regulators (CA-PRV-836A & B) based on surveillance results and corrective maintenance activities. During the past refueling outage (June 1993), both PORV diaphragms and covers were replaced. The diaphragms were replaced because of a valve surveillance failure, and due to the required preventive maintenance frequency. The replacement was controlled under replacement item evaluation (RIE) form PEG-CYOE-93-0062, which upgraded the operator to allow for a longer time interval between diaphragm replacement. The replacement diaphragms were of different material and bolt hole configuration. The revised diaphragms were developed by the valve vendor (Copes-Vulcan) for model D-100-160 operators. The new material used was ethylene propylene rubber (EPR) versus Buna N. EPR has a 50 degree Fahrenheit higher temperature limit. The replacement diaphragm has a twenty-four hole configuration versus the twelve hole configuration in the original diaphragm.

The diaphragms had been replaced prior to June, 1993 for both PORV's. In 1991, the PORV (PR-AOV-568) diaphragm was replaced due to air leakage around the valve shaft, and the PR-AOV-570 diaphragm was replaced after air leak around the diaphragm was identified during surveillance testing.

The two pressure regulators PRV-836A & B have had various corrective maintenance activities during the last four years. Valves PRV-836A & B were replaced in June, 1993 primarily due to water intrusion from the containment air system. The event was documented by CYAPCo in licensee event report (LER) 93-007-00. Between 1990 and 1992, corrective maintenance

activities involved repairing air leakage around the regulator identified by the failure of the pressure decay test during technical specification surveillance SUR 5.7-98, "Inservice Testing of Containment Control Air Supply Check Valves to PORV's and PORV Air Receiver."

The CYAPCo department responsible for the pressure regulators (PRV-836A & B) has initiated a preventive maintenance request since 1986 to replace the regulators every refueling outage. However, the regulators were not changed between 1986 and 1993 even though an active purchase order (277937) existed, because the regulator vendor (Conoflow) was unable, until recently, to satisfactorily pass the required pressure test to show conformance with Grinnel report No. 3412 for the regulators.

The inspector noted a CYAPCo engineer recommendation in early 1992 to develop a project assignment to reevaluate the PORV air system design basis, and to recommend modifications to increase the maintainability of the system. The recommendation was based on the failure to procure a replacement air regulator within a reasonable time frame, and the restrictive technical specification limit of 0.3 psi/hour leakage from the air accumulator to PORV's.

Corrective Actions

CYAPCo initiated authorized work orders (AWO's) CY 9401631 and 940164 to troubleshoot the failure of the PORV's. CYAPCo's troubleshooting activities identified various deficiencies in the air supply to the PORV's. The deficiencies included air leakage between the diaphragm and the cover assembly, loose cover assembly capscrews, pressure regulators (PRV-836A and B) low "as-found" setpoints, and small radial cracks in both PORV diaphragms. At the end of the inspection period, the licensee was reviewing the failures to determine the root cause of the air leakage from the PORV diaphragms. Additionally, the Unit Director assigned the engineering department a significant unresolved issue to evaluate the PORV air system and propose upgrades. The recommendations from engineering were to be developed by May, 1994.

Based on the failures on February 19, CYAPCo changed procedure PMP 9.5-264, "PR-AOV-568 & 570 Pressurizer Power Operated Relief Valve Maintenance," in the section involving valve diaphragm replacement. The basis of the changes were to provide better controls on seating and forming the diaphragm in the operator during replacements. The revision added cleaning the sealing surface of the cover and actuator base, application of permatex aviation form-A gasket around the bolt circle on both sides of the diaphragm, and application of loctite 242 to the case capscrews and nuts. The procedure revision also changed the torque value of the capscrews from 24 +/-2 ft-lbs to 25 +/-1 ft-lb. The inspector verified the incorporation of the changes, and discussed the basis of the changes with maintenance personnel and the system engineer.

Summary

The inspector noted from the maintenance history for the PORVs that system air leakages and subsequent surveillances failures have existed. The licensee has implemented hardware and procedure changes to PMP 9.5-264 to provide better maintenance controls to properly seat the diaphragm. CYAPCo recognizes the need to review the PORV air system design. The issuance of a significant unresolved issue, and a proposed project assignment to address this area is appropriate.

The inspector considers the root cause of the surveillance failure and resolution of the air supply problems as an unresolved issue. This item is unresolved pending issuance of the licensee event report by the licensee and subsequent review of the operability determination by the NRC. Actions to resolve this problem prior to entering a plant operating mode that requires the PORVs be operable will be reviewed during a subsequent routine resident inspection **(UNR 94-03-01)**.

3.2 Surveillance Observations

The inspectors witnessed selected surveillance tests to determine whether: frequency and action statement requirements were satisfied; necessary equipment tagging was performed; test instrumentation was in calibration and properly used; testing was performed by qualified personnel; and, test results satisfied acceptance criteria or were properly dispositioned. Portions of activities associated with the following procedures were reviewed:

ENG 1.7-4, Inservice Testing of Emergency Diesel Generator Heat Exchangers

On February 8, the inspector observed the performance of ENG 1.7-4, "Inservice Testing of Emergency Diesel Generator Heat Exchangers," by a nuclear system operator (NSO). The objective of the test was to obtain the hydraulic resistance of the service water to both emergency diesel generator jacket water heat exchangers. The test frequency is weekly. The inspector observed good procedural adherence by the NSO; the hydraulic resistance data was acceptable. The inspector independently calculated the hydraulic resistance which was consistent to that of the CYAPCo system engineer calculations.

SUR 5.7-148B, A and B Service Water Pumps Substantial Flow Test

On February 15, 1994, with the plant in cold shutdown, the licensee completed a substantial flow test for the 'A' and 'B' service water (SW) pumps in accordance with SUR 5.7-148B, Revision 3. During the test, the total dynamic head (TDH) for pump 'A' was in excess of the required action acceptance criteria. In addition, the TDH for all other curve points was higher than the baseline curve generated on July 11, 1993.

The licensee was unable to identify the specific root cause for the excessive TDH. The licensee suspects that the installation of new pump discharge check valves and service water piping has decreased system resistance, resulting in the higher pump hydraulic performance.

The licensee performed an engineering evaluation of the pump's performance and determined that the pumps have undergone no degradation and, therefore, are acceptable for all modes of operation. The inspector reviewed the engineering evaluation and was satisfied with the licensee's conclusion.

SUR 5.1-12, Main Steam Line Isolation Valve Trip Valve Test

On January 26, the inspector observed operators perform SUR 5.1-12, "Main Steam Line Isolation Trip Valve Test," for valve MS-TV-1211-3. The surveillance test, which partially strokes the main steam trip valve, was performed as post-maintenance testing following adjustment of the valve's "live-load" packing. The inspector questioned the acceptability of the use of mechanical bars in the valve yoke casing during the surveillance. The mechanical bars prevent the main steam trip valve from closing in the event of a test solenoid failure. The surveillance test was successful. This is an inspector follow-up item **(IFI 93-04-02)**.

3.3 Main Steam Safety Relief Valve Testing

The inspector reviewed CYAPCo plans to test the main steam safety relief valves during power operation, and the surveillance test results obtained during the plant shutdown.

On January 20 during power operations, CYAPCo initiated plant information report (PIR) 94-011 that documented a test failure of the "active" pilot valve for main steam safety relief valve MS-SV-14 at the vendor facility. Prior to disassembly of the safety relief valve for investigation of the root cause of a previous body-to-bonnet leakage, the vendor placed the valve on a boiler for preliminary testing. The testing included verifying leakage from the gasket area and measuring pressure to the unloader, as well as setpoint testing of the pilot valves. The vendor (Anderson Greenwood) identified that the setpoint of the safety valve was at 1430 psig instead of the required 1034 psig +/-3%. The valve tested by the vendor had been removed from the main steam system during a November, 1993 plant shutdown (reference inspection report 50-213/93-21).

The main steam safety valves are operated with two pilot valves that control the pressure in the valve unloader. The safety valve operates when differential pressure across the unloader reaches a set value. One of the two pilot valves is considered "active" in that it is valved in to sense steam inlet pressure. The other pilot valve is considered "inactive" in that it is isolated from the steam inlet to the safety relief valve. The setpoint of the safety valve is directly related to the setpoint pressure of the pilot valve. The relief valve function is provided by a solenoid valve that bypasses the pilot valve to allow for remote operation.

The vendor disassembled the failed pilot valve and identified oxide build-up on the disc. The pilot valve spindle and guide showed smooth travel and no signs of foreign material or deposits. The vendor recommended to the licensee, that the installed valves be tested, first with the "inactive" pilot valves, then transfer to the "active" pilots to verify the "as-found" setpoints.

CYAPCo did not declare the installed safety relief valves inoperable. The basis of operability was that no specific cause of failure in the pilot valve was evident, and the valve that failed was no longer in service. Nonetheless, the licensee initiated a plan to test the main steam line safety relief valves during power operation to acquire additional information. The valves installed in the main steam system had successfully passed the setpoint surveillance during the last refueling outage in July, 1993.

The licensee developed a draft special test (ST) 11.7-135, "Special Setpoint Testing for Main Steam Safety Relief Valves MS-SV-14, 24, 34, and 44," that allowed for testing of the two pilot valve setpoints during power operation. The inspector discussed with CYAPCo the prudency of performing the surveillance at power, and the potential consequences if a safety relief valve were to inadverfently open during testing of the pilot valves. The inspector performed a field walkdown of the special test, and reviewed the consequences of an excessive steam demand event as documented in the Updated Final Safety Analysis Report Chapter 15. The inspector reviewed the emergency operating procedure actions, and the results of CYAPCo's simulator test of the plant response following a postulated failure of the safety relief valve (with and without a manual reactor trip). The inspector reviewed the expected actions in the emergency plan implementing procedures on emergency classifications, and reviewed "critical" procedure steps in ST 11.7-35. Critical steps were those action steps where a human error could result in the safety relief valve opening. The inspector identified no inadequacies in the proposed test method. Subsequently, CYAPCo decided to not perform the pilot setpoint verification during power operations because, even though the test method provided assurance the test could be done safely, the consequences of opening a valve at power were deemed unacceptable.

On February 12, the licensee commenced a plant shutdown to a cold shutdown condition to repair the service water system piping (see report detail 2.2.). On February 15, during a cold shutdown condition, CYAPCo initiated the performance of surveillance procedure SUR 5.5-69, "MS-SV-14, 24, 34, & 44 Main Steam Safety Valve Surveillance Testing." The testing indicated that the "active" pilot valves for MS-SV-34, 44 and 14 did not lift at a nitrogen pressure of 1,500 psig. The licensee stopped testing of the valves, and initially concluded that the failures were due to low ambient temperatures (approximately 20 degrees Fahrenheit). CYAPCO reperformed SUR 5.5-69 on February 17. The inspector observed the surveillance. The pilot valves sensing lines were warmed by the installation of heat lamps and insulation. All eight pilot valve setpoints were outside the setpoint range of 1034 +/-3% psig. The licensee identified that the test nitrogen pressure indication was out of calibration. The pressure indication was calibrated prior to the start of the surveillance as required by the test; however, due to either cold ambient temperatures, or mishandling of the sensor it was out of calibration approximately 180 to 200 psig.

CYAPCo performed a third test on February 20 using a different test pressure sensor. All pilot valve setpoints were acceptable except for the "active" pilot of MS-SV-34 and the "active" and "inactive" pilot valves for MS-SV-44. CYAPCo reported the surveillance failures as a condition prohibited by technical specifications. At the end of the inspection period, the licensee was

working with the vendor to understand the cause of setpoint variation on the pilot valves. The licensee was reviewing the industry experience with pilot valves, and implementing a root cause investigation.

Summary

CYAPCo reversed an initial decision to test the main steam safety relief valves during power operation. This demonstrated thorough management and engineering review of the technical issue, and reflected a conservative safety ethic. The valves subsequently failed the surveillance during cold shutdown. The root cause of the setpoint failures for the main steam safety relief valves was not conclusive at the end of the inspection period. The inspector will evaluate CYAPCo's proposed actions and implementation, and will review the operability assessment and corrective actions documented in the licensee event report. This item is unresolved pending completion of the above licensee actions and subsequent review by the NRC **(UNR 94-03-03).**

3.4 MCC-5 ABT Testing

The inspector reviewed activities in progress throughout this period to test the automatic bus transfer (ABT) for motor control center 5 (MCC-5). The inspection was initiated following the licensee's report that the MCC-5 failed during a test on February 16. The ABT failure during testing was the second such occurrence in nine months. The ABT failures are safety significant since: MCC-5 is not single failure proof; MCC-5 powers redundant plant valves in the emergency core cooling system; and, the proper operation of MCC-5 is essential to mitigate certain design basis accidents.

Past NRC inspections have described licensee testing of the MCC-5 ABT. The transfer scheme was the focus of a special NRC inspection (reference Reports 50-213/93-80) after it failed a test during the 1993 refueling outage. The inspector witnessed the performance of test PMP 9.5-285, "MCC-5 Supply Breaker X-relay Drop-Out Verification," on November 10, 1993 (reference 50-213/93-21). The November 10 test was the first performance of a surveillance written to implement the new technical specification requirements issued on November 1, 1993 as part of Amendment #169 to the plant license. Technical Specification 3.8.3.1.2 provided a limiting condition for operation for MCC-5 and its ABT and allowed for the test of the ABT with the plant operating at power.

The test of the ABT on November 10 was successful and was repeated periodically with the plant operating at power. The last successful test at power was performed on January 28. The purpose of the test was to assure continued operability of the ABT by de-energizing the 52X relay in the Westinghouse AK-25 breaker supplying power to MCC-5. A schematic of the MCC-5 bus and the ABT logic diagram are enclosed with this report as Figures 1 and 2, respectively. For the tests at power, the normal supply was from 480 volt Bus 5, which fed MCC-5 via breakers 9C on Bus 5. The test plan was to de-energize control power to breaker 9C to drop the 125 Vdc supply to the associated 52X relay. The 125 Vdc power was removed by opening the knife switch in the Bus 5 control power supply cabinet. Once control power was

removed, test personnel verified proper operation of the 52X relay by listening for the drop sound of the moveable core piece, and by visually verifying the that core piece was in the down position. This action occurred satisfactorily when the test was done periodically during operation at power.

ABT Failure - Initial Testing on February 16

On February 16, the ABT was tested in accordance with ST 11.7-126, "Functional Test of the MCC-5 Automatic Bus Transfer." This was the first test of the ABT with the plant in cold shutdown. The transfer scheme was functionally tested by actually de-energizing the associated MCC-5 supply buses, first Bus 5 and then Bus 6, while verifying that the MCC-5 remained energized. Essential plant loads were transferred to alternate power supplies prior to the test of the ABT.

The first test phase was completed on February 16 in accordance with Section 6.1 of ST 11.7-126 with Bus 5 as the preferred source for MCC-5. Bus 5 was deenergized by opening the transformer feeder circuit breaker 4851. The loss of Bus 5 was sensed by the ABT, and the 9C supply breaker from Bus 5 opened as required, and the 11C supply breaker from Bus 6 closed as required. Plant personnel then reenergized Bus 5 by closing breaker 4851. The ABT sensed that Bus 5 was energized, and opened breaker 11C from Bus 6, and then closed breaker 9C from Bus 5, as required. MCC-5 remained energized. Plant personnel reset the associated lockout relays and returned plant loads to the normal configuration.

Upon completion of phase 1, plant personnel began procedure step 6.2 to test the scheme in a transfer from Bus 6 to Bus 5. To set up for the phase 2 test, plant personnel placed selector switch SS43 from position 1 to position 2 at 1:40 a.m. This action should have caused breaker 9C to open, and breaker 11C to close. Breaker 9C did open, but breaker 11C did not close as required. MCC-5 deenergized. After consultation with the control room operators, testing was secured and test personnel were directed to reenergize MCC-5 from Bus 5. Test personnel first placed switch SS43 in position 1; but MCC-5 remained deenergized. MCC-5 was reenergized when test personnel manually closed breaker 9C at Bus 5. Test personnel observed the 52X relay in both the 9C and 11C breakers, and noted that both relays were deenergized, the moveable core pieces were in the "down" position, and the relays were ready for a close signal. Further testing was suspended pending the development of a troubleshooting and test plan to investigate the failure in the "as-found" condition. Since the 52 X relays appeared to have operated correctly, the licensee investigation focused on switch SS43 and on a cell switch as the potential cause of the failure.

Failure Investigation and Subsequent Testing on February 16

The licensee developed a troubleshooting plan in accordance with authorized work order CY 94-01445 to investigate the failure. The troubleshooting plan used instrumentation to monitor contacts in the ABT as the loss of power test per ST 11.7-126 was repeated. The sequence of testing during the evening of February 16 and the results were as follows. After establishing

conditions per ST 11.6-126, test personnel initiated a transfer per Section 6.1 by de-energizing Bus 5 at 7:44 p.m. The ABT failed to transfer MCC-5 to Bus 6. Bus 5 breaker 9C opened as required, but breaker 11C attempted to close and then tripped clear. Test personnel checked the cell switches for both breakers, and then manually reclosed breaker 11C with a hand tool. MCC-5 was energized from Bus 6. After checking the status of monitoring instrumentation and the ABT, Bus 5 was re-energized at 7:47 p.m. The ABT sensed the presence of power on Bus 5 and successfully transferred MCC-5 back to Bus 5.

Since no anomalies were noted in the operation of the ABT, and since breaker 11C was involved in the ABT failures at 1:40 a.m. and 7:44 p.m., the investigation focused on the misoperation of the breaker. Breaker 11C was removed for inspection and a spare breaker (marked 16C) was installed in Bus 6 compartment. The ABT operated properly during subsequent testing on February 16 with the new breaker in Bus 6. Specifically, MCC-5 remained energized when Step 6.1 was performed which caused the ABT to transfer MCC-5 from Bus 5 to Bus 6 and back to Bus 5, in a test sequence starting at 9:00 p.m. At 9:49 p.m., test personnel placed switch SS43 in position 2 to set up for the Bus 6 test. The ABT operated properly at that time. Finally, MCC-5 remained energized when Step 6.2 was performed which caused the ABT to transfer MCC-5 from Bus 6 to Bus 5 and back to Bus 6, in a test sequence starting at 9:50 p.m.

The ABT functioned properly again at 9:51 p.m. when MCC-5 was restored to the normal configuration (energized from Bus 5 with SS43 in position 1). Further investigation was deferred pending the development of additional plans to troubleshoot breaker 11C and to test breaker 16C in the ABT scheme. During the test activities on February 16, the licensee noted and corrected a problem with a loose fuse holder (primary side of fuse B13), which powered the agastat relays used in the ABT. The licensee determined that the fuse holder problem could not have caused the noted ABT failures. The inspector independently confirmed this conclusion (reference drawing 16103-31035, Sheet 6).

Visual Inspection of Breaker on February 19, 1994

Breakers 9C and 11C are Westinghouse Model DB-25 air circuit breakers. Figures 3 through 5 show the relevant features of the DB-25 design details. The licensee conducted visual inspections of the breaker 11C components on February 19. Covers to the auxiliary switches were removed and the auxiliary switch wiring and contacts were visually inspected. No abnormalities were identified during the visual examination of the auxiliary switches. The amptector (overcurrent device) and the cover to the closing/trip linkage was removed. During a visual inspection of the linkage, the licensee identified that the snap ring on the manual closing linkage was not properly located in the snap ring slot (see Figure 5). The snap ring was back away from the slot, toward the manual closing handle, approximately 1 to 1 1/2 inches. This allowed the manual breaker closing linkage to protrude into the closing/trip linkage.

The manual breaker closing linkage interfered with the breaker trip linkage due to the improper position of the snap ring. The licensee was able to demonstrate that a slight rotation of the manual closing linkage tripped the breaker. The licensee then protracted the manual linkage to

it's normal position and bench tested the breaker by providing a dc power to the breaker from a test source. The breaker operated 2 times satisfactorily and then tripped free and failed to close on the third attempt. This test was repeated and the breaker again failed on the third attempt. The snap ring being improperly located would cause the 11C breaker to have intermittent failures. Vibrations of the breaker would cause the trip to occur at times and not to occur at other times. This condition would result in intermittent failures of the MCC-5 ABT. The ability to manually close the breaker using the manual close handle would not be impaired by the mislocation of the snap ring. The operation of the breaker using the handle would tend to retract the manual linkage when the handle is removed, which would allow the breaker to successfully operate during the subsequent few cycles.

Based on the presence of dust on the lubrication on the manual close linkage, it appears that the snap ring was mispositioned for quite some time. There was no apparent recent scrapping of lubricant off the linkage. It does not appear that if the snap ring was properly placed in the groove that the snap ring could jump out of the groove. The Westinghouse engineer stated that the snap rings are sometimes removed to facilitate lubrication of the breaker linkage. The licensee's PM procedure did not remove the snap ring or inspect for the proper location of the snap ring. The inspector concluded that the snap ring was most likely mispositioned during past breaker assembly or maintenance. The licensee is revising the PM procedure to address the snap ring. The licensee conducted visual inspections to verify that the snap rings in other breaker are properly installed. This inspection was done without disturbing the installed breakers by visual examination and the use of a "rod" to verify the location of the snap ring. The inspector independently confirmed the proper placement of snap rings by examining a randomly selected sample of 27 of 48 breakers in the 480 bus sections.

Evaluation of the February 16 Test Failures

The first failure occurred (1:40 a.m. on February 16) when the licensee selected position 2 on the preferred bus selector switch. Breaker 9C opened and 11C failed to close. If this mechanism were the cause of the failure, the breaker would always attempt to close and then trip open. The licensee personnel located at the breaker stated that they did not hear any motion of the 11C breaker. However, at the time of this failure the licensee had just tested the ABT and did not believe their was a problem with the ABT. Therefore, the maintenance staff located in the area of the ABT may not have heard 11C tripping free. It would also have been difficult to here breaker 11C trip free when breaker 9C was tripping in the same area. If the manual breaker close mechanism were to interfere with the trip linkage the breaker would not have closed. This failure mechanism would explain the events that occurred.

The second failure of breaker 11C occurred when Bus 5 was deenergized (7:44 p.m. on February 16). At this time breaker 9C properly opened and breaker 11C failed to close. During this test, maintenance staff were specifically focused on observing breakers 9C and 11C operation and heard breaker 11C momentarily closing and then opening. The operators then locally closed breaker 11C. When power was restored to Bus 5, by closing breaker 4851, the ABT automatically swapped back to Bus 5 by closing breaker 9C. The breaker close latch

problem would also explain this sequence of events. When Bus 5 was deenergized breaker 11C tripped free. The bus selector was in position 1 and when power was restored to Bus 5 the ABT swapped back and breaker 9C closed. The events can be directly attributed to the 11C breaker in the trip free condition. The manual close linkage snap ring being dislocated would cause this condition to occur.

The failure observed in June 1993 may also be attributed to this failure mechanism. This test was a 6-5-6 MCC-5 transfer sequence. Bus 6 was the preferred source of power for MCC-5. When Bus 6 was deenergized the ABT swapped to Bus 5 but did not swap back to Bus 6 when power was restored to Bus 6 by the diesel generator. Again a trip free condition by breaker 11C would cause this to occur. Following the ABT failure the operator changed the position selector switch to position 1. The swap to Bus 5 did not occur because the 52X relay was never deenergized. The licensee conducted bench tests to verify that the momentary closing of the 11C breaker in the trip free condition does not rotate the auxiliary switch and close the 52/b auxiliary contacts. The 9C breaker was then manually closed.

Prior to the June 27, 1993 failure during the 6-5-6 test sequence, the ABT initially operated properly in a 5-6-5 test sequence on June 26. Both the June 26 and the June 27 tests were performed with the ABT MCC-5 in the "as-found" condition. This test history demonstrates that the failure mechanism is intermittent, and allows for successful ABT operation. This test history also suggests that the maintenance that resulted in the mispositioned snap ring most likely occurred some time prior to the 1993 outage.

Further Test and Repair Plans

The licensee initiated plans on February 19, to proceed with testing of the ABT. The test would be contingent upon the installation of a jumper that will provide power to MCC-5 via a source other than breakers 9C and 11C. This would allow test personnel to conduct repeated tests of the ABT without disrupting power to MCC-5. It would also provide additional time to troubleshoot the ABT if a failure were to occur. The jumper development and approval took 2 days to complete. The licensee removed the close/trip mechanism from breaker 11C. A new close/trip mechanism was installed. The licensee plans to use the rebuilt breaker as a spare. The rebuild of the breaker was a precautionary measure. The licensee conservatively chose to install a new trip/close mechanism rather than just returning the snap ring to the appropriate position.

Safety Impact

The proper operation of MCC-5 is important to assure the reliable power to redundant valves in the low pressure safety injection and high pressure safety injection systems. These engineered safety system valves are credited to operate for postulated loss of reactor coolant accidents that occur with the plant operating at full power, and assuming the concurrent loss of normal power for the plant. Since the plant was in Mode 5 (cold shutdown) at the time of the test, the impact of the ABT failure on actual plant safety was minimal.

Based on the test and troubleshooting sequence detailed above, and the successful test history per PMP 9.5-285 during the latter part of 1993 and the tests on February 16, the inspector concluded that the MCC-5 ABT would have operated at least once in the as-found condition. Thus, the ABT was operable if called upon during the period of plant operation from July 1993 (plant startup) until February 1994 (plant shutdown). However, the ABT was unreliable due to the intermittent failure mechanism. The licensee determined this issue is reportable to the NRC and intends to submit a licensee event report (LER). The licensee concluded the loss of redundancy in the ABT constituted operation in a condition not allowed by the technical specifications. The operability issue will be reviewed further by the NRC upon completion of the licensee's formal root cause analysis of the failure.

Findings

The inspector determined that CYAPCo staff performed well investigating the ABT failure during this period. The actions to inspect and investigate Breaker 11C were very good. The inspector observed good coordination and cooperation between operations, maintenance and testing personnel. The root cause investigation started on February 18 was thorough. The support by the site engineering and design engineering groups was good. The inspector observed good performance regarding procedure controls, including the activities to test the ABT, install the bypass jumper; and to implement the troubleshooting plan.

NRC review of licensee activities for this issue were in progress at the end of the inspection period. This item is considered open pending: completion and NRC review of the operability determination; completion of formal root cause investigation; review of long term actions to address the root cause; completion of actions to report the issue; and, completion of the ABT modifications and acceptance testing **(UNR 94-03-03)**.

3.5 Examination and Replacement of Service Water Piping

History

In May 1993 with the plant shutdown for a refueling outage, the licensee replaced a defective segment of service water (SW) pipe in the supply line to the 'B' emergency diesel generator (EDG). The defect was initially identified by through wall leaks in a weld, and was characterized as localized (refer to NRC Inspection Report 50-213/93-03, Detail 4.2). Actions were completed during the outage to replace the pipe containing the degraded weld. Two welds on either side of the degraded weld were also replaced with the section of pipe. The adjacent welds were destroyed during the replacement process and were not available for subsequent evaluation. After removing an extensive coating of macrofouling (tubercles), subsequent examination by site personnel identified apparent lack of weld penetration (LOP) and extensive corrosion over the full inside diameter (ID) circumference of the weld that leaked. A similar section of pipe in the supply to the 'A' EDG was also replaced due to similarities in geometry and conditions. The similar weld in the 'A' header also showed extensive degradation. The

samples of degraded welds from both headers were sent to the Berlin materials laboratory to evaluate the root cause of the condition. The root cause evaluation proceeded in parallel with actions on site to complete the outage and to restart the plant.

The materials laboratory provided the results of its evaluation in a memorandum (CTS-93-754) to site engineering dated June 21, 1993. The laboratory could not perform a complete analysis because the samples had been disturbed (i.e., the tubercles were removed along with scale and deposits), to expose the degraded weld. The laboratory evaluation concluded that extensive degradation existed in a crevice running on the inside diameter of the weld. The defect was enhanced by the original poor quality weld (concavity and ID mismatch), and was accentuated by corrosion. The pits and "worm holes" in the defects were characteristic of microbiologically influenced corrosion (MIC). Although the corrosion had the characteristics of MIC, live samples would be required to prove this potential root cause conclusively. Cultures of the welds necessary to positively identify MIC as the corrosion mechanism were not obtained with the May 1993 sample, because MIC was not a suspected failure mechanism. The laboratory recommended that future samples be submitted immediately after removal with all deposits intact to confirm the influence of MIC.

An engineering evaluation was completed in the summer of 1993 to assess the structural integrity of the degraded joint, and assuming that flaws similar to the weld removed from the system flawed welds existed in other locations of the SW system. This evaluation concluded that the pipe would be able to withstand design stresses, including seismic loads. The SW lines (and EDGs) were considered operable and actions were initiated to assess the condition of the remaining welds in the supply pipe to the EDGs where MIC could develop. The structural assessment was formally provided in a NUSCo memorandum (DECY-94-502) to CY engineering dated January 5, 1994.

Due to limitations in the ability to fully characterize the defects by ultrasonic (UT) and radiographic (RT) examination, the licensee made plans to cut out an elbow in the supply line to the 'B' EDG to allow full non-destructive and destructive examination of two welds contained in the sample. The actions to replace the elbow in the 'B' EDG header were completed within a 72 hour action statement for the diesel on January 25-27, 1994. The plans were to RT the samples removed from the system on the as-found condition, and in this manner "benchmark" the RT process for future examination of other welds in the SW system while the plant was on-line and the SW system was in service. A conceptual design change was drafted and piping material was procured in advance of the January EDG outage in anticipation of the need to shutdown the plant to replace SW piping, if that action was indicated by an evaluation of the welds in the elbow sample.

NRC inspection of this topic began with a review of the elbow replacement work within this inspection period. A chronology of licensee activities regarding the service water corrosion issue was developed during this inspection period as described above; additional details are provided in Attachment A to this inspection report. The CYAPCo actions developed over the Fall of 1993 under the presumption of continued operability of the SW system.

Scope

The scope of the NRC inspections for this topic during this period included reviews by the resident inspector, and on February 8 and 9, the reviews by the Chief, Materials Section, and the Acting Deputy Director of the Division of Reactor Safety, NRC Region I. In addition, numerous phone conversations and telephone conferences between the NRC staff and the licensee occurred as necessary to understand the licensee's position and to solicit commitments for supplemental actions.

The inspection included reviews of: the actions to replace the elbow in the supply line to the 'B' EDG; the actions to complete full non-destructive and destructive examination of the pipe samples; the engineering and NU Materials Laboratory evaluations of the pipe samples removed in May 1993 and January 1994, and of the cause(s) for the accelerated corrosion evident in the SW samples; the engineering evaluation of the degraded welds removed from the SW headers in May 1993, including (i) uniform wall thinning analysis and (ii) a fracture mechanics analysis per ASME Section XI, Appendix H; the initial and updated operability evaluation for the SW system and its bases; the NDE (RT, UT & ECT) activities conducted to support the operability evaluations; actions to complete RT examinations of SW piping to identify the presence of severely degraded welds and to bound the scope of the corrosion; chemistry controls to address corrosion; sampling and analysis for MIC; the detailed examination of degraded welds #21 & #12 and #22 in the SW supply to the EDGs, and actions to characterize the defects in these welds; and, the decision to shutdown the plant following the development of a pin hole leak in the 'A' diesel supply line. Following the plant shutdown, the inspector reviewed the continuing actions to inspect and examine SW piping to identify the scope of the corrosion.

Elbow Removal in January 94 and Sample Evaluation

The licensee completed work under AWO 94-0077 on January 25 - 27, 1994, to replace a elbow on line 6"-WS-121-168 in the supply to the 'B' EDG. The work was completed during a scheduled EDG outage, and provided two welds for evaluation for the suspect corrosion. The NRC inspected the replacement activities, the history on the issue, and the condition of the two welds removed from the system. Samples of the pipe corrosion material were obtained and were cultured for MIC. Both welds showed some evidence of degradation and corrosion, but in general were in much better condition than the samples removed in May 1993. In particular, the weld had full penetration over most of the circumference, and showed much less severe corrosion. While the welds showed various indications that require dispositioning (including porosity, surface indications, pits and undercut), the indications were characterized as not significant enough to jeopardize the integrity of the joint.

The results of the MIC cultures were provided in a NUSCo letter (CES-94-554) dated February 10, 1994, based on work performed by an independent vendor (Thomas M. Laronge, Inc). The samples were cultured for sulfur reducing bacteria (SRB), acid-producing bacteria (APB), general anaerobic bacteria, and general aerobic bacteria. Very little growth was seen after 14 days of growth for APBs, aerobic bacteria and anaerobic bacteria. SRB was present, but a

minimum detectable levels. Due to the sometimes slow growth periods, plans were set to measure the cultures after 30 days. Examination of the pipe wall found evidence of conditions typical of oxygen concentration cell corrosion (OCCC).

Second Operability Assessment

The NRC review in January 1994 of the licensee's initial operability assessment identified no inadequacies in its conclusions, within the limits of the methodology used. Subsequent NRC review on February 2, noted that the assessment was based on the stresses attendant with uniform wall thinning, and that this method might not be conservative when the stress risers associated with the lack of weld penetration (LOP), pits and "worm holes" were considered.

The licensee completed a more detailed analysis assuming the combination of LOP/MIC corrosion was a "crack", using the fracture mechanics analysis (FMA) of the ASME Code, Section XI, IWB 3650 and Appendix H. The analysis was documented in NUSCo Calculation CY-LOE-1014-MY, and showed with as little as 0.095 mils remaining in the degraded pipe samples (nominal wall thickness for new pipe was 0.280 inches), the pipe was capable of withstanding the stresses attendant to normal and faulted conditions, including seismic loading. The NRC staff discussed the results of the fracture mechanics analysis on February 3, which showed the piping system was still operable if defects of the type removed were still in the system. An advanced copy of the calculation was provided to the NRC staff on February 4. The NRC performed the same analysis using the licensee's data for input, and arrived at the same conclusion. The licensee chose 100 mils as the acceptance limit for defects to assure a degraded weld was bounded by the FMA.

The licensee initiated a program to radiograph (RT) as many welds in both service water headers that are accessible. Based on NRC questioning, the licensee revised the RT planned schedule so that the RTs would be done as expeditiously as possible and with a quality sufficient only to identify the gross "lack of penetration" obvious in the first samples. All accessible welds would be examined in this manner, and defects would be further characterized as necessary for comparison with the bounding defect analyzed in the operability assessment. For any one weld found to constitute an inoperable condition, the licensee intended to declare both service water headers inoperable and shut the plant down in accordance with the technical specifications.

The licensee instituted compensatory measures starting on February 4 to enhance existing procedures and operator training for responding to earthquakes and a complete loss of service water. The compensatory actions included pre-staging materials needed to align a supply of EDG cooling water from the fire water system. The compensatory measures were meant to provide alternate means to provide EDG cooling, and not to compensate for an inoperable SW system. The inspector reviewed the revised procedures, witnessed the operator training, and walked down the staged equipment. No inadequacies were identified.

The licensee committed on February 3 to submit on the docket the results of his examinations, and would include a description of his long term plans, including his considerations to replace affected portions of the SW system, a program to monitor the MIC corroded piping until replacement, and a program to address MIC. Once the RTs of the welds in the SW piping to the EDGs were completed, the licensee planned to evaluate other susceptible lines in the SW system. The initial plans included the performance of ultrasonic examination of susceptible pipe for corrosion. This information was subsequently provided to the NRC in letter (B14755) dated February 22, 1994. Calculation CY-LOE-1014-MY was included with the submittal.

Although the NRC staff did not reject CYAPCO's operability decision, the staff expressed concerns regarding the status of the remaining pipe and the potential for the presence of defects that were worst than those identified. While the licensee planned initially to perform RT examination of the piping by April, 1994, based on NRC concerns, that schedule was advanced to begin the exams as soon and the work could be organized. The licensee chose to remove the pipe insulation to enhance the quality of the RT results. The RTs were taken with water in the process lines.

Examination of Additional Service Water System Welds

During the period from February 3 - 5, RTs were completed for 19 welds in the SW supply to the EDGs, and on 6 welds in the SW supply to the travelling screenwash system at the intake structure. Three other welds (for a total of 22 accessible welds in the EDG supply piping) were not RT'd because of structural interferences. The inspector reviewed a sampling of the RTs for the entire set of welds to verify the overall characterization of the findings. The completed NDE exam sheets accurately reflected the indications present in the RT films.

The welds at the intake structure had backing rings. None of the welds in the screenhouse showed the LOP/MIC type indications that are of concern. Those welds did have indications that require dispositioning, including porosity, surface indications, concavity, and slag. This evaluation continued during the week of February 7. The welds in the EDG supply piping also showed various indications that require dispositioning, including porosity, surface indications, concavity, pits, lack of fusion, lack of penetration, corrosion, erosion, burn through, undercut, and slag. The indications for sixteen (16) of the 19 EDG supply line welds were characterized as not significant degradation, and did not jeopardize the integrity of the joint. Thus, most welds were similar to the overall quality of the SW pipe segment taken out of the 'B' EDG supply line on January 25.

Three of the remaining EDG welds had indications that resemble the LOP/MIC indications observed on the weld removed in May 1993. The welds were #22 on the 'A' EDG header, and #21 and #12 on the 'B' EDG header. The welds locations were as follows (See Figure 6): Weld # 21 - 'B' EDG supply, first "old" weld downstream of main SW header and just upstream of the first header isolation valve V-146B; Weld # 12 - 'B' EDG supply, second "old" weld-

downstream of main SW header and just downstream of the header isolation valve V-146B; and, Weld # 22 - 'A' EDG supply, first "old" weld downstream of main SW header and just upstream of the first header isolation valve V-144A.

Summary of RT Results For the Three Worst Welds

The inspector reviewed the NDE results for the three welds in detail. Weld #21 showed lack of fusion over 6 inches in 3 of 4 sectors of the weld, plus localized areas of concavity, porosity and voids. The vendor remarked the weld showed possible MIC. The indication follows the root pass around the circumference and was mostly narrow - showing MIC irregularities along the surface of the base material. Weld #22 showed LOP/MIC similar to that on weld #21, but the indication was less severe and did not cover the full extent of the weld. This is consistent with the findings with the May samples in which the weld on the 'A' header show somewhat less severe degradation. For weld #12, the indications were also similar to the weld #21, but the LOP noted in the other welds was not apparent. Instead, the general area of MIC corrosion was broad along the root pass, and covered most of the extent of the weld. Significantly, the area covered by the MIC corrosion appeared to widen from the root toward the toe of the weld. Of concern was whether the MIC was merely staying shallow but reaching into the base metal of the pipe, or travelling up the heat affected zone of the weld, resulting in a partially circumferential defect that was about to break through the surface.

The licensee concluded that the indications required further characterization, but appeared to be bounded by the analysis for the May 1993 sample, because the indications on welds #22 and #12 did not appear to be as deep and did not cover the full extent of the weld. The indications for weld #21 did cover the full extent of the weld and most closely resembled the May sample taken for the 'A' header, in which the MIC had not progressed as deep as on the 'B' header. Still all 3 welds required further characterization to assure the FMA was still bounding.

Initial ECT and UT Evaluations

Welds #12, 21 and 22 were selected for further evaluation using ultrasonic and eddy current (subsurface) examination to better characterize the depth of the defects and to allow for comparison with the bounding defect that was subjected to the fracture mechanics analysis. A calibration standard for ECT was selected using machined blocks and portions of the May 1993 SW pipe samples with circular and groove defects cut into it. After extensive trials to calibrate to a multitude of defects on February 6, the calibration block selected was one containing a defect that was 65% through wall, or had about 0.100 inches of wall material left. This depth corresponded to the wall assumed for the FMA analysis. Thus, any signal on the ECT would represent a defect that was approaching the FMA acceptance criteria thickness. The initial examinations were completed on February 5 - 6.

The UT standards were similarly chosen. The NU examiner chose two probes: (i) a straight beam for shooting down the crown of the weld; and, (ii) a 70 degree 'L' wave probe, which could be used to shoot under the crown of the weld. However, field measurements quickly

revealed that the surface of the weld was too rough to provide a reliable measurement through the crown - there was too much noise. The 'L' probe was effective in shooting under the crown to help investigate indications found by ECT.

For welds #21 and #22, no ECT signals were observed around the circumference of either weld (or the pipe wall - which was randomly sampled near the weld). All areas examined clearly passed the 0.100 inch criteria. For weld #12, the general wall thickness on the crown and on either side of the weld met the 0.100 inch criteria around the entire circumference. There were four highly localized signals (two in sector 2 - 3 and two in sector 3 - 0) where ECT showed some signal below the baseline - indicating the presence of pinholes (worm holes) that might be approaching the 0.100 inch thickness. All four defects were on the toe of the weld (rather than the crown).

Follow up UT exams using the straight and 'L' wave probes to scan the pipe wall confirmed: (i) the apparent lack of indications climbing up the heat affected zone of the weld from the root to the toe; and (ii) generally good pipe wall (mostly >0.200 inches) around the weld. However, the results near the weld were still considered inconclusive due to roughness of the surface of the pipe and the weld crown.

Continuing Operability Assessment on February 9 - 11

The licensee's initial NDE evaluations (RT, UT & ECT) for welds #21, #22, & #12 showed that the degradation caused by LOP/MIC was still bounded by the FMA provided for the May sample. Based on the above, CYAPCo engineering concluded that the SW piping was operable. This conclusion was presented to plant management on February 7 for consideration in developing the action plan to address the SW system welds. The inspector followed the RT, UT and ECT calibrations and the conduct of the examinations. The inspector independently confirmed the conclusions reached by the licensee.

These results were discussed in detail with NRC Region I personnel who visited the site on February 8 and 9 to review the licensees activities. At the time of the reviews on February 9, the final accuracy of the ECT results could not be determined. The licensee continued to refine the ECT measurements by using the May 1993 welds in a standard to correlate the degraded weld conditions against the ECT signal obtained from a calibration standard made from electro-discharge machined notches. To help improve the confidence in the NDE results, the licensee used a segment of the May samples in a mockup of the pipe geometry with water to obtain additional RTs of the flaws.

No additional FMA or stress calculations were performed on February 6. However, the stress analyst noted that the pipe stresses used in the bounding FMA analysis are the worst case stresses found in the headers supplying the EDGs. The highest stresses occur in the locations of the welds removed from the system in May 1993. The stresses at welds #21, #22 and #12 are about 40% to 50% of the stresses used in the bounding analysis. Notwithstanding the above

conclusions, the licensee committed to install clamps on the degraded welds with the intention to use the clamps as a temporary measure to restore margin to the stress load limits. The clamps would be installed on the known degraded welds by February 25.

During reviews of the calculations on February 9, the NRC noted that the licensee intended to refine the analysis further by using dynamic loadings for the piping system, instead of applying the worst case loading at the location of the known defect. It was expected that the results of the refined calculation would be bounded by the preliminary results, and that the operability conclusion would not change. The licensee estimated that the refined calculation would show acceptable results with a little 80 mils of ligament remaining in the pipe wall.

Further NDE was planned to better characterize the defects and to quantify the flaw depths. This plan included the need to prepare the welds for UT examination. The NRC staff discussed the CYAPCo operability determination and on February 11 reviewed the plans to prepare the weld joints for further evaluation. Due to NRC staff concerns regarding the status of the EDG supply piping located underground and not inspectable, the licensee committed on February 11 to replace the untested piping. The pipe would be replaced during an outage scheduled to occur prior to river water temperature exceeding levels necessary to support diesel operability with the temporary fire hoses, or June 15, 1994, whichever occurred first. This commitment was made in a telephone conversation with the NU Executive Vice President.

Weld Preparation - Through Wall Defect

With the plant operating at 100% full power on February 12, plant workers prepared two welds in the service water system for UT examination. The plan was to prep both welds #21 and #22 by grinding the weld either flush with the pipe, or by flattening the crown as necessary to perform a UT examination. The plan was to grind the crowns about 30 to 40 mils in this manner. The amount to be ground and the locations was chosen with consideration from the pipe stress analyst and the RTs to assure the 0.100 inch criteria would be met throughout the process. The plan included grinding both welds over a portion of the circumference in this manner. The piping was marked on February 11 to designate the areas to be ground in areas determined from the RTs to have "good" wall thickness.

On February 12, plant engineering requested that test sites be ground out first in areas where the pipe wall was known to have excess wall thickness, but only over a sector about 2 to 3 inches in length. This approach was chosen to gain confidence in the technique before grinding a large section of the weld. A segment of weld #21 on the 'B' EDG header was ground by about 40 mils on February 12 without incident. UT examination of the segment confirmed the eddy current findings that at lease 0.100 inches of wall was present in that location.

A three inch segment on weld #22 ('A' EDG header) was ground about 40 mils. However, while this operation was in progress, the NDE personnel noted weepage from a pin hole defect in the weld. The leaky weld was on the upstream side of the isolation valve for the 'A' EDG supply header, was not isolable from the main SW header, and thus potentially affected the supply to the 'B' EDG as well.

The leakage was noted at 9:45 a.m. and was reported to the control room operators. Subsequent review by the licensee noted that the actual location ground was about two inches to the left of the intended area. Thus, instead of grinding in an area where the RT had shown what was expected to be good wall thickness, the area ground was actually over the site of two pin hole "pits" noted on the RT. However, the previous ECT exams had not identified that the pits were within 0.100 inches of the surface. Subsequent UT measurements on the segment confirmed the presence of 0.100 inches of wall over most of the 3 inch segment of weld, except in the area of the two wormhole defects.

Since the grinding operation caused a through wall defect in an area that was thought to have wall thickness margin based on the best available NDE data, the licensee management concluded the event called into question the ECT inspection process used to characterize the defects, and based on which the operability evaluation for welds #12, #21 and #22 were dependent upon. Although the weld still had structural integrity and both supply lines to the diesels were functional, the licensee declared both service water system headers inoperable.

Plant Shutdown - Unusual Event

The loss of two service water headers exceeded the minimum requirements for the SW system specified in Technical Specification (TS) 3.7.3. The licensee entered the action statement for TS 3.0.3 at 9:50 a.m. and began a controlled shutdown. An Unusual Event emergency was declared due to a shutdown required by the TS, which required that the plant be placed in Mode 5 (cold shutdown) within 36 hours. The reactor entered Mode 3 (reactor subcritical) at 3:23 p.m. on February 12, and Mode 5 at 6:10 p.m. on February 13. At which time the Unusual Event was terminated. The licensee notified the NRC Duty Officer at 9:59 a.m. on February 12. The resident inspector responded to the plant and followed the shutdown through termination of the event. This began an outage to inspect SW piping for corrosion and replace affected piping.

The licensee initiated actions to first repair the leaky weld and to complete nondestructive examinations of other welds and piping in the service water system to identify other MIC induced degradations. All known degraded SW welds/piping would be repaired as needed prior to returning the plant to power operation. This included the replacement of the entire service water header to each EDG, including the underground piping. The minimum job scope for SW replacement includes the headers to both EDGs, the headers to the RHR heat exchangers, and the Adams filter bypass lines. The plant outage was scheduled to last about 55 days.

Following removal from the system, the NRC inspector visually examined welds #21, 22 and 12 and noted defects similar to those removed from the SW system in May 1993: extensive corrosion around welds with initial construction defects, with "wormhole" type defects penetrating the crevice. Each sample contains a significant circumferential ligament with a wall thickness estimated to exceed 100 mils.

Most other welds examined by RT in the SW system (both stagnant and flowing sections) were similar to the type of defects noted in the sample removed from the SW system in January 1994. Two welds in the RHR lines had defects similar to those noted in the May 1993 sample. CYAPCo actions were in progress at the end of the period to characterize the SW defects and to complete an operability assessment in accordance with the bounding Appendix H analysis.

Management Responsiveness/Assessment

During the week of February 7, site management concluded the plant organization did not have the initiative in addressing the SW corrosion issue. The Unit Director initiated actions and plans starting on February 8 to regain the initiative in solving the problem. This message was addressed in a meeting with the principle plant staff on February 10 in which expectations on the approach to the problem were discussed, along with the need to accelerate the pace of the investigations. The approach taken would be one in which the staff would not assume the problem has been limited. Station management recognized the weaknesses in its own and the engineering group's past actions relative to the issue. The Unit Director accelerated plans to conduct a service water system operability review (SWOPI). Further, the licensee directed that a third party assessment be completed to evaluate the management and engineering decision making process. The NUSCO Nuclear Safety Engineering group was tasked with the work.

Findings

The sequence of CYAPCo actions described in the February 22 letter to the NRC were reviewed and found to accurately capture the facts and chronology of events to address SW. Following substantial interactions with the NRC staff and in response to questions regarding the degraded pipe and weld conditions, on February 10 CYAPCo successfully demonstrated that the SW system remained operable to the extent the defects were known and accurately characterized.

The decision to shutdown the plant following the development of the through wall leak on February 12 was good and necessary in light of the uncertainties in flaw characterization based on the then available RT and ECT examinations. Post shutdown examination of the defects (welds #21, 22, 12) showed conditions similar to that noted for the May 1993 sample. CYAPCo actions are appropriate to complete its evaluation of the worst case flaws identified in the SW piping and to finalize the operability determination for the SW system. The licensee stated this matter will be further reviewed for reportability upon completion of that evaluation.

CYAPCo management and engineering did not display the usually strong questioning attitude in the pursuit of the issue and had lost the initiative to address this problem prior to substantial involvement by the NRC staff. The initiative was lost during the 1993 outage when inspections and analyses of degraded welds identified the potential for a wide spread problem affecting piping and welds in the SW system. These adverse conditions were not thoroughly investigated when the initial operability assessment was made. The anomalous conditions were not promptly investigated following the outage when plans were made to gather data to investigate the status of the SW system. The underlying assumption of presumed continued operability was not conservative in the face of the substantial uncertainty regarding the status of the SW pipe and welds, the exact mechanism causing the identified corrosion, and the uncertainty in how rapidly the corrosion progressed. CYAPCo appears to have regained the initiative on this issue starting from about February 7.

NRC review of this are was in progress at the end of the inspection period. A meeting between the NRC and CYAPCo staffs is planned on March 16 to further the NRC review of this topic. This item is considered unresolved for the following actions: (i) completion of modifications to SW system and acceptance testing; (ii) completion of the evaluation of the degraded welds/SW pipe to assure root cause is identified and addressed; (iii) completion of actions to meet commitments made in the February 10 conference calls and as described in the February 22 letter, including: the development of a MIC mitigation program by April 1, 1994, the reassessment of CYAPCo's response to Generic Letter 89-13, and the performance of a SWOPI; (iv) completion of the operability determinations for the historical condition and submittal of the licensee event report; and, (v) completion the third party root cause evaluation to understand how the SW corrosion issue was handled by CYAPCo engineering and management. This item is open (UNR 94-03-05).

4.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

The inspectors reviewed selected engineering activities. Particular attention was given to safety evaluations, plant operations review committee approval of modifications, procedural controls, post-modification testing, procedures, operator training, and UFSAR and drawing revisions.

4.1 Loose Sediment in Service Water Line to Residual Heat Removal (RHR) Heat Exchanger

On February 19, during cold shutdown (Mode 5) plant conditions, CYAPCo was removing sections of service water supply piping to the 'B' RHR heat exchanger. The pipe was removed due to corrosion (see report detail 3.5). During the pipe removal, the licensee identified approximately twenty five pounds of sedimentary material in two horizontal supply legs. The sediment was composed of fine silt and benthic material. Based upon the amount of sediment, and the potential to affect the RHR heat exchanger safety function, CYAPCo declared the service water supply piping inoperable. The inoperability resulted in a 10 CFR 50.72 (b)(2)(i) notification to the NRC at approximately 9:10 a.m. CYAPCo initiated plant information report (PIR) 94-033 to document the event, and to identify potential corrective

actions. The inoperability did not directly affect shutdown cooling operations, since the heat exchanger is normally cooled by component cooling water, and the post-accident safety function (post-LOCA sump recirculation) was not applicable in cold shutdown.

Background

The RHR heat exchangers are normally used for shutdown cooling operation. Each heat exchanger is aligned to component cooling water as described in normal operating procedure (NOP) 2.9-1, "Placing the RHR System in Service." The service water supply is normally isolated from the RHR heat exchanger and is used during emergency operating procedures ES-1.3, "Transfer to Sump Recirculation," as the safety-grade cooling supply to the RHR heat exchangers to cool containment sump water.

Two twelve inch service water supply headers (12"-WS-121-257 and 12"-WS-121-104) are stagnant lines with some limited stream flow. The limited stream flow is provided by one and one half inch supply lines to the steam generator sample chiller condensers. On a quarterly basis, the normally closed motor-operated valves (SW-MOV-5 and SW-MOV-6) are cycled for the ASME Section XI inservice test program per SUR 5.7-67, "Inservice Testing of SW Isolation Valves, SW-AOV-8,-9, SW-FCV-129, and SW-MOV-5 and -6." During the test, the twelve inch supply header is flushed via a 1 1/2 inch drain line downstream of the motor-operated valves for at least two minutes. The licensee performs this test to assure silt does not accumulate above the seats of MOV 5 and MOV 6.

The inspector evaluated CYAPCo's program against the actions identified in NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." CYAPCo's response to NRC Generic Letter 89-13 dated January 25, 1990, stated that the RHR heat exchangers baseline performance will be verified during the current refueling outage. CYAPCo's response further stated that the RHR heat exchangers are not susceptible to biofouling concerns, and therefore no subsequent testing or monitoring will occur. The NRC's guidance, as documented in NRC Generic Letter 89-13, was that performance testing of infrequently used cooling loops should include an initial test frequency of each refueling cycle, but after three tests the licensee could determine the best frequency. The inspector verified that during the 1991 refueling outage, the licensee performed a baseline thermal performance test using component cooling water versus service water. The test results were satisfactory.

The inspector reviewed past service water flow tests through the RHR heat exchangers. Special test (ST) 11.7-10, "Service Water System Throttle Setting," verified that the heat exchanger outlet throttle valves (SW-V-250A and 250B) were in the proper position to provide the specified flow based on a Westinghouse design basis analysis, (WCAP-121916, "CY Ultimate Heat Sink Temperature Design Basis Change." ST 11.7-10 was performed in November 1989 and in January 1990. The design basis minimum service water flow through one RHR heat exchanger post accident is 2,250 gallons per minute (gpm). The recorded

service water flow in January, 1990 was 2,300 gpm to the 'A' RHR heat exchanger, and 2,500 gpm to the 'B' RHR heat exchanger. The November 1989 flows were 2,500 gpm and 2,400 gpm to the 'A' and 'B' heat exchangers, respectively.

Assessment

On February 24, CYAPCo retracted the 10 CFR 50.72 report issued on February 19. The engineering analysis concluded that the RHR heat exchangers were operable in the "as-found" condition when supplied with service water. The operability determination was based on engineering judgements regarding the adequacy of service water flow, and the prevention of heat exchanger shell side fouling. CYAPCo concluded that the sediment would not foul the vertically mounted heat exchangers for the following reasons: the sediment was a fine silt and would readily form a suspended solid in solution; and, the service water flows through the shell side of the heat exchanger from a top to bottom direction, resulting in a continuous flushing action. Finally, the past heat exchanger performance tests were conducted with a likely similar buildup of silt in the stagnant lines. The inspector reviewed the licensee's basis for operability of the service water supply lines to the RHR heat exchangers. Although no recent (since 1990) tests have occurred to support the judgements presented in the operability assessment, the bases for operability determination were reasonable, and the conclusion was acceptable.

The inspector also concluded that CYAPCo's actions in regard to RHR heat exchanger monitoring was not consistent with the expectations in Generic Letter 89-13. Specifically, CYAPCo elected to not perform heat exchanger monitoring since the baseline test in 1991, based on the assumption that fouling would not be a concern due to the chemically treated component cooling system water normally in the heat exchangers. However, it is evident from the February 19, 1994, inspections that fouling has occurred in the stagnant service water lines to the RHR heat exchangers. The inspector presented this issue to licensee management on February 25. At the end of the inspection period, the licensee stated that performance monitoring using the component cooling water would occur to both RHR heat exchangers, and both stagnant lines were being replaced. The inspector considers this item open to verify the performance monitoring of the RHR heat exchangers, and to review future activities planned by the licensee **(IFI 94-03-05).**

4.2 Improper Pipe Flanges on the Low Pressure Safety Injection System

On January 11, CYAPCo identified that the discharge pipe flanges for flow element (FE-660) were A182-F304 300 psi class. The piping specification (Class 603) requires that flanges between 2.5 inches to 16 inches to be A182-F304 600 psi ratings. The flange size on flow element FE-606 was a 10 inch flange. The system engineer identified the incorrect pipe flange during a preliminary walkdown supporting plant design change PDCR 1461, "Removal of FE-660." The engineer was measuring flange thickness to determine the gasket raised face dimension, when he noticed that the flange was the wrong class.

Upon discovery of the discrepancy, CYAPCo initiated a walkdown of all accessible pipe flanges in the low pressure safety injection (LPSI) system. The walkdown also identified that both LPSI pump discharge flanges were carbon steel lap-joint flanges with a 300 psi rating. Piping specification CYS-1550A class 603 does not allow lap-joint flanges, but the suction piping class 153B for the LPSI suction piping allows lap joint flanges for sizes ranging between 0.5 to 4 inch sizes. The LPSI pump discharge flanges are 10 inch. Additionally, the LPSI pump suction flanges were 300 psi lap-joint flanges whereas piping specification 153B requires a weld neck type flange with an ASTM specification A183-F304 150 psi rating.

CYAPCo performed an operability evaluation of the LPSI piping system based on the identification of the "as-built" construction deficiencies. The operability determination compared the 300 psi flange rating using ANSI B 16.5 table 2-300 to that of LPSI design conditions. Engineering standard ANSI B 16.5 is the reference in the original piping specification CY-1550A. The licensee concluded that the system pressure boundary integrity was maintained and the system was considered operable in the "as-found" condition. The inspector verified the licensee's conclusion by reviewing ANSI B 16.5 for the grade identified and found the following flange ratings: 620 psig/100° F and 550 psig/300° F. The Updated Final Safety Analysis Report states that the LPSI pumps are designed for 350 psig and 100° F with normal operating temperatures ranging between 50 to 100 degrees F. CYAPCo further evaluated worst case conditions at FE-660 and concluded that worst case temperature was residual heat removal entry conditions (300° F) and a system pressure of 430 psig. The worst case temperature and pressure at FE-660 assumes that the upstream check valves (SI-CV-103 and SI-CV-107A or B) between the RHR and LPSI systems are leaking excessively. The inspector determined that the licensee's operability decision was appropriately supported.

At the end of the inspection report period, CYAPCo was evaluating the acceptability of the flange bolting pursuant to ASME section 3650 evaluations. The evaluations were being performed on static as well as dynamic conditions.

The inspector noted that the differences between the piping specification and the "as-built" configuration might affect other engineering evaluations (i.e. SEP seismic calculations, and future plant modifications). Procedure NEO 5.05, "Design Inputs, Design Verification, and Design Interface Reviews," states that a design input source document is the original equipment design documents, such as calculations, specifications, and calibrations. NEO 5.05 step 6.5.3 states that design deficiencies identified by other project personnel, audits, tests, or failures during operation shall be reported via the appropriate corrective action program mechanisms. This matter was discussed with the Unit Director on February 26, who stated actions would be taken to assure that these noted as-built deviations from the construction specifications would be included in the plant design basis documentation. The inspector considers the accuracy of piping specifications as related to past engineering evaluations an open item **(IFI 94-03-06).**

4.3 Modification to MCC-5

The documentation for Plant Design Change Request PDCR 1434, Rev 0, "MCC-5 Automatic Bus Transfer (ABT) Re-Design," was reviewed. The intent of this modification, in part, is to prevent unnecessary ABT operations caused by the preferred bus position logic. The modification added some complexity to the current ABT logic. Included in the modification were two new breaker control switches, a new automatic/manual relay, a new control room alarm, and a change in the function of the existing preferred bus position switch. The inspector questioned whether the additional relays and contacts would reduce the overall ABT reliability.

The addition of the manual to automatic transfer of the breaker control adds several additional components to the logic. The licensee technical staff stated that the new breaker control switches will be located at the breakers. The additional controls would facilitate breaker testing when racked out in the bus compartment. The DB-25 breaker design already includes a manually actuated breaker close and trip capability. This capability is completely separate from the ABT logic. Therefore, if the ABT were to fail, the proper operator action would be to manually close the breakers using the existing manual close handle on the breaker.

The present ABT design provides a needless transfer of the ABT when both bus 5 and 6 had power. If the ABT had transferred to a energized bus it would leave the perfectly good bus and transfer back to the preferred bus. This feature of the ABT could be eliminated by removing the preferred bus feature from the ABT logic. The rest of the logic would remain as-is. The ABT would still always seek and find the energized bus as it presently does.

The licensee acknowledged the inspector's comments. The licensee stated the proposed design change was reviewed by the probabilistic risk assessment (PRA) group and was included in the PRA model for Haddam Neck. The PRA group found that, although the proposed modification added complexity to the ABT, the overall impact of the new design would result in an improvement in the core melt frequency for Haddam Neck by an order of magnitude. The licensee stated the details of this calculation would be provided for inspector review.

The changes described above could simplify the ABT logic and make the ABT more reliable. The licensee stated the inspector's comments would be considered in the ongoing plant and engineering evaluation of the proposed ABT modification. Licensee actions in this area will be included in future routine inspections of engineering activities.

5.0 PLANT SUPPORT (40500, 71707, 90712, and 92701)

5.1 Radiological Controls

During routine inspections of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's radiological controls program. The inspector reviewed utilization and compliance with radiation work permits (RWPs) to ensure that they provided detailed descriptions of radiological conditions and that personnel adhered to RWP requirements. The inspectors observed controls of access to various radiologically controlled areas and the use of personnel monitors and frisking methods upon exit from those areas. During the period, the inspectors periodically observed health physics controls during radiography of service water piping welds. Appropriate pre-job briefings, postings, and surveys were performed in accordance with radiation protection manual (RPM) 2.5-1, "Radiography." The inspectors verified that posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were in accordance with licensee procedures. The inspectors determined that the health physics technician control and monitoring of these activities were good.

5.1.1 Locked High Radiation Controls

The inspector reviewed licensee actions on February 7, in response to an issue involving a locked high radiation area (HRA) gate. While conducting a routine tour of the radiation control area (RCA) at about 9:00 am on February 7, a plant security guard noted that the gate to the ion exchange pipe trench was closed but not locked. The guard locked shut the gate and contacted the health physics supervisor.

Licensee investigation determined that gate had last been opened at 7:19 a.m. that morning by a health physics technician. The gate was opened as part of checks per Attachment A of procedure RPM 2.3-2, "Daily Routine Checklist," which is completed to assure gates are secured. The technician performing the gate check failed to assure the gate latched completely after it was opened to check the gate alarms. A radiological posting sign hung on the gate had interfered with full closure and prevented the gate from latching securely.

As corrective action, the licensee immediately verified the status of all other gates listed in procedure RPM 2.3-2 and confirmed that the gates were secure. The technician who performed the daily check was subjected disciplinary action. The posting was moved so it could not interfere with gate closure. The licensee evaluated the incident and noted that the access to the high radiation area was lessened but not compromised during the period the gate was not secure. A hatch providing access to the high radiation area controlled by the gate was locked in place with both security and health physics padlocks. Thus, no violation of the Technical Specification 6.12.1 requirements for controlling access to a locked high radiation area occurred.

Nonetheless, the failure to secure the gate during the checks completed at 7:19 a.m. was contrary to the requirements of procedure RPM 2.3-2. Licensee health physics supervision demonstrated a high regard for the control of locked high radiation areas, and the need to address personnel performance issues. Thus, no violation will be issued since, in accordance with the NRC Enforcement Policy in Section VII.B of 10 CFR 2, Appendix C, the violation was identified by the licensee, it was classified as a Severity level IV, it could not be prevented by the corrective action from a previous violation, and the licensee corrective actions were appropriate. The inspector concluded that the security officer who noted the open gate displayed a good regard for plant radiological controls.

5.1.2 Containment Purge Operations

The inspector reviewed the controls implemented by the licensee to monitor and control the release of radioactivity during the shutdown for the service water piping replacement. The inspector reviewed stack releases using the process radiation monitor readouts in the main control room, and reviewed the release calculations provide in gaseous release permit G-19 dated February 25, 1994. The permit was written to allow the initiation of purge operation for the primary containment. Containment purging began on February 25, which was 13 days after the shutdown from full power, and became continuous as the containment was opened for outage related work.

The inspector reviewed the licensee calculations for the number of curies of the isotope xenon-133 released. The initial discharge resulted in a release of 9.86 curies of radioactivity over 24 hours, with a release rate of 114 micro-curies per second. The release rate was 0.05% of the amount allowed by the technical specifications. The estimated total site boundary dose rate was 0.0036 milliRem. No inadequacies were identified.

5.2 Plant Operations Review Committee

The inspectors attended several Plant Operations Review Committee (PORC) meetings. The inspectors verified Technical specification 6.5 requirements for member attendance were met. The meeting agendas included procedural changes, proposed changes to the Technical Specifications, Plant Design Change Records, and minutes from previous meetings. PORC meetings were characterized by frank discussions and questioning of the proposed changes. The major issues were reviewed very well and included the work this period on the main steam safety valve test plan and failures, the MCC-5 ABT failure and investigations, and the activities to investigate the SW system corrosion. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. The inspector determined that the committee closely monitored and evaluated plant performance and conducted a thorough self-assessment of plant activities noted above.

5.3 Follow-up of Previous Inspection Findings

The inspectors reviewed licensee actions taken in response to open items and findings from previous inspections. The inspectors determined if corrective actions were appropriate and thorough and whether previous concerns were resolved. Items are closed where the inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action is warranted remain open. The following item was reviewed:

(Closed) Inspector Follow Item 92-15-02, Corrective actions and Root Cause for Licensee Event Report 92-020-00

This item was open pending review of the licensee root cause determination, and the corrective actions for the failure of the '2B' steam generator wide range level indicator. Licensee event report (LER) 92-20-00 documented a condition prohibited by technical specification. The basis for the report was CYAPCo's inability to insert a trip signal within one hour on the '2B' wide range level instrument. The trip signal was necessary based on a momentary failure of the instrument in July 1992.

CYAPCo's root cause investigation of the momentary failure of the '2B' wide range steam generator level instrument was inconclusive. The operating experience since the July 1992 event has not identified any failures.

The inspector verified the licensee's corrective actions to review technical specification instrumentation in regard to insertion of trip signals, and implementation of a plant modification to install permanent trip switches for the eight channels of the steam generator wide range level instruments. CYAPCo's review of instrumentation design identified that the 4,160 volt bus 8 and 9 undervoltage level signals could not be placed in a tripped condition within the one hour allowed by the technical specifications. CYAPCo developed procedure CMP 8.8-1, "Installation and Removal of UV Trip Signals Bus Levels 1, 2, and 3." The inspector reviewed the adequacy of the procedure, and concluded that appropriate actions were identified to accomplish the removal of one of the UV channels. The inspector verified that the applicable control room annunciator procedures reference CMP 8.8-1 to be accomplished by the generation test personnel when a channel failure is evident.

Plant modification PDCR 1344, "Install Steam Generator Wide Range Level Trip Switches," was implemented and successfully tested on June 26, 1993. The steam generator low level, and feed flow/steam flow differential control room annunciators direct the operators to have instrument and control specialists perform corrective maintenance procedure (CMP) 8.2-26, " Insertion and Restoration of Trip Signals."

The inspector considers this issue a violation that is not subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in section VII.B of 10 CFR Part 2, Appendix C. This item is closed.

5.4 Union Negotiation Contingency Plans (IP 92709)

Plant security officers are represented by the United Plant Guard Workers of America (UPGWA) Union, Local 538. The expiration date for the existing union contract was January 31, 1994. Burns International Security Services prepared a time line of events and a plan to promote ratification of a new contract. The inspector reviewed the licensee's plans and actions for responding to a work stoppage in the event of a job action. Licensee planning was formalized four months before the expiration date.

The inspector reviewed the licensee's plans to meet the minimum shift complement for normal security and contingency staffing requirements. The inspector also reviewed various licensee and contractor documents. The licensee kept the resident inspector and the NRC Region I Division of Radiation Safety and Safeguards Section informed of the contract negotiations and the planning status.

No inadequacies were identified regarding the contingency plans. A new four year contract was accepted by the union on January 29, 1994. The inspector found that the licensee security supervisor performed very well in promptly and fully informing the inspector of the status of the contract negotiations. The inspector identified no inadequacies in this area.

6.0 MEETINGS

6.1 Exit Meetings

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

In addition to the exit meeting for the resident inspection held on March 4, the following meetings were held for inspections conducted by Region I based inspectors.

Report No.	Inspection Dates	Reporting Inspector	Areas Inspected
50-213/94-04	2/7-2/8/94	Mayfield	Service Water Pipe Weld Degradation

6.2 Meeting with Local Officials

On February 18, the inspector met with the First Selectwoman for the Town of Haddam, CT. The purpose of the meeting was to meet the local official, to describe the role of the NRC, and discuss the inspection of activities at Haddam Neck. The types of information available to the public and the Town of Haddam on the 50-213 Docket were also discussed. The inspector felt the meeting was beneficial for enhancing communications with the town.

ATTACHMENT A

INSPECTION REPORT NO. 50-213/94-03

EDG SERVICE WATER EVENTS SUMMARY

The following chronology of licensee activities regarding the service water corrosion issue was developed during this inspection period in response to an inspector request.

3/8/93	PIR 93-07 initiated for pinhole leak in 'B' EDG supply. UT of surrounding base metal SAT. Relief request initiated in accordance with 90-05.
5/93	6" Piping from 12" east and west supply headers up to and including first elbows replaced on 'A' and 'B' EDG supply piping during RFO.
5/93	Sample of weld which leaked sent to NUSCO Materials for root cause evaluation.
6/93	Root cause memo (CTS-93-754) issued stating poor weld quality with possibility of MIC (no active samples acquired with welds).
7/93	PIR 93-027 and CR 93-240 for pinhole leak accepted and closed out by PORC withdrawal of previous relief request submitted.
8/93	Informal discussion began between NUSCO and CY personnel on need to inspect for other potential poor weld quality or MIC attack if present. Sample qualitatively evaluated and results consistent with PIR findings.
9/93	Investigated feasibility of performing RT inspections of potentially affected areas (i.e., stagnant, low flow service water).
10/93	Began developing inspection plan to evaluate potentially affected service water subsystems.
11/16/93	RHR and EDG piping inspection action plan memo issued. Inspections delayed by management to develop contingency plans. Decision acceptable based on weld operability.
12/93	Numerous meetings held and contingency plan developed to perform inspections and take necessary actions if operability is not met. Including shutdown and piping replacement PDCR if necessary.
12/22/93	NRC Region I Administrator , Tim Martin visits site, visually inspects samples and notes significant corrosion.

1/7/94 CYAPCo decided to remove an elbow with welds during diesel outage to clean HX on 1/25/94 at which time full metallurgical, RT and visual inspections will be performed. This data would "benchmark" the RTs for future inspection of in service piping. Further RT's without removing pipe discussed.

1/94 Documentation of operability assessment provided by Stress Engineer which reaffirmed samples are acceptable/operable, based on measurements and calculations.

2/2/94 NRC question regarding existing preliminary operability assessment prompts a flaw analysis IAW Section XI Appendix H to be performed by NUSCO. This analysis reconfirms operability to the extent known defects are characterized.

2/3/94 Began acquiring additional RTs of all accessible welds to EDGs to assess operability.

2/7/94 Initial screening of preliminary RT data identifies 3 welds (#21, 22 & 12) with flaws similar to those removed in May 1993, and which require further characterization to verify the defects are bounded by the Appendix H analysis. Eddy Current (ECT) examination confirms presence of at least 100 mils of ligament. Efforts continue to benchmark the ECT calibration standards against samples with the flaws removed from the system.

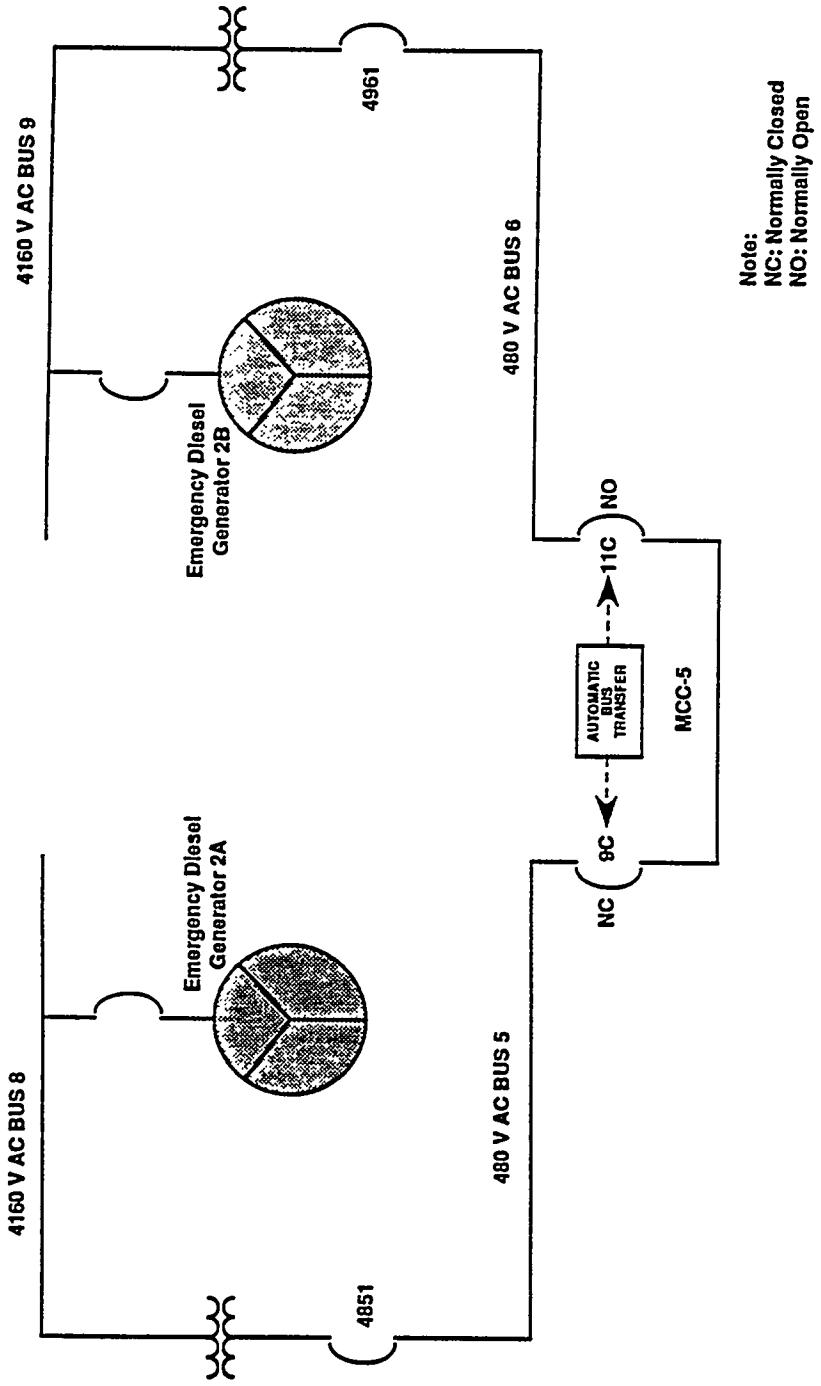
2/12/94 A through wall leak develops on weld #22 during actions to prepare the weld crown for UT examination. CYAPCo declares both SW headers inoperable based on loss of confidence in NDE methods to characterize weld defects. An Unusual Event is declared and a plant shutdown is started.

2/13/94 The plant reached cold shutdown on February 13. This began an expected 55 day outage to inspect SW piping for corrosion and replace affected piping.

2/26/94 End of period status: Minimum job scope for SW replacement includes the headers to both EDGs, the headers to the RHR heat exchangers, and the Adams filter bypass lines.

Visual examination of welds #21, 22 and 12 after removal from the system note defects similar to those removed from the SW system in May 1993; extensive corrosion around welds with initial construction defects, with "wormhole" type defects penetrating the crevice. Each sample contains a significant ligament with a wall thickness estimated to exceed 100 mils. CYAPCo actions in progress to characterize the defects and to complete an operability assessment in accordance with the bounding Appendix H analysis.

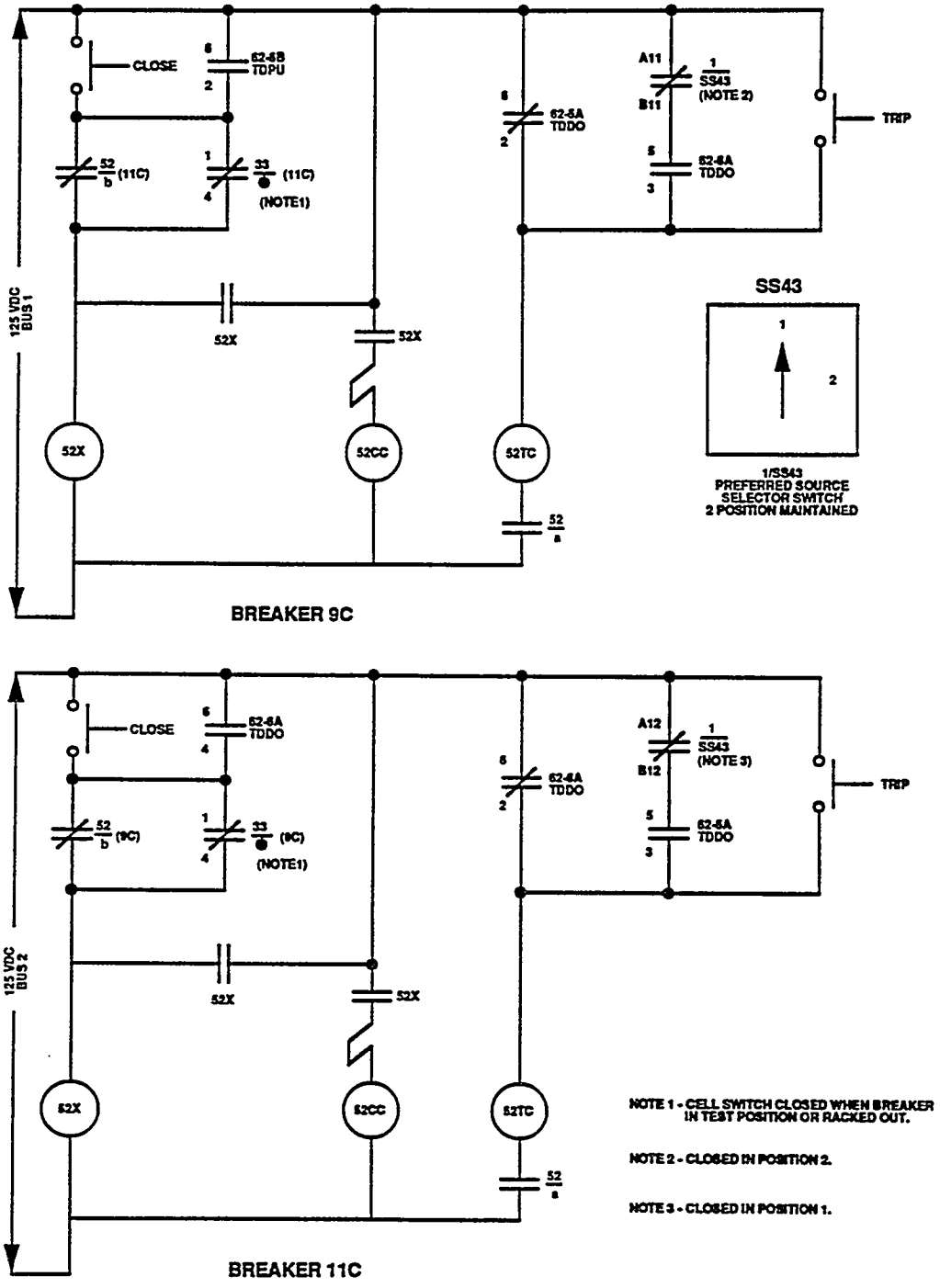
IR 94-03



MCC-5 SIMPLIFIED DIAGRAM

FIGURE 1

IR 94-03



ABT LOGIC DIAGRAM
FIGURE 2

IR 94-03

FIGURE 3
VIEW OF DB-25 BREAKER

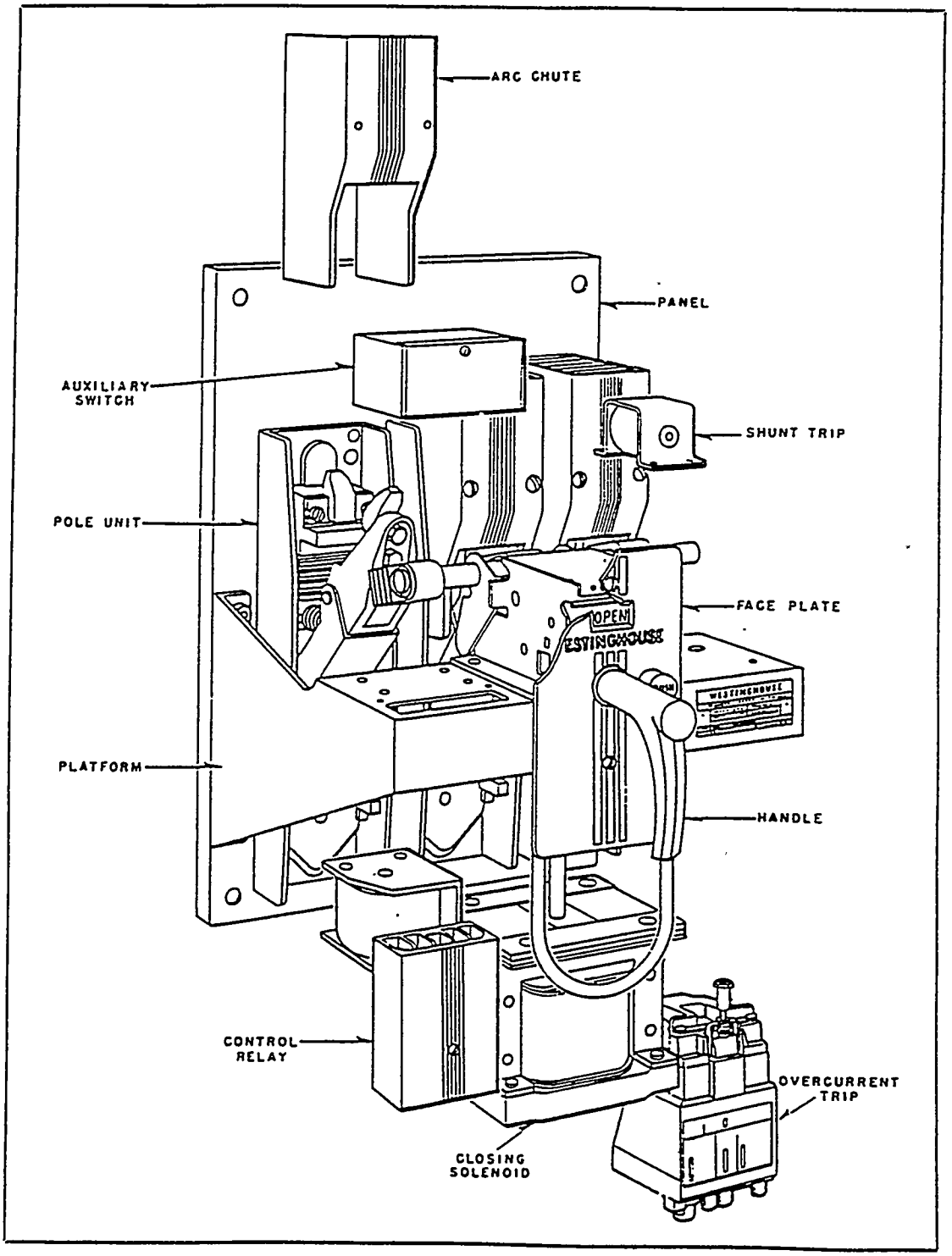
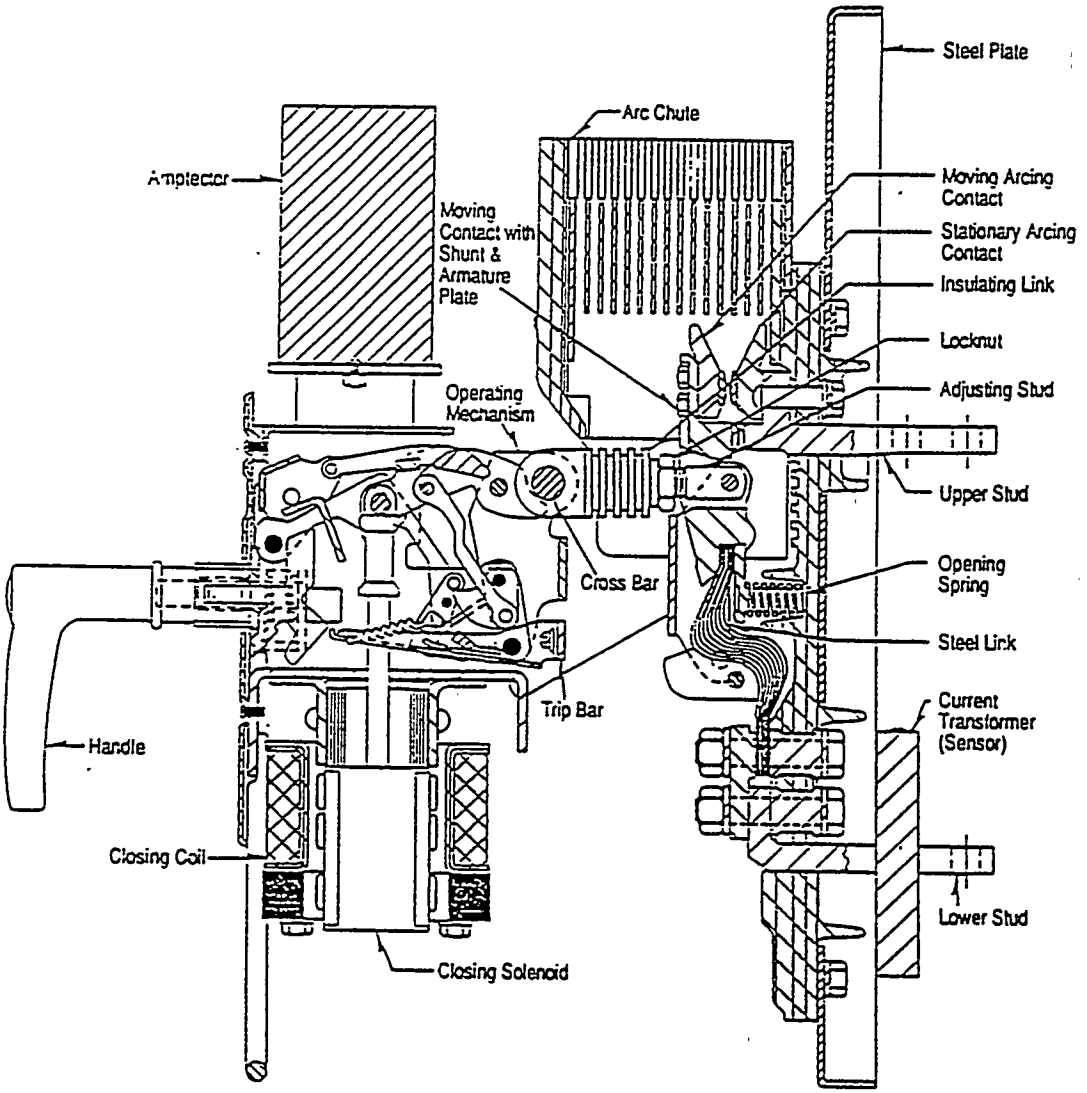
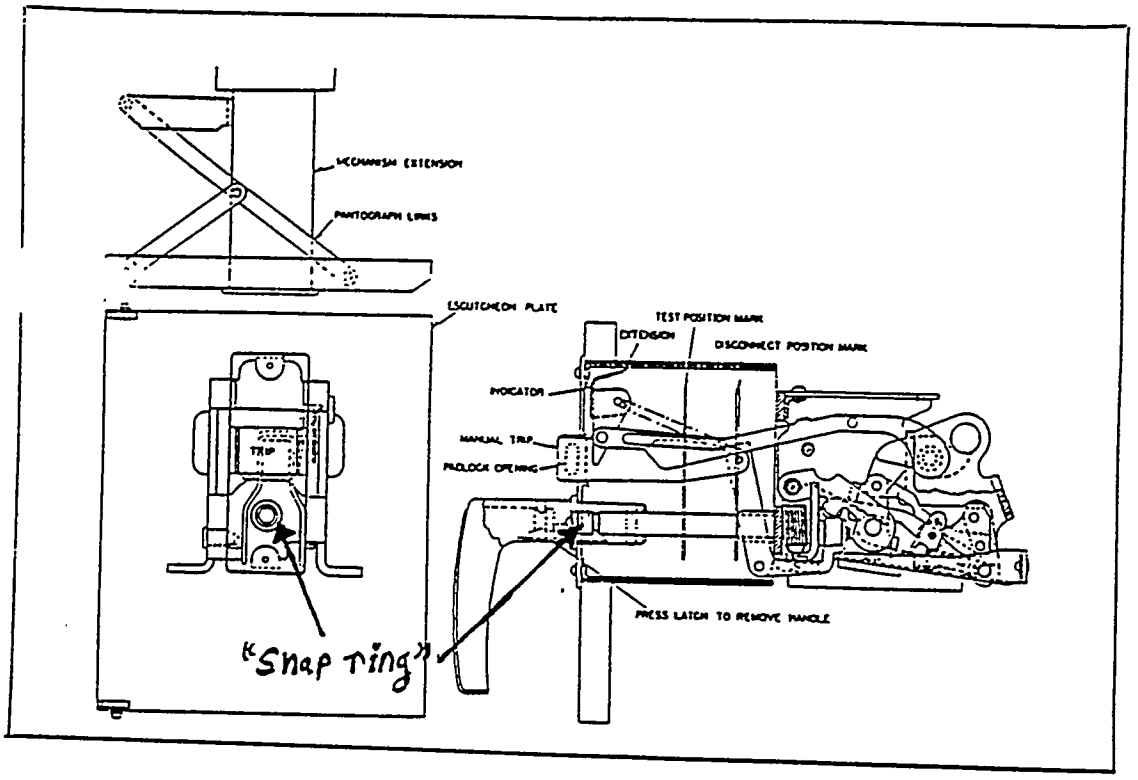


FIGURE 4
Cross Sectional View of DB-15/25 Breaker

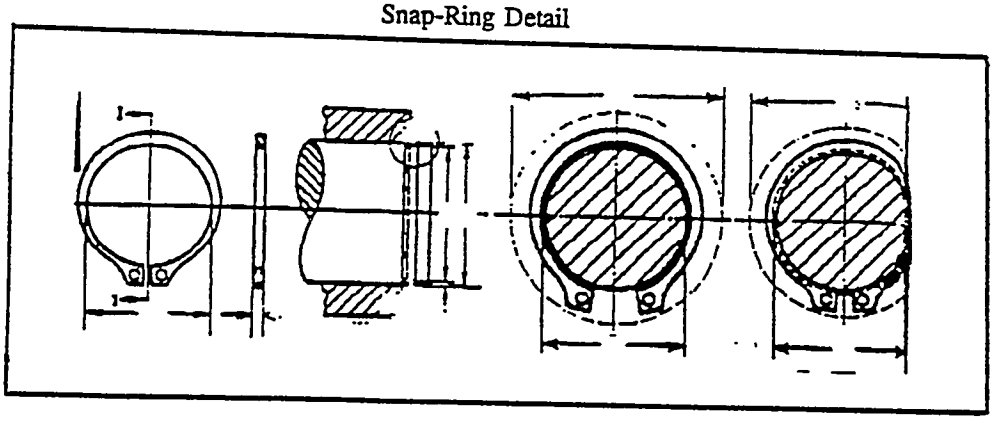


IR 94-03

FIGURE 5
DB-25 BREAKER OPERATING MECHANISM



Snap-Ring Detail



LER No. 219/94-010
Oyster Creek

NRC FORM 366N (5-92)

LICENSEE EVENT REPORT (LER)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oyster Creek, Unit 1	05000219	1 OF 4

TITLE (4)
Reactor Shutdown Commenced Due to Loss of Both Containment Spray Systems due to Biological Plugging

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
07	05	94	94	-- 010 --	00	08	04	94		05000
									FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	N
POWER LEVEL (10)	100

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
John Galanto	609.971.4349

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On July 5, 1994 at approximately 1155 hours, both Containment Spray and Emergency Service Water systems were declared inoperable due to high differential pressure on the tube side of the heat exchangerdue to biological plugging. A 30 hour plant shutdown was commenced per Technical Specifications. The heat exchangers were cleaned and returned to service prior to completion of the shutdown. The plant was returned to full power. The cause of this event was the release of Blue Mussel shells and other minimal biological debris into the heat exchangers.

Immediate corrective action was taken to clean, inspect, and return the heat exchangers to operability. Additional corrective actions are planned to inspect and clean the Emergency Service Water piping during the upcoming refueling outage and install inspection ports in the affected systems to assist in the early detection of possible future concerns.

NRC FORM 366 (5-92)

NRC FORM 366A (5-92) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		U.S. NUCLEAR REGULATORY COMMISSION APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95			
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Oyster Creek, Unit 1	05000219	94	-- 010 --	00	2 OF 5

DATE OF OCCURRENCE

The event occurred on July 5, 1994, at approximately 1155 hours.

IDENTIFICATION OF OCCURRENCE

While performing a scheduled monthly surveillance on Containment Spray (EIIS BO) and Emergency Service Water (EIIS BS) system 2, heat exchanger (EIIS HX) differential pressure was observed to increase beyond the operability limit specified in the procedure. Containment Spray and Emergency Service Water system 1 was then run with the same result. Both systems were declared inoperable and a 30 hour plant shutdown was commenced per Technical Specifications. This event is considered reportable in accordance with 10 CFR 50.73(a)(2)(i), 10 CFR 50.73(a)(2)(ii), and 10 CFR 50.73(a)(2)(v).

CONDITIONS PRIOR TO OCCURRENCE

The Reactor was operating at approximately 100% power. Containment Spray and Emergency Service Water system 2 was being operated for a normal monthly surveillance.

DESCRIPTION OF OCCURRENCE

On July 5, the normal monthly system operability test for Containment Spray and Emergency Service Water system 2 was commenced. Shortly after the pumps were started (one Containment Spray pump and one Emergency Service Water pump) it was noticed that both heat exchanger tube to shell differential pressure indications in the Control Room began to decrease to the alarm set point. Tube to shell differential pressure measures the inlet pressure to the heat exchangers on the Containment Spray (shell) side and the outlet pressure of the heat exchangers on the Emergency Service Water (tube) side. As the tube side of the heat exchangers plug, the tube to shell differential decreases. The operators checked the flow rate of the Emergency Service Water pump and found it to be twenty four hundred gallons per minute which is below the expected value of approximately thirty five hundred gallons per minute. The operators then checked the heat exchanger tube side differential pressures which are local gauges and found differential pressures exceeding the operability limit of 40 pounds per square inch differential (psid). The actual readings were 75 psid for the 1-3 heat exchanger and 58 psid for the 1-4 heat exchanger.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		U.S. NUCLEAR REGULATORY COMMISSION APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95			
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Oyster Creek, Unit 1	05000219	94	-- 010 --	00	3 OF 5

DESCRIPTION OF THE OCCURRENCE (Cont.)

System 2 was run for approximately twenty minutes prior to being shutdown and declared inoperable.

As a result of the plugging in Containment Spray system 2 heat exchangers, Containment Spray and Emergency Service Water system 1 was run to determine its operability. Within minutes of starting the Emergency Service Water pump the tube side differential pressure began to increase quickly and pump flow began to decrease. Heat exchanger differential pressures exceeded the operability limit of 40 psid. The system was shutdown and declared inoperable. This resulted in both Containment Spray systems being inoperable at the same time which required a reactor shutdown within 30 hours per plant Technical Specifications.

CAUSE OF THE OCCURRENCE

The cause of the heat exchanger high differential pressures was a result of biological plugging mostly consisting of blue mussel shells deposited on the first pass tube sheet. The mussels were nearly all found dead, with very little tissue left in the shells. It is strongly believed that the mussel shells found in the heat exchangers had been growing inside the Emergency Service Water piping and were released when the Intake water exceeded the temperatures which can support life. This can occur each summer when the Intake water reaches approximately 80 °F. The amount of biological plugging which occurred during this event is greater than any which had been previously experienced, and may have been aggravated by previous loss of the chlorination system.

ANALYSIS OF OCCURRENCE AND SAFETY SIGNIFICANCE

Oyster Creek has two Containment Spray and Emergency Service Water systems. Emergency Service Water pumps take suction at the Intake Structure (EIIS-NN) and supply Barnegat Bay water to the tube side of the Containment Spray heat exchangers. Plugging of the heat exchangers is an event typically experienced during the summer months and causes tube side differential pressures to increase. Past experience has shown that differential pressures trend up from test to test during the normal monthly surveillance but have never exceeded eleven psid from one test to the next. When differential pressures reach approximately 20 psid the heat exchangers are scheduled for cleaning. The operability limit is 40 psid. Data have been collected in the past for several days of Emergency Service Water system operation during the summer months with typically very little increase in heat exchanger differential pressure (several psid). The Emergency Service Water systems are chlorinated when idle.

ANALYSIS OF OCCURRENCE AND SAFETY SIGNIFICANCE (Cont.)

The Emergency Service Water systems provide for the long term heat removal of the energy released from the primary containment (EIIS BD) during a design basis Loss of Coolant Accident. Partial plugging of the heat exchangers does not cause a problem for the heat removal capability because they are four pass heat exchangers and are over designed. Also the flow rates are not reduced significantly when the units are plugged to normally expected levels. Although the indicated flow rate was twenty four hundred gallons per minute, the discharge pressure of the pump running at the time indicated a flow rate of approximately thirty two hundred gallons per minute. The lower indicated flow was a result of a plugged flow sensing element causing an indicated flow rate lower than the actual flow rate. The required flow rate for a design basis accident is three thousand gallons per minute. Even with the very high differential pressures, flow rate through the heat exchangers was above the required flow.

The structural limit for differential pressure across the heat exchanger baffle plates has been calculated to be seventy psid. The 1-3 heat exchanger reached a differential of seventy five psid. The baffle plates were inspected and found normal.

Continued operation of the Emergency Service Water systems under the plugged condition could have eventually caused structural damage to one or more of the baffle plates rendering the heat exchanger less effective for heat removal. There would have been no failure of the pressure boundary of the system.

This event has been determined to be potentially safety significant in that excessive heat exchanger plugging could interfere with heat removal during an accident and require operators to implement contingency procedures. Additionally, as corrective actions were initiated and completed prior to the complete dislodging of all the dead mussels, the final differential pressure which might have occurred across the heat exchanger tube sheet is not known.

CORRECTIVE ACTION

The System 2 heat exchangers were cleaned and placed back in service on July 6, 1994 within the thirty hour shutdown window. The shutdown was terminated and a return to full power was commenced. The System 1 heat exchangers were then cleaned, inspected, and placed back in service on July 8, 1994.

NRC FORM 366A (5-92)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Oyster Creek, Unit 1	05000219	94	-- 010 --	00	5 OF 5

CORRECTIVE ACTIONS (Cont.)

Additional corrective actions will include: 1) Performing an internal piping inspection on the Emergency Service Water system before the end of the upcoming refueling outage (15R) to determine if biological fouling of the piping still exists; 2) cleaning the Emergency Service Water piping in 15R if necessary to eliminate any growth that has occurred; 3) installing piping inspection ports during cycle 15 to assist in the early detection of any future biological growth inside the piping; and 4) determining, by the end of December 1994, the effectiveness of the chlorination system in each Emergency Service Water system.

SIMILAR OCCURRENCES

LER 85-018 Emergency Service Water Pipe Coating Failure

NRC FORM 366A (5-92)

LER No. 237/94-004
Dresden, Unit 2

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Dresden Nuclear Power Station, Unit 2 and 3	0 5 0 0 0 2 3 7	1 of 0 4

Title (4)

High Pressure Coolant Injection System Steam Drain Line Isolation Valves Installed Backwards Due to Construction Error

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 1 2	2 1 4	9 1 4	9 4	— 0 0 4	— 0 0	0 2	2 2	9 4	UNIT 3	0 5 0 0 0 2 4 9
									N/A	

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIRMENTS OF 10CFR (Check one or more of the following) (11)									
POWER LEVEL (10)	0 8 8		20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)		
			20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)		
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		Other (Specify in Abstract below and in Text)		
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii) (A)				
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)				
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)				

LICENSE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
Aras Lintakas, Plant Support Engineer Ext.2245	8 1 5 9 4 2 - 2 9 2 0

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
	Yes (If yes, complete EXPECTED SUBMISSION DATE)	NO			

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

On January 24, 1994 at 1140 hours, with Unit 2 at 88% and Unit 3 at 74% rated core thermal power, it was determined that the HPCI steam drain line isolation valves would not open under LOCA conditions. The unit 3 valve was replaced on January 15, 1994 as a result of leakage through the valve. During this valve replacement, the original valve was discovered to be installed backwards. When the valve was replaced, it was installed in the proper direction. The installed orientation of the Unit 2 valve was verified to be incorrect on January 17, 1994 at approximately 0800 hours. An engineering evaluation determined that, since a stronger spring had been installed on May 5, 1993, the Unit 2 valve would perform its design function. Prior to these dates, the valves would not have functioned as required. The safety significance was minimal because the HPCI system was capable of initiation during an event. A nuclear work request to re-orient the unit 2 valve has been initiated.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																					Form Rev. 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)									Page (3)			
									Year			Sequential Number				Revision Number					
Dresden Nuclear Power Station	0	5	0	0	0	2	3	7	9	4	–	0	0	4	–	0	0	0	2	OF	0	4

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

PLANT AND SYSTEM IDENTIFICATION:

General Electric-Boiling Water Reactor-2527 MWt rated core thermal power.

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

EVENT IDENTIFICATION:
High Pressure Coolant Injection System Steam Drain Line Isolation Valves Installed Backwards Due to Construction Error.

A. CONDITIONS PRIOR TO EVENT:

Unit: 2 (3) Event Date: 01/24/94 Event Time: 1140

Reactor Mode: N (N) Mode Name: RUN (RUN) Power Level: 88% (74%)

Reactor Coolant System Pressure: 1000 (1000)

B. DESCRIPTION OF EVENT:

On January 24, 1994 at 1140 hours, with unit 2 at 88% and unit 3 at 74% rated core thermal power, it was determined that the High Pressure Coolant Injection (HPCI) [BJ] steam drain line isolation valves (2301-28) on both units would not operate under LOCA conditions. These valves had been found to have been installed improperly during initial plant construction. These valves are designed to open with system pressure assisting, i.e. flow under the plug. With the valves installed backwards, the flow is from over the plug, so the system pressure inhibits the valve from opening. This condition would have prevented the valves from opening under LOCA conditions.

The improper orientation of the valves was discovered while the unit 3 valve was disassembled for repair of leakage through the valve. The best repair for the leakage was determined to be to replace the valve, at which time, on January 15, 1994, a new valve was installed in the proper direction.

Because of this discovery on Unit 3, the orientation of the unit 2 valve was questioned. The orientation of the Unit 2 valve could not be immediately ascertained, because there are no distinguishing marks on the outside of the valve body. On January 17, 1994, upon closer, more detailed scrutiny, barely perceptible engraved markings were found on the valve body which showed that the 2-2301-28 was also installed backwards. An engineering analysis was performed which determined that the valve would operate when required as a result of the installation of stiffer springs, as described later. The assumptions for this analysis, which included packing friction and actuator spring capability, were verified by testing the valve on January 20, 1994.

The Unit 2 valve was replaced in December 1990 under nuclear work request D82665. The existing valve was removed and the new valve was oriented to the same position. Additionally, the valve manufacturer was contacted for approval to install a stiffer actuator spring. This approval was obtained and the new spring was installed in May 1993 under nuclear work request D08593.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																						Form Rev. 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)										Page (3)			
									Year			Sequential Number				Revision Number						
Dresden Nuclear Power Station	0	5	0	0	0	2	3	7	9	4	–	0	0	4	–	0	0	0	3	OF	0	4

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

C. APPARENT CAUSE OF EVENT:

This event is being reported in accordance with 10CFR50.73(a)(2)(v)(D), which requires the reporting of any event or condition that alone could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident. It should be noted, however, that this condition would not have prevented initial HPCI initiation for core injection, but on subsequent HPCI initiations, potential equipment damage may have occurred.

The apparent cause of the events is that the valves were improperly installed during original plant construction, and this orientation was maintained during subsequent maintenance activities. The history for unit 2 reveals 15 work requests, while the history for unit 3 reveals 9. The valves demonstrated signs of re-occurring packing leakage, valve sticking and binding, and constantly requiring stem lubrication, defective diaphragm replacement, valve internal work, and spring tension adjustment to make the valves perform their function with load on them. It is apparent now that these symptoms are a result of the valve being installed backwards with pressure applied to the top of the valve plug. In summary, a more effective root cause analysis would have identified the potential for the valve being improperly installed.

D. SAFETY ANALYSIS OF EVENT:

The 2301-28 valve is a normally closed valve, it is maintained closed by air pressure, and it fails open due to spring force. Upon HPCI initiation, the valve is signalled to open. If the 2301-28 valve fails to open during an event in which HPCI is initiated, moisture could not drain from the HPCI steam line and would eventually back up through the drain line and the steam trap. Subsequently, if the HPCI turbine were tripped, upon re-initiation, any moisture collected at the HPCI Turbine Steam Inlet valve, 2301-3, would be introduced into the HPCI turbine steam chest. In either situation, moisture would be introduced into the HPCI turbine presenting potential impingement damage to the turbine blading. In addition, if sufficient water were to collect upstream of the 2301-3 valve, and the system were to re-initiate, a slug of water would become entrained in steam flowing through the turbine. The HPCI turbine design is capable of ingesting a water slug without casing damage occurring. The amount of water which would have actually entered the turbine in this event is unknown.

The safety significance of these events is minimal. In either event, the HPCI system would initiate and provide cooling to the core. Moisture impingement, which could occur during HPCI restart, would shorten the life of the turbine blades, but would present no problems for the operation of the system.

E. CORRECTIVE ACTIONS:

The Unit 3 valve was replaced under WR D23704. An operability evaluation was performed on the Unit 2 valve and it was determined to be operable with the stiffer springs installed, and will be replaced by D2R14. (NTS 237-180-94-00401)

The Integrated Reporting Program (IRP) has been implemented at Dresden since the installation of these valves. Had IRP been effectively

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																							Form Rev. 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)										Page (3)				
									Year			Sequential Number				Revision Number							
Dresden Nuclear Power Station	0	5	0	0	0	2	3	7	9	4	–	0	0	4	–	0	0	0	4	OF	0	4	

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

implemented at the time, it could have identified the recurring problems with these valves, and it could have prevented the subsequent ineffective root cause analysis performed.

Dresden is in the process of developing a matrix to establish the training recommended for investigators, team leaders, and reviewers, and this matrix will be completed by 10/01/94. (NTS 237-180-94-00402)

In addition, the IRP procedure will be revised to contain requirements to determine the reason the past corrective actions failed. These actions will be completed by 10/01/94. (NTS 237-180-94-00403)

F. PREVIOUS OCCURRENCES:

LER/Docket Numbers	Title

No previous occurrences were noted.

G. COMPONENT FAILURE DATA:

Manufacturer	Nomenclature	Model Number	Mfg. Part Number

None

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LER No. 237/94-006
Dresden, Unit 2

ACCESSION #: 9412050207 GE DEC 2 7 1994

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Dresden Nuclear Power Station, Unit 2 PAGE: 1 OF 4

DOCKET NUMBER: 05000237

TITLE: Unit 2 Shutdown Cooling Pump Motors did not have Relay Setting Orders Reviewed Prior to Motor Installations due to Inadequate Work Practices

EVENT DATE: 02/05/94 LER #: 94-006-01 REPORT DATE: ~~03/07/94~~ 11/30

OTHER FACILITIES INVOLVED: None DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 099

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

LICENSEE CONTACT FOR THIS LER:
NAME: George C. Eckert III, SEC Ext. 2796 TELEPHONE: (815) 942-2920

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

SUPPLEMENTAL REPORT EXPECTED: YES EXPECTED SUBMISSION DATE: 09/16/94

ABSTRACT:

At approximately 1300 hours on February 5, 1994 with Unit 2 at 99% power, it was discovered that the installed Unit 2 Shutdown Cooling Pump Motors, which were replacement motors, had different electrical characteristics than the original motors. It was determined that a review of the protective relay setpoints for these motors had not been performed.

Subsequent engineering analysis indicated that the relay setpoints should be reset to accommodate the installed motors. The analysis also indicated that the coordination between the motor feed breakers and the main feed breakers to ESS buses 23-1 and 24-1 had not been affected. The ESS buses were never in jeopardy of becoming unavailable due to a fault at or on any of the Shutdown Cooling Pump motors. The protective relay setpoints were reset and the pumps declared operable.

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END OF ABSTRACT

EVENT IDENTIFICATION:

Unit 2 Shutdown Cooling Pump Motors did not have Relay Setting Orders Reviewed Prior to Motor Installations due to Inadequate Work Practices.

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 2 Event Date: 02/05/94 Event Time: 1300 hrs

Reactor Mode: N Mode Name: Run Power Level: 99%

Reactor Coolant System Pressure: 1000 psig

B. DESCRIPTION OF EVENT:

At approximately 1300, on February 5, 1994 with Unit 2 operating at 99% power, it was determined that replacement motors installed on the 2A, B, and C Shutdown Cooling pumps did not receive an evaluation of the effect of the replacement motors on protective relay (breaker) settings. This problem was discovered during a similar installation on Unit 3.

The Unit 2 Shutdown Cooling Pumps were declared administratively inoperable per Dresden Administrative Technical Requirements 3/4.9 on February 5, 1994 at 1459. An ENS phone notification was made at 1459 EST, February 5, 1994 to report a condition affecting RHR Capability. Engineering analysis was performed to determine the correct relay setpoints and the effect the new setpoints would have on the ESS buses (EB). The analysis indicated that the relay setpoints should be reset to accommodate the installed motor. The new relay setpoints would not affect the coordination of any of the motor feed breakers with the upstream ESS bus feed breakers. Therefore, the upstream relays would not be reset.

The existing configuration of the installed motors and existing relay setpoints did not adversely affect the availability of the ESS buses. The existing relay setpoint had both the long time and instantaneous settings too low for the existing motor. As such, a motor may have spuriously tripped its feed breaker due to high current but would not have challenged the main feed breaker to the ESS buses.

C. CAUSE OF EVENT:

This report is being submitted in accordance with 10 CFR 50.73(a)(2)(v) which requires the reporting of any event or condition that alone could have prevented the fulfillment of the safety function of systems needed to remove residual heat.

The apparent cause of having motors installed without a review of their protective relay setpoints is due to a preconceived idea that this motor changeout was a like-for-like replacement and did not require an engineering review. This work was classified as reliability related. The existing work practices and procedures do not require an engineering review of this type of work package. The interaction of the replacement motor with the existing

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protective relaying was not understood or believed to be a problem. Consequently, the change was not compatible with the as built condition.

D. SAFETY ANALYSIS:

The Shutdown Cooling System is not considered safety related or used to mitigate the consequences of any design basis accident. The protective relays were found to be improperly set in the direction which would have resulted in spurious tripping of the affected motors. Engineering analysis of the installed protective relay setpoints determined that the safety related bus which feeds the affected motors would have been protected from a postulated fault. All three of the affected motors have been satisfactorily run since their installation thereby making it highly unlikely that all three Shutdown Cooling Pump motors would have simultaneously caused breaker trips upon demand. Furthermore, if all three Shutdown Cooling pumps were lost, procedural guidance exists per DOA 1000-1 if alternate Shutdown Cooling methods were required.

The ESS 23-1 and 24-1 4kv buses provide the electrical feed to the Shutdown Cooling Pump motors. At no time were these buses in jeopardy of being lost because of the improperly set protective relays for the Shutdown Cooling Pump motors. The protective relays for the Shutdown Cooling Pump motor breakers must coordinate with the protective relays on the main feed breakers to the ESS buses. Coordination ensures that a fault at a load will be cleared by the load breaker and will not propagate upstream to the main feed breaker. Coordination existed between the Shutdown Cooling Pump motor breakers and the main feed breakers both before and after the Shutdown Cooling Pump motors protective relays were reset. Therefore, if a fault condition existed at or on a Shutdown Cooling Pump motor, the motor feed breaker would have tripped without affecting the availability of the ESS bus.

E. CORRECTIVE ACTIONS:

1) The protective relays for all three Shutdown Cooling Pump motor breakers were reset on 2/11/94.

2) As a result of this event, a root cause investigation team was formed to determine what work procedures or practices should be modified to prevent recurrence of this event. The team consisted of representatives from operations, System engineering, electrical maintenance, stores, and site engineering departments. The root cause of the event was determined to be a breakdown in the station work request program. The new motors were believed to be a like-for-like substitution for the existing motors. However, although the new motors matched the existing motors in horsepower, voltage, RPM, and other parameters, certain characteristics were not the same. These characteristics, including the fact that the new motors were high efficiency, gave the new motors different electrical current requirements.

Existing procedures were reviewed to determine if they were violated, unclear, or lacking necessary information for this specific event. It was determined, however, that the existing procedures governing work request generation and processing were not violated and did not need to be revised. Instead a heightened level of awareness concerning motor

characteristics and their effects on electrical systems was achieved through engineering correspondence and training. The Site Engineering Plant Support department issued a letter (CHRON #0302044) listing certain motor parameters which affect relay setpoints. The letter was issued to Site and Systems Engineering personnel as well as electrical maintenance work analysts. For future reference the letter was incorporated into the Work Analyst's Guide to Work Package Preparation as a supplement for this lesson learned. This event was included in the operator's six week training cycle, and was presented in tailgate as a lessons learned item. To assure the lessons learned form this event were identified to the appropriate personnel, the maintenance and engineering individuals involved in the motor replacement were members of the root cause evaluation team and responsible for the lessons learned identification and these corrective actions. Also, the work analyst involved with the motor replacement recognizes and acknowledges his error and clearly understands the impact of motor characteristics on relays settings.

F. PREVIOUS OCCURRENCES:

There were no previous occurrences of this nature found.

G. COMPONENT FAILURE DATA:

None.

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LER No. 237/94-018
Dresden, Unit 2

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Dresden Nuclear Power Station, Unit 2	05000237	1 OF 7

TITLE (4): Potential Trip of Motor Control Centers Due to Improper Feed Breaker Settings

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
06	08	94	94	-- 018 --	01	07	07	94	Dresden, Unit 3	05000249
									FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N
POWER LEVEL (10)	000

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

	20.2201(b)		20.2203(a)(3)(i)		50.73(a)(2)(iii)		73.71(b)
	20.2203(a)(1)		20.2203(a)(3)(ii)	X	50.73(a)(2)(iv)		73.71(c)
	20.2203(a)(2)(i)		20.2203(a)(4)		50.73(a)(2)(v)		OTHER
	20.2203(a)(2)(ii)		50.36(c)(1)		50.73(a)(2)(vii)		(Specify in Abstract below and in Text, NRC Form 366A)
	20.2203(a)(2)(iii)		50.36(c)(2)		50.73(a)(2)(viii)(A)		
	20.2203(a)(2)(iv)		50.73(a)(2)(i)		50.73(a)(2)(viii)(B)		
	20.2203(a)(2)(v)	X	50.73(a)(2)(ii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
George C. Eckert II, Plant Support Engineer Ext. 2796	(815) 942-2920

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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

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

With Unit 3 in Refuel, while performing a 24 hour endurance run of the Unit 3 Emergency Diesel Generator, motor control center (MCC) 39-2 tripped. The trip of MCC 39-2 caused a trip of the Unit 3 Emergency Diesel Generator Cooling Water Pump and consequently a trip of the Unit 3 Emergency Diesel Generator on high temperature. Loss of MCC 39-2 also caused a loss of the 3B Reactor Protection System (RPS) MG-Set, the "B" Standby Gas Treatment (SBGT) Train, the 125VDC Charger #3 and the 250VDC Charger #2/3. The loss of the RPS MG-Set caused a Unit 3 half scram, and the loss of the "B" SBGT train caused a start of the "A" SBGT train, which is considered an ESF actuation. An operability determination was made which stated that the MCC trip was due to an improperly set feed breaker. It also stated that the MCC was operable provided the compensatory action of controlling running load on the MCC was implemented. Station Operations department controlled the loading on the MCC until trip settings could be revised. A review of the MCC loading indicated that the original setting of the breaker was adequate but that load additions over time had created an overload situation. This event initiated a review of all safety related MCC feed breakers. The review indicated that MCCs 28-3 and 38-3 also had improperly set feed breakers. A separate operability assessment was performed on these two MCCs, which included immediate compensatory actions of controlling running loads to below the breakers' trip settings. The loading restrictions remained in place until the breakers could be properly set.

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	2 OF 7

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

EVENT IDENTIFICATION:

Potential Trip of Motor Control Centers Due to Improper Feed Breaker Settings

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 2(3) Event Date: 06/08/94 Event Time: 1913 hrs

Reactor Mode: N(N) Mode Name: Run (Refuel) Power Level: 99% (00%)

Reactor Coolant System Pressure: 1005 (00) psig

B. DESCRIPTION OF EVENT:

On June 8, 1994 with Unit 3 in Refuel Mode, MCC 39-2 inadvertently tripped at 1913. The trip occurred concurrently with a 24 hour endurance run of the Unit 3 Emergency Diesel Generator [EK], during operation of the Unit 2/3 SBGT System [BH] "B" train, and during a Unit 2 High Pressure Coolant Injection (HPCI) [BJ] surveillance. There were no failed components which contributed to this event. The following equipment is fed by MCC 39-2 and consequently became unavailable when the MCC tripped:

Unit 3 Emergency Diesel Generator Cooling Water Pump [LB]
Unit 3 Emergency Diesel Generator Vent Fan [EK]
Unit 3 Emergency Diesel Generator Starting Air Compressor 3B [LC]
Unit 3 Emergency Diesel Generator Fuel Transfer Pump [EK]
CCSW Pump Cubicle Cooler C Fans 1 and 2 [BO]
CCSW Pump Cubicle Cooler D Fans 1 and 2 [BO]
SBGT Inlet Damper 2/3B [BH]
SBGT Air Heater 2/3B [BH]
SBGT Fan Discharge Damper 2/3B [BH]
SBGT Fan 2/3B [BH]
SBGT Outside Air Damper 2/3B [BH]
Reactor Building Vent to SBGT Damper 2/3B [BH]
RPS Motor-Generator Set 3B [JC]
125VDC Battery Charger 3 [EJ]
250VDC Battery Charger 2/3 [EJ]
Turbine Building Emergency Lighting [FG]
Condensate Transfer Pump 3B [KA]

Trips of these services caused the following system events to occur:

Loss of the SBGT [BH] "B" train caused an automatic initiation of the "A" train at 1913. This is considered an ESF actuation and an ENS notification was made at 2235 EST on June 8, 1994.

Loss of the Emergency Diesel Generator Cooling Water Pump [LB] and Vent Fan [EK] caused a trip of the Emergency Diesel Generator [EK] due to high temperature at 1914.

Loss of the RPS Motor-Generator Set [JC] caused a loss of power to the RPS and, consequently, a Unit 3 half scram.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	3 OF 7

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

Loss of the 125VDC charger #3 required that operators realign the Unit 3 125VDC system [EJ] to the available 125VDC charger #3A. Loss of the 250VDC charger 2/3 required that operators realign the Unit 3 250VDC battery system [EJ] to the available 250VDC charger #3. Both battery systems were realigned by 1928.

The next actions were to strip the MCC of all its loads and reclose the feed breaker at switchgear 39 which was completed at 1935. The SBGT "B" train was placed in off and then reenergized at 1937. The Emergency Diesel Generator Cooling Water Pump and Vent Fan were energized from MCC 39-2 and started. All remaining loads on MCC 39-2 were restored by 1942.

Due to existing plant conditions, the MCC trip was not believed to be a result of a fault condition. The trip was believed to be due to an overcurrent condition in the long time range of the feed breaker. Per discussions with operating personnel, the HPCI Auxiliary Oil Pump had been recently started when the breaker tripped. Starting the pump would cause the Unit 2/3 250VDC battery charger to go into a current limiting condition meaning that it would draw its maximum current rating from its AC source. This large load in conjunction with the other loads already running on the MCC caused a current of approximately 405 Amps to be drawn. This is in excess of the feed breakers 400 Amp trip setting. The trip of the breaker is not considered an equipment failure because it tripped as designed.

A review of the loads fed from MCC 39-2 indicated that the loads energized during the event may also be energized under certain accident conditions. This implied that the MCC and therefore the loads would not be available for accident mitigation under all scenarios. Because a basis for the existing feed breaker setpoint could not be immediately established, an operability determination was begun by Site Engineering to determine the worst case accident load scenario. The results indicated that the breaker was set too low for a postulated LOCA condition without loss of offsite power; a loading condition similar to the recent event. Immediate compensatory actions were directed to the station Operations Department. The compensatory actions included realigning the AC feed of the Unit 2/3 250VDC charger to MCC 29-2 and to consider the Condensate Transfer Pump 3B out of service. This would ensure the connected load would not trip the feed breaker under accident conditions.

The overcurrent trip device in MCC 39-2 is a General Electric dashpot type EC-2A device which is original plant equipment. Because a basis could not be established for the existing setting, all other MCCs using the original EC-2A devices were also suspect. A review was performed which determined that the remaining MCC feed breakers using EC-2A devices would not suffer from a similar overcurrent problem.

A review of all safety related MCC feed breakers, including those which used newer RMS-9 trip devices, was also performed. The review accounted for all accident conditions to determine the worst case loading and voltage conditions on the safety related switchgear and MCCs. The review indicated that the feed breakers for MCCs 28-3 and 38-3 were also set too low for all postulated conditions. Because the breakers to these MCCs were set too low for all postulated events, the emergency AC power system was believed to be outside of its design basis and an ENS notification was made at 1312 EST on June 13, 1994.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	4 OF 7

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

A second operability assessment was performed to address MCCs 28-3 and 38-3. Immediate compensatory actions similar to those for the previous operability determination were again directed to the station Operations Department. The actions included considering the Turbine Bearing Lift Pumps out of service on MCC 28-3 and considering the Turbine Turning Gear out of service on MCC 38-3. These actions would ensure the connected loads would not trip the respective feed breakers.

C. CAUSE OF EVENT:

This report is being submitted in accordance with 10CFR50.73(a)(2)(ii), which requires the reporting of any event or condition that results in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded, or results in the nuclear power plant being in a condition that is outside the design basis of the plant; and in accordance with 10CFR50.73(a)(2)(iv), which requires the reporting of any event or condition that results in manual or automatic actuation of any Engineered Safety Feature.

The trip of MCC 39-2 was due to an incorrectly set feed breaker. The feed breaker for this MCC had a General Electric dashpot type EC-2A overcurrent trip device which was original equipment. The setting for this breaker was 400 amps +/- 10% due to tolerance of the EC-2A device. A review of the original loading on the MCC indicates that the 400 Amp setting was adequate based on protective device setting standards at the time of original design. Load additions made to the MCC over time however, increased the available running load current above the 400 Amp setting. Therefore, the cause of the overload condition was a failure to assure that additions of plant loads were reviewed for impact on breaker settings.

The feed breakers to MCCs 28-3 and 38-3 have had their EC-2A trip devices replaced with General Electric solid state type RMS-9 trip devices. The new RMS-9 devices provide enhanced trip selectivity to allow 480VAC breaker coordination. The RMS-9 devices were installed in November 1991 for MCC 38-3 and March 1993 for MCC 28-3. Both of these feed breakers were set at 400 amps. Because the new devices were installed after implementation of the ELMS program, an investigation was performed by the Electrical / I&C department in Downers Grove to determine the cause of the protective device settings for MCCs 28-3 and 38-3 not reflecting all postulated load conditions. This department performed the investigation because it was responsible for control of 480 Vac Switchgear protective device settings at the time of the event.

The investigation determined that the new setting for MCC 38-3 was chosen to be identical to the original setting based on the assumption that the MCC loading had not changed over time. This was determined by interviews with the personnel involved with the setting calculations. Also, letter #173174 dated September 18, 1991, which transmitted the revised device setting, gave no basis for the setting and did not identify the potential for an overloaded protective device. However, since loading had changed, the total connected load was greater than the protective device setting. The cause of the overloaded condition is therefore a failure to assure that the addition of plant loads over time were reviewed for impact on breaker settings, and a failure to review plant conditions during the calculation of the protective device setting.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION		APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.			
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	5 OF 7

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

At the time the setting for MCC 28-3 was issued, it was recognized that the protective device setting was lower than the total connected load. That information is documented in letter #197606 dated February 2, 1993. However, since the new protective device setting was identical to the original setting, it was assumed that the running load during accident conditions would be within the setting of the protective device. The significance of the potential for an overloaded protective device was not understood by those receiving it or by its authors. The actual running load during a design basis accident was not considered during the device setting calculation. The cause of the overloaded condition on MCC 28-3 therefore, is the same as that for MCC 38-3.

D. SAFETY ANALYSIS:

The following discussion makes reference to the equipment fed by MCCs 28-3 and 38-3; the loads are printed here for ease of discussion.

28-3

Turning Gear Oil Pump	Turning Gear
Piggy Back Motor	Turbine Bearing Lift Pumps
Fire Protection Panel FP-2	Unit 2 250VDC Charger
Unit 2 EDG Circ Lube Oil Pump	Unit 2 EDG Turbo Lube Oil Pump
Unit 2 EDG Immersion Heater	Unit 2/3 EDG Cooling Water Pump

38-3

Turning Gear Oil Pump	Turning Gear
Piggy Back Motor	Turbine Bearing Lift Pumps
Fire Protection Panel FP-3	CCSW Cubicle Cooler A Fans 1&2
RPS MG-Set 3A	CCSW Cubicle Cooler B Fans 1&2
Unit 3 EDG Circ Lube Oil Pump	Unit 3 EDG Turbo Lube Oil Pump
Unit 3 EDG Immersion Heater	Unit 2/3 EDG Cooling Water Pump
Distribution Panel 2253-85	

The auxiliary power system is designed using safety related and balance of plant switchgear and MCCs to provide AC power to normal and emergency plant loads. The safety related equipment is divided into two separate divisions to provide diversity and redundancy. Under accident conditions, the safety related equipment is designed to have power supplied from the safety related Emergency Diesel Generators of the same division. There are two accident scenarios which are considered to present the worst case loading conditions for the safety related equipment; 1) a Loss of Coolant Accident with a Loss of Offsite Power (LOCA/LOOP) and, 2) a Loss of Coolant Accident with offsite power available (LOCA).

During a LOCA/LOOP condition, some loads on MCCs 28-3, 38-3 and 39-2 will trip and not reenergize when the Emergency Diesel Generators start and provide power to the emergency buses. As such, the loading on the MCCs is significantly reduced and the voltage levels are greatly improved thereby reducing the current draw. Preliminary analysis has been performed which indicates that under LOCA/LOOP conditions, MCC 28-3 may trip due to current levels above the feed breaker's setting. The other MCCs will not trip due to excessive current.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	6 OF 7

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

Loss of MCC 28-3 would cause a loss of the Unit 2/3 Emergency Diesel Generator Cooling Water Pump. Although this pump has a backup source of power from MCC 38-3, it is assumed that under Unit 2 LOCA and full site LOOP conditions, MCC 38-3 would not have a source of power. Therefore, the Unit 2/3 Emergency Diesel Generator would not have cooling water and is assumed to be unavailable. Assuming a single failure on the Unit 2 Emergency Diesel Generator would render all Unit 2 emergency AC power sources unavailable. However, the Division I crosstie between buses 34-1 and 24-1 would be available to provide AC power. The remaining loads on MCC 28-3 are not required to mitigate the consequences of an accident or to ensure operability of safety related equipment.

Under the second condition of LOCA with offsite power available, it is conservatively assumed that the offsite power is degraded to a level slightly above the second level degraded voltage relay setpoint so that the Emergency Diesel Generator has started on the LOCA signal but is not connected to the bus, thereby forcing onsite power to its lowest postulated value. Under this condition, preliminary analysis has shown that MCCs 28-3, 38-3 and 39-2 will trip due to current levels above the feed breakers' settings thereby causing all loads on the MCCs to become deenergized. The Unit 2/3 and Unit 3 Emergency Diesel Generator Cooling Water Pumps would be lost causing the Emergency Diesel Generators to fail or require manual operator action to be taken to restore cooling. An assumed single failure of the Unit 2 Emergency Diesel Generator would cause all on site emergency AC power to be unavailable. However, in the assumed scenario, offsite power is available to mitigate the consequences of the LOCA.

Another significant load is the feed to the SBGT "B" train. This event could have resulted in the "B" train being unavailable to maintain releases within 10CFR100 limits. However, the "A" train was not affected by this event. Also, loss of the CCSW cubicle cooler fans may cause a loss of the vaulted CCSW pumps and therefore inhibit long term cooling ability. This would again require operator action to mitigate the consequences of this loss. However, the CCSW motors are manually started loads and therefore operator action is already required. Loss of the remaining loads on the MCCs would not cause the inability to mitigate the consequences of an accident.

E. CORRECTIVE ACTIONS:

Immediate corrective actions during the loss of MCC 39-2 included reenergizing the tripped loads. Intermediate corrective actions included operability assessments performed by Site Engineering. The compensatory actions associated with the operability assessments included limiting the loads connected to the affected MCCs. Long term corrective actions of replacing the existing feed breakers to the affected MCCs with properly set breakers is complete. The feed breaker to MCC 39-2 has been replaced with a breaker that contains an RMS-9 trip device. All trip device settings have been reviewed and, where necessary, reset at levels that account for breaker coordination and worst case current levels expected at the individual MCCs.

Long term corrective actions also included reviewing various historical loading conditions on the auxiliary power system. The review considered the modifications to the auxiliary power system over the years including those due to degraded voltage considerations, addition of new MCCs, and other system

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 018 --	01	7 OF 7

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

changes. The review determined that loads were added which caused an overcurrent condition on these MCCs. However, long term corrective actions with regard to the modification process are not believed necessary due to this event. The load additions which created the overcurrent conditions were made prior to modification enhancements. The heightened level of awareness regarding the auxiliary power system design and the modification process in general have resulted in substantial required reviews during the process of adding loads. The modification process now requires a load analysis by the Electrical Load Monitoring System as well as breaker coordination and protective device setting calculations when a new load is added.

With regard to the improper review of plant loading conditions during device setpoint calculation, the investigation determined that Technical Information Document TID-E/I&C-13, 480 Volt Switchgear Trip Device Selection And Setting, was not issued until May 21, 1993. This TID gives guidance as to how a protective device for an MCC feed breaker is to be sized. Prior to issuing the TID, protective device setpoints were determined in accordance with procedure ENC-QE-59. However, the guidance in QE-59 is directed toward new design as opposed to modification of an older plant. In calculation of the device setpoints for Dresden, it was believed that the existing setpoints were adequate and that review of the running loads was not required. The personnel involved with the calculations recognize and acknowledge the error of this methodology, and understand the importance of reviewing plant conditions prior to calculating protective device settings. These personnel were responsible for the investigation into the event, the determination of the affected MCCs, and the corrective actions.

As an added action to prevent recurrence, additional controls have been placed on load changes and the resulting impact on the electrical distribution system trip device settings. The ELMS-AC+ program, used to evaluate the system load flow, has been revised to flag conditions in which the additional load current will exceed the ampacity of the connection. Through the load addition process, both the ELMS program and Relay Setting Program are updated. The ELMS program will flag cases in which the running load is higher than the cable ampacity, therefore requiring further evaluation to avoid nuisance tripping. The protective device settings are currently and will continue to be checked to ensure coordination. This action will preclude recurrence and assure proper review for protection and coordination within the electrical distribution system.

In cases where the connection ampacity is higher than the protective device setting, the device setting will be revised through the relay setting program. The new setting will reflect the additional load condition and thereby also avoid nuisance tripping. The current modification process requires a review of both the ELMS database and protective device settings when a new load is added or a current load is modified.

F. PREVIOUS OCCURRENCES:

There have been no previous occurrences in which a MCC spuriously tripped due to an incorrect breaker setting.

G. COMPONENT FAILURE DATA:

N/A

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Appendix I

LER No. 237/94-021
Dresden, Unit 2

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Dresden Nuclear Power Station, Unit 2	05000237	1 OF 10

TITLE (4)
HPCI Turbine Tripped on High Exhaust Pressure Due to a Failed Exhaust Check Valve

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
08	04	94	94	-- 021 --	01				None	
									FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)	099	20.2201(b)	20.2203(a)(3)(i)	50.73(a)(2)(iii)	73.71(b)
		20.2203(a)(1)	20.2203(a)(3)(ii)	50.73(a)(2)(iv)	73.71(c)
		20.2203(a)(2)(i)	20.2203(a)(4)	X 50.73(a)(2)(v)	OTHER
		20.2203(a)(2)(ii)	50.36(c)(1)	50.73(a)(2)(vii)	(Specify in Abstract below and in Text, NRC Form 366A)
		20.2203(a)(2)(iii)	50.36(c)(2)	50.73(a)(2)(viii)(A)	
		20.2203(a)(2)(iv)	50.73(a)(2)(i)	50.73(a)(2)(viii)(B)	
		20.2203(a)(2)(v)	50.73(a)(2)(ii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Mark Churilla, System Engineer Ext. 2788	(815) 942-2920

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	JB	INV	R340	Y						

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO		02	08	95

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

On August 4, 1994, at 1559 hours, with Unit 2 at 99% rated core thermal power, while performing Dresden Operating Surveillance (DOS) 2300-03, High Pressure Coolant Injection (HPCI) System Monthly Operability Verification, the turbine tripped due to high exhaust pressure. Inspection of the turbine drain system was performed. The rupture diaphragm was also replaced. The turbine was retested on August 7, 1994. The drain system and the exhaust line check valves were functionally tested. The turbine was manually tripped prior to exhaust pressure reaching 30 psig. Following a failed Local Leak Rate Test (LLRT) Unit 2 was shutdown. The cause of the high exhaust pressure was the failure of the 2-2301-74 check valve. The valve disc was found separated from the piston guide assembly. Tack welds which prevent the assembly from rotating were found cracked due to fatigue. The valve disc was reassembled with the piston guide and tack welded. The safety significance of this event is considered moderate. There have been no previous events.

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	2 OF 10

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

EVENT IDENTIFICATION:

HPCI [BJ] Turbine Tripped on High Exhaust Pressure Due to a Failed Exhaust Check Valve

A. PLANT CONDITIONS PRIOR TO EVENT:

Unit: 2 Event Date: 08/04/94 Event Time: 1559

Reactor Mode: N Mode Name: R Power Level: 99%

Reactor Coolant System Pressure: 1004 psig

B. DESCRIPTION OF EVENT:

On August 4, 1994, at 1559 hours, with Unit 2 at 99% rated core thermal power, while performing Dresden Operating Surveillance (DOS) 2300-03, High Pressure Coolant Injection System Monthly Operability Verification, the turbine tripped due to high exhaust pressure. Prior to the trip, the turbine was operated for approximately 5 minutes at 2500 rpm during manual trip verification. Following the manual trip, the turbine was rolled back up to 2500 RPM for a fifteen minute warming period. During the time the turbine was being rolled back up to 2500 rpm, steam was noted to be leaking from the Low Pressure Gland Seal area. The turbine automatically tripped approximately one minute into the warming evolution. The HPCI system was declared inoperable and the steam supply was isolated. Following the failure of the test, the exhaust line high pressure switches, 2-2368A and 2-2368B, were functionally checked. Both switches actuated at 100 psig (+/- 3 psig). In order to determine the cause of the steam leakage out of the low pressure gland seal, a walkdown of the cooling water valving was performed. The walkdown found the 2-2399-94 valve, the HPCI cooling sensing line valve, closed. The closure of this valve decreased the cooling water flow to the Gland Seal Condenser (GSC). The valve was restored to the proper position. There was no further testing or troubleshooting performed on August 4, 1994.

Based on Commonwealth Edison experience, the high exhaust pressure was believed to have been caused by the presence of water in the turbine exhaust. Two previous turbine high exhaust events, within Commonwealth Edison at other stations concerning HPCI/RCIC turbines, have been caused by the presence of water in the turbine exhaust. During this event, an unexpected exhaust drain [WK] pot high level alarm did annunciate and clear during the initial warming of the turbine indicating the presence of water in the turbine exhaust. In addition, several weeks earlier, the turbine exhaust drain pot high level alarm annunciated while the HPCI system was in its normal standby condition. The drain pot was drained and the leakage into the drain pot was later determined to be caused by steam leakage past AO2-2301-28, HPCI Inlet Drain Pot Discharge valve.

On August 5, 1994, a multi-disciplined troubleshooting team (team) was assembled to assess the turbine trip and prepare the system for a retest, if possible. The team consisted of the System Engineering Supervisor, HPCI System Engineer, Site Engineering Supervisor, General Electric Site Representative, Unit 2 Master Work Scheduler and the Operations Department Supervisor. In addition, the Quad Cities System Engineer was taking part in our teleconference for additional

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	3 OF 10

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

insight of similar problems at Quad Cities. The team was responsible for determining the cause of the turbine exhaust high pressure problem and to resolve it prior to retesting the turbine. The following actions were presented to the team by the HPCI System Engineer: inspection or functional check of the exhaust check valves 2-2301-45, HPCI Turbine Exhaust Check Valve 2-2301-74, HPCI Turbine Exhaust Check Valve, 2-2301-34, HPCI Turbine Drain Exhaust Check Valve, 2-2301-71, HPCI Turbine Drain Exhaust Check Valve, disassemble the rupture diaphragm, functionally check exhaust drain pot level switch, check turbine drain restricting orifices for blockage, inspect AO2-2301-28, review the potential impact of the new revision to DOS 2300-03, and functionally check gland seal condenser (GSC) drain pressure switch.

The team discussed the aforementioned items and the sequence of the events that occurred on August 4, 1994. The areas focused on were the high exhaust line pressure alarm and the steam leak from the low pressure gland seal area. The team determined that the probability of a turbine exhaust check valve failure was not the potential cause of the high exhaust pressure. This was based on the short duration of the exhaust high pressure alarm and the fact that the turbine operated for approximately 5 minutes prior to failure. It was determined that the HPCI exhaust check valves would be functionally tested during performance of the HPCI retest, as provided for in DOS 2300-03. The original duration of the exhaust alarm that was reported to the team on August 5, 1994, was .07 seconds. The exhaust alarm duration was determined from review of the Sequence of Events Recorder (SER) [IQ] print out. The following actions were recommended by the team: verified turbine case drain restricting orifice is free of blockage, functionally checked Gland Seal Condenser (GSC) pressure switch, functionally checked the Exhaust Drain Pot Level Switch, and installed exhaust line instrumentation to monitor pressure. The team reviewed the new DOS 2300-03 procedure revision that was used during the performance of the August 4, 1994, test, replaced the rupture diaphragm, and performed a valve check list on all valves in the HPCI room. The applicable changes made involved the initial speed at which the turbine is brought up to for manual turbine trip verification. The procedure was changed from 1000 rpm to 2500 rpm with General Electric concurrence and the first HPCI run, under the new speed, was conducted on August 4, 1994. General Electric has stated that the process of bringing the turbine up to an initial speed of 2500 rpm is acceptable. The HPCI turbine has been fast start tested numerous times without any exhaust pressure problems occurring. In addition, NRC Information Notice (IN) 82-26, RCIC and HPCI Exhaust Check Valve Failures, recommends that "System operation below the recommended turbine rated speed should be minimized." Therefore, based on previous operation of the turbine and recommendations from General Electric, it was determined that the new procedure revision used for this event was not a contributing factor to the high exhaust pressure.

Following the original recommendations, the duration of the high exhaust line pressure alarm was later verified, on August 5, 1994, to be 7 seconds instead of the reported .07 seconds. This oversight was the result of the HPCI System Engineer mis-reading the SER printout. After discovering the mistake, the decision was made by the team leader to continue with the present course of action and add the requirement to replace the rupture diaphragm.

In addition, the team recommended that the Operations Department perform a valve checklist on all valves in the HPCI room prior to the next test. The

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION		APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.			
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	4 OF 10

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

performance of the check list would identify any valve mispositioning prior to the performance of the next test.

The following repairs and inspections were completed successfully on August 6, 1994: verified turbine case drain restricting orifice is free of blockage, functionally checked Gland Seal Condenser (GSC) pressure switch, functionally checked the Exhaust Drain Pot Level Switch, installed exhaust line instrumentation to monitor pressure, the team reviewed the new DOS 2300-03 procedure revision that was used during the performance of the August 4, 1994, test and replaced the rupture diaphragms. In addition, the HPCI valve check list was performed on all valves in the HPCI room on August 7, 1994. Due to a lack of control room personnel manpower, the performance of the HPCI test was postponed until August 7, 1994.

On August 7, 1994, an extensive Heightened Level of Awareness (HLA) meeting was held with the operating crew prior to retesting HPCI. The HLA was conducted by the HPCI System Engineer. The areas that were covered extensively involved the verification of the HPCI Exhaust Line Check valves' operation. The Nuclear Station Operator (NSO) was informed that the expected exhaust line pressure would be a maximum of 35 psig at full turbine speed. The instructions were given to the NSO to trip the turbine if exhaust pressure approached 35 psig prior to reaching full power conditions on the turbine (4000 rpm).

At 1900 hours, the HPCI operability surveillance began. The initial warming of the turbine was performed to functionally check the drain system. The exhaust drain pot and associated drain line check valves were verified to be operating satisfactorily by the system engineer. The turbine was then rolled up to 1600 rpm when it was noted by the NSO that exhaust pressure was increasing at a higher than normal rate. The turbine was manually tripped prior to the exhaust pressure reaching 30 psig. The HPCI steam supply was immediately isolated to prevent the turbine from starting on an Emergency Core Cooling System initiation signal. The 2-2301-74 valve was then manually closed to isolate the exhaust line.

After the August 7th run, investigation of the turbine exhaust check valves was pursued. A local leak rate test (LLRT) of the check valve volume was performed and leakage was found which exceeded the Technical Specifications (TS) limit (the LLRT failure is being addressed in a separate Licensed Event Report (LER) Docket 50-237, number 94-022). Since the HPCI exhaust line check valves could not be repaired on line, the reactor was shutdown.

The 2-2301-45 valve HPCI Turbine Exhaust Check Valve, was disassembled and inspected under work request D26915. The check valve seats were found to be slightly worn due to normal valve operation. This failure did not affect the operation of the HPCI system.

The 2-2301-74 valve HPCI Turbine Exhaust Check Valve, was disassembled and inspected under work request D26919. The valve disk was found not attached to the valve guide piston. Further inspection revealed that the four tack welds, which prevent the assembly from rotating, had broken due to fatigue.

A search of industry operating experience was performed and two documents were found which are directly related to this event: INPO Significant Operating SOER Experience Report (SOER) 86-3, Check Valve Failures Or Degradation

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(Recommendation 1), and NRC Information Notice (IN) 82-26, RCIC and HPCI Turbine Exhaust Check Valve Failures.

Review of SOER 86-3, (Recommendation 1), was performed initially in July of 1986, addressing the preventive maintenance program for check valves. Dresden Administrative Procedure (DAP) 11-25, Check Valve Inspection Program, was issued in October, 1988, to implement the check valve preventive maintenance program. However, stop check valve 2-2301-74 was included in the preventative maintenance program for inspection/testing in January, 1994. Dresden's original response to SOER 86-3 stated that the HPCI system check valves would be included in the program. The reason for not including the 2-2301-74 valve in the original preventive maintenance program has not been determined. However, Site Engineering and Construction personnel recognized, in the fourth quarter of 1993, that the 2-2301-74 valve was not included in the preventive maintenance program and informally added it to the PM program in January, 1994, prior to this event. The 2-2301-74 valve had been scheduled for inspection during D2R14 starting in March of 1995.

NRC IN 82-26 concerned problems with HPCI turbine exhaust high pressures resulting from check valve problems. In the IN's discussion section, General Electric (GE) Application Information Document (AID) No. 56, High Pressure Core Injection and Reactor Core Isolation Cooling Turbine Exhaust Check Valve Cycling, recommended actions are provided.

Recommendation 5 states, "the turbine exhaust check valve internals should be inspected on a routine schedule such as every refuel outage" due to possible system flow blockage. In the response to this recommendation, the reviewer stated that local leak rate tests (LLRT) would be performed every outage rather than valve inspection and if the valve failed the LLRT, then an inspection would be performed. This response is deficient in three aspects. First, the response apparently failed to include the 2-2301-74 valve. If the LLRT failed, the focus for repairs would have centered on the 2301-45 check valve since this valve is the only valve taken credit for when performing LLRT on this volume. The reviewer also states that the IN does not apply because the failures in the IN are on swing check valves unlike the Duo-Check valve (2301-45), but fails to address the 2-2301-74 valve. Secondly, the focus of review is on primary containment, not elevated HPCI exhaust pressure. Leak rate testing is to assure valve closure and sealing and provides little indication of blockage in the line which could affect exhaust pressure. Thirdly, the scope of the review was too narrow. The generic applicability of turbine exhaust line blockage causing exhaust pressure to go high is not addressed.

C. CAUSE OF EVENT:

This report is being submitted in accordance with 10CFR50.73 (a)(2)(v)(B), which requires the reporting of any event that alone could have prevented the fulfillment of the safety function of systems that are needed to remove residual heat.

The root cause of this event is due to inadequate review of IN 82-26. If the reviewer had performed an adequate review of the IN, he may have recognized the need for inspection of both HPCI exhaust valves. If the HPCI exhaust valve internals would have been inspected, as recommended in IN 82-26, it is believed

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	6 OF 10

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

the valve degradation would have been found prior to the 2-2301-74 valve failure in August, 1994.

The 2301-74 valve is a stop check valve, of which none were initially included in the preventive maintenance program, in response to SOER 86-3. The reason the stop check valves were not included in the program was not documented at the time and cannot be determined. In the Station response to the SOER 86-3, it was stated that all check valves in the HPCI system would be included in the preventive maintenance program. However, the 2301-74 valve was not included in the tabulated list of valves for inspection/maintenance. Consequently, an inadequate review was performed and thus is a contributing cause to this event. It should be noted that all safety-related check valves, including stop check valves have been in the program since January, 1994. However, the 2(3)-2301-74 valves were not scheduled to be inspected until D2R14, starting in March, 1995 and D3R14, starting in January, 1996.

In addition, SOER 86-3 was reviewed for effectiveness on April 6, 1989, and October 22, 1993. Both reviews missed identifying the HPCI 2301-74 valve as being excluded from the preventive maintenance program. The April 1989 effectiveness review contains very little documentation, which prevents determining why the review missed the 2301-74 valve. The October, 1993 effectiveness review took a sampling of systems specified in the SOER 86-3 response and verified that those valves were included in the PM program. However, the sampling did not include the HPCI system, which prevented the reviewer from detecting the exclusion of the 2301-74 valve.

The closure of 2-2399-94, Cooling water sensing valve was determined to have been inadvertently closed during maintenance in the area on August 3, 1994. The valve is orientated next to oil filters which were cleaned. It is believed that during maintenance the valve was inadvertently closed by being brushed against.

Root Cause for 2-2301-74 valve separation:

On August 19, 1994, the tack welds that prevent the two components of the HPCI Turbine Exhaust stop check valve (2-2301-74) piston from disassembling were inspected by engineering and a member of the System Material Analysis Department (SMAD). Three important items were noticed during the inspection and are listed as follows:

1. The four tack welds were found broken. There was evidence of beaching marks (rough, chevron-shaped surface with curved rows extending from the initial crack area) on the surface of the tack weld fracture area. These marks are evidence that the initial cracks were caused by fatigue.

2. The tack welds were worn. Only two of the four tack welds had a surface with small remains of beaching marks.

3. The threads of the two components of the piston, which are normally covered if the two components are properly fastened, had very little corrosion. This is relative to the rest of the surface of the piston surrounding the threaded region.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	7 OF 10

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

From these observations, it was concluded that the fracture of the tack welds was due to fatigue, occurred recently and the separation of the two piston components occurred during the last HPCI turbine operation.

SMAD believed that the tack welds would be likely to fracture after twenty years of service in a high vibration, low cyclic stress environment. A tack weld fracture in this environment is not abnormal. The cause for the vibrations in the weld area is the loosening of the two piston components. Originally, the two components of the piston are tightened and tack welded, however, after time and many cycles of thermal expansion/contraction, the two components became loose. As the two components loosened, they were able to vibrate, and thereby caused cyclic stress in the tack welds, eventually initiating cracks and fracture in the welds.

The actual fracture of the tack welds was recent. This conclusion is proven by the condition of the surface of the fractures. The extent of the wear of the fracture surface was enough to remove most of the beaching marks except for the small traces found on two of the four tack welds.

The separation of the two piston components would have occurred during the last HPCI Turbine operation. This conclusion is supported by the fact that the HPCI Turbine Exhaust pressure has remained constant until this last turbine operation. This assumes that the HPCI turbine exhaust pressure will increase as the length of the piston is increased as it separates. Also, water was noted in the HPCI turbine before operation. This water can cause higher vibrations in the exhaust line and consequently an adverse effect on the check valve piston. These higher vibration amplitudes could have caused the two piston components to unscrew and finally separate; whereas, the previous vibration amplitude was not large enough. Therefore, it is believed that water in the HPCI turbine was a contributing cause to this event. Although the exhaust drain pot level alarm cleared during the performance of DOS 2300-03, it is believed that some water remained in the system. A verification which would have insured that the turbine was completely free of water, following the alarm, was not performed.

A maintenance history review indicated that the 2(3)-2301-74 valves have never been disassembled. A further review of the station safety related check valves with piston type design indicated that the 2-1402-8A, Core Spray [BM] pump discharge check valve, was a similar style and manufacturer. In addition, it was found that Quad Cities HPCI 2301-74 valve had a similar piston type design as Dresden's 2301-74 valve. The tack welds on the Quad Cities valve were found cracked during routine check valve inspection in April, 1994.

D. SAFETY ANALYSIS:

The HPCI system is designed with several exhaust overpressure protection devices. Pressure switches 2-2368A and 2-2368B are connected in parallel and are set to trip at 100 psig. Upon actuation of either pressure switch, the HPCI Turbine and Stop Valve will trip. The Exhaust Line also has a rupture diaphragm which opens at 125 psig to further prevent exhaust line overpressurization.

On August 4, 1994, the turbine tripped as designed when one of the exhaust pressure switches actuated. The HPCI system was isolated and declared inoperable. Further testing that was conducted on August 7, 1994 insured turbine exhaust pressure did not exceed 30 psig in order not to challenge the

turbine overpressurization devices. Following the testing the HPCI system, the supply steam was isolated to prevent the turbine from initiating. In addition, the 2-2301-74, HPCI Exhaust check valve, was manually closed to provide an exhaust isolation.

The safety significance of this event is considered moderate since the turbine protective devices operated as designed and all other Emergency Core Coolant Systems required by Technical Specification 3.5.C.a.2 were operable during this event.

E. CORRECTIVE ACTIONS:

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

Since the review of IN 82-26, the OPEX program has provided the reviewers with instructions to improve the responses and to assure that the concerns raised in the OPEX document are addressed. These instructions are part of DAP 2-11, Operating Experience Review, and have been in the DAP since May of 1993. The instructions ask for the specific and/or generic applicability to the station.

Dresden Station will create an administrative procedure to control corrective actions effectiveness reviews per Dresden Improvement Plan 1.II.4.4.1.d.

All safety related stop check valves have been informally included in the check valve preventative maintenance program.

Dresden Administrative Procedure (DAP) 11-25, Check Valve Inspection Program, will be updated to reflect the current additions to the check valve preventive maintenance program. (NTS# 237-180-94-02101)

HPCI Exhaust HI Pressure Switches 2-2368A & 2-2368B were functionally verified per Dresden Instrument Surveillance (DIS) 2300-09, HPCI Turbine Pressure Switch Surveillance on August 4, 1994.

The HPCI Turbine Drain System was inspected under work request D26905 on August 6, 1994. The exhaust drain check valves were functionally checked successfully during performance of DOS 2300-03 on August 7, 1994.

HPCI Exhaust Rupture Disks were replaced on August 6, 1994, under work request D25294 due to the diaphragms reaching a pressure greater than 80% of their burst pressure value.

The HPCI Gland Seal Drain Pressure HI switch was functionally verified per acceptance criteria. The switch was recalibrated and tested successfully under work request D25704 on August 6, 1994.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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EXPIRES 5/31/95

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	9 OF 10

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The system engineer was counseled to practice the "STAR" (Stop, Think, Act, Review) program and to take the appropriate time in reviewing items such as the SER print out or a verification that the HPCI turbine exhaust is free of water following an alarm.

Dresden Operating Procedure (DOP) 2300-M1/E1, HPCI Valve Checklist, was performed on all valves in the room to insure correct positions on August 7, 1994, prior to the performance of DOS 2300-03.

A cover was installed on the 2-2399-94 valve to prevent the valve from being inadvertently turned in the future.

The 2-2301-45, HPCI Turbine Exhaust Check Valve was disassembled, inspected and a new valve installed under work request D26915. The check valve seats were found to be slightly worn due to seat impacting. This failure did not affect the operation of the HPCI system.

The 2-2301-74, HPCI Turbine Exhaust Check Valve, was disassembled, inspected and repaired under work request D26919. The valve disk was found not attached to the valve guide piston. Further inspection revealed the tack welds, which prevent the assembly from rotating, had broken due to vibration fatigue. The valve was reassembled and tested satisfactorily during Unit 2 start-up on November 19, 1994.

The 3-2301-74, HPCI Turbine Exhaust Check valve, was disassembled and inspected under work request D27123. The valve internals were found to be intact. The valve was reassembled and tested satisfactorily during Unit 3 start-up on November 4, 1994.

A Problem Investigation Report was generated to address the potential Part 21 issue for the Edwards/Rockwell model exhaust check valve that failed during this event. (NTS# 237-200-94-19400)

AO2-2301-28, HPCI Inlet Drain Pot to Suppression Pool valve, was disassembled and inspected under work request D25302 during D2F23. The seat was found to have some minor indications. The valve seat was repaired and a seat contact check was performed satisfactorily. The valve was then successfully tested during Unit 2 start-up on November 19, 1994.

The Core Spray discharge check valve 2-1402-8A was inspected during D2F23. There were no problems noted during the inspection.

F. PREVIOUS OCCURRENCES:

None.

G. COMPONENT FAILURE DATA:

Edwards/Rockwell Stop Check Valve, Model No. 6504Y.

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station, Unit 2	05000237	94	-- 021 --	01	10 OF 10

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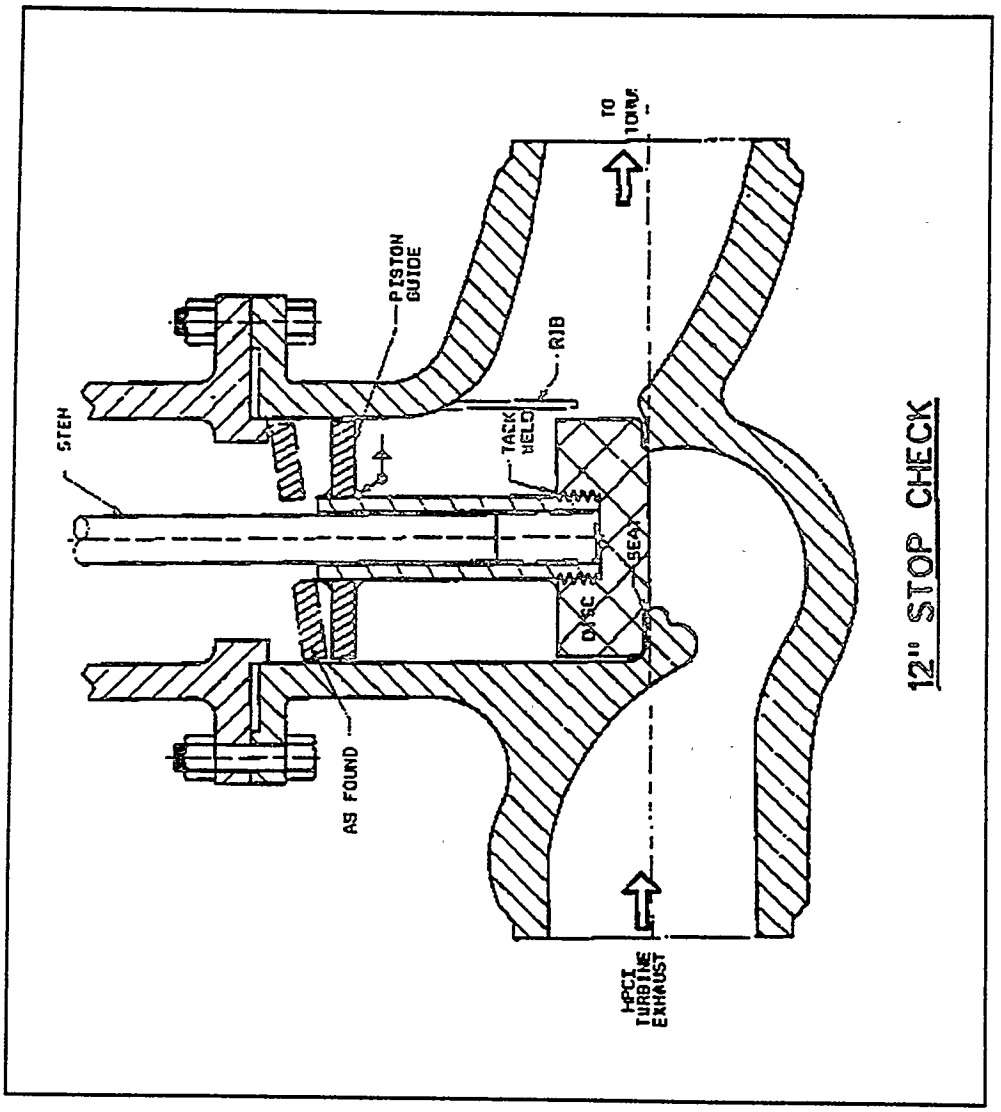

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Appendix I

LER No. 245/94-015
Millstone, Unit 1

NRC Form 366 (5 -92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 1	05000245	1 OF 6

TITLE (4): RPV Drain Down and Drywell Spray Event

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
										05000
04	10	94	94	- 015 -	00	05	10	94	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	R	THIS REPORT IS BEING SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)	0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Drexel N. Harris, Site Licensing	(203) 437-5903

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		08	31	94

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

On April 10, 1994, during the performance of a Low Pressure Coolant Injection (LPCI) System logic surveillance test, an inadvertent decrease in the Millstone Unit One reactor pressure vessel (RPV) water level occurred. The water level decrease was the result of a procedural deficiency that established a flow path from the Shutdown Cooling (SDC) System to the "A" LPCI drywell spray header through the LPCI cross-connect piping. This flow path allowed approximately 12,000 gallons of reactor coolant to spray into the drywell.

The RPV level decrease was recognized by the reactor operators who terminated the event by closing the LPCI drywell spray valves. The final water level remained above any automatic level setpoints (i. e. scram, isolations, or ECCS initiations). No emergency safety features actuated during this event.

This event resulted from a failure to recognize system interactions during the development, approval, and implementation of the LPCI System logic test procedure.

NRC Form 366 (5-92)

NRC Form 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 1	05000245	94	— 015 —	00	02 OF 06

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

I. Description of Event

On April 10, 1994, during the performance of a Low Pressure Coolant Injection (LPCI) System logic surveillance test (SP 412K), an inadvertent decrease in the Millstone Unit One reactor pressure vessel (RPV) water level occurred. The water level decrease was the result of a procedural deficiency that established a flow path from the Shutdown Cooling (SDC) System to the "A" LPCI drywell spray header through the LPCI cross-connect piping. This flow path allowed approximately 12,000 gallons of reactor coolant water to spray into the drywell. (See Figure 1)

The RPV water level decrease event occurred at approximately 1610 hours when the "A" drywell spray valves were opened during the performance of surveillance procedure SP 412K, "LPCI/Containment Cooling System Logic Test." At approximately 1613 hours, the drywell sump HI-HI level alarm was received in the control room. Approximately two minutes later, the valves were closed by plant operators, terminating spray flow into the drywell. RPV water level, which was initially at 83 inches (which is just below the main steam lines), dropped to approximately 6 inches on the FLOOD-UP level indicators. At all times during the event, RPV level remained above the reactor protection and emergency core cooling system actuation setpoints.

At the time of the water level decrease event, the SDC system was in service to maintain adequate decay heat removal. The RPV drain path was established when a containment spray header isolation valve (1-LP-16A) was opened. RPV level had decreased from 83 inches to about 40 inches on FLOOD-UP instrumentation when the sump HI-HI level alarm annunciated. Control Room operators evaluated the situation and terminated the event approximately two minutes later by shutting LPCI system valves. RPV flow to the drywell was totally secured at 1615 and approximately 12,000 gallons of water was pumped into the drywell. The surveillance test was immediately terminated and plant conditions were stabilized. The RPV water level was restored to 85 inches by injecting water into the RPV from the condensate transfer system.

Immediate actions by the plant operators included stopping the test and stabilizing RPV water level. Personnel involved in the event were interviewed by senior plant management to gain their perspectives regarding the event. All integrated testing activities were suspended. The Plant Operations Review Committee (PORC) met and established an Event Evaluation Team (EET) to perform a detailed root cause evaluation. Members on the EET were from several disciplines from within the organization including Operations, Engineering, Instrumentation and Controls, Training, Nuclear Licensing, and other support organizations. The Director of Unit One Engineering served as the Senior Management Representative.

II. Cause of Event

The cause of the RPV drain down and drywell spray event was a failure to recognize the system interactions during the development, approval, and implementation of the LPCI System logic test procedure.

NRC Form 366A (5-92)

NRC Form 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 1	05000245	94	- 015 -	00	03 OF 06

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III. Analysis of Event

The LPCI System logic surveillance test is performed to verify that the LPCI valves and timer relays actuate as required under simulated accident conditions. In accordance with the test procedure, valves in the "B" LPCI system were aligned as required. This resulted in a connection between the SDC system and the "A" LPCI system via the normally open system cross tie valve. The procedure then directed the positioning of the "A" LPCI system valves. This resulted in the opening of the inboard and outboard drywell spray valves at 16:10. At 16:13, the DRYWELL FLOOR DRAIN SUMP HI-HI LEVEL alarm was received. This was the first alarm received to indicate a potential problem. Prior to this alarm, all narrow range level instrumentation remained pegged high. Reacting to the alarms, operators evaluated the available RPV water level instrumentation and noted that water level was at 53 inches and decreasing rapidly. The crew realized that the LPCI System could be the source of RPV water level reduction. The event was terminated when the LPCI valves were closed at the direction of the shift supervisor.

When the LPCI spray valves were fully closed, RPV water level had decreased from approximately 83 inches to 6 inches on the FLOODUP and Narrow Range GEMAC level meters. Following the closure of LPCI spray valves it was verified that level stabilized. It was determined that RPV water was being directed to the drywell through the 'A' drywell spray valves. This flow path was the result of a valve line-up specified in the LPCI System logic surveillance test procedure. Specifically, with SDC running, a flow path was established from the SDC system through the LPCI cross- connect piping (from 'B' system to 'A' system) to the 'A' drywell spray header. (See Figure 1)

Immediately following the corrective actions taken by the operating crew, level was restored to 80 to 85 inches using the SDC and condensate transfer systems in approximately 25 minutes. Calculations determined that approximately 12,000 gallons of water flowing at approximately 2200 GPM and 140°F was sprayed into the drywell.

When this event was terminated, RPV water level indicated 6 inches on the FLOODUP instrumentation which is about 132 inches above TAF. Neither the low level scram nor the low low level Emergency Core Cooling System (ECCS) actuation setpoints were challenged. The SDC System, which was running for decay heat removal capability, continued to operate. There was no heat-up of the RPV inventory.

Had the operators not taken corrective action and closed the drywell spray valves to terminate the event, the RPV water level would have continued to drop until the Group 3 isolation setpoint was reached (at 8 inches on narrow range Yarways). Closure of any one of the remaining three SDC isolation valves would have isolated the SDC system, thus terminating the event at approximately 120 inches above TAF.

In this postulated scenario, the decay heat removal system would have been interrupted due to the isolation of the SDC system. Since this event occurred 85 days after the reactor shutdown, decay heat was very low (only 0.06%). The only other source of heat would have been the reactor recirculation pumps, which would have continued to run at minimum speed during this event. Based on recent data concerning plant heat-up with the SDC cooling system secured, there would have been sufficient time for restoration of both RPV water level and the SDC System. Also, RPV water temperature was 140°F and the operators would have had ample time to establish primary containment integrity (closing the drywell personnel hatch) if RPV water temperature approached 212°F.

The RPV water level transient itself was not safety significant due to the margin of water that remained above the core. In addition, the low decay heat levels due to the long time since shutdown and the operability of automatic isolation contribute to this conclusion. Nonetheless, although the actual event had minimal safety significance the event is considered a significant issue that is receiving the serious attention within the NU organization it deserves.

NRC Form 366A (5-92)

NRC Form 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 1	05000245	94	— 015 —	00	04 OF 06

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This event is reportable in accordance with 10CFR50.73(a)(2)(v)(B), as any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat.

IV. Corrective Action

Initial corrective actions were to isolate the leakage into the drywell, terminate the surveillance that initiated the event, and restore RPV water level.

Senior plant management suspended all integrated testing until a multi-discipline review team could be established to review the adequacy of integrated test procedures. An Event Evaluation Team was formed to thoroughly review the event and to make recommendations to prevent recurrence. The Event Evaluation Team performed an in-depth root cause evaluation of the event. The scope of the EET was divided into three distinct areas:

- Determine the cause of the RPV level transient and implement short term corrective action which would allow continuation of Refueling Outage 14 surveillance testing and design modification testing.
- Develop an inspection plan and evaluate both the drywell and torus equipment to ensure operability. Evaluate the need for a long term component inspection plan as a result of the drywell spray.
- Evaluate the circumstances prior to and following the RPV level transient to determine additional contributing factors.

Procedure Review Process

Since the cause of the event was directly related to the procedure development, review, and approval process associated with test procedures, a screening committee was organized to review all remaining outage related tests and surveillances. Based upon the results of the screening, selected procedures were designated for an in-depth, multi-discipline technical review and subsequent approval by the Plant Operations and Review Committee (PORC)

Drywell and Torus Equipment Inspections

The equipment recovery from the Drywell spray resulted in an extensive inspection effort. All motor operated valves, motors, electrical instrumentation, and various other components were inspected to assure operability. No electrical grounds resulted from the spray event. An extensive analysis was performed to evaluate the impact on the piping insulation and other mechanical components. These inspections concluded that the torus and drywell components were not affected by the spray.

Management Oversight

The current procedure development, review, and approval process associated with plant procedures is being evaluated. An increased awareness of all personnel involved with the performance of testing has been emphasized by the Unit Director and the Operations Manager. Additional requirements for the development and implementation of test procedures have been implemented. Long term procedure process changes are being evaluated.

Senior Utility management commissioned an Independent Review Team headed by the Nuclear Review Board Chairman to perform a global oversight review of the RPV level transient and the procedure process.

NRC Form 366A (5-92)

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 1	05000245	94	— 015 —	00	05 OF 06

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The EET report is still under management review. A follow-up report of this event will be submitted to document the results of the Independent Review Team and the implementation of additional long term corrective actions.

V. Additional Information

None

NRC Form 366A (5-92)

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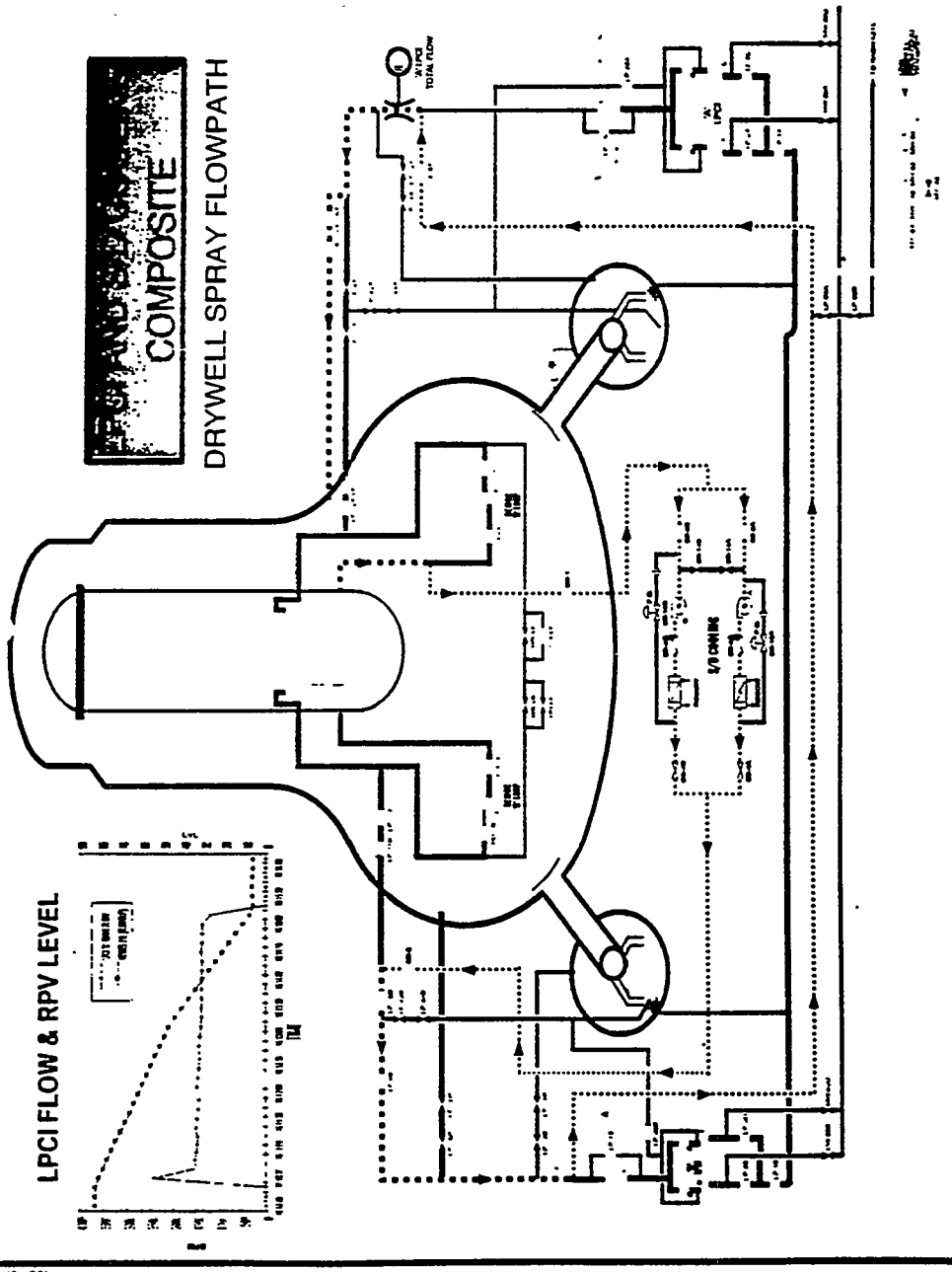

NRC Form 366A (5-92)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

July 15, 1994

NRC INFORMATION NOTICE 94-52: INADVERTENT CONTAINMENT SPRAY AND REACTOR VESSEL DRAINDOWN AT MILLSTONE UNIT 1

Addressees

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to the potential for inadvertent containment spray and reactor vessel draindown as a result of valve misalignment caused by inadequate procedures. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

Millstone Unit 1 was shut down in January 1994 for refueling. During the outage, the licensee planned to test the low-pressure coolant injection (LPCI) logic system. The LPCI logic system functional test procedure, which had been performed numerous times in the past, had been revised recently to permit the licensee to test system valves and the two-thirds core height LPCI/drywell spray interlock at the same time. This interlock permits manual initiation of drywell spray via the LPCI system after adequate core cooling has been achieved. When the event began, both recirculation pumps were running, both trains of shutdown cooling were operating, and LPCI was not operating (see Figure 1). The water level in the reactor vessel was 85 inches. Much of the equipment previously taken out of service during the outage had been restored to operable status and the licensee considered the shutdown risk from this test to be low. However, the test procedure included steps to rack out the breakers for the LPCI pumps and to place the control switch for the core spray pump in the "pull-to-lock" position, rendering these pumps incapable of automatically starting in response to a low water level in the reactor vessel.

Most boiling-water reactors use the same pumps for the shutdown cooling and LPCI functions, but Millstone Unit 1 has separate pumps. The licensee intended to functionally test the LPCI system valves without flow. While performing the test on April 10, 1994, the licensee opened the 10B valve,

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pressurizing LPCI loop B and, through the normally open 8A valve, LPCI loop A. Continuing the procedure, the licensee opened the 15A and 16A valves in the LPCI system, opening a flow path from LPCI loop A to the drywell spray header. This alignment allowed approximately 9500 liters per minute (2500 gpm) from the discharge of the shutdown cooling pumps to be diverted from the reactor vessel to the drywell (see Figure 2).

The licensee did not realize that the test procedure had established this flow path. Within about two minutes a high-level alarm for the drywell sump was received. Approximately two minutes later a control room operator closed the drywell spray valves, isolating the flow path. The water level in the reactor vessel decreased approximately 180 cm (70 inches), and a corresponding volume of water (approximately 46,000 liters [12,000 gallons]) was sprayed into the drywell. Shutdown cooling continued during the event. If the operator had not closed the drywell spray valves, the shutdown cooling discharge and suction valves would have started to close automatically about 30 seconds later. These shutdown cooling valves would have closed in less than 48 seconds, ending the event. The level instrumentation that initiates this automatic closure is independent of the instrumentation being tested by the two-thirds core height interlock logic test.

Normally, if the water level in the reactor vessel had decreased further, LPCI and the core spray system would have initiated automatically to restore the level in the reactor vessel. However, the breakers for the LPCI pumps were racked out for the test, and the core spray pump control switch was in "pull-to-lock," so an operator would have had to start the system.

Discussion

The root cause of this event was the failure of the licensee to adequately review the procedure. The revised procedure had formal concurrence, including a determination that integrated review was not required. The combined procedure was primarily the product of the instrumentation and control staff. The operations staff was not involved in preparing the procedure or in the subsequent training, but gave approval to perform the test. The test procedure gave directions to open not only the drywell spray valves but also the torus spray valves (13A and 14A) and the valves in a test line to the torus (43A and 44A). Any of these flow paths would have drained the vessel. However, during the test one of the torus spray valves was inoperable and was not opened, so the torus spray flow path was not established. The test flow path to the torus was not established because the test procedure was stopped as soon as the drywell spray event occurred.

This event demonstrates the importance of rigorously reviewing procedures for potential systems interactions and of avoiding inadvertent system lineups that have the potential to drain the reactor vessel.

Appendix I

LER No. 249/94-S01
Dresden, Unit 3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 7, 1994

NRC INFORMATION NOTICE 94-42: CRACKING IN THE LOWER REGION OF THE CORE SHROUD IN BOILING-WATER REACTORS

Addressees

All holders of operating licenses or construction permits for boiling-water reactors (BWRs).

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees that a 360-degree crack has been observed at a weld in the lower region of the core shroud in two boiling-water reactors. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

During the April 1994 refueling outage at Dresden Unit 3, Commonwealth Edison Company, the licensee, found a 360-degree crack that extended around the outside circumference of the core plate support ring weldment. The shroud is a 5.1 centimeter [2 inch]-thick stainless steel cylinder that directs the flow of water inside the reactor pressure vessel. The shroud is completely contained inside the reactor pressure vessel. The structural integrity of the reactor pressure vessel is not affected by cracks in the shroud.

The cracking was found during a visual inspection and was located in the lower section of the shroud in the heat-affected zone (HAZ) of weld H-5. (See Figures 1 and 2.) Weld H-5 is a horizontal weld that joins the core plate support ring to the core shroud. Subsequent ultrasonic testing, utilizing automated equipment from General Electric, determined that the maximum crack depth was 2.13 cm [0.84 inches].

Commonwealth Edison Company also performed a visual inspection of the Quad Cities Unit 1 core shroud. That inspection revealed a similar 360-degree circumferential crack located at the same place as the crack found at Dresden Unit 3. Both Dresden and Quad Cities units are BWR-3s and have similar core shroud geometries. Core shroud designs for other BWRs may exhibit some differences, and weld identification numbers are not necessarily congruent between the designs.

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Discussion

At Dresden Unit 3, in addition to the 360-degree circumferential crack in the HAZ of weld H-5, numerous crack indications were also found in the HAZ of weld H-3. The licensee plans to perform UTs and take boat samples at both Dresden Unit 3 and Quad Cities Unit 1 to help determine the root cause of the cracking.

Commonwealth Edison Company inspected the Dresden shroud using a criterion that required the resolution of a 25 micron [1 mil] wire with a 25-mm camera lens positioned to within 2.5 to 7.6 cm [1 to 3 inches] of the shroud surface. The same 25 micron [1 mil] wire resolution criterion had been used previously at Quad Cities, but with a 9 mm camera lens positioned approximately 15.2 to 30.5 cm [6 to 12 inches] from the shroud surface. Using this technique, no crack indications were initially detected at Quad Cities. However, after Commonwealth Edison Company detected the crack at Dresden, the H-5 weld at Quad Cities was inspected again, this time using the Dresden technique, and the 360-degree crack was detected.

Related Generic Communications

In Information Notice (IN) 93-79, "Core Shroud Cracking at Beltline Region Welds in Boiling-Water Reactors," (issued September 30, 1993) which discusses cracks detected at Brunswick Unit 1, the staff pointed out that camera and lighting positions were crucial in performing adequate visual inspections. It is imperative to position the camera or video probe as near to the examination surface as possible and to use an appropriate camera lens. The lighting direction and intensity are important factors and should be adjustable to enhance the detection of these tight surface crack indications.

Crack indications have been previously reported at shroud welds in domestic and overseas reactors at the beltline region and higher in the shroud. However, the severely cracked H-5 shroud welds at Dresden Unit 3 and Quad Cites Unit 1 are located 45.7 centimeters [18 inches] below the bottom of the fuel, suggesting that horizontal welds in all regions of the shroud may be susceptible to stress corrosion cracking

The IN 93-79 also referred to GE Rapid Information Communication Service Information Letter (RICSIL) No. 054, Revision 1, "Core Support Shroud Crack Indication." Since IN 93-79 was issued, GE issued additional information on core shroud cracks in October 1993, April 1994, and May 1994.

The BWR Owner's Group (BWROG) submitted an evaluation of core shroud cracking to the staff on April 5, 1994. After reviewing the evaluation, and in light of the Dresden and Quad Cities findings, the staff issued a list of questions to the Chairman of the BWROG Executive Oversight Committee on May 12, 1994.

The NRC staff is evaluating the safety implications of the shroud cracks for normal plant operating and accident conditions and will consider the need for additional generic communication.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

Brian K. Grimes, Director
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Office of Nuclear Reactor Regulation

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(301) 504-1175

Attachments:
1. Figure 1: Shroud Weld Locations for Dresden Unit 3
2. Figure 2: Details of Weld Locations H-5 and H-6 in the Dresden Unit 3 Core Shroud
3. List of Recently Issued NRC Information Notices

Attachment 1
IN 94-42
June 7, 1994
Page 1 of 1

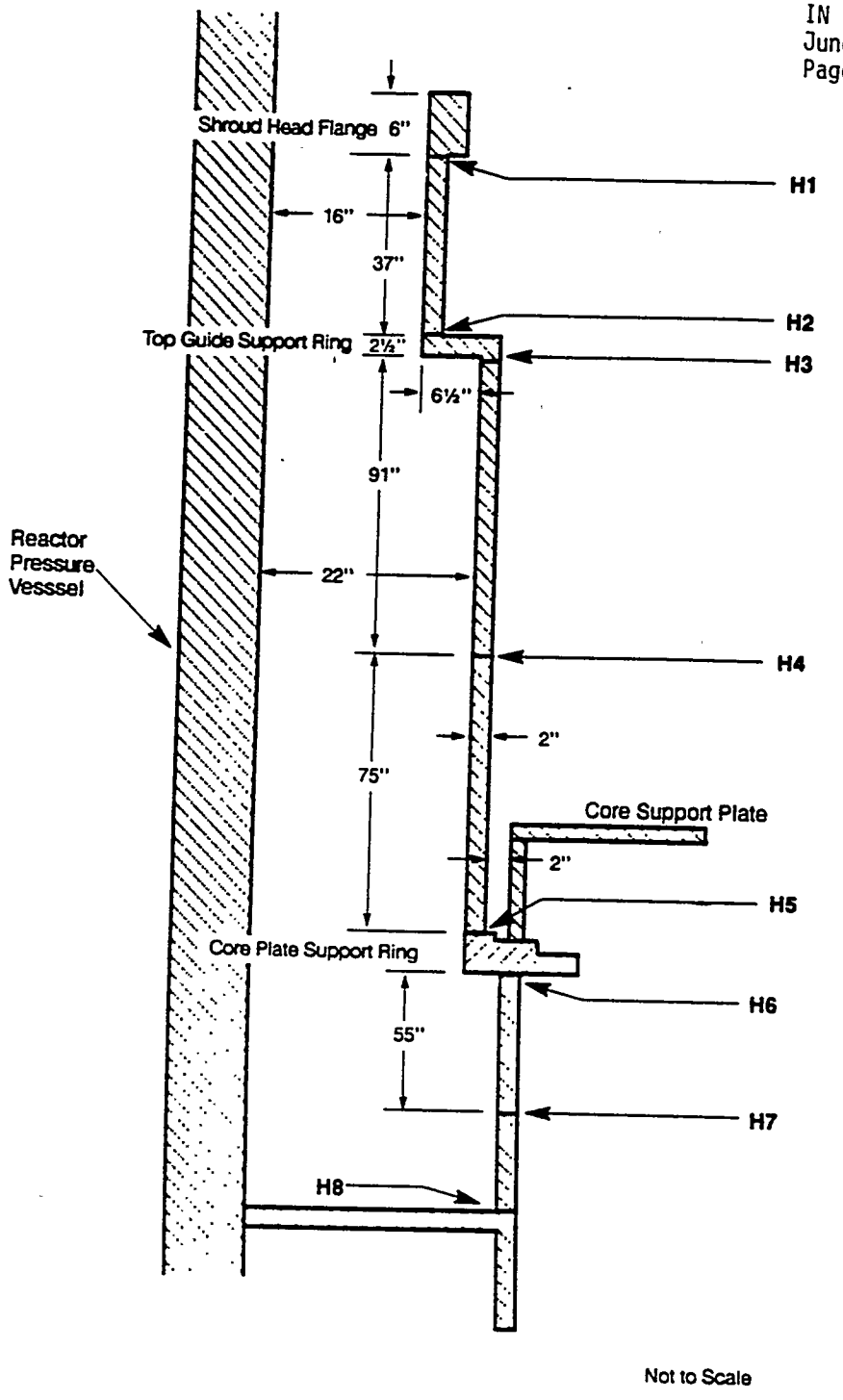
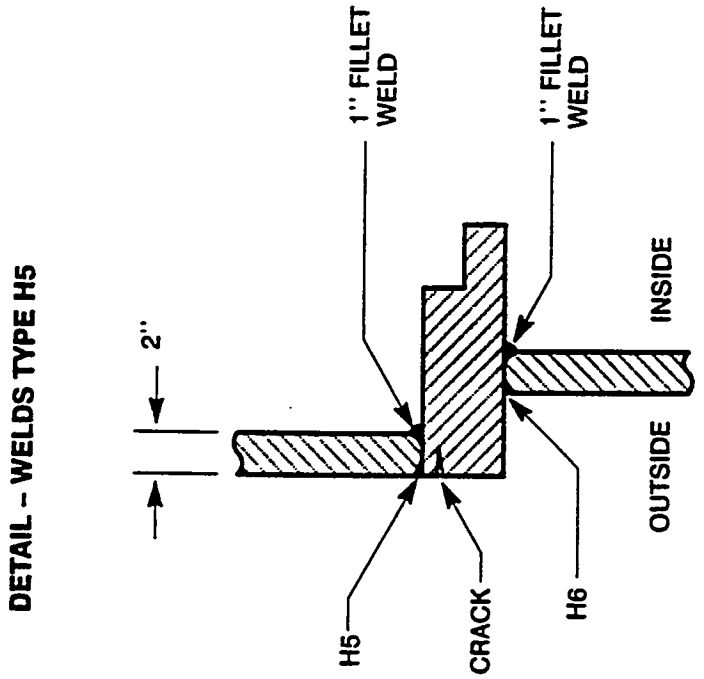


Figure 1. Shroud Weld Locations for Dresden, Unit 3

Attachment 2
IN 94-42
June 7, 1994
Page 1 of 1



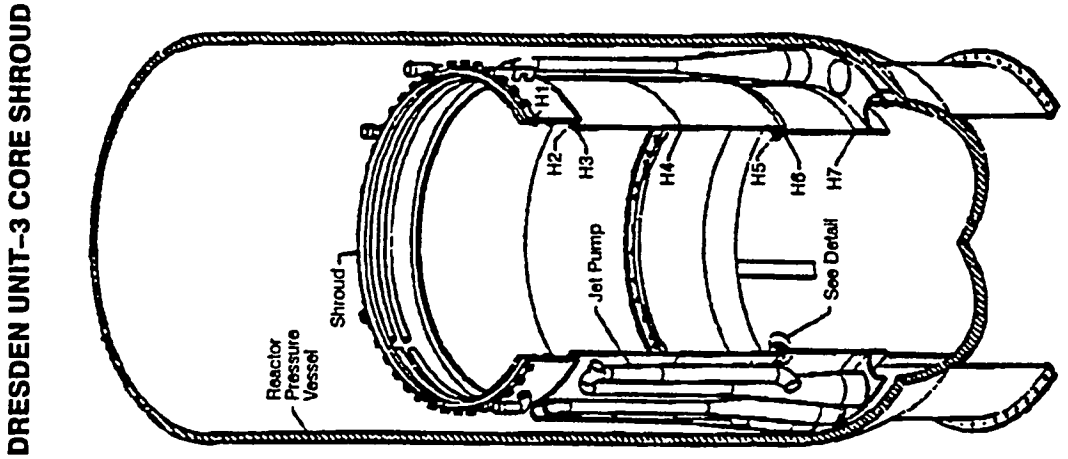


Figure 2. Detail of Weld Locations H5 and H6 in the Dresden, Unit 3 Core Shroud

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

July 19, 1994

NRC INFORMATION NOTICE 94-42, SUPPLEMENT 1: CRACKING IN THE LOWER REGION OF THE CORE SHROUD IN BOILING-WATER REACTORS

Addressees

All holders of operating licenses or construction permits for boiling water reactors (BWRs).

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this supplement to NRC Information Notice (IN) 94-42, "Cracking in the Lower Region of the Core Shroud in Boiling-Water Reactors," to give addressees more information on the core shroud cracking at Dresden Unit 3 and Quad Cities Unit 1. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Background

In Information Notice 94-42, NRC discussed the 360-degree cracking that Commonwealth Edison Company, the licensee, found while visually inspecting the core shroud at Dresden Unit 3 and Quad Cities Unit 1. The cracking is located on the outside diameter of the weld attaching the shroud to the upper side of the core plate support ring. This weld is designated the "H5 weld" (see Figure 1) at these plants. Cracks were observed in and adjacent to the weld heat affected zone (HAZ) in the core plate support ring weldment. The staff, in IN 93-79 and again in IN 94-42, pointed out the importance of an appropriate camera lens, positioning the lens as near as possible to the surface being inspected, and properly directing light of sufficient intensity during inspections.

In IN 94-42, the staff stated that the maximum crack depth at the H5 weld was 2.13 cm [0.84 inches] for Dresden, as indicated by in-vessel ultrasonic testing (UT) examinations using the General Electric (GE) automated tracking system. However, metallographic examination of four material (boat) samples taken from other areas demonstrated that the UT examination had underestimated the crack depth in these regions.

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Description of Circumstances

During the April 1994 refueling outage the licensee discovered the 360-degree cracking at the H5 weld location in the core shroud at Dresden 3. The licensee later visually inspected the Quad Cities 1 core shroud and found similar 360-degree cracking at the same H5 weld location as at Dresden 3. The licensee performed UT at both units to help characterize the depth of cracking on the outside and inside diameters of the H5 weld location. Finally, the licensee removed material (boat) samples by electric discharge machining to corroborate the UT results and determine the root cause for the cracking.

Discussion

The extensive cracking discovered by the licensee at lower core shroud weld locations other than those which had previously been considered to be limiting (i.e., H3 and H4) has brought into question the validity of the BWROG original rankings of the shroud welds with respect to cracking susceptibility. The BWROG is reevaluating the screening criteria proposed in GENE-5523-148-1193. The screening criteria were based on the examination of the H3 and H4 welds as a scoping study to determine if other weld areas need to be inspected. By this approach, the H5 and other weld locations would not necessarily be examined. Also, the H3 and H4 welds are generally accessible from both the inside and outside surfaces. Other shroud welds may require UT examination if visual inspection is impeded by reactor internals.

The licensee performed UT examinations using a variety of techniques. The first technique involved using manually-operated, pole-mounted 60- and 70-degree refracted longitudinal (RL) wave transducers to examine six locations on the H5 weld. This technique indicated a maximum H5 weld crack depth of 3.94 cm [1.55 inches] at Dresden 3. The licensee later performed UT examinations using a GE automated tracking system with two types of transducers. The first type was a 45-degree shear wave transducer intended to determine the presence or absence of cracking. The second type consisted of two 60-degree RL transducers to measure overall depth using pitch-catch tip diffraction methods. This technique indicated a maximum H5 weld crack depth of 2.13 cm [0.84 inches] at Dresden and 1.45 cm [0.57 inches] at Quad Cities. The accuracy of these results is discussed below. At Quad Cities 1, one indication about 5 cm [2 inches] in length was detected in the core shroud on the inside diameter above the H5 weld in the heat affected zone. The indication was estimated to be about 0.64 cm [0.25 inches] deep by UT examination.

To fully investigate the cracking observed at the H5 weld, the licensee used electric discharge machining to remove material (boat) samples from the outside diameter of the shroud at the H5 location. The licensee removed the boat samples from Quad Cities before UT examination, and the flaw depths present in the boat samples were compared to ultrasonic measurements from areas adjacent to the boat sample locations. The results from metallographic examinations of the boat samples show that the UT examinations using the

automated tracking system underestimated the size of the existing flaws by up to 0.79 cm [0.31 inches] at Dresden and up to 0.76 cm [0.30 inches] at Quad Cities. These discrepancies may be due to the tightness and fineness of the intergranular stress corrosion cracking (IGSCC) near the crack tip. The licensee confirmed that the cracking in the boat samples was intergranular stress corrosion cracking.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

Brian K. Grimes, Director
Division of Operating Reactor Support
Office of Nuclear Reactor Regulation

Technical contacts: M. Mitchell, NRR
(301) 504-2735

T. Greene, NRR
(301) 504-1175

Attachments:
1. Figure 1: Dresden and Quad Cities Core Shroud Weld Locations
2. List of Recently Issued NRC Information Notices

Attachment 1
IN 94-42, Supplement 1
July 19, 1994
Page 1 of 1

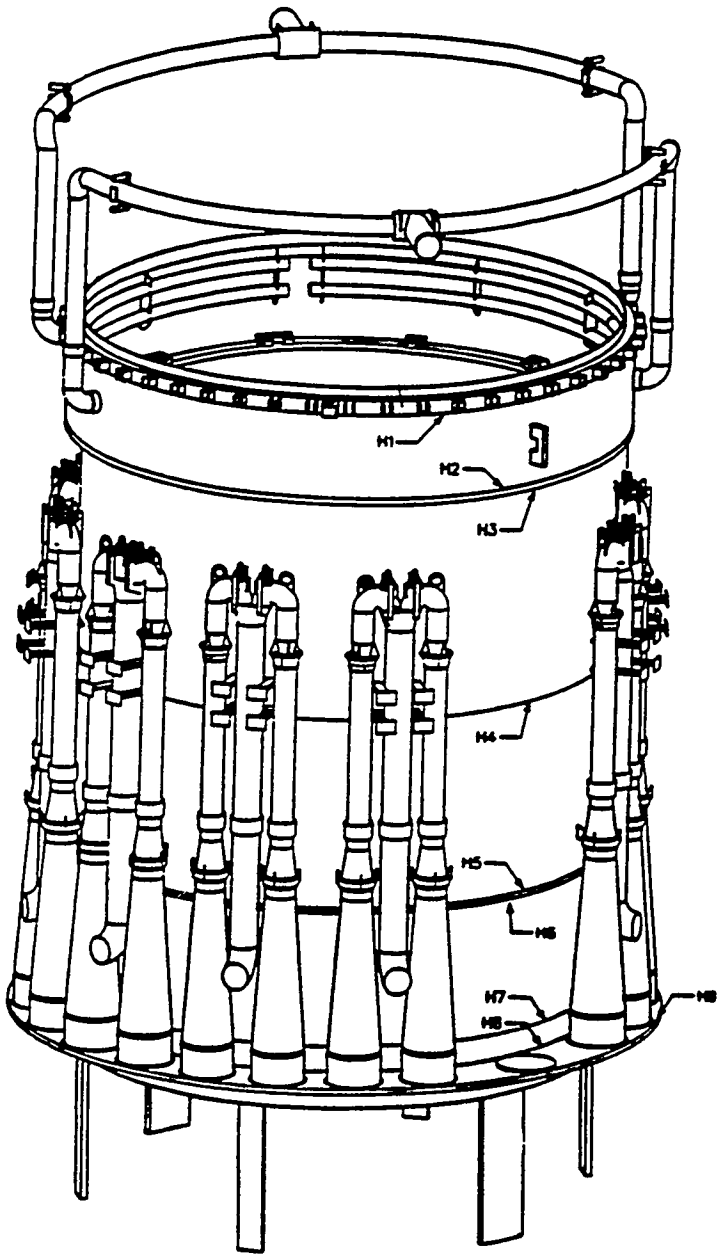

FIGURE 1
DRESDEN AND QUAD CITIES
CORE SHROUD WELD LOCATIONS

LER No. 250/94-005
Turkey Point, Unit 3

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
TURKEY POINT UNITS 3 AND 4	05000250	1 OF 18

TITLE (4) DESIGN DEFECT IN SAFEGUARDS BUS SEQUENCER TEST LOGIC PLACES BOTH UNITS OUTSIDE THE DESIGN BASIS

EVENT DATE (5)			LER NUMBER(6)			RPT DATE (7)			OTHER FACILITIES INV. (8)	
MON	DAY	YR	YR	SEQ #	R#	MON	DAY	YR	FACILITY NAMES	DOCKET # (5)
11	03	94	94	005	01	02	09	95	TURKEY POINT UNIT 4	05000251

OPERATING MODE (9)	1/5	10 CFR 50.73(a)(2)(ii), (a)(2)(v), (a)(2)(vii), 10 CFR 21
POWER LEVEL (10)	100/0	

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER
C. L. Mowrey, Licensing OEF Engineer/Analyst	305-246-6204

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	NPRDS?	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	NPRDS?
B	JE	34	A160	Y					

SUPPLEMENTAL REPORT EXPECTED (14) NO ☒ YES ☐	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
(If yes, complete EXPECTED SUBMISSION DATE)				

ABSTRACT (16)

On November 3, 1994, Turkey Point Unit 3 was in Mode 1 at 100% power, and Unit 4 was in Mode 5 during a refueling outage. During the Unit 4 Integrated Safeguards Test, the 3A sequencer failed to respond to the Unit 4 Safety Injection signal. A defect was found in the sequencer software logic which, for a limited period of time, could inhibit any or all of the four sequencers from responding to specific valid signals. The defect only affects the sequencers during manual or automatic testing. The sequencers were installed in late 1991.

Monthly manual testing of the sequencer has been resumed. Front panel visual examinations are being performed every 8 hours, and internal visual examinations are being performed every 24 hours. A permanent repair to the software logic is being evaluated. Independent consultants performed an assessment of the existing sequencer design, software design, and the Validation and Verification process. One other software error involving Containment Spray (CS) pump autostart was discovered, and determined to have minimal safety significance. The CS system remains operable.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	2 OF 18

I. DESCRIPTION OF THE EVENT

On November 3, 1994, Turkey Point Unit 3 was operating in Mode 1 at 100% power, and Unit 4 was in Mode 5 during a refueling outage. During the Unit 4 Integrated Safeguards Test, a failure of the 3A sequencer [JE:34] to respond to the opposite unit's Safety Injection (SI) signal occurred. Troubleshooting resulted in the discovery of a defect in the sequencer software logic which, under certain conditions, could inhibit the sequencer from responding to a valid emergency signal. The defect manifested itself in the failure of the 3A High Head Safety Injection (HHSI) pump [BQ:p] to start. Turkey Point has four HHSI pumps; one per train, per unit. Each HHSI pump is capable of providing 50 percent of system requirements, therefore two of the four are required to mitigate the consequences of accidents analyzed in the Updated Final Safety Analysis Report (UFSAR). In order to meet single failure criteria, each sequencer signals its associated HHSI pump to start, and the opposite unit's sequencers signal their associated HHSI pumps to start. For example, an SI signal on Unit 3, Train A, signals the 3A sequencer and both of the Unit 4 sequencers. With no equipment failures, all four HHSI pumps will respond to an SI signal on either unit.

The software logic defect is limited to the test function, but the defect is common to all four sequencers (one sequencer per train, per unit). The design intent of the sequencers is such that should a "real" emergency signal occur while the sequencer is being tested, the test signal clears, allowing actuation of the Engineered Safety Features controlled by the sequencer.

Because the sequencers would not have responded properly to an SI signal as designed, Turkey Point Units 3 and 4 have been operating outside their design basis. This condition was reported to the NRCOC at 1609 on November 3, 1994, in accordance with 10CFR50.72(b)(ii)(B).

The detailed review of the sequencer software, described in Corrective Action #6, resulted in the discovery of one other error in the software, which is independent of the test mode. A potential condition was identified which, for a remote set of circumstances, would preclude the automatic start of the Containment Spray (CS) pumps [BE:p]. The condition identified occurs when the Hi-Hi Containment Pressure (HHCP) signal is received by the sequencer during an approximate 60 millisecond (ms) time window just prior to the end of sequencer load block 3 for Loss of Coolant Accident (LOCA) or Loss of Offsite Power coincident with LOCA (LOOP/LOCA) events. The sequencer is designed to autostart the CS pumps 11 to 13 seconds after an SI signal (without LOOP) if the HHCP signal is present or at or after 44 seconds under conditions where the HHCP signal occurs more than 13 seconds after receipt of the SI signal. For a LOOP/LOCA, these times are shifted by the bus stripping and EDG start delay of approximately 16 seconds. Thus the 60 ms window occurs 12.886 to 12.945 seconds after receipt of an LOCA signal, or 28.886 to 28.945 seconds after receipt of a LOOP/LOCA signal.

Although Turkey Point is licensed to accommodate a LOCA with or without a concurrent LOOP, the sequencer was designed to accommodate non-concurrent LOOP/LOCA sequences as well. As a result, for certain non-concurrent events, a Main Steam Line Break or a Small Break LOCA (but large enough to cause a HHCP signal) can also create conditions under which this error may manifest itself.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	3 OF 18

Automatic CS pump start actually involves two HHCP signals; one via the sequencer logic as described above, and one directly from Engineered Safety Features Actuation System (ESFAS) relay [JE:44]. Because of the minimum pulse required to assure CS pump breaker [BE:bkr] closure, and a potential relay race with a CS pump start permissive from ESFAS, the CS pump breaker may not receive a close signal of sufficient duration to assure breaker closure. The identified condition is unique to the start of the CS pump because the CS pump start signal duration decreases as the postulated receipt of a HHCP signal approaches the end of load block 3. All other sequenced equipment receives a start pulse of fixed duration, either 2 or 5 seconds. This condition was determined to be not significant, in part because the manual start capability of the CS pump is not affected (and is adequately proceduralized), and in part because the probability of occurrence of the condition is lower than the probability of a common-mode failure of both trains of containment spray. The significance of the condition is discussed further in Section III.

SEQUENCER DESIGN BASIS AND FUNCTIONAL REQUIREMENTS

Each of the four sequencers, 3C23A-1, 3C23B-1, 4C23A-1, and 4C23B-1, is associated with a given train (3A, 3B, 4A, and 4B, respectively). They are designated Class 1E, Seismic Category I, since their operation is required for safe shutdown of the reactor in the event of a Loss of Offsite Power (LOOP) and to mitigate the consequences of a design basis accident.

The sequencers are Programmable Logic Controller (PLC)-based cabinets using a PLC for bus stripping and load logic and control. The signal path structure of the PLC uses dedicated input modules, control logic, and dedicated output modules.

LOOP Signal Only

On a LOOP in a given unit, both sequencers associated with that unit will respond accordingly to clear their associated buses, stripping all 4.16KV loads and specified 480V loads within one second after the LOOP signal is generated. The Emergency Diesel Generators (EDGs) [EK:dg] will start, and within 15 seconds the EDG output breakers [EK:bkr] close, then loads required for safe reactor shutdown are sequentially connected to the corresponding bus; the first load block output signal is generated 16.5 seconds after the onset of the LOOP.

LOCA Signal Only

If either unit experiences a LOCA, and preferred (offsite) power is available, bus stripping signals and EDG breaker closure permissive signals will not be initiated by the sequencers. Vital loads will be sequentially connected to the buses by the sequencers (including the opposite unit's HHSI pumps). If an EDG is already operating and parallelled to offsite power, and either unit experiences a LOCA, the EDG breaker will trip. The EDG will continue to run in a standby condition. On the LOCA unit, Engineered Safety Feature (ESF) equipment will be sequentially loaded onto the bus by the sequencer. Following a LOCA, if any given train experiences undervoltage, bus stripping, EDG breaker closure, and sequentially loading will be directed.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	4 OF 18

LOOP/LOCA

After a LOOP on both units, if one unit experiences a LOCA, the buses associated with the LOCA unit will be stripped and ESF loads will be loaded onto the bus. On the non-LOCA unit, both buses are stripped again, and reloaded with essential equipment; both HHSI pumps will also start.

Sequencer Testing

Each sequencer is provided with Manual test and Automatic Self-test capability. The test mode is determined by a three-position Test Selector switch. The three positions are AUTO (self-tests 15 steps or scenarios in the automatic test sequence), MAN (each test is manually initiated), and OFF (no test signals are generated). In the automatic test mode, the sequencer continuously tests the input cards, output cards, and output relay coils, and exercises the program logic. The sequencer is designed to abort the manual and automatic test modes in response to a valid input. The automatic self-test function is normally in operation, however it is not required to be in service for the sequencer to perform its safety function. The manual test, in addition to testing all the conditions covered by the automatic test, actuates the output relays. However, blocking relays energize before the output relays energize, and the output relays de-energize before the blocking relays de-energize.

Placing the Test Selector switch in MAN stops automatic self-testing.

Manual testing involves five stripping/clearing scenarios (bus clearing, 480V undervoltage with SI present, 480V degraded voltage, 4.16KV undervoltage, and safety injection [LOCA] on an isolated bus). Upon completion of the stripping tests, sequencing scenarios are tested manually by rotation of a Sequencing Mode Test Selector switch through eleven steps or loading scenarios (LOOP; LOOP/LOCA same train; LOOP/LOCA other unit; LOCA same train; LOCA other unit; LOOP/LOCA same train with concurrent HHCP; LOOP/LOCA same train with HHCP before 13 seconds; LOOP/LOCA same train with HHCP after 13 seconds; LOCA same train with concurrent HHCP; LOCA same train with HHCP before 13 seconds; LOCA same train with HHCP after 13 seconds).

Automatic self-testing cycles through 15 of the 16 test steps in the same order (the bus clearing scenario is not tested in AUTO). The test steps start roughly an hour apart, and there is one hour in the automatic test sequence in which no testing takes place, so a full cycle of automatic self-testing takes approximately sixteen hours. Then the cycle begins again. Should a valid process input signal be received during manual or automatic testing, the testing stops, the test signal clears, and the inhibit signal is supposed to clear if present, allowing the valid signal to sequentially energize the output relays and their associated ESF equipment.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	5 OF 18

II. CAUSE OF THE EVENT

The 3A sequencer failed to respond as expected to an opposite unit SI signal. The 3A sequencer had dropped out of the Automatic Self-Test without alarming, indicating that it had received a valid input signal. During troubleshooting, the input LED for a 4A SI signal was found to be lit, indicating the signal was still present. The 3A sequencer response should have been to start the 3A HHSI pump after a 3 second delay. However, the pump failed to start because it did not receive a start signal from the sequencer.

Following the failure of 3A HHSI pump to start in response to a 4A SI input signal as described above, an analysis of the sequencer software logic was performed to determine the root cause of the failure. A software design defect was discovered whereby the start signal for the 3A HHSI pump remained inhibited during sequencer automatic test step 3 (LOOP/LOCA other Unit) even though a valid process input was present. In parallel with the above analysis, this particular fault was duplicated on the sequencer simulator which is identical to the 3C23A-1 (3A) sequencer. This is in contrast to the original design bases of the sequencer Automatic Self-Test and Manual Test functions.

The review was then expanded to include additional test modes, process inputs, and required outputs. It was found that the problem exists during both manual and automatic testing, during sequencer test steps 2, 3, 6, 8, and 10. These steps correspond to the following scenarios:

Step 2	LOOP/LOCA
Step 3	LOOP/LOCA other Unit
Step 6	LOOP/LOCA with concurrent High High Containment Pressure
Step 8	LOOP/LOCA with High High Containment Pressure less than 13 seconds later
Step 10	LOOP/LOCA with High High Containment Pressure more than 13 seconds later

Note that these are tested scenarios, not potential plant events. Note too that all five of the affected test step scenarios involve LOOP and LOCA.

If a valid SI signal is received 15 seconds or later into one of the above tests, the test signal clears as intended, but the inhibit signal is maintained by means of latching logic. This latching logic is originally established by the test signal, but may be maintained by the process input signal if it arrives prior to removal of the test signal.

Since the above condition is applicable to both the automatic self-test and manual testing, the sequencer must be considered inoperable during both testing modes. Note, however, that this defect will not cause a sequencer operating malfunction with the Test Selector switch in any position for any design basis scenario which involves a loss of offsite power.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	6 OF 18

This software logic defect was introduced during the detailed logic design phase of the software development. The detailed logic designer and the independent verifier failed to recognize the interaction between some process logic inhibits and the test logic. The defect in the software logic was not detected during the Validation and Verification process (V&V) because the response to valid inputs was not tested during all stripping and loading sequences of the automatic and manual testing logic. FPL has evaluated the V&V for the sequencers and concluded that the existing V&V adequately addresses operation of the sequencers with the Test Selector switch in OFF.

This logic defect can occur when the sequencer is in either the manual or automatic test mode, and the test sequence currently being executed is loading sequence test 2, 3, 6, 8, or 10. This was determined based on a review of the sequencer logic drawings for the 15 steps in the automatic test sequence, and design basis event signals. The sequencer simulator was used to confirm the results of the review. The defect cannot affect sequencer operation with the Test Selector switch OFF.

In loading sequence tests 2, 6, 8, or 10, the sequencer may be inhibited from responding to a valid SI signal on the same train. In loading sequence test 3, the sequencer may be inhibited from responding to a valid SI signal on the opposite unit.

III. ANALYSIS OF THE EVENT

As a result of the erroneous inhibit signals, the potential exists for any sequencer output to be prevented from being generated when required. Exactly which output or outputs is(are) determined by a combination of factors, i.e., which test scenario is in progress, how long since the test scenario was initiated, and which process input or inputs are received. In general, for the approximate one-hour duration of each of the above test steps (with the Test Selector switch in AUTO), the sequencer will not respond correctly to a valid process input signal.

With the sequencer Test Selector switch in AUTO, the sequencer steps sequentially through sixteen steps as described above; first the five bus stripping/clearing steps, followed by the eleven LOOP and/or LOCA scenarios. Note that the five test steps affected by the software defect are all in the loading sequence test steps, so the first affected step is the seventh step in the total testing sequence. During each of these affected test steps, fifteen seconds after the initiation of the step, the sequencer would not have responded properly to a valid process input signal. So the sequencer was inoperable for about five hours out of each sixteen hour period as long as its Test Selector switch was in AUTO. The sequencer was also inoperable for the duration of any Manual test of the five test steps listed above. A complete manual test on one sequencer takes about one hour.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	7 OF 18

POTENTIAL ACCIDENT CONSEQUENCES FOR SEQUENCER FAILURE MODES

Test Logic Defect
The review of the sequencer logic determined that improper operation of the sequencer could occur for only certain sequencer stripping/loading scenarios in which an SI signal without LOOP occurs. The sequencer logic software defect does not affect any scenarios where a LOOP also occurs, whether before, after, or concurrent with an SI signal. A failure modes and effects matrix identified the following four potential plant events where the logic software defect could affect the operation of the sequencer, depending upon which of the five affected test steps (discussed above in II. CAUSE OF THE EVENT) are being performed when the SI signal is received by the sequencer:

#1 LOCA Same Train

#2 LOCA on other Unit

#3 LOCA w/High High Containment Pressure (HHCP) < 13 seconds

#4 LOCA w/HHCP > 13 seconds

Note that these are potential plant events, not test step scenarios. Note too that in contrast to the list of affected test step scenarios presented earlier, none of the potential plant events affected involve a LOOP.

For each of these events, the sequencer could receive a valid SI signal but the logic defect could inhibit the sequencer from starting equipment. Events #1, #3, and #4 above each have four logic test steps out of a total of sixteen which would inhibit the sequencer from providing a start signal to the equipment it controls while event #2 is affected by only one of the sixteen logic test steps.

The probability that an individual sequencer would not respond to a valid same train SI signal is 4 hours/16 hours = 2.5E-1. The probability that an individual sequencer would not respond to a valid opposite unit SI signal is 1 hour/16 hours = 6.25E-2.

The equipment affected due to the failure of a sequencer was identified from plant drawings. The equipment listed below is specific to the 3A sequencer. The equipment lists would be similar for the other three sequencers.

For event #1, the following equipment would not be automatically loaded by the sequencer:

Residual Heat Removal Pump 3A [BP:p]
HHSI Pump 3A
Intake Cooling Water Pumps 3A (1) and 3C (1) [BI:p]
Emergency Containment Cooler Fan 3B and 3C [BK:fan]
Component Cooling Water Pumps 3A (1) and 3C (1) [CC:p]
Emergency Containment Filter Fans 3B and 3C [BK:fan]

Note (1): The equipment identified may already be in operation and may not require manual action to start.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	8 OF 18

For events #3 and #4 (LOCA w/HHCP < 13 sec; LOCA w/HHCP > 13 sec), Containment Spray Pump 3A would be affected in addition to the equipment identified above for event #1.

For event #2 (LOCA other Unit), only the 3A HHSI Pump would not be automatically started.

It should be noted that one of the initiating signals for Auxiliary Feedwater (AFW) system [BA:p] is bus stripping, which is controlled by the sequencer. No credit is taken, however, for bus stripping in the accident analyses for initiating AFW. AFW is also initiated on low-low steam generator level, SI, manual initiation and trip of all Main Feedwater pumps [SJ:p].

Using the above information, the defect in the sequencer test logic represents a potential concern for events where SI is required for mitigation and no LOOP is experienced.

CS Pump Autostart Software Error
Using the Turkey Point baseline Probabilistic Safety Assessment model, the probability of dual train failure of the CS system if called on to operate has been estimated to be approximately 2.6E-3. This estimate reflects CS system and support system component failure probabilities not including either of the software errors reported here.

The failure to automatically start a CS pump due to this software error can only occur under a very remote set of circumstances. The 60 ms window is on the same order as the tolerance on relay pick-up times and the sequencer processing and timing tolerances. Even with sophisticated timing equipment, it is unlikely that the failure mode could be demonstrated repeatedly. The probability of receipt of a HHCP signal during a 60 ms window of vulnerability compared to the range of timing conditions for which the sequencer is designed is considerably smaller than the overall system reliability identified above. If it is assumed that HHCP can occur at any time within approximately two minutes after the SI signal (the earliest time at which SI is postulated to be reset), then the probability of the evaluated condition occurring on one train is:

$$0.060 \text{ sec} / (2 \text{ min} \times 60 \text{ sec/min}) = 5.0E-4$$

The estimate of the probability of a CS pump not starting automatically in a LOCA or LOOP/LOCA due to the reported software error is therefore approximately a factor of five below the estimated probability of both CS trains failing during a design basis event.

The probability of the software error affecting both trains is considerably lower, since it would require: 1) the initiating SI signals to be at the sequencer inputs within 60 ms of each other; 2) the two trains of HHCP both occurring within the 60 ms window of vulnerability; 3) the sequencer input processing times to be identical; and 4) the timing of the two sequencers in synchronization. The difference in the cumulative delay time for relay actuations on the two trains of ESFAS and differences in sequencer processing, in all likelihood would be sufficient to preclude the condition on both trains. This conclusion is supported by a review of previous Integrated Safeguards Test data. The difference between the train A and B CS pump recorded start times during a simulated LOOP/LOCA has been between 90 and 500 ms. Since some timing differences between the trains can be expected, and timing differences greater than 60 ms have been recorded during previous safeguards tests, the probability that the specific error could affect both trains of Containment Spray is therefore considerably less than the single train probability.

Effect on Analyzed Accidents

A review of the Turkey Point UFSAR Chapter 14 Accident Analyses was performed to determine which accidents would be potentially affected by the sequencer test software logic defect. This review identified 7 of the 22 accidents which may be affected. Two of the seven, "Loss of External Load" and "Loss of A.C. Power" were determined to be dependent on the sequencer but not affected, since the inhibited sequencer failure mode applies to loss of coolant accident (LOCA) scenarios only, i.e., no LOOP.

The five accidents both requiring SI, and affected by the sequencer test software logic defect, are the following:

1. Large Break Loss-of-Coolant Accident (LBLOCA)
2. Small Break LOCA (SBLOCA)
3. Rupture of a Steam Pipe (Main Steam Line Break, or MSLB)
4. Steam Generator Tube Rupture (SGTR)
5. Rupture of a Control Rod Mechanism Housing

The effects of the sequencer test logic defect will be discussed below for each of the five accidents. In each case, the transient is described and equipment necessary for mitigation of accidents is identified. Each transient is then evaluated assuming all four sequencers fail to operate properly. Credit is assumed for operator action to start HHSI pumps as well as other ESF equipment within 10 minutes as described below.

LARGE BREAK LOSS OF COOLANT ACCIDENT

A LOCA would result from a rupture of the Reactor Coolant System (RCS) or any line connected to that system up to the first closed valve. For a postulated LBLOCA, a reactor trip is initiated by pressurizer low pressure (1790 psig) while the SI signal is actuated by pressurizer low pressure at 1636 psig. The consequences of the LBLOCA are limited in two ways:

1. Reactor trip and borated water injection supplement void formation in causing rapid reduction of nuclear power to a residual level corresponding to fission product decay.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive temperatures and provide long term cooling.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	10 OF 18

The reactor is designed to withstand the thermal effects caused by a LBLOCA including the double ended severance of the largest RCS pipe. The reactor core and internals, together with the Emergency Core Cooling System (ECCS), are designed so that the reactor can be safely shutdown and the essential heat transfer geometry of the core will be preserved following an accident.

The LBLOCA analysis presented in Section 14.3 of the UFSAR assumes that 2 of 4 HHSI pumps and 1 of 2 RHR pumps are automatically actuated during the accident. If all four sequencers were inoperable because of the simultaneous presence of the test logic defect, SI actuation would not occur automatically.

The LBLOCA is a design basis event whose probability of occurrence is extremely small. A LBLOCA is considered to be a break with a total cross-sectional area equal or greater than 1.0 ft^2.

LBLOCA sensitivity studies, performed in 1988 to assess the impact of delaying SI, indicate that the maximum permissible SI delay is about 1 minute in order not to exceed the Peak Clad Temperature criteria of 10 CFR 50.46, and about 5 minutes to avoid exceeding fuel melt temperature, for a generic Westinghouse four-loop PWR. As a result of the test logic defect, Turkey Point tested operator reaction times to manually start SI in the absence of an automatic start (described below under **MITIGATION OF SEQUENCER FAILURE MODES**). The maximum time did not exceed 4 minutes. This information was provided to Westinghouse, who then determined that if SI is delayed 3 minutes and 15 seconds, the peak clad temperature for the hot rod will not exceed 1922 degrees Fahrenheit. If a conservative adiabatic heat up rate of six degrees per second is assumed for the fuel, SI may be delayed until four minutes into the LOCA without exceeding 10 CFR 50.46 PCT criteria. Therefore,if reasonable operator action is credited, no core damage would be expected.

Containment Response to a LBLOCA

A LBLOCA results in a significant mass and energy release into containment that results in pressurization of the containment structure. The UFSAR indicates that the pressurization event is limited by the size of containment, by containment heat sinks, and by the operation of containment cooling equipment (containment sprays and emergency containment coolers).

The containment analysis for the LBLOCA was assessed using better estimate techniques in 1989 by Westinghouse. This analysis showed that peak containment pressure for a Double Ended Pump Suction (DEPS) to be on the order of 42 to 45 psig. Using the mass and energy release values developed for the design basis reconstitution work, Westinghouse re-performed the Turkey Point containment analysis assuming no operation of the containment spray pumps or the emergency containment coolers, for ten minutes. This reanalysis shows that the peak pressure of the DEPS LOCA to be approximately 44.3 psig. Accordingly, since this peak pressure is less than the design pressure of 55 psig and less than the originally analyzed peak pressure of 49.9 psig, the results are acceptable. The ultimate strength of the Turkey Point containments is estimated to be approximately 140 psig based on the Individual Plant Examination (IPE) analysis work.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	11 OF 18

Dose Consequences for a LBLOCA

The UFSAR contains an offsite dose evaluation that assumes a total core release (100% noble gas, 50% halogens) occurring at time t = 0 with results that remain within 10 CFR Part 100 guidelines. The event under review, however, is different than that evaluated in the UFSAR in that engineered safety features are assumed to be delayed. Using knowledge learned from observation of accident phenomena and advanced light water reactor development programs, it has been concluded that an instantaneous core melt and release of fission products to containment is not credible. Rather, significant release to the containment would not be expected to occur during the first ten minutes of an accident. During this time, credit is taken for operator action to start SI, containment sprays, etc. Manual actuation of the containment sprays and emergency filters would provide for fission product cleanup within containment. While a calculation has not been performed, it is expected that the offsite dose consequences for this event will not exceed those stated in the UFSAR. Operation of sprays and filters will provide radioactive material cleanup prior to any significant fission product release from the containment.

SMALL BREAK LOSS OF COOLANT ACCIDENT (SBLOCA)

SBLOCAs are slow transients which take longer to initiate SI and therefore are less sensitive to delays in the actuation of the HHSI pumps. Containment response and dose consequences for the SBLOCA event are bounded by LBLOCA discussions above.

MAIN STEAM LINE BREAK

The UFSAR analyzes two separate steam line break events; opening a relief or safety valve, and main steam piping failure. The piping failure bounds the opening of the relief or safety valve. Since the sequencer issue is only a concern for the offsite power available case, only a main steam piping failure with offsite power available will be addressed. The most limiting cooldown event occurs at zero power with no decay heat. As indicated in the UFSAR, credit is taken for a single HHSI pump to provide borated water to return the core to a subcritical state.

Westinghouse re-performed the limiting MSLB accident with offsite power available assuming SI was not available for ten minutes. The results of this analysis indicate that the event can be accommodated without SI for ten minutes with acceptable results.

Containment Response to an MSLB

A Main Steam Line Break inside containment also results in a containment pressurization transient. This event was rerun by Westinghouse assuming no active containment pressure mitigating features (i.e. no containment sprays or containment coolers). Assuming no safeguards actuation, peak containment pressure for the MSLB was 48.8 psig occurring approximately 300 seconds (5 minutes) into the transient. This is within the containment design pressure of 55 psig and is therefore acceptable.

STEAM GENERATOR TUBE RUPTURE

The event examined in the UFSAR is a complete tube break adjacent to the tube sheet. Each steam generator tube has a nominal diameter of 0.875 inches with a wall thickness of 0.050 inches. Accordingly, the cross-sectional break area of a double ended tube rupture is less than 1.0 square inches. This small break area shows that this event is bounded by the SBLOCA in terms of assessing the potential for core damage resulting from this event, and that dose releases for this event will not increase as a result of delayed SI.

RCCA EJECTION - RUPTURE OF A CONTROL ROD MECHANISM HOUSING

The event examined in the UFSAR is a failure of a control rod mechanism pressure housing such that RCS pressure would eject the control rod and drive shaft to a fully withdrawn position. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution. The reactivity transient is terminated by the Doppler reactivity effects of the increased fuel temperature; and by subsequent reactor trip before conditions are reached that can result in fuel melt.

Actions are included in the Emergency Operating Procedures (EOPs) to address a SBLOCA that could be caused by a failed control rod mechanism pressure housing. Accident consequences of a SBLOCA in the reactor vessel upper head are bounded by the design-basis SBLOCA in the cold leg.

Summary of Potential Accident Consequences

Of the five UFSAR accidents affected, four are bounded by the LBLOCA. Consequences of a LBLOCA are acceptable if operator action to start ESF equipment takes place within four minutes of the start of the accident. The consequences of a MSLB are acceptable without operator action for ten minutes, since containment pressure peaks, below the design pressure, five minutes into the accident.

MITIGATION OF SEQUENCER FAILURE MODES

Because the presence of an SI signal during sequencer testing (automatic or manual mode) may render the sequencer inoperative, the dependence on SI was the primary consideration for determining the five affected accidents. For each of the affected accidents, the EOPs were reviewed to determine what mitigating actions would be taken by the operator. The effectiveness of the mitigating actions was also assessed based on its sequence within the procedures.

Upon initiation of any of the five affected accidents discussed above, the reactor would trip placing the operators in procedure 3/4-EOP-E-0, "Reactor Trip or Safety Injection." At Step 4 in EOP-E-0, the operator verifies whether SI is actuated or is required. If an SI is required, the operator verifies that HHSI and RHR pumps have started, or he is required to manually start these pumps in Step 8. These two steps are part of the immediate actions to be taken by an operator following a reactor trip.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	13 OF 18

In addition, the foldout pages for EOP-E-0 contains specific reactor trip and SI actuation criteria which require operators to start the HHSI pumps. Therefore FPL concludes that for these five accidents, there is a high probability that timely mitigating actions would have been taken by the operators to activate safeguards equipment even if the sequencer had failed.

To assess the operators' ability to accommodate sequencer test software logic defects, the Turkey Point Training Department constructed three different scenarios involving design basis accidents with failed sequencers. The failure mode modeled was a failure of the sequencer to load safeguards equipment. These scenario runs were completed on November 5, 1994. The three scenarios were:

1. A LOOP/LBLOCA with Unit 3 sequencers failed.

2. A LBLOCA with no LOOP, with Unit 3 sequencers failed.

3. A SBLOCA with no LOOP, with Unit 3 sequencers failed, Unit 4 HHSI pump breakers racked out, and the Unit 3 HHSI pump control switches in PULL TO LOCK on the Unit 4 control board.

Six control room crews ran each of the three scenarios, for a total of 18 simulator exercises. The Training Department was primarily interested in determining how long it took the control room crew to successfully energize all available safeguards equipment. A summary of the control room crew response times follows:

CREW	RESPONSE TIMES FOR FULL SAFEGUARDS INITIATION (IN MIN:SEC)		
	LOOP/LOCA SCENARIO	LBLOCA SCENARIO	SBLOCA SCENARIO
A	2:40	2:30	2:45
B	2:00	2:10	1:40
C	2:50	1:30	1:30
D	8:00	1:30	1:55
E	4:40	3:15	1:05
F	2:50	1:32	1:20

The simulator training coordinator stated that the longest time required to initiate SI flow was during Crew D's 8 minute LOOP/LOCA scenario; it took them approximately 4 minutes. However, the sequencer defect is not present for LOOP scenarios. The longest non-LOOP response time was 3 minutes and 15 seconds. An assumed operator response time of 10 minutes is therefore conservative.

In addition to the scenario exercises described above, a review of earlier observations of operating crews in simulator training during July and August 1994 was made. These observations illustrated that it took each crew 4 to 5 minutes from event initiation to complete alignment of the required safeguards equipment associated with a full sequencer failure.

Operator verification of SI, and HHSI pump flow, is performed within the immediate action steps (Steps 4 and 8 respectively) of EOP-E-0. The first 14 steps are memorized by the control room crew. In addition, immediate action steps are required to be re-verified by the operators. Therefore FPL concludes that the control room crew would be successful in timely initiation of HHSI pump flow in the event of a sequencer malfunction.

PROBABILISTIC SAFETY ASSESSMENTS

A probabilistic safety assessment was performed to estimate the safety impact of inhibited emergency sequencer operation due to a logic error in the software associated with the test feature. The assessment is based on the Turkey Point IPE Submittal and subsequent updates, and includes the effect of the failure of all four sequencers. The recovery actions are added to the model for different scenarios, e.g., recovery for LBLOCA vs. SBLOCA. These operator actions are calculated based on the time available to do the actions (NUREG/CR-4550, Vol. 3, Rev. 1, Part1), and the time it takes the operators to perform the actions obtained from a review of 3/4-EOPs-0 and from simulator scenario runs.

The probabalistic safety assessment determined that the estimated change in the Core Damage Frequency (CDF) under the above conditions, with all four sequencers inoperable, is 6.3E-6/yr. However, all four sequencers were not inoperable at all times. Each sequencer is inoperable during 5 of the 16 tests. In order for all sequencers to fail simultaneously, all sequencers would have to be in an affected test. This would happen most often if all four sequencer test cycles were synchronized. Even if all four sequencers were synchronized on the same test cycle, the sequencers would all be inoperable during only 5 of the 16 tests. Therefore, all four sequencers would be inoperable approximately one-third of the time. This results in an estimated change in CDF of 2.1E-6/yr. This change in core damage frequency increases the baseline CDF by 3.2%. The PRA calculation considers an average probability over a one year period.

The 3.2% increase in the CDF is a conservative estimate for this situation. This increase in CDF is not safety significant, based on the acceptance criteria stipulated in the draft EPRI PSA Application Guide.

The estimated risk impact of loss of sequencers for LBLOCAs is relatively low due to the low initiating event frequency of LBLOCAs, and recovery actions described in the early steps of the EOP E-0 for reactor trip and SI. Although SBLOCAs have a higher initiating event frequency the risk is relatively low because the operator has more time available to perform recovery actions.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	15 OF 18

An estimate of the potential risk impact of the failure of the CS pumps to automatically start was performed. The scenario is assumed to occur for a certain size LOCA or MSLB such that the HHCP signal is generated at the 12.9 to 13.0 second window during which the sequencers may not actuate CS pumps automatically. A further assumption is that failure of all containment spray with a medium LOCA leads directly to core damage. The core damage frequency increase is thus estimated to be:

CDF = (frequency of event [medium and small LOCAs, MSLB]) times
(probability of "right size" break to cause the event) times
(probability of failure of manual starting of CS pumps)

= (1.0E-4 + 1.0E-3 + 1.0E-4) x (5.0E-4) x (6.0E-3)

= 3.6 E-9 / year

Note that the frequency of the event is conservatively estimated to be that of the medium LOCA (6-13.5 inches), the small LOCA (2-6 inches) or a MSLB. Since a specifically-timed LOOP would be required for either the small LOCA or the MSLB to be of concern, the CDF is actually lower.

A estimated increase in the CDF of 3.6E-9/yr is insignificant compared to the baseline CDF of 6.63E-5/yr.

SAFETY SIGNIFICANCE AND OPERABILITY

The periodic inoperability of all four sequencers, as described above, has existed since the sequencers were installed during the dual unit outage in 1990/1991. The sequencers were accepted as operational in September and October, 1991, for Units 3 and 4, respectively. From early December, 1991, until November, 1992 (Unit 3) and May, 1993 (Unit 4) the sequencers' Test Selector switches were in OFF except for monthly manual tests, as described in LER 251/91-007.

Since then, there have been four challenges to the bus sequencers (between the two units). LER 251/92-004 reported an inadvertent Safety Injection on Unit 4; all plant equipment responded as designed, including the Unit 3 HHSI pumps. LERs 250/92-009 and 250/92-013 reported a LOOP (due to hurricane Andrew), and an inadvertent 3A bus stripping. In these three instances the sequencers' Test Selector switches were not in AUTO, and they performed as designed.

LER 250/94-002 reported an inadvertent ESF actuation on Unit 3, in which all equipment responded as design, except the 4A HHSI pump. At that time the failure of the 4A HHSI pump was attributed to an intermittent failure, which could not be reproduced. As a result of the discovery of the defect reported herein, that earlier event can now be reproduced at will on the sequencer simulator. FPL believes that the 4A HHSI pump failed to start because of the same defect that caused the 3A HHSI pump failure to start, reported in this LER.

Since there have been no actual events requiring Engineered Safety Features actuation to protect the plant, the health and safety of the public has not been affected by the periodic inoperability of the sequencers.

This event is reportable under the requirements of 10 CFR 50.73(a)(2)(i)(B), (a)(ii)(A), (a)(ii)(B), (a)(v), (a)(vii), and 10 CFR 21.

Regarding the second software error involving the CS pump autostart, FPL has concluded that the CS system remains OPERABLE because, in the highly unlikely event that the condition were to occur, simple operator action to start the CS pumps, in accordance with the plant's emergency operating procedures, would ensure compliance with the system specified functions. The ability to manually start the CS pumps as much as ten minutes into the event and maintain required cooling is supported by analysis, procedures, and training. In addition the safety significance of the evaluated condition is extremely low because the probability of the evaluated condition is lower than the probability of a common mode failure of both CS trains, as discussed earlier under Possible Accident Consequences for Sequencer Failure Modes. In any case, the contribution to CDF of this software error is negligible.

IV. CORRECTIVE ACTIONS

1. The Test Selector switches on all four sequencers were placed in OFF. Tags have been hung on each switch to require specific permission from the Nuclear Plant Supervisor to change the position of the switch. With the sequencer test mode switch in the OFF position, the automatic test logic is disabled. The sequencer is fully functional and will respond properly to input signals. The automatic test function is not a requirement for periodic surveillance of the sequencer.

2. With the Test Selector switch in OFF, additional visual inspections are being performed on a eight hour basis as described below:

   a. The local reflash annunciators points are verified not in alarm.

   b. The I/O power, PLC Power, and ANN Power switches are verified in the ON position and the Processor Power white indicating light is verified illuminated.

   c. The Test Selector switch is verified in the OFF position; the Stripping Clearing Test Selector and Sequencing Mode Test Selector Switches are verified in the OFF position.

   d. The 2 green test reset indicating lights and the sequencing reset green indicating lights are verified illuminated.

   e. The other indicating lights are verified not to be illuminated (except the ground fault indicating lights are supposed to be dimly lit).

   f. Every 24 hours, the sequencer door is opened, the Processor Indicator LED is verified to be a solid green and the 9 indicator I/O cards "ACTIVE" LED are verified to be a solid green.

3. A detailed review of the original Validation and Verification process was performed; it has been concluded that an oversight occurred because not all sequencer functions were validated during all modes of automatic and manual testing. The existing verification and validation sufficiently covers the sequencer safety functions if the Test Selector switch remains OFF.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	17 OF 18

4. Functional testing on the sequencer simulator of design basis inputs has been repeated with the Test Selector switch OFF, with acceptable results.

5. A safety evaluation has been issued demonstrating sequencer operability with the test selector switch in the OFF position. This safety evaluation was approved by the Plant Nuclear Safety Committee on November 4, 1994.

6. Independent consultants were retained to perform an assessment of the existing sequencer design, software design and V&V. This "Independent Assessment Team" (IAT) concluded that operation of the sequencers with the Test Selector switch in OFF represented a safe condition and that FPL's evaluation of the condition was appropriate.

   The second phase of the IAT's assignment was to provide a detailed review of the software documentation. Some drawing discrepancies were identified and have been evaluated. In general the discrepancies dealt with the inclusion of additional information on the logic diagrams not reflected in the ladder diagrams, to aid in understanding the logic diagrams. One other software error was identified involving autostart of the CS pumps, and has been discussed earlier in the LER. The drawing discrepancies will be corrected when the software is modified (see Corrective Action #9 below).

   The IAT confirmed that the V&V was not comprehensive enough to test certain aspects of the logic. "The plan was weak in that it relied almost completely on testing as the V&V methodology. More emphasis on the analysis of the requirements and design would have increased the likelihood of discovering the design flaw." A revision to the V&V documentation will be made coincident with the design modifications described on Corrective Action #9 below.

7. The original software vendor, United Controls, Inc. has been notified of this defect and its significance.

8. In order to eliminate issues related to the use of one-of-a-kind or first-of-a-kind equipment, FPL implemented Nuclear Policy NP-905, Equipment Selection, in October of 1991. This policy states in part that, "FPL's nuclear engineering department shall select only specific models of equipment with proven records of reliable performance for use in FPL nuclear facilities. Verification of the equipment reliability must be established through contact with NPRDS, nuclear station managers, or other appropriate sources. If no prior operating experience is available, appropriate prototype testing, under equivalent plant operating conditions, must be undertaken to establish its reliability before it is placed in service at FPL nuclear facilities." The Engineering Quality Instructions contain the Nuclear Policy requirements for design outputs.

9. Design modifications to eliminate the software logic problems will be implemented during the next refueling outages of each unit.

10. Other safety-related process computer suppliers were notified of the event on November 14, 1994. These suppliers responded that similar software errors do not exist in other safety-related process computers.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 3	05000250	94-005-01	18 OF 18

11. An FPL Nuclear Engineering standard will be developed on the use of PLCs, prior to the procurement of any additional PLC-based equipment.

12. Manual testing of the sequencers was resumed on January 11, 1995.

V. ADDITIONAL INFORMATION

EIIS Codes are shown in the format [EIIS SYSTEM: IEEE component function identifier, second component function identifier (if appropriate)].

The Programmable Logic Controllers used in the sequencers are made by Allen-Bradley; the sequencers are assembled by United Controls, Inc. (UCI). According to UCI, Florida Power & Light Company is the only utility to which UCI supplied this sequencer.

LER No. 254/94-S01
Quad Cities, Unit 1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 7, 1994

NRC INFORMATION NOTICE 94-42: CRACKING IN THE LOWER REGION OF THE CORE SHROUD IN BOILING-WATER REACTORS

Addressees

All holders of operating licenses or construction permits for boiling-water reactors (BWRs).

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees that a 360-degree crack has been observed at a weld in the lower region of the core shroud in two boiling-water reactors. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

During the April 1994 refueling outage at Dresden Unit 3, Commonwealth Edison Company, the licensee, found a 360-degree crack that extended around the outside circumference of the core plate support ring weldment. The shroud is a 5.1 centimeter [2 inch]-thick stainless steel cylinder that directs the flow of water inside the reactor pressure vessel. The shroud is completely contained inside the reactor pressure vessel. The structural integrity of the reactor pressure vessel is not affected by cracks in the shroud.

The cracking was found during a visual inspection and was located in the lower section of the shroud in the heat-affected zone (HAZ) of weld H-5. (See Figures 1 and 2.) Weld H-5 is a horizontal weld that joins the core plate support ring to the core shroud. Subsequent ultrasonic testing, utilizing automated equipment from General Electric, determined that the maximum crack depth was 2.13 cm [0.84 inches].

Commonwealth Edison Company also performed a visual inspection of the Quad Cities Unit 1 core shroud. That inspection revealed a similar 360-degree circumferential crack located at the same place as the crack found at Dresden Unit 3. Both Dresden and Quad Cities units are BWR-3s and have similar core shroud geometries. Core shroud designs for other BWRs may exhibit some differences, and weld identification numbers are not necessarily congruent between the designs.

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Discussion

At Dresden Unit 3, in addition to the 360-degree circumferential crack in the HAZ of weld H-5, numerous crack indications were also found in the HAZ of weld H-3. The licensee plans to perform UTs and take boat samples at both Dresden Unit 3 and Quad Cities Unit 1 to help determine the root cause of the cracking.

Commonwealth Edison Company inspected the Dresden shroud using a criterion that required the resolution of a 25 micron [1 mil] wire with a 25-mm camera lens positioned to within 2.5 to 7.6 cm [1 to 3 inches] of the shroud surface. The same 25 micron [1 mil] wire resolution criterion had been used previously at Quad Cities, but with a 9 mm camera lens positioned approximately 15.2 to 30.5 cm [6 to 12 inches] from the shroud surface. Using this technique, no crack indications were initially detected at Quad Cities. However, after Commonwealth Edison Company detected the crack at Dresden, the H-5 weld at Quad Cities was inspected again, this time using the Dresden technique, and the 360-degree crack was detected.

Related Generic Communications

In Information Notice (IN) 93-79, "Core Shroud Cracking at Beltline Region Welds in Boiling-Water Reactors," (issued September 30, 1993) which discusses cracks detected at Brunswick Unit 1, the staff pointed out that camera and lighting positions were crucial in performing adequate visual inspections. It is imperative to position the camera or video probe as near to the examination surface as possible and to use an appropriate camera lens. The lighting direction and intensity are important factors and should be adjustable to enhance the detection of these tight surface crack indications.

Crack indications have been previously reported at shroud welds in domestic and overseas reactors at the beltline region and higher in the shroud. However, the severely cracked H-5 shroud welds at Dresden Unit 3 and Quad Cites Unit 1 are located 45.7 centimeters [18 inches] below the bottom of the fuel, suggesting that horizontal welds in all regions of the shroud may be susceptible to stress corrosion cracking

The IN 93-79 also referred to GE Rapid Information Communication Service Information Letter (RICSIL) No. 054, Revision 1, "Core Support Shroud Crack Indication." Since IN 93-79 was issued, GE issued additional information on core shroud cracks in October 1993, April 1994, and May 1994.

The BWR Owner's Group (BWROG) submitted an evaluation of core shroud cracking to the staff on April 5, 1994. After reviewing the evaluation, and in light of the Dresden and Quad Cities findings, the staff issued a list of questions to the Chairman of the BWROG Executive Oversight Committee on May 12, 1994.

The NRC staff is evaluating the safety implications of the shroud cracks for normal plant operating and accident conditions and will consider the need for additional generic communication.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

Brian K. Grimes, Director
Division of Operating Reactor Support
Office of Nuclear Reactor Regulation

Technical contacts: R. Hermann, NRR
(301) 504-2768

J. Schapker, RIII
(708) 829-9715

T. Greene, NRR
(301) 504-1175

Attachments:
1. Figure 1: Shroud Weld Locations for Dresden Unit 3
2. Figure 2: Details of Weld Locations H-5 and H-6 in the Dresden Unit 3 Core Shroud
3. List of Recently Issued NRC Information Notices

Attachment 1
IN 94-42
June 7, 1994
Page 1 of 1

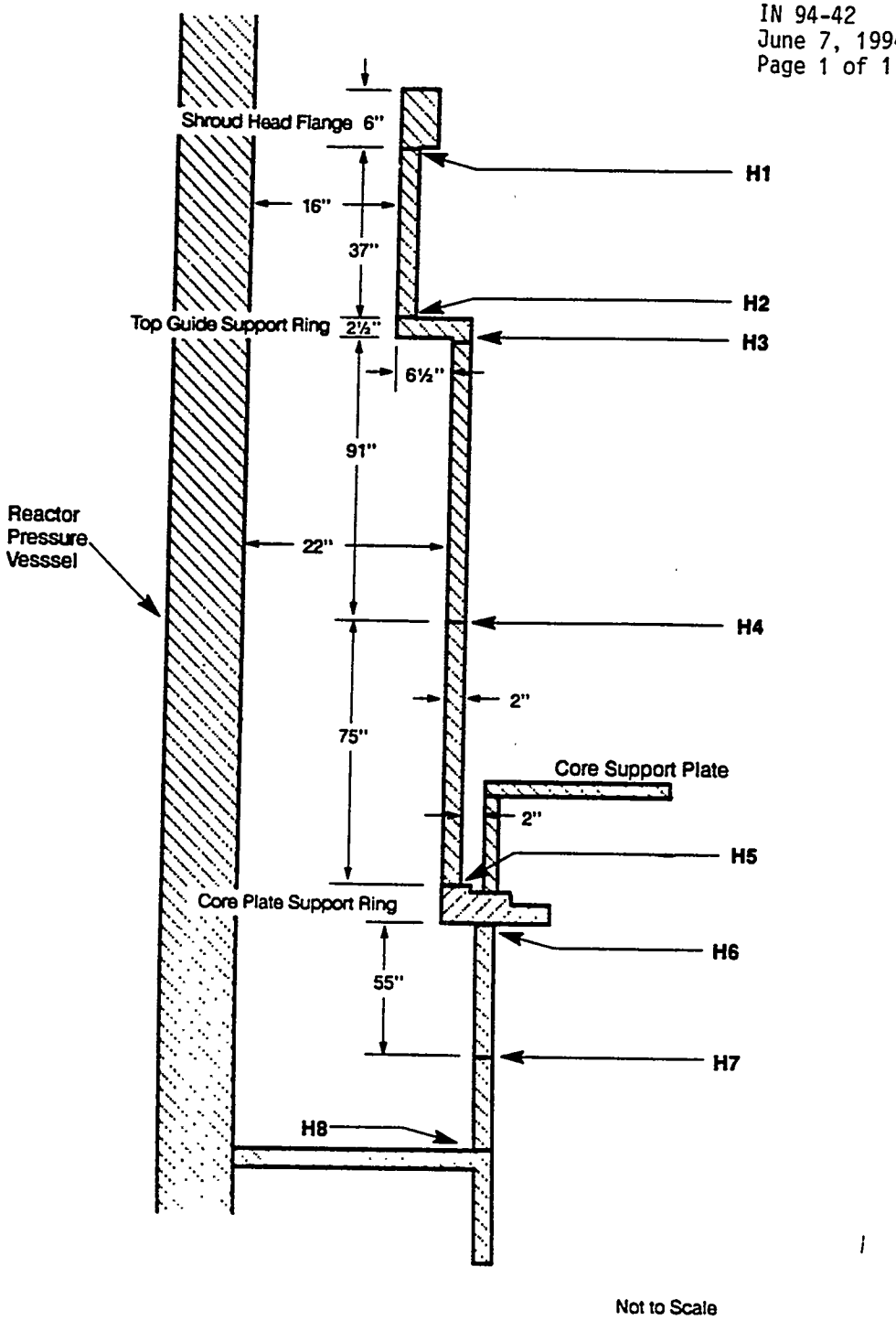

Figure 1. Shroud Weld Locations for Dresden, Unit 3

Attachment 2
IN 94-42
June 7, 1994
Page 1 of 1

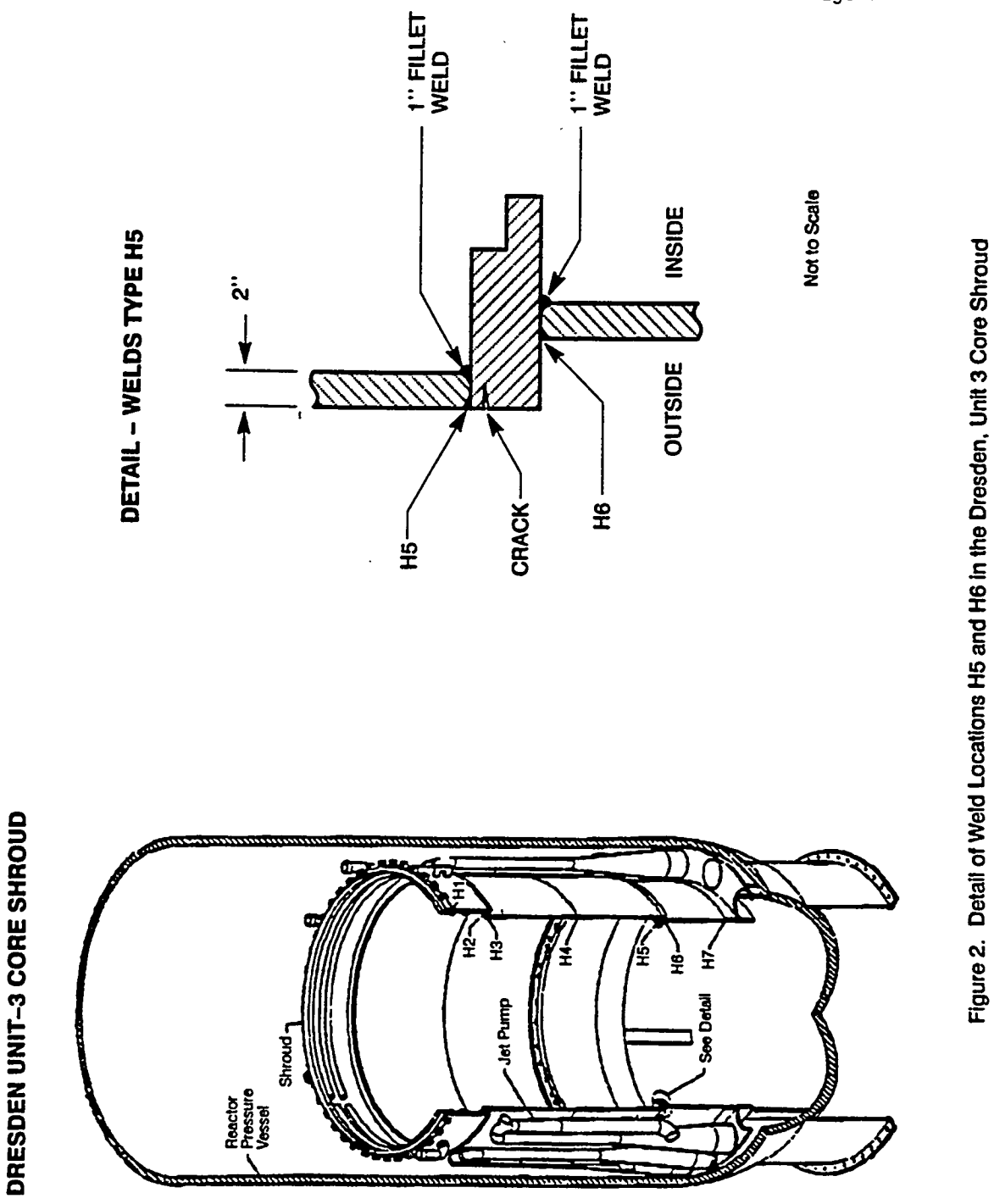

Figure 2. Detail of Weld Locations H5 and H6 in the Dresden, Unit 3 Core Shroud

Attachment 3
IN 94-42
June 7, 1994
Page 1 of 1

LIST OF RECENTLY ISSUED
NRC INFORMATION NOTICES

Information Notice No.	Subject	Date of Issuance	Issued to
94-41	Problems with General Electric Type CR124 Overload Relay Ambient Compensation	06/07/94	All holders of OLs or CPs for nuclear power reactors.
94-40	Failure of a Rod Control Cluster Assembly to Fully Insert Following a Reactor Trip at Braidwood Unit 2	05/26/94	All holders of OLs or CPs for pressurized-water reactors (PWRs).
94-39	Identified Problems in Gamma Stereotactic Radiosurgery	05/31/94	All U.S. Nuclear Regulatory Commission Teletherapy Medical Licensees.
94-38	Results of a Special NRC Inspection at Dresden Nuclear Power Station Unit 1 Following a Rupture of Service Water Inside Containment	05/27/94	All holders of OLs or CPs for NPRs and all fuel cycle and materials licensees authorized to possess spent fuel.
94-37	Misadministration Caused by a Bent Interstitial Needle during Brachy-therapy Procedure	05/27/94	All U.S. Nuclear Regulatory Commission Medical Licensees authorized to use brachy-therapy sources in high-, medium-, and pulsed-dose-rate remote afterloaders.
94-36	Undetected Accumulation of Gas in Reactor Coolant System	05/24/94	All holders of OLs or CPs for nuclear power reactors.
91-81, Supp. 1	Switchyard Problems that Contribute to Loss of Offsite Power	05/19/94	All holders of OLs or CPs for nuclear power reactors.

OL = Operating License
CP = Construction Permit

LER No. 255/94-008
Palisades

NRC Form 366 (9-83)

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

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Palisades Plant	0 5 0 0 0 2 5 5	1 OF 0 8

TITLE (4) LACK OF SEPARATION OR ISOLATION BETWEEN 1E AND NON-1E CIRCUITS - SUPPLEMENTAL REPORT

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (8)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	
									N/A	0 5 0 0 0
0 3	2 9	9 4	9 4	- 0 0 8	- 0 1	0 8	2 9	9 4	N/A	0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	1 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Paul J. Gire, Staff Licensing Engineer	AREA CODE 6 1 6 7 6 4 - 8 9 1 3

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

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

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

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

Between March 29, and May 3, 1994, with the plant in cold shutdown, twelve discrepancies were identified where Class 1E and non-Class 1E equipment was not isolated or separated as required by the Palisades FSAR and IEEE 279 - 1971. These discrepancies are reportable as required by 10CFR50.73 (a)(2)(ii)(B) as conditions which were outside the plant's design basis.

Causes for the deviations from separation or isolation criteria include inadequate design reviews and design installation controls utilized at the time of either plant construction or subsequent modifications in the 1980's that added cabling or additional control circuits to the plant.

Eleven of the twelve discrepancies have been corrected. The twelfth will remain in place under an NRC approved deviation until the 1995 refueling outage. Longer term corrective actions include full utilization of the recently enhanced modification review process, providing training to design reviewers regarding specific separation or isolation modification guidelines previously developed, and developing accurate schematics for affected systems. This report addresses all of the plant's discoveries made as a result of a review of isolation and separation issues.

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 2 OF 0 8

Event Description:

On March 29 and 30, and April 9, 1994, with the plant in cold shutdown, it was discovered that some Class 1E (safety-related) circuits were not isolated or separated from non-Class 1E circuits. Requirements for electrical independence and isolation are defined in the Palisades FSAR, Chapters 7 and 8, which commit to IEEE 279-1971. These require that non-Class 1E circuits be isolated from Class 1E circuits so that a fault in a non-Class 1E circuit would not affect the Class 1E circuit. Four discrepancies were identified involving isolation or separation of circuits for the Reactor Protection System (RPS), Engineered Safety Features (ESF), and on the Subcooled Margin Monitor (SMM). Subsequently, it was discovered that additional Class 1E (safety-related) circuits were not isolated from non-Class 1E circuits. The plant was in cold shutdown at the time of discovery of all the deficiencies. The following discrepancies were noted:

Low Temperature Overpressure Protection: The first discovery on March 29, 1994, involved a lack of isolation between Class 1E Primary Coolant System (PCS) temperature transmitters that provide inputs to the Reactor Protection System (RPS) via the Thermal Margin Monitor (TMM) and the Class 1E Low Temperature Overpressure Protection (LTOP) system. These circuits were not isolated from non-Class 1E PCS temperature indicators used for plant control. The LTOP is considered to have been outside the required isolation design basis since its installation in 1989.

Thermal Margin Monitor: Also on March 29, it was found that four channel circuit independence was not provided between the safety related "upper" and "lower" nuclear power range signals nor between the safety related TMM circuits. Redundant channels in both the nuclear power range indication system and the TMM systems are routed through the same raceway. In addition, each of these systems is connected to both the non-Class 1E Critical Function Monitoring System (CFMS) and plant data logger without adequate circuit Class 1E to non-Class 1E isolation. An analysis of the effects of both discoveries lead to the conclusion that the TMM had been outside the plant's separation and isolation design basis since the TMM was installed in 1988.

Inverter Power Cables: As a result of ongoing drawing reviews and physical walkdowns of systems, another discrepancy was identified on March 30, 1994. The power cables from inverters to RPS and ESF instrument loops were not separated in accordance with Palisades design basis cable separation criteria. Cables for "right" channel inverters Y20 and Y40 were routed together in the same cable tray, as were cables for "left" channel inverters Y10 and Y30. This condition had existed since original plant construction.

Subcooled Margin Monitors: On April 9, in the course of further examinations prompted by the previous discoveries, plant personnel identified that power feeds to the Class 1E Subcooled Margin Monitors (SMMs) were not isolated from power feeds to non-Class 1E devices. The SMMs had been installed in 1980 to meet requirements of NUREG 0737 Item II.F.2. One requirement was that primary and backup display channels should be electrically independent, supplied from Class 1E sources, and physically separated from other devices per Reg Guide 1.75.

NRC Form 366A (9-83)

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 3 OF 0 8

Reactor Protection System: On April 17, 1994, it was found that there was no isolation between Reactor Protection System (RPS) "B" channel and a 120-volt standard power outlet installed in the same cabinet. Both are supplied by the same breaker. The RPS channel is Class 1E while the outlet, which may be used for any purpose, is not restricted to class 1E loads. This condition had existed since original plant construction.

Auxiliary Feedwater: Class 1E Auxiliary Feedwater (AFW) flow control and indication circuits and non-Class 1E Main Feedwater (MFW) recirculation control circuits were found on April 17, 1994, unisolated. Circuits were protected by the same fuses. This condition resulted from modifications in 1982 and 1984.

Condensate Storage Tank Level: One of the two Class 1E Condensate Storage Tank (CST) level indication circuits was found April 19, 1994, to be protected by the same fuse as the non-Class 1E diesel fuel oil tank level circuit and the non-Class 1E engineered safeguards room cooler temperature instrument circuit. This condition appears to have resulted from a modification made in 1981 or was left in place from original plant construction.

Reactor Protection System Temperature Protection and Thermal Margin Monitor: A fused connection from a breaker used for the Reactor Protection System (RPS) temperature protection and Thermal Margin Monitor (TMM), both Class 1E, was also used for the non-Class 1E audible count rate drawer. This discrepancy was identified on April 20, 1994. This condition appears to have resulted from modifications made in 1980 or 1988, or was left in place from original plant construction.

Inverter output: On April 22, 1994, it was found that Class 1E breakers are used as isolation devices between Class 1E and non-Class 1E circuits on all four of the plant's safety related inverters. The impact of a short circuit on any one of the non-Class 1E circuits isolated by these breakers could reduce output voltage on all four inverters below the manufacturer's design amount. This could result in an extended trip time of the breaker, allowing a reduced voltage to feed the Class 1E loads until the breakers tripped. This condition resulted from a combination of original plant construction and modifications made in 1984.

Core Exit Thermocouples: On April 27, 1994, it was found that there was no isolation device separating the 16 Class 1E qualified Core Exit Thermocouples (CETs) to the non-Class 1E primary data logger computer. The plant had initially committed to removing the 16 qualified CETs from the primary data logger. A request for a deviation from that previous commitment was made to the Commission on May 20, 1994, and was subsequently approved by the NRC on June 1, 1994. The CETs were connected to the Primary Data Logger as part of a modification in 1988.

Subcooled Margin Monitor Isolators: On April 28, 1994, the plant identified that Primary Coolant System Instrumentation Class 1E isolators were not fully qualified in accordance with Reg. Guide 1.97 and Reg. Guide 1.75 because they were not tested to demonstrate acceptable isolation from output to input. The instrumentation affected included hot and cold leg temperature indicator channels, four channels of the Thermal Margin Monitors (TMM), two channels of the Low Temperature Overpressure Protection system (LTOP), two SMMs and two recorders. This condition appears to have resulted from modifications made in 1980 and 1988.

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 4 OF 0 8

Main Steam Isolation Valves: On May 3, 1994, ongoing reviews identified that the Class 1E main steam isolation valve solenoids were not electrically isolated from non-Class 1E equipment. Non-Class 1E equipment powered from the same fuse as Class 1E equipment included main feedwater block solenoid valves, atmospheric steam dump solenoid valves, turbine bypass solenoid valves and a non-safety related solenoid valve associated with the auxiliary feedwater pump steam supply. This condition had existed since original plant construction.

For each isolation or separation deficiency identified above, operability determinations were made and the appropriate equipment was declared inoperable. Those cases which required resolution prior to startup from the maintenance outage were identified and corrected. Because each condition identified to date showed the plant outside its design basis, they are reportable in accordance with 10CFR50.73(a)(2)(ii)(B).

Cause Of The Event:

For all of the discrepancies addressed in this report an inadequate or incomplete review of electrical design allowed the circuits to be modified or left in place without adequate isolation or separation. A contributor to the problem was a lack of engineering design guides identifying standards, methods, and examples that are needed to achieve isolation or separation. A second contributor was a lack of composite schematic diagrams for use by engineering.

Analysis of the Event and Safety Significance

Low Temperature Overpressure Protection: This discrepancy involved a lack of electrical isolation between Class 1E and non-Class 1E temperature monitoring circuits. In two cases, a single fuse was utilized to power non-Class 1E temperature monitoring instrumentation as well as Class 1E temperature monitoring loops which provide input to the Reactor Protection System (RPS) and low temperature overpressure protection (LTOP). The fuse also provided power to the Thermal Margin Monitor (TMM) which provides input signals to the RPS for variable low pressure and high power trips. A fault in the non-Class 1E temperature monitoring instrumentation could have caused the fuses to blow, resulting in a loss of Class 1E functions. This fault would have been immediately apparent to the operators as a loss of power to the TMM would result in generation of a reactor trip signal on one of the four RPS cabinets.

Faults resulting in blowing fuses would also affect the LTOP system. Loss of the temperature input would cause the LTOP to alarm, however, the low temperature input to the system would also result in generation of a signal to open the primary coolant system (PCS) power operated relief valves (PORV). An alarm would be generated to alert the operator to the PORV opening. During power operations, opening of a PORV would not be of any consequence as the PORV block valves are normally closed. Opening of a PORV during reduced temperature operations would result in a pressure reduction in the PCS. The operator could terminate this pressure reduction by closing the PORV block valves.

Thermal Margin Monitor: This discrepancy involved a lack of four channel cable separation for cables connected to the input of the TMMs. All four channels of upper and lower nuclear power inputs to the TMM were routed to remote data processors through a single cable. The upper and lower nuclear power signals are used in the TMM to generate an axial shape imbalance (ASI) signal. This ASI signal is then used to generate a variable PCS low pressure trip setpoint for

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	- 0 0 8	- 0 1	0 5 OF 0 8

input into the RPS. Failure in the common cable carrying signals for all four channels would have resulted in erroneous calculation of ASI and generation of an incorrect low pressure trip setpoint. The TMM however, also generates a constant minimum low pressure trip value and selects the higher of the ASI biased value or the minimum value. Therefore faults in the cable would have resulted in a default to the constant low pressure trip setpoint and not a complete loss of low pressure trip capability.

Inverter Cable Separation: This deficiency, identified on March 30, 1994, involved a lack of power cable separation from inverters to RPS and ESF instrument loops. Cables for the "right" and "left" channels were installed in the same cable trays rather than separated.

The RPS is designed as a deenergize-to-trip system. Postulated failures of the cables (short, open or ground) sharing a common raceway would have resulted in a loss of power to the system. This loss of power would deenergize the associated RPS channel resulting in the one channel failing to a trip condition. If both cables faulted, the two out of four trip logic of the RPS would have been satisfied, resulting in a reactor trip.

The ESF detection circuits are designed deenergize to actuate whereas the actuation circuits (two out of four logic) are designed energize to actuate. Postulated failures of the cables (short, open or ground) sharing a common raceway would result in a loss of power to the system. If both cables faulted, two of the four detection relays would drop out, providing inputs to both "left" and "right" channel actuation circuits. As one of the faulted cables also powers one channel of actuation circuits, only one channel of required safeguards equipment would have been actuated.

Subcooled Margin Monitors: On April 9, 1994, the Subcooled Margin Monitors (SMM) were declared inoperable when it was found that this Class 1E system was powered from the same fuse as the non-Class 1E feedwater control solenoid valves. Loss of the SMM would be obvious to the operator as the digital display would be dark. In a case where both SMMs are lost, plant procedures require that the operator manually calculate subcooling margin using pressure and temperature curves or steam tables.

Reactor Protection System: This deficiency involved a 120-volt AC outlet being connected to one channel of the RPS without adequate electrical isolation. A fault in equipment connected to the 120-volt power outlet could have resulted in losing power to one channel of the RPS. Each of the four RPS channels is designed to trip on loss of power. This fault could have resulted in tripping one channel, leaving the RPS in a one out of three tripping scheme. As the 120-volt outlet was only connected to one channel of the RPS, this lack of isolation is not considered to be safety significant.

Auxiliary Feedwater: This discrepancy involves a lack of electrical isolation between non-Class 1E instrumentation in the main feedwater system and Class 1E auxiliary feedwater instrumentation. For the "Left" channel circuitry, a fault in the non-Class 1E components would result in a loss of 1 of 2 auctioneered DC power supplies which provide auxiliary feedwater flow control and indication. The remaining auctioneered power supply would remain available and auxiliary feedwater control and indication would not be affected. Two backup redundant AFW flow

NRC Form 366A (9-83)

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 6 OF 0 8

indicators (one per steam generator) would, however, lose power and be unavailable. For the "Right" channel circuitry, a fault in the non-Class 1E components would result in a loss of flow control and indication to both steam generators. The flow control valves in this train of AFW would fail open assuring that a supply of feedwater was available for removing heat from the steam generators in the event that AFW cooling was required. The operator would rely on steam generator level to control AFW flow by cycling the AFW pumps as necessary.

Condensate Storage Tank Level: This discrepancy involves a lack of electrical isolation between non-Class 1E instrumentation and Class 1E condensate storage tank level instrumentation. A fault in either of the two non-Class 1E indication loops could result in a loss of tank level monitoring loop LT-2021. A redundant tank level monitoring loop, LT-2022, would have been available to provide control room operators with an indication of Condensate Storage Tank level.

Reactor Protection System Temperature Protection and Thermal Margin Monitor: This discrepancy involves a lack of electrical isolation between the non-Class 1E source range audible countrate amplifier and Class 1E temperature monitoring equipment. A fault in the non-Class 1E audible count rate drawer could cause a loss of the Class 1E RPS temperature protection channel "D". This would result in the loss of that channel's inputs to the Subcooled Margin Monitors (SMMs) and one channel of Variable High Power (VHP) and Thermal Margin/Low Pressure (TM/LP) trips. With the loss of the "D" channel inputs to the SMMs the operator would receive an annunciator alarm. However, the SMM would continue to function using redundant temperature inputs from other sources. The loss of the "D" channel of TM/LP/VHP trips would also be alarmed in the control room, "D" channel could be placed in the bypass condition, and the resultant two out of three tripping logic would be used. It has been concluded that, even with the fault, the (RPS) would still have been capable of performing its safety function.

Inverter output: Class 1E inverter output breakers were used as isolation devices between Class 1E and non-Class 1E circuits on all four 120 vac preferred power inverters. Due to the current limiting nature of inverters, short circuits on the non-Class 1E loads have the potential to reduce voltage below the manufacturer's minimum requirements for the equipment being fed from the inverters for a period of between 8 and 25 seconds. A short circuit on one of the unfused non-Class 1E inverters would result in a trip of one channel of the reactor protection system. The remaining three inverters would remain available to power vital instrumentation. The affected inverter's output voltage would recover in 8 to 25 seconds.

Core Exit Thermocouples: Palisades has 16 core exit thermocouples (CETs) which provide operators information on primary coolant conditions during accident conditions. These CETs were found connected to a non-Class 1E data logger computer. A fault on the non-Class 1E data logger computer could potentially render all of these thermocouples inoperable. Although it is considered unlikely that a single fault would affect all 16 circuits, other temperature indications including hot and cold leg temperatures would still have been available. These temperature indicators in conjunction with the reactor vessel level monitors and SMMs would provide the operator with sufficient information to monitor for potential inadequate core cooling. The plant requested, and received approval for, a temporary deviation from the commitment to remove the 16 CETs from the data logger on June 1, 1994. The CETs will, however, be disconnected from the non-class 1E datalogger during the 1995 refueling outage.

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 7 OF 0 8

Subcooled Margin Monitor Isolators: This discrepancy involved electrical signal isolators in the primary coolant system temperature monitoring loops. No documentation was available for these isolators demonstrating their ability to prevent a fault on the output side of the device from degrading below an acceptable level for the circuit connected to the device input. These isolators are used for two applications. First is isolation of two temperature channels which feed the SMMs. An electrical fault in one of these channels or the SMM could result in a reactor trip if two of the High Power trips or two of the TM/LP trips were actuated. In the event the reactor did not trip because of erroneous indication, the control room would have quickly noted the problem given the high visibility of the Variable High Power Trip instrumentation. The second application of these isolators is to isolate non-class 1E instrumentation used for reactor control. A fault in control circuitry could propagate to the safety channel circuitry. One channel of the instrumentation would be disabled. A reactor trip could not result but any temperature error would be quickly noted due to the high visibility of the instrumentation in the control room. Although no qualification tests were available for these electrical isolators, they are similar in design to other isolators (transformer coupled) which have been successfully qualified. It is believed that if these isolators had been tested they would have been shown to be acceptable for their application.

Main Steam Isolation Valves: This discrepancy involves a lack of electrical isolation between the Class 1E main steam isolation valve (MSIV) actuation solenoid valves and non-Class 1E equipment including the atmospheric dump valve and turbine bypass valve control circuitry. A fault in the non-Class 1E circuitry could have resulted in blowing fuses which provide power to the MSIV solenoids. These solenoids are energize to actuate and operate valves to remove air from the MSIV operators to allow them to close. There are two redundant MSIV isolation control circuits and each of those circuits provides output signals to close both valves. Thus, even if the fuses were blown in one of the circuits, the redundant circuit would have remained available to actuate both MSIVs if required. The control power schemes for the MSIVs contain power available lights located in the control room. Had the MSIV fuses blown, the control power lights would have extinguished. This would have been noted by the control room operators during their routine rounds in the control room.

Corrective Actions:

To provide higher quality designs, a number of enhancements to the plant's design change program have taken place in recent years. In the early 1990s, modification procedures were revised to more clearly identify separation and isolation requirements. By 1993, engineering guidelines had been developed to identify specific approaches to implementing effective channel separation and Class 1E to non-Class 1E isolation in the field. These guidelines are now referenced in the plant modification procedures.

Prior to 1994 the plant's modification process was revised to require a multi-disciplinary group review of all safety-related design changes just prior to their release for installation.

NRC Form 366A
(9-83)

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 0 8	– 0 1	0 8 OF 0 8

During the recent maintenance outage an overall review of channel separation and Class 1E to non-Class 1E isolation was conducted. As part of this review, composite connection diagrams for preferred AC power circuits were developed. Prior to startup from that outage, all identified separation and isolation deviations were corrected with the exception of the Core Exit Thermocouples which will be corrected during the 1995 refueling outage. A request for a deviation to allow the CETs to remain in place was granted by the NRC on June 1, 1994. Training of plant personnel regarding the Class 1E to non-Class 1E isolation and associated design guidelines and bases will be conducted as part of technical staff training.

Previous Occurrences:

LER 94-008
LER 93-006

LER No. 255/94-014
Palisades

NRC Form 366 (9-83)

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

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Palisades Plant	0 5 0 0 0 2 5 5	1 OF 0 3

TITLE (4) POTENTIAL SUMP BLOCKAGE FROM SIGNS, ADHESIVE LABELS, AND TAPE

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

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(v)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(iv)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
James L. Kuemin, Licensing Administrator	AREA CODE 6 1 6 7 6 4 - 8 9 1 3

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

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

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 6	3 0	9 4

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

On April 28, 1994, with the plant in cold shutdown, signs, adhesive labels, and tape which have the potential to block the containment sump were identified. The initial operability evaluation assumed, in a worse case scenario, that if these items became loose they could obstruct the containment sump screens and cause an unacceptable flow blockage for recirculation of the containment sump water. The root causes are a lack of controls on the use of material used to attach signs and labels to walls and equipment in containment, lack of consideration of the impact the loose signs, labels, or other material could have on post accident containment sump water recirculation path and a less than adequate containment cleanliness verification process. An extensive containment cleanliness and re-labeling effort was undertaken. Also, an engineering analysis demonstrated that clogging of the containment sump by the remaining identified signs, labels, and tape is unlikely.

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 1 4	– 0 0	0 2 OF 0 3

EVENT DESCRIPTION

On April 28, 1994, with the plant in cold shutdown, signs, adhesive labels, and tape which have the potential to block the containment sump were identified. Specifically, double sided tape was found in use to attach signs to walls and installed equipment and piping. Also found were self adhesive labels and duct tape used for labeling purposes. The initial operability evaluation assumed, in a worse case scenario, that if these items became loose they could obstruct the containment sump screens and cause an unacceptable flow blockage for recirculation of the containment sump water. This assumption prompted personnel to declare inoperable both the High Pressure Safety Injection (HPSI) pumps and the three Containment Spray System (CSS) pumps.

CAUSE OF EVENT

This event was due to a failure to recognize the need for a comprehensive sign, tag, and labeling standard for the containment building. A less than adequate containment cleanliness verification process was also evident.

ANALYSIS OF EVENT

Following a design basis accident, the Safety Injection Refueling Water Tank (SIRWT) supplies water to the Safety Injection System (SIS) and to the CSS. On receipt of the recirculation actuation signal (RAS), suction for both systems is switched to the containment sump. Particles or debris that may have migrated to the containment sump following the accident are prevented from being drawn into the CSS or SIS systems by screens located around the suction lines in the containment sump. The identified problem is the unanalyzed potential for labeling material to migrate to the sumps following a design basis event, and cause screen blockage.

An analysis of the as found condition has not been completed.

Following identification of the labeling material an extensive clean-up and re-labeling effort was undertaken. Over a dozen containment entries involving several groups of 2-man teams removed duct tape and self adhesive labels. The 2-man teams consisted of a worker and an verifier to assure that configuration control was not compromised (i.e., equipment identification removal intact). All areas including levels accessible by ladders were included in the clean-up and re-labeling effort. Removed were all non-essential vendor self adhesive labels from equipment, Dymo-tape labels, self adhesive labels, duct tape, and other adhesive tapes used as markers on cable trays. It is estimated that about 100 square feet of labeling material was removed. It is also estimated that less than 10 square feet of labeling material remains in areas that was not accessible to the workers. A few items that are considered essential for personnel safety were allowed to remain in containment.

In parallel with the clean-up and re-labeling effort an engineering analysis was performed. This analysis demonstrated that plastic signs and labels greater than 5.1 feet radial distance from the containment sump downcomer would not be drawn into the containment sump. Likewise duct tape greater than 10.1 feet radial distance from the containment sump downcomer would also not be drawn into the sump. These areas (zones of influence) were completely cleared of potential debris. The cleaning and re-labeling effort was conservatively extended throughout all of the containment building as mentioned previously.

NRC Form 366A (9-83) U.S. NUCLEAR REGULATORY COMMISSION APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palisades Plant	0 5 0 0 0 2 5 5	9 4	– 0 1 4	– 0 0	0 3 OF 0 3

The result of the containment clean-up, equipment re-labeling effort, and the engineering analysis is that with the limited labeling materials left in containment, there will be no effect on the operability of the containment sump.

SAFETY SIGNIFICANCE

When the deficiencies were discovered, plant Operations declared CSS and HPSI pumps inoperable. The decision was based on the conservative assumption that, if the signs, labels and tape were to come loose, they would migrate to the containment sump and would obstruct the sump's screen. The conclusion of the engineering analysis was that the containment sump screen would not be significantly blocked by any of these items.

CORRECTIVE ACTIONS

- An Engineering Analysis was completed to estimate the impact of loose signs, labels, tags or duct tape on the containment sump.
- The containment cleanliness checklist will be revised prior to use, by the end of this outage. It will address sump blockage from signs, labels or tags secured by adhesives material.
- An independent verification of the containment using the revised containment cleanliness checklist will be completed prior to startup from the maintenance outage.
- The plant consumables control program will be revised to ensure consumables used in containment will not deteriorate or fail under accident conditions.
- The plant will develop a comprehensive sign, tag, and labeling standard which will include consideration of materials used and the method of attachment.
- Engineering design guidelines will be revised to ensure that containment materials are evaluated and qualified for use in containment.

Appendix I

LER No. 266/94-002
Point Beach, Unit 1

ACCESSION #: 9403160301

LICENSEE EVENT REPORT (LER)

APR 1 4 1994

FACILITY NAME: POINT BEACH NUCLEAR PLANT, UNIT 1 PAGE: 1 OF 6

DOCKET NUMBER: 05000266

TITLE: INOPERABILITY OF BOTH EMERGENCY DIESEL GENERATORS

EVENT DATE: 02/08/94 LER #: 94-002-00 REPORT DATE: 03/09/94

OTHER FACILITIES INVOLVED: PBNP UNIT 2 DOCKET NO: 05000301

OPERATING MODE: N POWER LEVEL: 100%

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION: 50.73(a)(2)(i)_10

LICENSEE CONTACT FOR THIS LER:
NAME: CURTIS A. CASTELL, SENIOR ENGINEER-LICENSING TELEPHONE: (414) 221-2019

COMPONENT FAILURE DESCRIPTION:
CAUSE: B SYSTEM: EK COMPONENT: DG MANUFACTURER: E147
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

At 0339 hours, on February 7, 1994, with both units operating at full power, Emergency Diesel Generator (EDG) G02, the Train B EDG, was voluntarily removed from service for annual maintenance. This required placing both PBNP units into the LCO defined in Specification 15.3.7.B.1.g which states that an emergency diesel generator can be inoperable for up to 7 days provided the other emergency diesel generator (in this case the Train A EDG G01) is tested daily to ensure operability. On February 8, 1994, at 2204 hours, EDG G01 was declared inoperable due to abnormal voltage regulator indications. The declaration of EDG G01 as inoperable placed both units in a condition, which by Technical Specification 15.3.0.A, required both units be placed in hot shutdown within 3 hours (by 0104 hours on February 9, 1994). A Notice of Enforcement Discretion (NOED) was requested from the NRC, to allow additional time in the LCO to return at least one EDG to service. The NOED was granted at 2320 hours on February 8, 1994. At 0244 hours, EDG G01 was returned to an operable status, Technical Specification LCO 15.3.0.A was exited and the 7-day LCO required when one EDG is inoperable (EDG G02) was continued.

END OF ABSTRACT

TEXT PAGE 2 OF 6

EVENT DESCRIPTION

At 0339 hours, on February 7, 1994, with both Point Beach Units operating at full power, EDG G02, the Train B EDG, was voluntarily removed from service for maintenance. This required placing both PBNP units into the LCO defined in Specification 15.3.7.B.1.g which states that an emergency diesel generator can be inoperable for up to 7 days provided the other emergency diesel generator (in this case the Train A EDG G01) is tested daily to ensure operability.

On February 8, 1994, at 0753 hours, the daily test of EDG G01 was being performed as required. During this test, at 0951 hours, the control room received an EDG G01 alarm on Main Control Board C02. A check of the EDG G01 local alarm panel revealed that the fuel pressure alarm was in and the electric fuel oil pump was malfunctioning. Engineering and maintenance personnel were called to troubleshoot EDG G01.

The troubleshooting determined that the electric fuel pump for EDG G01 had become decoupled from its motor. EDG G01 continued operating with fuel oil supplied from the shaft driven mechanical fuel oil pump. The mechanical fuel oil pump is fully capable of starting and operating the EDG independently, without reliance on the redundant electric fuel oil pump. Therefore, EDG G01 was operable because the electric fuel pump is not necessary for starting or operating the EDG. At 1202 hours, EDG G01 was placed in automatic mode to enable it to respond to a loss of AC power automatically. EDG G01 was maintained running in an unloaded condition to provide additional assurance that it was operable. At 1940 hours, the electric fuel oil pump repairs were completed and EDG G01 was shutdown.

At 2046 hours, EDG G01 was started and loaded to clean the exhaust system of carbon and other contaminants which may have built up as a result of running the diesel engine unloaded for an extended period of time during the trouble-shooting and repair of the electric fuel oil pump. At 2100 hours small swings in power on the varmeter were observed. The intensity of these swings increased such that at 2204 hours EDG G01 was declared inoperable and TS 15.3.0 was entered.

At 2208 hours, load decreases of 15% per hour was commenced for both units. An Unusual Event was declared at 2210 hours in accordance with our emergency plan based on the loss of both trains of standby emergency power. At approximately 2230 hours, engineering and maintenance trouble-shooting determined that the malfunction was caused by shorting of the DC exciter voltage between a rotating bus bar and one of the two stationary brush jumper cables which connects the slip rings within the generator.

TEXT

At 2320 hours, NRC regional representative Mr. Robert Greger verbally approved our request to suspend the requirements of the LCO specified in TS 15.3.0, pending review of a request for a Notice of Enforcement Discretion (NOED). Therefore, at 2320 hours, the power reductions on Unit 1 and Unit 2 were stopped and the units were maintained at 86% and 85% power, respectively. A NOED was requested to allow additional time on the 3-hour LCO to return an EDG to an operable status and for sequential shutdown of PBNP Units 1 and 2, if efforts to return at least one EDG to an operable condition were unsuccessful. The NOED was granted by NRC Region III personnel at 0225 hours to hold in abeyance the shutdown of both units until 0800 hours on February 9, 1994, at which time the orderly rampdown of the units would be initiated if an EDG had not been restored to an operable status. Also, three hours were granted for placing one unit in a hot shutdown condition and an additional three hours granted for placing the other unit in hot shutdown.

The return to service test for EDG G01 was completed and results were accepted at 0244 hours. EDG G01 was declared operable at 0244 hours and the extended 3-hour LCO on both units was exited. The 7-day LCO required when one EDG is inoperable (EDG G02) was continued. At 0247 hours, a load increase on both units was initiated. Unit 2 achieved full load at 0350 hours and Unit 1 achieved full load at 0446 hours.

EDG G02 was declared operable at 1638 hours on February 11, 1994 and the 7-day LCO, which was entered at 0339 hours, on February 7, 1994 for EDG G02, was exited.

CAUSES

EDG G01 was declared inoperable at 2204 hours on February 8, 1994, due to power fluctuations as seen on the varmeter in the control room during a load test. Trouble-shooting determined that the power fluctuations were caused by shorting of the DC exciter voltage between a rotating bus bar and one of the two stationary brush jumper cables which connects the slip rings within the generator.

The brush jumper cable had been installed in an improper orientation 5 days earlier on February 3, 1994, during the annual maintenance outage on EDG G01. The brush jumper cable was inspected as part of the routine EDG annual maintenance. Based on the inspection, in which some damaged and loose strands were noted near the lug, the brush jumper cable was removed, re-lugged, and replaced. The amount of damaged and loose strands did not pose an operability concern for the EDG, therefore, the re-lugging was not considered absolutely necessary and was performed as normal corrective maintenance.

A Human Performance Root Cause evaluation (HPRC 94-02) was performed and documented for this event. HPRC 94-02 concludes that the improper installation of the brush jumper cable was caused by (1) lack of adequate work control and (2) lack of adequate post-maintenance testing for the maintenance that was performed, which should include inspection for interference while rotating the generator.

CORRECTIVE ACTIONS

The immediate corrective action that was completed for this situation of both emergency diesel generators being inoperable was to expedite the return to service of one of the emergency diesel generators (EDG G01). The damaged bus bar and jumper wire were replaced by using the identical parts from EDG G02. The proper clearance between the brush jumper cable and the rotating bus bars was verified, prior to returning EDG G01 to service.

Long term corrective actions include:

1. The plant policy and procedure for performing maintenance that is beyond the scope of the preventive maintenance or surveillance work control documents that are being used will be revised to require appropriate work controls for the corrective maintenance being performed. For example, in this case, the routine maintenance procedure used for the EDG G01 maintenance required an inspection of the generator. Based on this inspection, the brush jumper cable was re-lugged. The work control documents should have been revised or supplemented to provide additional work controls for the re-lugging of the brush jumper cable. This corrective action will be implemented by May 31, 1994.

2. Review and revise the Post Maintenance Test Procedure (PBNP 3.2.6) and/or other procedures as necessary to include manual rotation and inspection to verify adequate internal clearances after removal and replacement of parts near rotating equipment. This corrective action will be completed by May 31, 1994.

COMPONENT AND SYSTEM DESCRIPTION

The emergency diesel generators, G01 and G02, at Point Beach, provide emergency electrical power to the safeguards buses if the normal power supply is interrupted or not available. The safeguards buses provide power to equipment that is used to safely shutdown the units and mitigate the consequences of an accident.

TEXT

The emergency diesel generators, G01 and G02, were manufactured by the General Motors Electro-Motive Division, Model Number 999-20. The IEEE Standard 803A-1983 component identifiers for these components are:

Diesel Generator	DG
Exciter	EXC

REPORTABILITY

This Licensee Event Report is provided pursuant to the requirements of 10 CFR 50.73(a)(2)(i)(B), "Any operation or condition prohibited by the plant's Technical Specifications."

A 1-hour notification to the NRC was made at 2257 hours in accordance with 10 CFR 50.72(a)(1)(i), "The declaration of any of the Emergency Classes specified in the licensee's approved emergency plan," and 10 CFR 50.72(b)(1)(i)(A), "The initiation of any nuclear plant shutdown required by the plant's Technical Specifications."

SAFETY ASSESSMENT

During this event, EDG G02 was out of service for a maintenance outage. EDG G01 failed during testing due to a brush jumper cable that had been installed in an improper orientation 5 days earlier on February 3, 1994, during the annual maintenance outage on EDG G01. EDG G01 had been tested three times prior to the test in which it failed on February 8, 1994. The dates of these tests and the approximate run durations are as follows:

February 4, 1994	3 hours
February 7, 1994	1.9 hours
February 8, 1994	10.3 hours

The failure caused by repeated impingement of the rotating bus bar on the brush jumper cable was such that as EDG G01 was run, cable damage was accumulated. This type of failure mode eventually lead to the short circuit of the brush jumper cable to the bus bar which caused the perturbation of the exciter voltage. Therefore, EDG G01 was able to perform its safety function after the annual maintenance outage ended on February 4, 1994 for approximately 15 hours prior to failure, based on the accumulated run time during testing.

If a loss of off-site power occurred and both emergency diesel generators failed during this event, a Station Blackout would have occurred. If this had occurred, the gas turbine generator (G05) was operable and

available to provide power to the required safe shutdown loads. In addition, both units were at normal operating temperatures which would have allowed the use of the steam generators and auxiliary feedwater system for the removal of decay heat. If the units had been in cold shutdown, a loss of decay heat removal capability would have occurred until the required shutdown loads were repowered from G05, which can be started and loaded within one hour. A loss of decay heat removal for one hour or less would not be expected to cause fuel damage.

SIMILAR OCCURRENCES

Other Licensee Event Reports that describe events that occurred while one EDG was out of service and electrical system operational errors that affected both trains of Engineered Safety Features include:

Unit 1 and Common

LER 88-010	Electrical System Misalignment
LER 93-002	Inoperability of Both Emergency Diesel Generators
LER 93-009	Inoperability of Both Emergency Diesel Generators

Unit 2

LER 80-006	Defeat Containment Spray Actuation during Surveillance
LER 80-007	Loss of RHR Redundancy During Surveillance

LER No. 269/94-004
Oconee, Unit 1

NRC FORM 366 (5 92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
OCONEE NUCLEAR STATION, UNIT 1	05000 269	1 OF 10

TITLE (4)
POST ACCIDENT CORE COOLING TECHNICALLY INOPERABLE DUE TO A DESIGN DEFICIENCY

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
07	27	94	94	-- 04 --	01	03	30	95	Oconee, Unit 2	05000 270
									Oconee, Unit 3	05000 287

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)					
POWER LEVEL (10)		20.402(b)		20.405(c)		50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v) (D)	73.71(c)
		20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)	OTHER
		20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Lanny V. Wilkie, Safety Review Manager	(803) 885-3518

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPROS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPROS

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On July 13, 1994, during the planning process for maintenance on the High Pressure Service Water System (HPSW), System Engineering (SE) was asked to determine the applicable Limiting Conditions for Operations. SE determined that the HPSW was required for Emergency Condenser Circulating Water (ECCW) siphon flow when lake level is low, and this could render the Low Pressure Service Water (LPSW) System inoperable. As a result, SE performed an operability evaluation. On July 26, 1994, with all three Oconee Units at 100 % Full Power, SE completed the evaluation which revealed that the ECCW System could not maintain siphon flow as required following a Loss of Offsite Power event if lake level is less than 798.13 feet and the Elevated Water Storage Tank is unavailable. The evaluation also determined that the LPSW System had been inoperabile for short durations in the past due to this condition. Further evaluation completed by SE on February 15, 1995 revealed that the LPSW System had been past inoperable on other occasions due to the Unit 1 MFB being out of service greater than 72 hours. The root cause of this event is a Design Deficiency, Unanticipated Interaction of Components, (Design Oversight). Planned corrective actions included reviewing and revising design basis documents.

NRC FORM 366 (5-92)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION
(5-92)

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	2 OF 10

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

BACKGROUND

The Condenser Circulating Water (CCW) System [EIIS:BS] supplies the Low Pressure Service Water System (LPSW) [EIIS:BI] through the CCW crossover header. The Emergency Condenser Circulating Water System (ECCW) is a part of the CCW System and performs two separate functions. One of these functions is to recirculate CCW to the intake canal following the loss of Lake Keowee (Dam Failure). The second function is an unassisted siphon during Loss of Offsite Power (with or without a Loss of Coolant Accident). This siphon has two distinct purposes; one supplies suction for the LPSW System (Post Accident Core Cooling) and the other provides cooling water flow through the condenser. Each units' CCW System includes four CCW Pumps, each with an associated discharge valve. Each CCW Pump has a pump/valve interlock such that when the last CCW Pump is turned off or upon loss of power, the last pump's discharge valve will remain open to ensure siphon flow. All open valves stay open if all pumps stop at the same time.

The LPSW System provides cooling for components in the Turbine Building [EIIS:NM], the Auxiliary Building (AB) [EIIS:JE] and the Reactor Building (RB) [EIIS:NH]. Engineering Safeguards [EIIS:JE] equipment located in the AB and RB (such as the Low Pressure Injection [EIIS:BP] and Reactor Building Coolers [EIIS:BK]) is cooled by the LPSW System. The LPSW System is required to be operable per Technical Specification 3.3.7.

The High Pressure Service Water System (HPSW) [EIIS:KP] consists of HPSW Pump A, Pump B and a Jockey Pump which, together with the Elevated Water Storage Tank (EWST) provide a source of fire protection, bearing lubrication, sealing, and cooling water to various equipment on all three Oconee units. All three pumps are powered from the Unit 1 Main Feeder Busses. In the event of Loss of Offsite Power, the HPSW via the EWST automatically supplies cooling water to the Turbine Driven Emergency Feedwater Pump and its associated oil cooler. It also maintains CCW pump seal water and supplies CCW pump motor cooling.

The Continuous Vacuum Priming System (V) [EIIS:SH] maintains the ECCW System operable to initiate ECCW siphon flow from the intake canal, through the main condenser to the discharge. The V System includes two Emergency Steam Air Ejectors, one for Unit 1 and Units 2 and 3 share the other.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	3 OF 10

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

EVENT DESCRIPTION

On July 13, 1994, during the planning process to repair a leaking High Pressure Service Water (HPSW) valve (HPSW-25), System Engineering (SE) was asked to determine which Limiting Conditions for Operations (LCO) should be entered if the Elevated Water Storage Tank (EWST) is taken out of service. SE determined that sealing water supplied from the EWST to the Condenser Circulating Water (CCW) pump shaft seals is necessary to prevent the loss of ECCW siphon flow when lake level is less than 798.13 feet (approximately two feet below full pond), during a Loss of Offsite Power (LOOP) event. The initial response was that a seventy two hour LCO would be applicable for the Low Pressure Service Water (LPSW) since the EWST supports the suction flow of the LPSW pumps. Further discussions led to the conclusion that the 72 hour LCO is for removing one LPSW pump from service. However, the loss of the EWST would result in the loss of suction flow to all LPSW pumps during a LOOP. This concern was entered into the Problem Investigation Process and SE continued the evaluation.

On July 21, 1994, temporary operational guidance was given to Operations on the importance of the EWST and HPSW Pumps to LPSW Pumps suction during a LOOP event.

On July 26, 1994, with all three Oconee Units at 100 % Full Power, SE completed an operability evaluation. The evaluation concluded that, if lake level is equal to or greater than 798.13 feet (approximately two feet below full pond), gravity flow will supply suction to the LPSW pumps during a LOOP event. However, if lake level is less than 798.13 feet, and the EWST is unavailable during a LOOP, the Emergency Condenser Circulating Water System (ECCW) may not maintain siphon flow due to assumed air inleakage through the CCW Pump seals, thus rendering the LPSW pumps inoperable.

The evaluation by SE revealed that the EWST had been taken out of service during 1985 and 1990 while lake level was less than 798.13 feet (approximately two feet below full pond). In 1985, between August and November, the EWST was removed from service to be painted (inside and out) and lake level was eight feet below full pond. In 1990, at various times between July and September, the EWST was removed from service, as a result of maintenance on HPSW-25 (Altitude Valve), with lake level four feet below full pond. The evaluation concluded that the ECCW and LPSW had been technically inoperable during these time periods.

NRC FORM 366A (5-92)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION
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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	4 OF 10

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

An investigation into the event revealed that in 1985 when the EWST was removed from service, compensatory actions taken were in regard to fire protection and cooling water for the Turbine Driven Emergency Feedwater Pump. During maintenance of the Altitude Valve (HPSW-25) in 1990, the same compensatory actions were taken. No compensatory actions were taken in regard to the loss of suction to the LPSW Pumps. No calculations existed that determined the minimum lake levels required to maintain net positive suction head to the LPSW Pumps. A calculation was performed on May 14, 1993 and revised on March 3, 1994. The purpose of this calculation was to determine the required lake level that maintains siphon flow to the ECCW System.

On February 7, 1995, SE discovered a condition that could prevent the LPSW System from being single failure proof. During a review of the HPSW DBD, it was discovered that during Unit 1 outages, when a Main Feeder Bus (MFB) could be taken out of service for maintenance, the remaining HPSW pump and Jockey pump would be fed from the remaining MFB. Since HPSW is required to support the ECCW, which is required to support LPSW suction during a design basis LOCA, a Limiting Condition for Operation (LCO) should be entered. This concern was entered into the Problem investigation Process and SE continued the evaluation.

On February 15, 1995, SE completed an operability evaluation. The evaluation revealed that this condition is known to have existed for periods exceeding 72 hours during one or more Unit 1 refueling outages. If the remaining HPSW pump(s) were affected by a single failure, the HPSW system would not be able to make up to the EWST. After a short period of time motor cooling water would be lost to the operating CCW pumps on all units, and the CCW pumps would have to be shutdown (resulting in trip or shutdown of the operating units). In the past, the potential effect of such a condition on CCW and LPSW of all three units was not recognized and, the appropriate LCOs were not applied. As a result, the LPSW System was determined to be past inoperable.

CONCLUSIONS

Prior to this event it was not understood that the removal of the Elevated Water Storage Tank (EWST) and one of the two Unit 1 Main Feeder Busses from service could result in the loss of suction to the Low Pressure Service Water (LPSW) Pumps. During the times the EWST or one of two Unit 1

NRC FORM 366A (5-92)

NRC FORM 366A 5-92. U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	5 OF 10

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

Main Feeder Busses were removed from service, the only concern was fire protection and cooling water for the Turbine Driven Emergency Feedwater Pump. It is apparent in the original plant design that the High Pressure Service Water System was not recognized as being required to function in order to support the Emergency Condenser Cooling Water, which provides suction for the LPSW system during design basis accidents. Therefore, the root cause of this event is a Design Deficiency, Unanticipated Interaction of Components, (Design Oversight).

A review of LERs, written within the last two years, revealed that two events (LERs 269/93-04 and 269/94-01) involved design deficiencies from a failure to anticipate interaction of systems, design oversight. LER 269/93-04 involved a potential single failure that could close all Condenser Circulating Water Pump Discharge Valves on a single unit following a Loss of Coolant Accident/Loss of Offsite Power. LER 269/94-01 involved a potential seismic interaction that could have resulted in the loss of Emergency Condenser Circulating Water (ECCW). Both of these events involved the loss of ECCW. Therefore, this event is considered to be recurring. The corrective actions for the events identified above included modifications and the completion of the single failure analysis. Because the periods of inoperability reported in this report occurred prior to the discovery of the problems reported by those LERs, the associated corrective actions could not have prevented this event. Enhancements in the design process, since the original design of Oconee Nuclear Station, should prevent this type of design oversight in the future.

This event did not involve equipment failure and therefore was not NPRDS reportable. There were no radiological overexposures, radioactive releases or personnel injuries associated with this event.

CORRECTIVE ACTIONS

Immediate

1. System Engineering verified lake level and Elevated Water Storage Tank availability to assure Emergency Condenser Circulating Water was not currently inoperable.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	6 OF 10

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

Subsequent

1. Temporary operational guidance was given to Operations on the importance of the Elevated Water Storage Tank and High Pressure Service Water System to Low Pressure Service Water pump suction during a Loss of Offsite Power event.

Planned

1. Revise the Emergency Condenser Circulating Water to Low Pressure Service Water Single Failure Calculation to include High Pressure Service Water components as they relate to possible failure of the Low Pressure Service Water System.

2. Review the High Pressure Service Water (HPSW) Design Basis Document (DBD) to ensure that it properly indicates the importance of the HPSW Pumps, and the check valves/HPSW-25 following a Loss of Offsite Power event. Revise the HPSW DBD as required to reflect the results of review.

3. Review the Condenser Circulating Water (CCW) Design Basis Document (DBD) to ensure that it properly indicates importance of the Elevated Water Storage Tank in a Loss of Offsite Power event. Revise the CCW DBD as required to reflect the results of review.

4. Revise the appropriate procedures to provide administrative controls of the High Pressure Service Water System and the Elevated Water Storage Tank to Low Pressure Service Water following a Loss of Offsite Power event.

5. Revise Selected Licensee Commitment 16.9 to reflect the required lake levels for taking the Elevated Water Storage Tank out of service and provide proper compensatory measures.

6. Review the HPSW DBD to determine if changes need to be made to reflect the consequences of removing a Unit 1 Main Feeder Bus (MFB) from service. Update the DBD as required.

NRC FORM 366A (5-92)

NRC FORM 366A 5-92 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	7 OF 10

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

7. Review Operations procedures to determine if procedures changes need to be made to reflect the consequences of taking a Unit 1 MFB out of service. Make appropriate procedure changes as required.

8. Review Selected Licensee Commitment 16.9.8 to determine if it needs to be revised to reflect the consequences of removing a Unit 1 MFB from service. Revise if required.

SAFETY ANALYSIS

The emergency function of the Condenser Circulating Water (CCW) system is to provide a source of water to the Low Pressure Service Water (LPSW) system, which, in turn, provides cooling water for the Low Pressure Injection (LPI)(Decay Heat Removal) System, the Reactor Building Coolers (RB Ventilation), and various motor, oil, and auxiliary heat exchangers.

In the event of a Loss of Off-site Power (LOOP), the CCW pumps would be tripped either by undervoltage relays or by the Emergency Power Switching Logic "Load Shed" feature. In either case, the intent of the system design is that the CCW pump discharge valves would remain open to provide a path for gravity/siphon flow, which would be adequate for all emergency functions.

There are several applicable scenarios:

1. In scenarios where the LOOP does not affect all three Oconee units, isolation valves could be opened to cross connect the affected unit to the CCW system of one of the unaffected Oconee units.

   If the LOOP affects only Unit 1, the HPSW pumps would be affected while the Main Feeder Busses were deenergized, but would auto start as needed as soon as the Main Feeder Bus was reenergized by the Emergency Power Switching Logic.

2. LOOP on three units, without a Loss of Coolant Accident (LOCA).

   Without a LOCA, the Emergency Feedwater system would be removing decay heat rather than the LPI/LPSW systems. As described in the Final Safety Analysis Report (FSAR), power is restored to the Main Feeder Busses within approximately 48 seconds. With the EWST

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	8 OF 10

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

unavailable, and lake level less than 798.13 feet (two feet below full pond), sealing water would have not been available to the CCW Pumps. Therefore, depending upon the condition of the pump shaft seals, there could have been excessive air inleakage into the system. Siphon flow may have been lost after a short period of time. Manual operator action would be required to start a CCW pump to restore flow. The applicable Emergency Procedure contains steps to perform this action within 1.5 hours. The High Pressure Service Water (HPSW) pumps would have auto-started upon restoration of power and would have supplied sealing water and pump motor cooling for restarting the CCW pump. Therefore, this scenario should not have any significant effect on decay heat removal.

3. LOOP on three units, with a LOCA on one unit.
NOTE: The probability of a LOCA/LOOP occurring is very low.

As described in the FSAR, power is restored to the Main Feeder Busses within approximately 48 seconds. With the EWST unavailable, and lake level less than 798.13 feet (two feet below full pond), sealing water would have not been available to the CCW Pumps; therefore, depending upon the condition of the pump shaft seals, there could have been excessive air inleakage into the system. Siphon flow may have been lost after a short period of time. The Continuous Vacuum Priming System was aligned to take suction on the CCW lines to prevent, or minimize, any effect of air inleakage on siphon flow. During the time periods in question, the Continuous Vacuum Priming System was considered adequate to handle expected inleakage. Testing performed at low lake levels in 1986 demonstrated that, with seals in poor condition, air inleakage interfered with proper siphon flow. However, with new seals, siphon flow was maintained for four hours without support of either Continuous Vacuum Priming or HPSW seal supply water. Since that time, CCW pump seals have been included in the Preventive Maintenance program for the CCW pumps. Each refueling outage one CCW pump seal is replaced. However, subsequent tests have not verified the ability to maintain siphon flow without seal flow.

Manual operator action would be required to start a CCW pump to restore flow. The applicable Emergency Procedure contains

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	9 OF 10

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

steps to perform this action within 1.5 hours. The High Pressure Service Water pumps would have auto-started upon restoration of power and would have supplied sealing water and pump motor cooling for restarting the CCW pump. If, for some reason, a CCW pump cannot be restarted on the unit without siphon flow, the operators could cross connect to a unit with siphon flow as described in scenario 1. Siphon CCW flow for one unit would be adequate to provide required flow and Net Positive Suction Head for the LPSW system on the affected unit.

LPSW does not provide any significant contribution to core cooling until the water inventory in the Borated Water Storage Tank is depleted and the LPI system is placed in recirculation mode to take suction from the Reactor Building emergency sump. This is typically several minutes into the LOCA scenario, and should occur after a CCW pump has been restored to service. During this time, Reactor Building temperature would be elevated, and may not remain within the envelope calculated for maintaining environmental qualifications of equipment located inside the reactor building. However, most of the affected active components would have moved to their post-accident positions soon after the LOCA occurred. Therefore, prompt operator action may minimize or prevent any significant effect on decay heat removal capability due to this scenario.

4. "Station Blackout" on three units, without LOCA (e.g. Appendix R event)

Depending upon the exact scenario, the Turbine Driven Emergency Feedwater Pump may be available for decay heat removal to maintain the unit at hot shutdown. Alternatively, the Standby Shutdown Facility (SSF) is a separate seismically qualified building which houses the systems and components necessary to provide an alternate and independent means to achieve and maintain hot shutdown conditions for one or more of the Oconee Units. The SSF was designed to resolve the safe shutdown requirement for fire protection, turbine building flooding, and physical security. The SSF has the capability of maintaining hot shutdown conditions on all three units for approximately three days following a loss of normal AC power. The SSF takes its water supply from the Unit 2 CCW line, so that it would be affected by this design deficiency only if the air inleakage occurred on Unit 2. A submersible pump is also available and can be

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
OCONEE NUCLEAR STATION, UNIT 1	05000 269	94	- 04 -	01	10 OF 10

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

employed within 3.5 hours through damage control procedures to add water to the Unit 2 CCW intake piping.

5. An additional scenario was discovered. If Unit 1 has a Main Feeder Bus deenergized or one HPSW pump is out of service, then the remaining HPSW pumps are subject to being lost due to single failure (such as failure of the other main feeder bus). In the past, the potential affect of such a condition on CCW and LPSW of all three units was not recognized and, therefore, appropriate LCOs would not have been applied. This condition is known to have existed for periods exceeding 72 hours during one or more Unit 1 refueling outages. If the remaining HPSW pump(s) were affected by a single failure, the HPSW system would not be able to make up to the EWST. After a short period of time, motor cooling water would be lost to the operating CCW pumps on all units, and the CCW pumps would have to be shutdown (resulting in trip or shutdown of the operating units). The units could remain in hot shutdown (using the SSF, if necessary). If any units were already at cold shutdown or subject to a LOCA, LPSW cooling could be lost, if lake level were low enough, due to the effect of seal leakage on siphon flow. One train of HPSW would need to be restored or alternative compensatory action taken prior to re-establishing CCW pumped flow.

In summary, in the unlikely event of a LOCA/LOOP during the short time periods that the EWST and/or HPSW was unavailable, decay heat cooling may have been lost if 1) excessive seal leakage existed, 2) Continuous Vacuum Priming failed, and 3) power could not be restored to a CCW pump and a HPSW pump prior to loss of siphon flow. This combination, while possible, is not considered probable. Therefore, the potential for loss of decay heat cooling due to this design deficiency is not considered significant. But, if this scenario had occurred, long term core cooling and RB cooling could have been adversely affected. During these periods of inoperability no LOOP events occurred. Therefore, the inoperability of the Emergency CCW System did not adversely affect the health and safety of the public.

NRC FORM 366A (5-92)

LER No. 271/94-002
Vermont Yankee

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

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EXPIRES 4/30/92
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FACILITY NAME (1)	DOCKET NO. (2)	PAGE (3)
VERMONT YANKEE NUCLEAR POWER STATION	0 5 0 0 0 2 7 1	0 1 OF 0 5

TITLE (4) Alternate Cooling System Water Temperature Greater Than Design Basis During Warm Weather Circ Water System Operation Due to Inadequate Analysis of the Alternate Cooling System

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NO.
ROBERT J. WANCZYK, PLANT MANAGER	CODE 8 0 2 2 5 7 - 7 7 1 1

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

CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS		CAUSE	SYST	COMPONENT	MFR	REPORTABLE TO NPRDS	
B	B I	C T W	C 7 4 8	Y							

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

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

During a Self Assessment of the Service Water System and as a result of evaluations conducted to respond to issues identified by this assessment, several design conditions were identified which may have precluded the Alternate Cooling System from performing its intended design basis functions.

The root cause of this event has been determined to be an inadequate analysis of the Alternate Cooling System to ensure that it could achieve its design basis function to remove sensible and decay heat from the reactor under all postulated design basis events.

Corrective actions included procedure changes, the documentation of a Basis for Maintaining Operability (BMO) and an update to the FSAR under 10CFR50.59 to ensure that the FSAR accurately describes required parameters.

NRC Form 366 (6-89)

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMS NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-350), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

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

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

DESCRIPTION OF EVENT

BACKGROUND INFORMATION

On November 30, 1966 Vermont Yankee Nuclear Power Corporation (VYNPC) filed with the Atomic Energy Commission (AEC) an application for an AEC license to construct and operate the Vermont Yankee Nuclear Power Station (VYNPS). The information contained in the application, which included the original Plant Design and Analysis Report (PDAR, 1966), was evaluated by the AEC regulatory staff and the Advisory Committee for Reactor Safeguards (ACRS).

On April 12, 1967, in Amendment 3 of the PDAR, Vermont Yankee responded to the following question: 'Please state the sea level elevation of the station service water intake. If this is higher than the Connecticut River low-flow elevation at this point without the Vernon Dam, please provide the justification.' The VYNPS response to this question was that consistent with the design criteria for the structures and equipment required for a safe shutdown of the VYNPS, the Vernon Dam was analyzed for the maximum 0.14g earthquake and found to be stable.

On May 19, 1967, in Amendment 5 of the PDAR the following information was transmitted to the AEC by VYNPC: 'The loss of water from the Vernon Pond would result in uncovering the station service water pump suction and would preclude the normal functions of the Residual Heat Removal System heat exchangers. Although the dewatering of the Vernon Pond is considered to be a most remote possibility, an alternate means of providing for reactor decay heat removal will be included in the plant design.'

On July 7, 1967, the AEC Safety Evaluation Report (SER) discusses and further summarizes the basis for alternate cooling. It states, 'The station service water intake is at a higher elevation than would exist for the Connecticut River if the Vernon Dam, which is approximately 2500 feet downstream from the site, were to fail. Although it appears to our consultant, Dr. N.M. Newmark, that the dam can probably accommodate the maximum (no loss of safety function) earthquake, we have required that in the event of a dam failure, service water (or its equivalent in cooling capacity) always be available for shutdown cool... The applicant has responded by assuring us that an alternate scheme for removing decay heat from the Reactor Shutdown Cooling System will be provided (Amendment 5). Our acceptance criteria for this system will include: (1) conformance to Class I design standards, (2) power requirements within the capability of emergency on-site power source, and (3) heat removal capability equivalent to what is provided for shutdown when the normal river-water source is available.'

On December 31, 1969, VYNPC filed a revised application along with the FSAR and requested an operating license. In the FSAR, Section 2.4.3.4, it states that the "Standard Project Flood" at Vernon results in a Vernon Pond Elevation of 235.1 ft MSL, some 15 feet below plant grade of 250 feet MSL.

On June 19, 1970, the AEC requested the probable maximum flood (PMF) at the plant be estimated using a method consistent with the U.S Corps of Engineers Probable Maximum Flood calculation. On October 23, 1970, VYNPC submitted Amendment 16 of the FSAR. This document shows that the PMF river stage is 252.5 feet MSL at the plant when using a method consistent with the U.S. Corps of Engineers.

On February 5, 1971, VYNPC submitted a Supplement to Amendment 16 of the FSAR. Because the new PMF affects the intake structure it is discussed in this Supplement. In particular, 'Service water pumps would provide for normal reactor cooling When their service is terminated due to river water leakage into the intake structure, the alternate cooling water system would be put into service from within the station to provide for reactor cooling.

On June 1, 1971, VYNPC received the Safety Evaluation Report on flooding and service water system.

As can be seen from the above, the Alternate Cooling System was originally designed to accommodate a loss of the Vernon Dam, and later to provide shutdown cooling in the case of a Probable Maximum Flood. There were no requirements for redundancy, and the system was not designed for accident mitigation, nor was it ever intended or designed to be single failure proof. There is no Safety Design Basis for the Alternate Cooling System in the FSAR.

NRC Form 366A U.S. NUCLEAR REGULATORY COMMISSION (6-89) LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-350), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

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

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

BACKGROUND (CONT.)

In 1983, Vermont Yankee completed a Safe Shutdown Capability Analysis to address 10CFR50 Appendix R, to ensure the capability to achieve safe shutdown if a fire were to occur in any given area of the plant. For a fire in the intake structure, the Service Water Pumps are assumed to be lost, and the Alternate Cooling System would be used. No detailed analysis of system operation was performed to support this conclusion.

In January/February 1994, Vermont Yankee conducted a Self Assessment of the Service Water and Alternate Cooling Systems. In order to address the open issues identified as a result of this Self Assessment, a project team was established. The issues identified below are a result of the Self Assessment and evaluations conducted in response to this assessment.

DESCRIPTION

On February 9, 1994 while operating at 100% power, it was identified that the Alternate Cooling System (EIIS = BI) could be operated in a manner inconsistent with the supporting design information described in the FSAR during certain periods of plant operation. The supporting design information contained in Section 10.8 of the FSAR states that the Alternate Cooling System is designed to supply 85 degree cooling water to three Residual Heat Removal (RHR) Service Water (EIIS = BI) pumps. During certain periods of warm weather operation the initial temperature of water in the Alternate Cooling System storage reservoir (deep basin) was greater than 85 degrees. This was considered operation outside the design basis of the plant, and operation in an unanalyzed condition for those periods.

The water supply for the Alternate Cooling System is contained in a deep basin located under one of the two eleven cell cooling towers which are used in conjunction with the Circulating Water System. The cooling towers are normally used to ensure water discharge temperatures from the plant remain within limits of the NPDES permit. During operation of the cooling towers the water in the deep basin can reach temperatures above 85 degrees. The Alternate Cooling System uses the number one cell of the west cooling tower.

An engineering evaluation was initiated to assess the ability of the Alternate Cooling System to provide the required cooling if the deep basin temperature was above 85 degrees. Each of the components included in the Alternate Cooling System was evaluated, and the entire system was incorporated in a computer model to ensure that required flows could be provided to each component with elevated water temperatures.

On June 1, 1994, it was determined that existing operating procedures were insufficient to ensure that adequate cooling could be provided by the Alternate Cooling System. In reviewing the design of the Alternate Cooling tower cell, it was determined that a minimum of 8000 gpm water would be required to ensure that significant channeling within the cooling tower (uneven flow distribution) would not impact the heat removal capability of the cooling tower. Based on our recently completed flow model, with RHR heat exchanger flow restrictions contained in the operating procedure, 8000 gpm to the cooling tower would not be obtained. In order to obtain 8000 gpm to the cooling tower, four RHRSW pumps would need to be operated through two RHR heat exchangers with the flow through each heat exchanger above that normally permitted by the operating procedures.

Additionally, with high initial temperatures in the deep basin, if the Alternate Cooling System was required to provide Torus Cooling, required flow through the RHR heat exchangers would exceed the flow limitations contained in the operating procedures. These conditions were also contrary to the description contained in the FSAR. Based on this conclusion, the Alternate Cooling System was declared inoperable. Reactor operation is allowed for 7 days with the Alternate Cooling System inoperable.

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMS NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-350), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

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

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

CAUSE OF EVENT

The root cause has been determined to be an inadequate analysis of the Alternate Cooling System to ensure it could achieve the design basis function to remove sensible and decay heat from the reactor during all postulated design basis events. Although the Alternate Cooling Tower System had been designed to provide 85 degree cooling water, insufficient analysis was performed to assess the effects of a high initial deep basin temperature, and to ensure the required flow to the cooling tower could be provided under the operating restrictions contained in the procedures. Additionally, when the Alternate Cooling System was assumed to be available in the unlikely event of a fire in the intake structure which disables all four Service Water Pumps, no analysis was conducted to ensure the heat removal requirements of the system could be met.

ANALYSIS OF EVENT

The Alternate Cooling System provides for the removal of shutdown heat loads in the event of: (1) a loss of the Vernon Dam; (2) during the postulated Probable Maximum Flood; and (3) in the event a fire in the intake structure destroys all four service water pumps. If the Alternate Cooling System had been required to provide cooling in any of the above situations, the heat removal capability of the system may have been below the design levels. If extensive channeling exists in the cooling tower, it is difficult to predict with any confidence the amount of heat that would be removed. With channeling, the hot water return temperature would be increased, which in turn increases the actual heat removal performance of the cooling tower. The system is designed to remove decay heat at three hours after shutdown, when the reactor is depressurized to allow Shutdown Cooling to be placed in service. For this to occur within three hours, the cooldown rate during depressurization would have to be approximately one hundred degrees per hour (the upper limit of technical specifications), which is not likely. A normal cooldown rate would rarely exceed fifty degrees per hour, thus depressurization would take considerably longer than three hours, and the decay heat rate would be significantly lower than design. The net effect of a reduced heat removal capability would be to extend the time required to obtain cold shutdown conditions.

The Appendix R fire in the intake structure is the most severe of these three postulated events, as it is assumed to occur instantaneously while the plant is at 100% power along with a simultaneous loss of offsite power. During this scenario, there is a period of time when no cooling water is available to remove decay heat. Operation of HPCI, RCIC, and SRV's will transfer heat to the torus, resulting in increasing torus temperature until the Alternate Cooling System can be placed in service. Although the Appendix R rules require assuming the loss of all four service water pumps due to a fire in the intake structure instantaneously, this is not realistic for postulated fire scenarios. The power supply to each service water pump is in separate conduit and the routing is separated such that a credible fire could not reasonably affect all four pumps simultaneously. It is highly unlikely that a fire would affect more than two pumps. The intake structure is a fire control area which ensures transient combustibles and transient ignition sources are minimized. Also, due to the lack of continuity of insitu combustible loading, it is unlikely that a major fire will develop in the room. A smoke detector is located in the room, thus the control room would be quickly alerted to a fire in the service water pump room. The fire brigade would respond quickly upon receipt of a fire alarm.

The loss of the Vernon Dam scenario includes approximately 1.6 hours of continued service water operation until the level of the Vernon Pond drops below the level of the intake necessary for Service Water pump operation. In this scenario, the service water pumps can provide for containment (torus) cooling, and the total heat load on Alternate Cooling is reduced since the torus temperature will not be as high as the Appendix R fire scenario. Failure of the Vernon dam is highly unlikely. The seismic capability of the dam is well in excess of the Vermont Yankee Safe Shutdown Earthquake design of 0.14g.

The flooding scenario is by far the least limiting scenario. This is due to the fact that the Probable Maximum Flood would occur with significant warning over a period of days. With the amount of rainfall required to produce flooding to a level where the Service Water Pumps would be unable to operate, sufficient advance warning is available to shut the plant down and cool down long before Alternate Cooling would be needed. Thus the heat load on the system would be the least of the three scenarios described. In addition, in accordance with the Vermont Yankee Technical Specifications, the Alternate Cooling System is not required to be operable once the reactor coolant temperature is below 212 degrees F. Per FSAR Chapter 2.4.3.4, the flood of March 19, 1936, which was the greatest and most destructive flood on this portion of the Connecticut River, resulted in a

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

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMS NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-350), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3160-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20603.

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

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

ANALYSIS OF EVENT (CONT.)

stillwater level of 231'4" which is approximately six feet below the intake structure elevation. Thus, Alternate Cooling System operation would not be required for a repeat of this worst historical flood.

Based on the above, this event had minimal safety significance.

CORRECTIVE ACTIONS

Extensive engineering evaluations of Alternate Cooling System operation have been conducted. The procedure for Alternate Cooling System operation was revised on June 8, 1994 to ensure that the system will be operated in a manner consistent with these evaluations. A Basis for Maintaining Operability (BMO) was documented and reviewed by the Plant Operations Review Committee. The Alternate Cooling System was declared operable at 1630 on June 8, 1994. A change to the FSAR has been made under 10CFR50.59 to recognize the current analysis and procedural requirements to operate four RHRSW pumps and two RHR Heat Exchangers at increased flows. Evaluations were performed assuming a maximum initial deep basin temperature of 105 degrees. Deep basin temperatures rarely exceed 95 degrees. A peak circulating water return temperature of 102 degrees was recorded over a 2 hour period in 1988. Based on our current analysis, even if the initial temperature were 105 degrees, it would be reduced to less than 85 degrees within 12 hours of Alternate Cooling System operation.

Vermont Yankee is continuing to assess the requirements of the Alternate Cooling System. Required pump flows are based on conservative assumptions and analyses, which may be reduced with further evaluations and/or planned testing of the Alternate Cooling Tower. Any future changes would be conducted in accordance with 10CFR50.59 and included in the next updated FSAR submittal to the NRC.

LER No. 272/94-007
Salem, Unit 1

NRC FORM 366 (5 92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50 0 HRS FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Salem Generating Station - Unit 1	05000 272	1 OF 09

TITLE (4) Reactor Trip From 25% Power/Two Safety Injections, Manually Initiated Main Steam Isolation, And Discretionary Declaration Of ALERT.

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
04	07	94	94	-- 007 --	01	05	10	94		05000
									FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	1
POWER LEVEL (10)	073

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

	20 402(b)		20.405(c)	x 50.73(a)(2)(iv)	73.71(b)
	20 405(a)(1)(i)		50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	50.73(a)(2)(vii)	x OTHER
	20.405(a)(1)(iii)	x	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iv)		50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)		50.73(a)(2)(iii)	50.73(a)(2)(x)	Special Rep.

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
M. J. Pastva, Jr. - LER Coordinator	(609) 339-5165

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

At 1050 hours on 4/7/94, an automatic Reactor trip occurred, was immediately followed by an Emergency Core Cooling System (ECCS) Safety Injection (SI) and, at 1100 hours an Unusual Event was declared. At 1105 hours, the SI signal was reset and ECCS flow reduction began. Reactor Coolant System temperature increased, Pressurizer level increased to >100%, steam generator pressure increased and main steam safety valves lifted, and at 1128 hours, a second automatic SI occurred. At 1316 hours, a precautionary ALERT was declared. HOT SHUTDOWN was achieved at 0106 hours on 4/8/94, and at 1124 hours (same day), COLD SHUTDOWN was achieved. The trip resulted from assigning inappropriate priority of actions and improperly monitoring reactor power while withdrawing rods. The first SI resulted from inadequate control of primary loop temperature, concurrent with a false high steam flow signal. The second SI resulted from low Pressurizer pressure due to lifting a steam generator safety valve. Involved personnel will complete remedial training and evaluation. Operating procedures have been revised, as appropriate. Component testing, repairs, and modifications have been made, as required.

NRC FORM 366 (5-92)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 2 of 9

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

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

IDENTIFICATION OF OCCURRENCE:

Reactor Trip From 25% Power/Two Safety Injections, Manually Initiated Main Steam Isolation, And Discretionary Declaration Of ALERT

Event Date: 4/7/94

Original Report Date: 5/6/94
Supplement Report Date: 5/10/94

This report was initiated by Incident Report No. 94-102.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 1 Reactor Power 73% - Unit Load 800 MWe
T_{ave} at 562 degrees Fahrenheit (F). Control Rods in manual control with Bank D rods at 195 steps.

The Unit was at reduced power due to seasonal problems with excessive Delaware River marsh grass/debris affecting the Circulating Water (CW) {UA} intake structure. The amount of grass/debris loading in the river in was excess of four times the seasonal average recorded over a 17 year period.

Operational challenges were being encountered maintaining the CW circulators {UA} and traveling screens in service. Between 1016 and 1043 hours on April 7, 1994, a load reduction was in progress to take the Main Turbine {TA} off-line following "emergency" tripping of 13A and 13B CW traveling screens and subsequent trips of 11A, 11B, and 12A circulators. Reactor power had been reduced to 7% with Unit load at 80 MWe. 11A and 12B circulators were in service prior to the trip. In response to decreasing T_{ave}, at approximately 1049 hours (same day) control rods were being manually withdrawn to increase Reactor Coolant System (RCS) {AB} temperature.

DESCRIPTION OF OCCURRENCE:

During rod withdrawal to restore Reactor Coolant System (RCS) temperature, Reactor power increased to 25% and, at 1050 hours, on April 7, 1994, an automatic Reactor Protection System (RPS) {JC} trip occurred. This was immediately followed by an Emergency Core Cooling System {BQ} Safety Injection (SI), (Train A) and, at 1100 hours, an Unusual Event (UE) was declared. Following the reactor trip/safety

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station	DOCKET NUMBER	LER NUMBER	PAGE
Unit 1	5000272	94-007-01	3 of 9

DESCRIPTION OF OCCURRENCE: (cont'd)

injection, the Main Steam isolation valves were closed due to the primary plant temperature decrease below 547 degrees F. The RCS temperature started to increase at this time.

At 1105 hours, the SI signal was reset on Train A. The ECCS pumps were secured and normal charging was placed in service. Pressurizer level increased to greater than 100% indication (solid condition) and pressure increased due to the SI charging flow and increasing RCS temperature. At 2335 pounds per square inch gauge (psig), the Pressurizer power operated relief valves (PORVs) {AB} cycled automatically. Steam Generator (SG) pressure also increased and two safety valves on 11 SG loop lifted causing RCS temperature and pressure to drop rapidly. At 1128 hours, a second SI automatically occurred on Train B. After the second SI was reset at 1143 hours, the Pressurizer Relief Tank (PRT) {SB} rupture disc operated due to discharge from the PORVs. At 1316 hours, an ALERT was declared, in accordance with Event Classification Guide 17B, as a precautionary step to mobilize engineering resources for assistance, if needed. Required notifications were made in accordance with 10CFR50.72 and the Salem Emergency Plan.

NRC discretionary enforcement was obtained, to provide an additional 12 hours beyond the six hours to HOT SHUTDOWN, required by Technical Specification (TS) 3.0.3, due to the blocking of the automatic SI signals. The Pressurizer bubble was reestablished at approximately 1500 hours. At 0106 hours on April 8, 1994, cooldown to HOT SHUTDOWN was achieved and at 1124 hours (same day), COLD SHUTDOWN was achieved.

ANALYSIS OF OCCURRENCE:

On the morning of April 7, 1994, Salem Unit 1 encountered problems maintaining Main Condenser vacuum due to the ongoing seasonal river grass/debris influx affecting CW circulator availability. A Unit load reduction was in progress to take the Main Turbine off-line. Reactor power was reduced to 7% with Unit load at 80 MWe. Reduction of power to less than 10% automatically reinstated low power trip setpoints. Due to the power reduction, T_{ave} was 553 degrees F. Two manual borations were performed and control rods were manually inserted to return T_{ave} to program. During this time, the Senior Reactor Operator (SRO) directed the primary Nuclear Control Operator (NCO) to transfer the power supply to the Group Buses from the station Auxiliary Power Transformer to the 11 and 12 Station Power Transformers. During this evolution, T_{ave} decreased to 530 degrees F.

Control rods were then withdrawn to increase T_{ave} and Reactor power

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 4 of 9

ANALYSIS OF OCCURRENCE: (cont'd)

increased to 25%. Power Range channels 1N42 and 1N44 initiated an automatic Reactor trip and trip of the Main Turbine. An SI occurred immediately thereafter, when the steam line high steam flow bistables actuated on a short duration pressure pulse, concurrent with T_{ave} below 543 degrees F. SI Train A logic partially actuated and SI Train B logic did not actuate due to the short duration of the high steam flow signal.

The high steam flow signal was due to a pressure pulse in the main steam lines caused by closure of the turbine stop valves. Emergency Operating Procedures (EOPs) were entered and components were positioned in response to the SI signal. The SI Train A was reset with the automatic actuation in the "blocked" condition. The Train B automatic logic remained armed. After the Main Steam isolation valves were closed, T_{ave} increased due to decay heat and Reactor Coolant Pump {AB} operation. Pressurizer pressure increased, due to increasing T_{ave} and SI charging flow and the Pressurizer power operated relief valves, 1PR1 and 1PR2, automatically cycled at 2335 psig. SG pressures also increased in response to increasing T_{ave}. The secondary NCO did not open the Main Steam atmospheric relief valves (MS10s) {SB} in response to the increasing SG pressures. Two safety valves {SB} on 11 SG loop lifted causing T_{ave} and primary pressure to drop rapidly. Operators were in the process of initiating a manual SI to respond to the plant condition, however, a second SI, from the Train B logic automatically occurred. The Pressurizer Relief Tank (PRT) rupture disc operated due to the PORVs relieving to the PRT. The SI was terminated, the Pressurizer bubble was reestablished and COLD SHUTDOWN was achieved.

Personnel Performance

For approximately six weeks prior to the event, the Salem operating shift crews were challenged by the marsh grass/debris affecting the CW intake structure. This has resulted in extended periods of load reductions and numerous transients regarding maintaining operation of the CW circulators.

The Reactor trip is attributed to personnel error, including inadequate command and control. This occurred when the operating crew took inappropriate action, which resulted in an automatic RPS actuation on the Nuclear Instrumentation System {IG} power range low setpoint. The control rod withdrawal to correct T_{ave} was not correctly implemented and resulted in reactor power increasing at a faster rate than anticipated by the NCO. The Nuclear Shift Supervisor (NSS) did not maintain adequate oversight of changing plant conditions and inappropriately prioritized the actions of the operating crew.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 5 of 9

ANALYSIS OF OCCURRENCE: (cont'd)

Personnel Performance (cont'd)

He directed the primary NCO to transfer the power supply to the Group Buses from the station Auxiliary Power Transformer to the 11 and 12 Station Power Transformers. As a result, the NCO's focus was divided between a number of monitoring activities. The NSS recognized the low T_{ave} condition and withdrew control rods a few steps, but realizing this was counter to management expectations and training he discontinued this action. After the electrical bus transfer was completed, the NSS directed the NCO to restore T_{ave}.

Following the reduction of Reactor power to 7% and transfer of the Group Buses, the primary Nuclear Control Operator (NCO) recognized that T_{ave} was below the program value. Because of his focused attention on restoring T_{ave}, the NCO did not properly monitor reactor power while withdrawing rods.

The MS10s were set in automatic control, but did not respond to the increasing pressure. The operating crew did not adequately communicate RCS temperature and no trending of the T_{ave} value was performed by the NCOs. The required action of the secondary NCO, to take manual control of the valves and open them to prevent lifting of the SG safety relief valves, was not done in a timely manner.

Equipment Performance

At the time of the event, rod control for the Unit was in manual for troubleshooting of suspected problems with automatic rod control. Subsequent troubleshooting, which included testing of the Rod Speed circuitry, showed the Rod Control System was fully functional.

Due to "shadowing" by rod position and T_{ave} being off program low, the Nuclear Instrument System (NIS) Intermediate Range (IR) Rod Stop at 20% did not actuate to prevent the increase in power to above 25%. It was concluded that the system, functioned, as designed. (The NIS is not an Engineered Safety Feature and credit for it is not taken in the plant accident analysis.)

The first SI occurred due to T_{ave} below program coincident with an erroneous high steam line flow signal. Due to the short duration of the high steam line pressure pulse, the SI signal was only generated by the Train A Solid State Protection System (SSPS) {JC}. Train B SSPS did not respond to the SI signal due to acceptable differences in the actuation time of the SSPS.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 6 of 9

ANALYSIS OF OCCURRENCE: (cont'd)

Equipment Performance (cont'd)

The high steam line flow signal occurred when the turbine stop valves closed following the Reactor trip signal. This generated a pressure pulse of sufficient magnitude and duration to actuate the steam line high steam flow bistables. Post event testing verified both channels of high steam flow were functioning within overall time response required by TS and showed no indication of degradation.

Following the first SI, main steam isolation valves (MSIVs) {SB} 13 and 14 MS167 closed, while MSIVs 11 and 12MS167 did not automatically close. The 11 and 12MS167 did not close due to differences in the response of the actuation circuitry to the short duration pulse of the SI signal.

The closure of the Main Turbine stop valves caused a pressure pulse of sufficient magnitude and duration to initiate a high steam flow signal. Due to the short duration of this signal, the SI cleared before some plant equipment could latch and operate to allow completion of all component actions. Although Train "B" did not respond due to the short duration of the pulse, it operated within design specifications and no equipment failures were noted.

Several main steam safety valves operated, per design, during the event, due to the increase in secondary loop pressure.

Operation of the PRT rupture disc occurred per design.

During the cycling of PORVs 1PR1 and 1PR2, the valves performed as designed.

Response of the MS10s to open in automatic is a previously identified condition. The valves have a delay in opening due to the valve controller being below its setpoint for an extended period of time. The design of the valve controller allows the controller output to saturate low when the process is below the control setpoint. This necessitates manual action by the control operator. Following this event, individual problems involving a binding servo drive in the 11MS10 controls, a logic transfer circuit board in the 13MS10 controls, and a missing gear tooth and a misaligned drive shaft in the 14MS10 controls were also identified.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 7 of 9

ANALYSIS OF OCCURRENCE: (cont'd)

Equipment Performance (cont'd)

The following SI components did not respond to the first SI signal:

Train A

11 and 12MS167, main steam isolation valves for 11 and 12 SGs, did not close.

11, 12, 13, and 14BF13, SG feedwater motor-operated inlet isolation valves did not close.

11 and 12 SG feed pumps did not trip.

Train B

SSPS Train B did not respond to the high steam flow SI.

Subsequent testing and analysis indicates the pressure pulse from closure of the main turbine stop valves was not of sufficient duration to initiate the complete train logic. Therefore, it is concluded the above-listed equipment responded, as designed.

The second SI of this event constituted the 21st accumulated SI actuation cycle to date.

APPARENT CAUSE OF OCCURRENCE:

This event is attributed to "Personnel Error", as classified in Appendix B of NUREG-1022. The Reactor trip and initial SI occurred when the NSS failed to maintain adequate command and control, communications, and assigned inappropriate priority of actions in response to the changing plant conditions. The NCO added positive reactivity change at a rate which caused power to increase too quickly, resulting in the reactor trip. The response of the operating crew to the changing conditions of the event was affected by some equipment problems and procedural guidance.

PREVIOUS OCCURRENCES:

Prior events involving excessive CW intake grass/debris have been reported in LERs 272/83-033/01T, 272/93-011-00, and 311/89-013-00.

A prior event involving greater than 100% level (solid condition) in

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 8 of 9

PREVIOUS OCCURRENCES: (cont'd)

the Pressurizer was reported in LER 311/89-005-00.

SAFETY SIGNIFICANCE:

This event did not affect the health and safety of the public. This event is reportable pursuant to 10CFR50.73(a)(2)(iv), due to the RPS and SI actuations and 10CFR50.73(a)(2)(i)(B), due to entry into TS 3.0.3. In addition, this report fulfills the requirement for a Special Report within 90 days of an SI, as required by TS 3.5.2., ACTION: b.

The combination of all personnel actions and equipment performance contributed to the plant response. An analysis of that response was performed which addressed the safety significance of all contributing factors. The plant response was reviewed against Condition II safety criteria from Chapter 15 of the Salem Updated Final Safety Analysis Report. This review, which included the safety limits on peak primary and secondary system pressure, and minimum Departure from Nucleate Boiling Ratio, showed these limits were not exceeded. In addition, similar consideration was given to plant component fatigue, fuel integrity, and the effects of lower than normal T_{ave}. This showed all component fatigue analytical conclusions remain valid, no fuel failures have resulted from the event, and the effects of the lower than normal T_{ave} were insignificant with respect to plant safety.

CORRECTIVE ACTION:

The PRT rupture disc has been replaced.

The CW traveling screens were repaired and returned to service.

Operating procedures have been revised, as appropriate.

Simulator training on this event has been conducted with all operating shifts.

The MS10s controls have been tested and repaired, as required.

Modifications have been made to the MS10s to improve performance.

Changes to the plant design have been implemented to dampen/filter the erroneous high main steam flow signal generated by closure of the Main Turbine stop valves.

The involved licensed personnel were removed from Licensed Operator duties. Remedial training and evaluation will be performed for these

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 1	DOCKET NUMBER 5000272	LER NUMBER 94-007-01	PAGE 9 of 9

CORRECTIVE ACTION: (cont'd)

personnel, prior to their resuming licensed duties.

The PORVs have been inspected and greater than expected wear was noted on several components. Internal parts will be replaced, as required, prior to return to power.

The Salem Emergency Operating Procedures will be reviewed and revised, as required.

General Manager -
Salem Operations

MJPJ:pc

Appendix I

AIT No. 272/94-80
Salem, Unit 1

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

REPORT/DOCKET NOS.	50-272/94-80 50-311/94-80
LICENSE NOS.	DPR-70 DPR-75
LICENSEE:	Public Service Electric and Gas Company P.O. Box 236 Hancocks Bridge, New Jersey 08038
FACILITY:	Salem Nuclear Generating Station
INSPECTION DATES:	April 8-26, 1994
INSPECTORS:	Stephen Barr, Resident Inspector, Salem, DRP (Asst. Team Leader) J. Scott Stewart, Examiner, DRS Iqbal Ahmed, Senior Electrical Engineer, NRR Warren Lyon, Senior Reactor Systems Engineer, NRR John Kauffman, Senior Reactor Systems Engineer, AEOD Larry Scholl, Reactor Engineer, DRP Richard Skokowski, Reactor Engineer, DRS Howard Rathbun, NRR Intern
STATE OBSERVER:	Richard Pinney, New Jersey Department of Environmental Protection and Energy
TEAM LEADER:	R. J. Summers, Project Engineer Projects Branch 2, DRP — Date: 6/23/94
APPROVED BY:	James T. Wiggins, Acting Director Division of Reactor Safety — Date: 6/23/94

EXECUTIVE SUMMARY

Areas Inspected: An Augmented Inspection Team (AIT), consisting of personnel from Region I AEOD and NRR, inspected those areas necessary to ascertain the facts and determine probable causes of the automatic reactor shutdown and multiple automatic initiations of the safety injection system that occurred on April 7, 1994. The team assessed the safety significance of the event, including the resultant plant operation with a water (liquid) filled pressurizer and its challenge to the primary coolant boundary integrity and the potential vulnerability of the ultimate heat sink to the same marsh grass intrusions that challenged the plant normal heat sink, which was the initiating event for the sequence of events on April 7. The adequacy of the licensee's design, maintenance and troubleshooting practices relative to the safety injection system was reviewed. The possibility for any potential generic implications posed by the Salem event was assessed.

Results: The Augmented Inspection Team (AIT) developed a sequence of events detailing the circumstances surrounding a Salem Unit 1 plant trip and a series of safety injection system actuations. It was found that the events led to the loss of the pressurizer steam bubble and the normal reactor coolant system pressure control system, and an Alert declaration. The AIT noted through an event sequence and causal factor analysis that the root causes of key events generally included a combination of component failure and human error. Additional procedural guidance for, and prioritization of work activities of control room operators would have resulted in a better response to the event. The AIT found in general that the licensee response to the almost daily event of grass clogging of the circulating water screens was very well planned and coordinated for the additional workload at the circulating water structure. However, as indicated by the performance of personnel and equipment in response to the April 7 event, the licensee did not adequately plan for, and coordinate, the activities corresponding to the additional workload in the control room resulting from the same event.

Finally, even though some equipment and licensed operators performed poorly during the ensuing transient on April 7, the core and its primary protective barriers were maintained throughout the event.

In addition, the following conclusions were developed as a result of the AIT review and discussed at a public exit meeting held on April 26, 1994:

Summary of Conclusions:

1. No abnormal releases of radiation to the environment occurred during the event (Section 3.4).

2. The April 7, 1994 event challenged the RCS pressure boundary resulting in multiple, successful operations of the pressurizer power operated relief valves and no operations of the pressurizer safety valves (Section 3.2).

3. Operator errors occurred which complicated the event (Section 4).

EXECUTIVE SUMMARY (CONT'D)

4. Management allowed equipment problems to exist that made operations difficult for plant operators (Section 7.2).

5. Some equipment was degraded by the event, but overall, the plant performed as designed (Section 3).

6. Operator use of emergency procedures was good. However, procedural inadequacies were noted with other operating procedures (Section 4).

7. Licensee's investigations and troubleshooting efforts were good (Section 5).

TABLE OF CONTENTS

EXECUTIVE SUMMARY ii

EXECUTIVE SUMMARY (CONT'D) iii

TABLE OF CONTENTS iv

1.0 INTRODUCTION 1
1.1 Event Overview 1
1.2 Augmented Inspection Team Activities 1

2.0 GENERAL SEQUENCE OF EVENTS 2

3.0 PLANT RESPONSE TO EVENT 4
3.1 Solid State Protection System (SSPS) Response 4
3.2 Pressurizer PORVs, Safety Valves & Associated Pipe 7
3.3 Circulating and Service Water Systems 13
3.4 Reactor Systems Response 16
3.5 Atmospheric Steam Dump Valves and Steam Generator Safety Valves . . 21

4.0 PLANT OPERATOR PERFORMANCE & PROCEDURE ISSUES 21
4.1 Operator Response Prior to the Plant Trip 22
4.2 Operator Response Following the Plant Trip and Safety Injections 25
4.3 Procedure Adequacy and Use 28
4.4 Event Classification & Notifications 30

4.5 Simulator Demonstration 30
4.6 Reactor Vessel Level Indication System (RVLIS) Monitoring 30
4.7 Operations Conclusions 32

5.0 EVALUATION OF TROUBLESHOOTING ACTIVITIES 34

6.0 OTHER FINDINGS 40

7.0 SAFETY SIGNIFICANCE AND AIT CONCLUSIONS 42
7.1 Safety Significance 42
7.2 AIT Conclusions 43

8.0 EXIT MEETING 49

ATTACHMENT 1 - AIT Charter
ATTACHMENT 2 - Safety Injection System Logic Diagram
ATTACHMENT 3 - Confirmatory Action Letter
ATTACHMENT 4 - Sequence of Events
ATTACHMENT 5 - Acronyms
ATTACHMENT 6 - Exit Meeting Attendees
ATTACHMENT 7 - Figures

DETAILS

1.0 INTRODUCTION

1.1 Event Overview

On April 7, 1994, operators at Salem Unit 1 were operating that unit at 73% power. The plant was at a reduced power level due to the reductions of condenser cooling efficiency resulting from the problems river grass had been causing at the unit's condenser circulating water (CW) intake structure. Shortly after 10:00 a.m. that morning, a severe grass intrusion occurred at the intake structure, and many of the Unit 1 CW pumps began to trip. Operators consequently began to reduce plant power in order to take the unit turbine off line. As a result of operator error and equipment complications, a Unit 1 reactor trip and automatic safety injection occurred at 10:47 a.m., and a subsequent second automatic safety injection occurred at 11:26 a.m. The subsequent sequence of events resulted in the Unit 1 primary coolant system filling, resulting in a loss of normal pressurizer pressure control at normal operating temperature and pressure. The licensee declared an Unusual Event and subsequently an Alert condition at the unit.

The events of April 7, from the initiating downpower transient to the ensuing reactor trip and safety injections, were complex and involved a combination of personnel errors and equipment failures.

1.2 Augmented Inspection Team Activities

On April 7, 1994, senior NRC managers determined that an AIT was warranted to gather information on the plant trip and subsequent safety injection system actuations at Salem Unit 1. The AIT was initiated because of the complexity of the events, the uncertainty of the root causes of some of the conditions and equipment problems that had been encountered during the events, and possible generic implications. A charter was formulated for the AIT and transmitted to the team on April 8, 1994 (Attachment 1). The NRC Region I Regional Administrator dispatched the AIT early on April 8, 1994. The AIT met with PSE&G management and staff regarding the facts known at that time for the April 7 event.

On April 8, 1994, NRC Region I issued a confirmatory action letter (CAL) that documented the verbal commitments made by the licensee to the NRC regarding the control of activities for equipment that failed to operate properly during the event, PSE&G support of the team inspection activities and the subsequent restart of the unit. The CAL is enclosed as Attachment 3.

The team completed initial inspection activities on April 15, 1994. Additional onsite inspection was conducted on April 17, 20 and 21, 1994, to perform additional operator interviews and to review the results of ongoing troubleshooting and testing activities. The work directed by the AIT charter was completed and a public inspection exit meeting was held on April 26, 1994. The AIT participated in two congressional staff briefings, a public NRC and PSE&G

management meeting on May 6, 1994 and an NRC Commissioners' briefing on May 11, 1994. The AIT provided information/findings to NRC Region I for use in developing the issues warranting corrective action or further analysis prior to restart of Unit 1.

2.0 GENERAL SEQUENCE OF EVENTS

On April 7, 1994, prior to the reactor trip and safety injection events, Salem Unit 1 was operating at approximately 73% power. Operators were operating the plant at less than full power due to the effect marsh grass in the Delaware River was having on the Salem units' circulating water (CW) systems. Over the course of late winter and early spring, heavy accumulations of the river grass at the CW structure were clogging the CW system travelling screens which protect the CW pumps from river debris.

By approximately 10:30 a.m. on April 7, the power level at Unit 1 had been decreased to about 60 % power as a result of an increase in condenser back pressure due to river grass interfering with the travelling screens at the CW structure. In response to the approaching loss of CW, Unit 1 operators began a unit load reduction at 1% power per minute. From 10:15 a.m to 10:40 a.m., several of the Unit 1 CW travelling screens clogged with grass and caused the corresponding CW pump to trip off line. Operators attempted to restore the pumps as they tripped, but by 10:39 a.m. only one CW pump was available. As the CW pumps were lost from service, operators increased the rate of the downpower maneuver from 1% to 3% to 5% to eventually 8% per minute. As the operator responsible for controlling turbine power reduced the unit load, the operator responsible for reactor power correspondingly reduced reactor power by inserting the reactor control rods and by boration.

Initially, during the downpower maneuver, operators reduced turbine power ahead of reactor power, and the resulting power mismatch caused slightly higher than normal temperature for the primary coolant system. At about 10:43 a.m., the Nuclear Shift Supervisor (NSS) directed the operator controlling reactor power to go to the electrical distribution control panel to begin shifting plant electrical loads to offsite power sources. At that time the control room crew members believed the plant was stable; however, they failed to recognize that reactor power was still decreasing due to the delayed effect of a boron addition that had been made. This led to reversal of the power mismatch and a decreasing T_{avg}. At 10:45 a.m., the NSS identified the resultant over-cooling condition, went to the reactor control panel and began withdrawing control rods to raise coolant temperature, and then turned over control once again to the original operator. This operator continued to withdraw the control rods, and reactor power increased from approximately 7% to 25% of full reactor power. Since power dropped below 10% power, the power range "high neutron flux-low setpoint" trip had automatically reinstated, establishing 25% reactor power as the automatic reactor trip setpoint. When reactor power reached the 25% setpoint, at approximately 10:47 a.m., the reactor automatically tripped.

Almost immediately following the reactor trip, an automatic safety injection (SI) actuated. The SI was initiated only on Train A of the SI logic on high steam flow coincident with low primary coolant T_{avg}. Although the operators did not recognize it at the time, the licensee later

determined that the high steam flow signal was a result of a pressure wave created in the main steam lines by the closing of the turbine stop valves when the turbine automatically tripped. In response to the reactor trip and SI, the operators entered Emergency Operating Procedure (EOP) EOP-Trip 1 at 10:49 a.m. Due to the nature of the initiating signal, the SI actuation did not successfully position all necessary components to the expected, post-actuation position, and the operators, as part of EOP performance, manually repositioned affected components. At 11:00 a.m., the licensee declared an Unusual Event based on a "manual or automatic emergency core cooling system actuation with a discharge to the vessel." During further performance of the EOP, operators had to reset the SI logic, and it was at this point that they realized that Train B of the SI logic had not actuated and that there was thus an apparent logic disagreement.

As the operators were performing the required EOP steps, the primary coolant system continued to heat up due to decay heat and running the reactor coolant pumps. As the primary heated up, steam generator pressure consequently increased, and because of pre-existing problems with the steam generator atmospheric relief valve (MS10) automatic control, steam generator pressure was not properly controlled by these valves. Concurrently, due to primary heatup and the volume of water added by the SI, the pressurizer filled to solid or near-solid conditions, and the pressurizer power operated relief valves (PORVs) periodically automatically opened to control primary pressure. Shortly before 11:26 a.m., steam generator pressure increased to the ASME code safety valve lift setpoint in the Number 11 and/or 13 steam generator(s). The opening of the safety valve caused a rapid cooldown of the primary coolant system, and due to the solid water state of that system, a coincident rapid decrease in primary system pressure. At 11:26 a.m., primary pressure reached the automatic SI setpoint of 1755 psig, and since Train B of the SI logic remained armed, a second automatic SI was actuated by that train of logic. Operators had also identified the decreasing primary pressure and manually initiated SI moments after the automatic initiation.

Following the second SI, operators remained in the EOP network and pursued stabilizing plant conditions. At 11:49 a.m., the pressurizer relief tank (PRT) rupture disk ruptured to relieve the increasing tank pressure which resulted from the volume of primary inventory relieved to the PRT. At this point, the operators were faced with cooling down the plant from normal operating temperature and pressure without having a steam bubble in the pressurizer to control primary pressure during the transient. Once the ECCS injection was terminated, operators controlled plant pressure through a combination of charging and letdown using the chemical and volume control system. At 1:16 p.m., licensee management declared an Alert under Section 17.B, "Precautionary Standby," of the Salem Event Classification Guide. The licensee decision to voluntarily enter this Emergency Activation Level was made in order to assure the activation of the Salem Technical Support Center (TSC) to provide the Salem operators with any technical assistance that would be required as they cooled down the plant. By 2:10 p.m., the TSC had been fully staffed, and at 3:11 p.m., the operators restored a bubble in the pressurizer.

At 4:30 p.m., operators restored pressurizer level to the normal band and returned level control to automatic. The operators subsequently exited the EOPs and used integrated operating procedures to cool the plant down to Mode 4 (Hot Shutdown), which was achieved at 1:06 a.m. on April 8, and then to Mode 5 (Cold Shutdown), which was achieved at 11:24 a.m. on the same day.

A detailed sequence of events is provided in Attachment 4.

3.0 PLANT RESPONSE TO EVENT

3.1 Solid State Protection System (SSPS) Response

3.1.1 SSPS Description

The function of the reactor protection system is to sense an approach to unsafe conditions within the reactor plant and then initiate automatic actions to protect the reactor fuel, the reactor coolant system and the primary containment from damage. A block diagram of the system logic is given in Attachment 2. Process sensors monitor various plant conditions and provide an output to the system bistables. When a trip setpoint is exceeded the bistable deenergizes its associated input relays which then provide an input to the solid state logic circuitry. The solid state logic processes the various inputs, determines if an unsafe condition is being approached and, when appropriate, actuates the output relays to cause a protective action. The protective action may be a reactor trip or the actuation of the safeguards equipment. As shown in the block diagram, each channel bistable controls a relay in both Protection System Trains A and B. The two protection trains have identical functions to ensure that in the event of a failure of one train the automatic protection actions will be ensured. Another design feature of the system is that, once initiated, a protective action shall go to completion. This feature is achieved by various means for the different safeguards equipment. In some cases relays within the solid state protection system electrically seal in and thereby ensure the protective action continues to completion regardless of the duration of the signal. For some components this feature is accomplished by components and circuitry downstream of the solid state protection system circuitry. For example the main steam isolation valve closure (MSIV) action is "sealed-in" when a mechanically latching relay, within the MSIV control circuitry, is released by the action of a solid state protection system buffer relay. For these components, the duration of the input signal must last long enough for the latching relays to actuate.

System Actuation Logic

The protection system is designed such that the failure of a single component cannot prevent a desired automatic protective action from occurring. Likewise, the design ensures that a single component failure cannot cause an unnecessary system actuation. These design objectives are accomplished by having multiple instrumentation channels and redundant protection trains. A vital component of the protection trains is the solid state logic. This logic ensures that more than one instrumentation channel is sensing an unsafe condition; however, it does not require

all channels to initiate a protective action. For example, to protect the plant from the effects of a main steam line break accident, the protective system monitors differential pressures from which main steam line flow rates may be inferred, main steam line pressures and the average reactor coolant temperature (T_{avg}). One of the conditions required to cause a protective action is the coincident existence of both:

1. High steam flow in two of the four main steam lines. (Each steam line has two flow instruments with an associated bistable. The logic considers steam flow in a particular steam line to be high if one of the two bistables are tripped.)

and,

2. Low T_{avg} condition on two of four reactor coolant system loop temperature instrument channels; or low steam line pressure on two of the four main steam line pressure channels.

When this logic is satisfied the protective actions that are initiated are the isolation of the main steam lines and a safety injection. The safety injection logic then results in closure of the feedwater control and bypass valves, main feedwater isolation, trip of the feedwater pump turbines, realignment of various system valves and dampers and actuation of the safeguards equipment control systems (e.g. safety injection pump and emergency diesel generator starting).

The solid state logic processes the various system inputs in a similar manner as necessary to generate the appropriate protective action based on the particular accident analysis.

Some of the safeguards equipment receives actuation signals from both protection trains (e.g. emergency core cooling pumps, emergency diesel generators). Other equipment (consisting mostly of train specific safety injection system valves) receive actuation signals from only one of the protection trains. The system design is such that the components that are actuated from a single train alone, result in completing the safety function. Therefore, a single logic system failure will not result in a total loss of safety function.

When the solid state logic generates a protective action signal one of two actions occur. For a reactor trip the undervoltage coils of the reactor trip circuit breakers are deenergized directly by the solid state logic circuits. For all of the other protective actions, the solid state logic circuits control the operation of a master relay in the Safeguards Equipment Cabinet. Depending on the number of relay contacts that are needed to accomplish a protective function, additional slave and buffer relays are utilized. The slave relays are controlled by a master relay and buffer relays by a slave relay. Some of the control circuits use additional control relays in the operation of the safeguards equipment, as discussed previously. For the MSIV system, each latching relay, once actuated, operates solenoid valves that cause individual MSIVs to close. The resultant effect is that for the MSIVs the series operation of a master, slave, buffer and latching relay is required before the protective action, generated by the SSPS logic, is assured of going to completion.

3.1.2 SSPS Response During the Event

During the plant transient that occurred on Salem Unit 1 on April 7, 1994, the solid state protection system responded to a sustained low T_{avg} condition and coincident short duration high steam flow indications. The low T_{avg} condition was a result of actual plant conditions experienced during the rapid plant power reduction. The short duration high steam flow signals occurred following the main turbine trip. These high steam flow signals were not the result of an actual high steam flow condition resulting from a postulated steam line break; but rather, were caused by a pressure wave in the main steam lines that occurs when the turbine stop valves rapidly close during a turbine trip.

High Steam Flow Signal Analysis

The team reviewed PSE&G's analysis of the high steam flow signal associated with the initial safety injection on April 7, 1994. At Salem Generating Station the steam flow in each main steam line is determined by measuring the pressure difference across the steam line flow restrictor. The flow restrictor is a venturi type flow meter. However, the pressure taps are on each side of the flow restrictor and there is no pressure tap at the throat.

Following a reactor trip the P-4 permissive selects a new setpoint for the high steam flow safety injection and steam line isolation. This new setpoint is equal to a 40% power steam flow equivalent. Additionally, P-4 also initiates a turbine trip. According to PSE&G analysis, the quick closing of the turbine stop valve associated with a turbine trip generates compressive pressure waves in the main steam line. These pressure waves travel upstream toward the steam generator and are reflected back and forth from the two ends of the pipe. These waves are also reflected such that they enter the pressure sensing lines for the pressure transmitters, where a pressure difference is then indicated, and intermittent, short duration, high steam flow signals are generated.

The team questioned whether either Salem unit had experienced similar intermittent high steam flow signals following previous reactor/turbine trips. PSE&G reviewed past reactor/turbine trips and identified at least three occasions where short duration high steam flow signals were generated following reactor/turbine trips. Although PSE&G had identified short duration high steam flow signals following previous reactor/turbine trips, as a result of the analysis during those prior events they determined that the condition resulted from the P-4 high steam flow setpoint change and the time actual steam flow decreases below 40%. PSE&G considered this to be an expected response of the instrumentation and that no modification was necessary. The spurious high steam flow signals caused by the pressure waves following a reactor/turbine trip were not identified; and therefore, not evaluated until the April 7, 1994 event.

Also, following the April 7, 1994, event PSE&G found that safety injections due to the spurious high steam flow signals had occurred at another Westinghouse plant and that time delay circuits were installed to address this problem.

Plant Response

A review of the sequence of events generated by the plant computer following the reactor trip and turbine trip indicated that protective action signals were generated in response to the high steam flow/low T_{avg} signals two times. The sequence of events program divides each one second time interval into 60 cycles and identifies events that occur and/or clear within each one cycle time interval. AIT review of the sequence of events computer printout determined that the coincident high steam flow and low T_{avg} conditions were logically satisfied twice just after the reactor trip on April 7. The first occurrence occurred and cleared within one electrical cycle (0.0167 second). The second occurrence occurred during one cycle and cleared in the next cycle. Since it is not possible to determine when, within the first cycle, that the initiation occurred, or when, within the second cycle, the trip condition cleared, the actual duration that the trip signal was present cannot be determined other than it was present for a maximum of two cycles (0.033 second).

The first occurrence was of such short duration that neither the A nor B protection system trains was able to actuate any safeguards equipment prior to clearance of the input signal.

The second occurrence was sufficient for protection train A to respond and resulted in a partial actuation of the safeguards equipment. The difference in the response times of the A and B logic trains resulted in the single train actuation. The reason for the partial actuation of the equipment associated with the A protection train is that the short duration signal did not allow sufficient time for all of the seal-in and/or latching relays to respond. The safeguards components that are actuated as a result of operation of a solid state protection system slave relay (with a seal-in design) all performed as expected for the A protection system train. Other components, that have seal-in or latching relays within their specific control circuits, did not all operate. The later set of components included two of the four MSIVs that failed to close, the main feedwater pump turbines that failed to trip and the main feedwater isolation valves that failed to close. PSE&G tested the system response to varying duration input signals to validate these conclusions. This testing is discussed in Section 5 of this report.

3.2 Pressurizer PORVs, Safety Valves & Associated Pipe

The pressurizer for each Salem reactor coolant system (RCS) is equipped with two power operated relief valves (PR1 and PR2) that can be isolated from the pressurizer by block valves. The PORVs are set to open at 2335 psig. They actuated over 300 times during the event to relieve water and successfully prevented an RCS overpressure condition that could have challenged the pressurizer safety valves. Also, they successfully opened and closed several times after the event.

Post-event examination showed that both PORVs incurred wear of the valve internals; however, the valves still worked after the event. Prediction of future valve operation, particularly due to the galling observed in PR2's valve stem, is judged impractical by the AIT. The galling could

lead to failure at any time, or the valve may operate numerous additional times before failure. Damage to PR1 was found to be generally less severe than to PR2. The licensee subsequently replaced the worn internals, which the AIT considered an appropriate action.

PORV Design

Figure 1 in Attachment 7 shows the Salem PORV design. The valve is air actuated with the actuation diaphragm moving a stem (9) that passes through packing located in the valve bonnet. The stem is threaded into a plug (20) and an anti-rotation pin (8) is driven through the threaded junction to prevent rotation. The bonnet is bolted in place, and holds the cage (19) against a gasket (18) in the bottom of the valve body via the cage spacer (21). The valve seat surfaces are on the bottom of the plug and along the inside of the cage toward the bottom. Lifting the plug moves the plug seat away from the cage seat, allowing flow. At the time of the event for Salem Unit 1, the stem was 316 stainless steel with a chrome plating, the anti-rotation pin was 300 series stainless steel, and the plug and cage were 420 stainless steel. The valves are manufactured by Copes-Vulcan.

This valve model was tested in the 1981 EPRI test program except that a combination of two different valve internals types were tested (a Stellite plug in a 17-4 PH cage, and a 17-4 PH plug in a 17-4 PH cage). Some delayed closures were identified in the EPRI tests due to scoring and galling of some surfaces for the valve with the 17-4 PH plug. Originally, Salem Unit 1 used the 17-4 PH plug and cage internals. Subsequently, the licensee changed to a 316 stainless steel, Stellite plug.

The change to the 420 stainless steel valve internals was completed in 1993. These new internals had no service life other than testing prior to the April 7, 1994 event.

Subsequent to the event, the licensee replaced the valve internals using the 316 stainless steel stellite plug in a 17-4 PH cage.

PORV Performance During Event

The PORVs actuated over 300 times during the event to relieve water and successfully prevented an RCS overpressure condition. Figure 2 in Attachment 7 depicts the RCS pressure during the transient after the second SI actuation. It was during the period from about 11:30 a.m. to 12:00 noon that the PORVs experienced the greatest amount of operation.

Each PORV is equipped with a "valve not fully closed" position indication activated from the valve stem. This provides a positive indication if the valve is more than ~ 5% open and is a recorded indication. The licensee reconstructed the number of valve cycles from this indication by counting a cycle as a combination of passing 5% on an opening motion followed by passing 5% on closing. On this basis, PR1 cycled 109 times and PR2 cycled 202 times. Cycle times varied from 0.3 sec to 2 sec.

Post-Event Examination and Evaluation

The licensee obtained the following information for temperature downstream of the PORVs from the Technical Support Center logs:

Approximate time, April 7	Tail pipe temperature, °F	Pressurizer temperature, °F	Pressurizer pressure, psi
3:30 p.m	215	650	2250
4:16 p.m	212		2260
6:53 p.m.	211		
7:00 p.m.		605	1800
8:00 p.m.	205	595	~ 1500

Roughly 212 °F or greater is expected under these conditions if the valve is open or leaking significantly. The observed behavior from 6:53 p.m. to 8:00 p.m. indicated that the PORVs were closed and not leaking significantly. The earlier values could be due to tailpipe cooldown following the event. For comparison, the Unit 2 thermocouples indicated 135 - 150 °F at about 5:00 p.m. on April 23, 1994, while that unit was operating at power.

Following the event, licensee personnel observed that the leak rate into the pressurizer relief tank (PRT) was similar to that existing before the event (0.66 gpm prior to the event; about 0.64 gpm at 5:00 p.m. following the event). The source of the leak appeared to be from a pressurizer safety valve, as is discussed later in this section.

The AIT noted that the licensee initially intended to accept the PORVs as operable following the event without a visual inspection of the valve components. However, as a result of an AIT request for the engineering evaluation of the PORVs upon which that operability determination was based, the licensee then elected to open the valves for inspection.

The licensee post-event, preliminary examination of PORV PR2 showed galling of the stem where it passed through the bonnet and severe wear/scrapes, but little or no galling, along part of the plug and cage. The damage was concentrated on the side toward the outlet, which the licensee indicated was consistent with past experience. The licensee also indicated the cage appeared softer than the plug. The seat did not exhibit obvious cutting. The plug was reported as freely movable in the cage by hand. Valve PR1 did not exhibit stem wear, although there was some wear to the plug and cage and there was a possible cut in the valve seat. Both valves had an axial crack on both sides of the anti-rotation pin. This crack passed through the backseat.

The licensee planned to reassemble the internal parts and the bonnet from PR2 in a different valve body and test to destruction with water at ~ 2300 psi if a test facility can be found that will use the radioactive components. The internal parts from PR1 will be carefully examined. The licensee will examine new internal parts for the PORVs to see if there are cracks in the vicinity of the anti-rotation pins.

Primary Code Safety Valves

The pressurizer for each Salem reactor coolant system (RCS) is equipped with three safety valves (PR3, PR4, and PR5) that are set to open at 2485 psig (± 1%). Pressure never reached the safety valve setting during the event, although the PR4 tailpipe temperature indicated high. Post-event testing showed that PR4 was weeping; a condition the AIT judges to have existed before the event. The licensee plans to replace PR4 and will also remove and test PR3 and PR5.

Valve tailpipe temperature for PR4 was observed to be ~ 216 °F at ~ 12:00 noon on April 7 (220 °F via post trip review report), while PR3 and PR5 indicated a more normal 130 - 135 °F range. (Roughly 212 °F or higher is expected under these conditions if the valve is open or leaking significantly, depending upon both the pressurizer and pressurizer relief tank conditions. Note that the Unit 2 thermocouples indicated 135 - 150 °F on about 5:00 p.m. on April 23 while the unit was in mode 1. Also note that these temperatures are not recorded. The only information was from logs and personnel recollections.) This elevated tailpipe temperature raised the question of whether PR4 lifted during the event.

Attempts to evaluate the tailpipe temperature indication operability following cooldown failed; apparently mistakes were made by the licensee in selecting sensors to test and the instrumentation was damaged during PORV disassembly and during instrumentation evaluation.

Review of RCS pressure data and PORV open/close behavior shows that the pressure never significantly exceeded the PORV lift pressure of 2335 psig. Thus, PR4 should not have lifted unless its setpoint was significantly low. Each pressurizer safety valve has a 0.15 to 0.3 inch limit switch, which corresponds to ~ ¼ to ½ open. There is no record of a limit switch indicating open during the event.

The leak rate into the pressurizer relief tank (PRT) was 0.66 gpm before the event and was estimated as ~ 0.64 gpm at 5:00 p.m. following the event. This is consistent with a leak that was unaffected by the event.

Post-event testing of PR4 at Wylie Laboratories showed valve lift at 2515, 2516, and 2524 psig, with seat leakage at 90% of the setpoint value. (The valves are supposed to open at 2485 psig with a ± 1% tolerance, which gives a maximum allowable of 2510 psig.) Wylie indicated to the licensee that 25% to 35% of the safety valves they test will exhibit such leakage.

The combination of event pressure, leak behavior, and post-event valve testing support a conclusion that PR4 was leaking prior to, during, and following the event and did not lift during the event. The AIT did not assess the slightly out-of-tolerance lift setpoint for PR4 since it had no effect on the event.

PORV/Code Safety Valve Piping

The licensee performed a visual inspection of the piping and supports downstream of the PORV and safety valves immediately after the event and stated there was no evidence of damage. Later, after examining piping upstream of the valves, the licensee reported two support rods were bent; but that these were not believed to have been damaged during the event. The licensee found no other pipe or support related damage. After the AIT effort, the licensee completed their evaluation of the associated piping and determined that no flaws occurred as a result of this event. This evaluation was reviewed by Region I as part of the effort supporting restart assessment and will be documented in a future report.

The licensee discussed pressurizer nozzles and its piping system with Westinghouse regarding pressure transients upstream of the PORVs and reported an expectation that there was little effect. The pressurizer volume would be expected to dampen such transients and no safety valve operation would be expected. The licensee reported that an analysis assuming 2350 psig and 680 °F resulted in a usage factor of 0.01 for 350 full-open/full-close cycles.

The licensee's analysis was based upon PORV opening times of 0.5 sec and 2 sec for closure. The licensee did not address shorter times, the influence of a lower temperature (pressurizer temperature during the event was probably as low as ~ 550 °F), the effect of both valves being in operation rather than one, or the influence of the valve not going fully open before receiving a close signal. The AIT believed additional analysis was necessary to establish the lack of impact upstream of the PORVs. This concern was discussed with the licensee. Subsequent to the AIT completing its inspection activities, the licensee provided additional evaluations of the associated piping to the NRC for review prior to restart. The AIT did not assess this additional information.

AIT Evaluation of PORVs, Safety Valves and Associated Pipe

The galling (or deep gouging) observed on the stem of PR-2 is of concern. The valve is designed with a clearance around the stem such that it should not touch the bonnet. With this clearance closed and with the stem dragging against the inside of the bonnet, the ability of the plug to open or close could be severely affected. Of interest, the stem damage and plug damage were both on the downstream side of the internal assembly which leads to the hypothesis that the damage could have been at least partly flow-induced.

As previously mentioned, this valve model was tested in the 1981 EPRI test program, except that different valve internals were tested. The 420 stainless steel plug and cage in the PORVs at the time of the event, is a martensitic stainless whose hardness is dependent on the heat treatment. This is a much-used alloy where wear and corrosion resistance are both important. PSE&G and Copes Vulcan indicated the valve with the 420 stainless steel internals performed well in the field in similar applications.

The AIT found the PORVs' operability to be indeterminant after the event because of the observed damage, although noting that the valves opened and closed upon command shortly before disassembly. The AIT also notes the PORVs were relied upon for low temperature overpressure protection (LTOP) following the event, but prior to disassembly, and were also relied upon as a vent. The AIT concluded that the licensee met the legal requirements for demonstrating the PORVs operable prior to reliance for LTOP purposes. However, the AIT believed that since the PORVs were operated in a condition beyond that envisioned in the FSAR (i.e. multiple actuations involving steam and water), additional evaluation was appropriate.

Salem's FSAR analyses include an allowance of 20 minutes to reset safety injection for inadvertent actuations. Westinghouse recently provided information on this topic to the licensee as required by 10 CFR 21.21(b) (Gasperini, J. R., "Inadvertent ECCS Actuation at Power," Letter to Dave Perkins, Public Service Electric and Gas Company from Westinghouse Electric Corporation, PSE-93-212, June 30, 1993.). This stated that:

> "Westinghouse has discovered that potentially non-conservative assumptions were used in the licensing analysis of the Inadvertent Operation of the ECCS at Power accident. Based on preliminary sensitivity analyses, use of revised assumptions could cause a water solid condition in less than the 10 minutes assumed for operator action time. If the PORVs were blocked, the PSRVs (safety valves) would relieve water and potentially cause the accident to degrade from a Condition II incident to Condition III incident without other incidents occurring independently. Per ANS-051.1/N 18.2-1973, a Condition II event cannot generate a more serious event of the Condition III or IV type without other incidents occurring independently."

The letter further stated that Westinghouse adopted the following criterion:

> "The pressurizer shall not become water solid as a result of this Condition II transient within the minimum time required for the operator to identify the event and terminate the source of fluid increasing the RCS inventory. Typically, a 10 minute operator action time has been assumed."

(NOTE: Chapter 15 of the Salem FSAR defines Condition II events as faults of moderate frequency including "spurious operation of the safety injection system at power;" and, Condition III events as infrequent faults including small break LOCAs.)

The AIT concluded that the Westinghouse recommended actions may need to be re-examined in light of the Salem experience. The Salem operators took about 17 minutes to terminate safety injection during the first SI and 12 minutes to terminate the injection on the second SI. The pressurizer did in fact become water solid and yet, plant operators responded appropriately to the inadvertent EECS actuations per approved EOPs.

Solid plant operation as encountered during the event is not specifically addressed in Salem's licensing basis as addressed in Chapter 15 of the Final Safety Analysis Report (FSAR). Licensing basis analyses generally do not reach solid plant conditions. For example, the applicable LOCA analyses involve two phase conditions rather than the single phase resulting from a solid RCS, and a licensing basis inadvertent safety injection does not lead to a solid RCS. Regardless, the pressure and temperature challenge to the RCS pressure boundary is generally enveloped by the composite of analyses addressed in Chapter 15 of the FSAR.

Consequently, the AIT evaluated the event with respect to challenge to the RCS pressure boundary and addressed whether the event could have logically progressed to a more serious condition. The AIT found that no RCS pressure boundary design parameters were exceeded during the event. The operators restored a pressurizer steam bubble before conducting a planned plant cooldown, thus eliminating the potential problems that may have occurred if a solid cooldown were attempted. The AIT judges that not being strictly within the licensing basis envelope is not a significant safety concern for this event.

The AIT addressed the possibility of progression to a more serious accident due to PORV or safety valve problems and concluded that multiple additional failures would have been necessary. Further, the AIT judges the most likely such accident sequence would have been a loss of coolant accident (LOCA), which is within the design basis for the plant.

3.3 Circulating and Service Water Systems

Overview

As discussed previously, the event of April 7, 1994 evolved from an initial problem of plugging of the Salem circulating water (CW) intake screens followed by CW pump automatic trips as water level difference across the intake screens reached the 10 foot trip value. Although CW is necessary for plant operation at power, it is not essential to the plant's safety. However, the vulnerability of the CW system to grass intrusions challenge continued power operation of the plant as well as challenge the plant operators and safety systems in response to the resultant transient conditions, as occurred during this event. Consequently, the AIT assessed aspects of CW operation.

In contrast to CW, service water (SW) is vital to safety - it provides the safety related ultimate heat sink. Salem CW, Salem SW, and Hope Creek SW are located in three similar intake structures along the Delaware River. This observation immediately raises the question of whether the problems that occurred with CW could also occur with SW. Consequently, the AIT assessed the potential for a loss of Salem SW in light of the problems with the Salem CW.

Hope Creek experienced a loss of one SW pump while the team was on site, and the AIT briefly assessed this event for applicability to general SW reliability, and concluded that the failure was unrelated to the events causing CW difficulties at Salem.

Findings

The AIT found that the continuing problems experienced with Salem CW present an important challenge to plant operation. This could become a safety concern because of continuing plant perturbations that cause unnecessary plant transients, distracts the operators, and potentially leads to unnecessary challenges to the operators and plant safety systems. While noting that the licensee had previously approved a long term fix by modifying the CW design, the AIT believed a short term fix was warranted, such as improving the operating procedures to respond to the resultant transients.

SW operability was found to not be a short term issue, requiring corrective actions. The licensee indicated that they have never had a SW failure due to debris and the AIT found no other evidence to the contrary, indicating that SW was not vulnerable the same initiator. The AIT suspected that the design of the circulating water structure lends itself to such vulnerability and that the service water structure design is potentially unaffected by debris. The AIT further concluded that additional NRC review of service water system vulnerability was warranted but was not within the scope of the AIT inspection.

Description of Salem and Hope Creek Water Intake Structures and Related Machinery

Salem and Hope Creek have three water intake structures positioned as shown in Fig. 3 in Attachment 7.

Salem's SW intake is about 100 yds upstream (north) of the CW intake and Hope Creek's SW intake is about 3/8 mile upstream of the Salem SW intake. Water entering each intake structure passes through a trash rack, a moving screen, a pump, and, for SW, a filter. These are shown in Figs. 4 - 6 in Attachment 7. The bottom of both SW intakes is at about the river bottom, about 30 feet below surface grade. The CW intake bottom is 50 ft. below grade and the river bottom is dredged to that depth for the width of the intake structure and for a distance of 100 ft. from shore.

CW Performance During the Event

In anticipation of additional grass intrusion events, the licensee had removed the front covers of the traveling CW screens and laid fire hoses that were used to wash accumulated grass and debris from the screens before the built-in screen washes were reached. Quick-disconnects had been provided on covers in the screen drives so that shear pins could be replaced quickly (3 to 7 minutes).

Despite the fire hoses and running the screens as fast as possible, the screen loads became so heavy during the event that shear pins were failing and screen clogging was causing a significant water level drop across the screens. One licensee representative estimated that the water level drop across the trash racks was about 1 - 1½ ft. CW pumps tripped when level reached a 10 foot differential across the screens.

There is no easily obtainable record of CW screen operation. However, CW pump operation was obtained and is summarized as follows:

> Five CW pumps were in operation during the initial part of the grass intrusion. Various pumps tripped and were restored to operation by the efforts of the personnel staged at the CW structure. Just before the reactor trip, only one pump remained, and at the time of reactor trip, two were in service.

An AIT member observed one grass intrusion during the onsite inspection. Fire hoses were being operated to clean an estimated 1 - 1½ inch thickness of debris off of the screens. Immediately after the attack, debris around the screen machines was ankle to knee deep. Licensee personnel said the debris was waist deep following the April 7 event.

SW Reliability

Licensee representatives informed the AIT that they had never seen a correlation between Salem CW debris problems and problems with SW at the Salem or Hope Creek sites. They further indicated no historical problems with loss of SW due to debris. The AIT found no instances that contradict those descriptions.

The licensee provided excerpts from its evaluation of a June 1993 turbine trip/reactor trip due to loss of CW (SERT Report 93-07). (That loss of CW event was attributed to actions of a diver cleaning a circulator trash rack.) This stated that:

> "...service water rake and screens are not challenged by debris as are the circulating water systems. As a result, service water screens operates (sic) periodically as compared with constantly for circulating water. The service water trash rake is used infrequently while the circulating water trash rack must be cleaned at least daily during heavy grassing periods.... The Service Water intake has not been subject to the same accumulation of trash and silt as the circulating water intake. For example, while the Corps of Engineers was dredging upriver in 1983, silting caused the shutdown of all circulating water pumps, but the service water intake was not affected. This difference in susceptibility to trash and silting is attributed to the location of the service water intake directly on the river front. The circulating water intake is in a diverging section of the river and the resulting drop in velocity and eddy formation is more conducive to trash and silt accumulation."

Licensee personnel also often cited the high velocity at the CW intake as a major contributor. In addition to such factors, the AIT judges that the CW high flow rate is a major factor in that it affects a much larger section of river bottom than affected by the SW systems and a 20 foot deep "pit" is dredged in front of the CW structure. Material falling into this pit is likely to be sucked into the CW intakes.

Based on this information, the AIT concluded that there was no immediate concern regarding the reliability of the service water system; however, as previously stated, this issue warrants further review by NRC as part of the planned reviews of service water systems and individual plant evaluations.

Additional Information Regarding Hope Creek SW

The Hope Creek licensee stated that no recent SW traveling screen failures have occurred due to shear pin failure. Several years ago, the screens were not routinely in operation unless there was a pressure differential across the screen. Then the screen would start at normal speed and immediately shift to high speed. Shear pin failure would often follow.

Each screen at Hope Creek is now operated whenever the respective SW pump is operating, and a shift to high speed does not cause shear pin failure. An unacceptable increase in pressure differential when the screen is operating at high speed is addressed by starting another SW pump and stopping the first pump to allow the screen to clear via normal wash while it continues to operate. According to the licensee, switching between pumps in this manner has always been sufficient to prevent a problem. The potential is still recognized in procedure HC.OP-AB.ZZ-0122 (Q), "Service Water System Malfunction," 7/9/93, which states:

> "Loss of service water can occur due to reed intrusion. The event typically occurs following marsh burns followed by heavy rains and the next high tide.... This heavy intrusion overloads the screen wash system with subsequent intrusion of the reeds into the suction of operating service water pumps. The resulting heavier than normal fiber intrusion clogs the service water pump strainers."

The inspector was told that there are relatively heavy debris "hits" roughly 3 times in the fall and 3 or 4 times in the spring in which high differential pressure alarms across the traveling screens are received in the Hope Creek control room. The response is to start a different SW pump and shut down the operating pump while the screen continues to operate. The built-in screen spray system has always been adequate to clean the screen once the flow was removed, and the problem has been handled without further complication by swapping back and forth, a capability made possible by the two trains of three pumps each.

3.4 Reactor Systems Response

The Salem Unit 1 event included aspects of potential concern with respect to the reactor fuel and the reactor coolant system (RCS). These are as follows:

1. Power and criticality control
2. Adequate margin to the departure from nucleate boiling ratio (DNBR)
3. Adequate subcooling margin (SCM)
4. Rate of change of temperature
5. Rate of change of pressure

6. Challenge to fuel cladding
7. Low temperature overpressure
8. Pre-Cooldown and Cooldown Operations
9. Post-Event Usage of the PORVs (power-operated relief valves)
10. Piping Considerations

Each is addressed as follows:

Power and criticality control

Control of power and avoidance of conditions that could lead to rapid power excursions are important to protection of the fuel cladding and the RCS pressure boundary. Although power was rapidly reduced during the April 7, 1994 event, no unusual configurations resulted and the reduction rate was small when compared to a typical transient associated with a reactor trip from full power. This aspect of the event was not a challenge to the fuel or the RCS.

The power increase rate just before the reactor trip was about normal, and actual power was small in comparison to full power. Heatup aspects of the transient were probably of little consequence since there was not a large local transient effect. For this reason, the AIT did not investigate such areas as transient temperature distribution within the fuel.

Reaching a lower temperature than permitted by Technical Specifications raises questions such as: adequate rod control to attain shutdown; and, could a positive moderator temperature coefficient have been encountered. The licensee investigated these questions and reported that shutdown margin was always significantly greater than required. The moderator temperature coefficient always remained significantly negative. These conclusions were independently verified by the AIT.

Examination of intermediate and power range nuclear instrumentation indications was performed by the licensee and no significant deviations were found between the indications and actual plant power during the power ascension transient.

The AIT concludes that no local or overall power conditions were reached that are of concern.

Adequate departure from nucleate boiling ratio (DNBR)

An adequate DNBR is necessary to assure that the fuel cladding does not become blanketed with steam, a condition that would cause a rapid cladding temperature excursion. The licensee investigated core thermal limits and the axial power distribution during the event and concluded that DNBR limits were not approached. The AIT concurs with this assessment.

Adequate subcooling margin (SCM)

Maintenance of an adequate SCM with an adequate DNBR assure that the fuel cladding remains cooled. The reactor coolant pumps (RCPs) remained running throughout the event and consequently large temperature variations did not result and the reactor vessel upper head remained cooled. The pressure/temperature behavior during the event was evaluated and the minimum SCM was determined to be 39 °F. This occurred during the pressure transient at the time of the steam generator safety relief valve(s) lift. Much of the time the SCM was > 80 °F.

Although all temperature and pressure indications substantiated that adequate SCM was always maintained, annunciator data indicated loss of SCM at approximately 12:20 p.m. during the event. The licensee investigated these alarms and reported that overhead windows D-40 and D-48, SCM low, are set to actuate at ≤ 10 °F SCM, and that post event evaluation of annunciator historical data showed the following alarms:

Item	Date	Time	Train
1	4/7/94	12:20:02 - 12:20:05	A
2	4/7/94	12:22:57 - 12:23:00	B
3	4/7/94	21:21:38 - 21:29:01	B
4	4/7/94	21:48:03 - 21:56:58	A
5	4/8/94	03:30:42 - 03:46:36	B
6	4/8/94	04:00:55 - 04:10:31	A

The licensee attributed these apparent losses of SCM to the core exit thermocouple processing system (CETPS) indication that results from pushing a train A or train B CETPS reset button or when a train of the CETPS is tested.

Each of the two CETPS trains is provided with the following inputs:

1. 29 incore thermocouple temperatures
2. RCS pressure
3. Containment radiation
4. Containment pressure

The licensee stated that the apparent losses of SCM indicated in items 1 and 2 were due to the nuclear control operator pressing the CETPS reset button. The rational is as follows. The bottom of the containment radiation scale is 1 R/hr whereas actual containment radiation is close to zero. A zero will cause an alarm. The operator will respond by acknowledging it on CETPS followed by pushing the system reset button to re-arm the containment radiation input alarm.

Depressing the reset button causes indicated SCM to go to zero, a result noted in the operator's procedure. The specification for CETPS data transmittal time provides a maximum of 4 sec, consistent with the 3 sec time observed in table items 1 and 2.

Table items 3 - 6 were attributed to performance of RCS hot leg pressure channel functional testing. Placing the channel switch in the test position causes the RCS pressure input to CETPS to be zero. The licensee stated it verified this testing as the cause by reviewing the control room narrative logs and the overhead annunciator historical data.

The AIT concurs with this explanation of the loss of SCM indications and concurs that adequate SCM was maintained throughout the event.

Rate of change of temperature

The temperature change prior to initiating the controlled cooldown was less than 100 °F and the cooldown was conducted slowly and deliberately without approaching cooldown rate limits. Rate of change of temperature was not a problem.

Rate of change of pressure

No large pressure excursions occurred that would represent a direct challenge to the RCS pressure boundary (except as noted below) or the fuel cladding.

Challenge to fuel cladding

The licensee reported that there was evidence of one or two fuel cladding defects before the event and observed an iodine spike consistent with that number of defects after the reactor trip. As discussed above, no conditions were found that could represent a challenge to the cladding during this event.

The licensee obtained a gas sample from the reactor vessel head on April 13 that consisted of about 96% nitrogen, 3% hydrogen, and minor amounts of other gases. No significant radioactive components were found. This is consistent with a conclusion of no fuel damage since no significant quantities of fission product gases were found.

The AIT concludes that there was no fuel cladding damage and no conditions existed that represented a challenge to the fuel cladding.

Low temperature overpressure

Temperature during the event never reached a value where low temperature overpressure would be a concern.

Pre-Cooldown and Cooldown Operations

The operators elected to restore the vapor space in the pressurizer after the initial solid operation in which pressure was controlled by the PORVs rather than initiating an immediate cooldown. They additionally elected to not trip the RCPs. The AIT concurs with these decisions. A choice to trip the RCPs or to attempt a solid plant cooldown could have significantly complicated the event.

The question of tripping RCPs was raised during the event. The AIT considers such questions to be part of a reasonable examination of alternative actions. In discussion with key personnel who were in the control room area during the event, it became clear that this alternative was never seriously considered for implementation.

Maintaining RCP operation during solid operation assured uniform RCS temperature, provided better temperature control, and allowed eventual entry into cooldown with a normal plant configuration. Tripping RCPs would have introduced a significant temperature variation into the RCS and would have caused average RCS temperature to increase, a particularly difficult situation since a variation of only 1 °F would change RCS pressure by about 100 psi.

Reactor coolant system pressure for several hours following the second safety injection is summarized in Fig. 2 in Attachment 7. The part of the event during which the PORVs were controlling pressure occurred from about 11:30 a.m. to 12:00 noon. Following that, the PORVs were not challenged again. The operators essentially set the letdown rate and RCS temperature, and controlled pressure by varying the charging rate with the objective of maintaining 2150 ± 50 psig. A pressurizer bubble was restored and pressurizer level reached 50% at 4:30 p.m. A normal cooldown from hot standby was initiated at 5:15 p.m. and was conducted without difficulty.

Post-Event Usage of the PORVs

The pressurizer PORVs were relied upon for low temperature overpressure protection and for venting following the event. There was no evidence of a malfunction during this usage although, as discussed in Section 3.2, significant damage was found when the PORVs were disassembled.

Piping Considerations

As discussed in Section 3.2, the AIT has little concern with piping downstream of the PORVs and safety valves. Previous analyses, tests, and the post-event examination of the piping by the licensee have shown this piping was not challenged during the event. The AIT questioned the licensee regarding the potential for damage upstream of the PORVs. The principal concern was the possibility of damage that could lead to a LOCA. This question had not been closed at the time of the AIT's exit from the facility, but was addressed by the licensee prior to requesting

restart agreement from NRC Region I. This additional information was reviewed by NRC Region I in order to lift the provisions of the CAL that was in place. Results of that review will be documented in a resident inspection report.

Pressurizer Relief Tank (PRT) Rupture Disk

During the safety injection actuations, the PRT rupture disk ruptured to relieve the increasing tank pressure, which resulted from the volume of primary coolant inventory relieved to the PRT. As a result, approximately one gallon of primary coolant was spilled onto the containment floor. Subsequent to the event, the rupture disk was replaced and the PRT inspected. The rupture disk operated as designed and no damage occurred to the PRT.

Based on the AIT assessment of the reactor systems response during the event, no protective barriers failed and no abnormal releases of radiation to the environment occurred.

3.5 Atmospheric Steam Dump Valves and Steam Generator Safety Valves

Following the plant trip and initial safety injection, the reactor coolant system temperature increased as a result of core decay heat and reactor coolant pump heat. This RCS heatup, and the corresponding increase in steam generator pressures were not recognized by the plant operators. Steam generator pressures increased above the setpoint of the steam generator safety valves because of the failure of the atmospheric steam dump valve (MS10) controllers to promptly respond. Consequently a steam generator safety valve lifted and the steam release through the valve caused a cooldown that initiated the second automatic safety injection due to an actual low pressurizer pressure condition.

The reason for the slow response of the atmospheric steam dump valve was investigated by PSE&G and reviewed by the team. The results of this review is described in Section 5 of this report. The steam generator safety valves and low pressurizer pressure safety injection initiation circuitry operated as designed.

4.0 PLANT OPERATOR PERFORMANCE & PROCEDURE ISSUES

Grass intrusions at the circulating water intake structure at Salem are a seasonal phenomenon, with more severe attacks in spring and autumn. Losses of circulating water pumps or screens affect condenser vacuum. Degradation of condenser vacuum can necessitate reducing reactor power or removing the turbine from service. The operator actions to cope with a grass intrusion are governed by procedures. In general, however, the actions taken by operators are a function of the extent and rapidity of the grass intrusion (and resultant loss of circulators and condenser vacuum), and prospects for recovery of any lost circulators.

4.1 Operator Response Prior to the Plant Trip

Preparations and Response At The Circulating Water Intake Structure

PSE&G management had undertaken extensive efforts at the intake structure to combat the circulating water grass intrusion and minimize the resultant, at least twice daily, transient. Management had assigned a shift supervisor, a maintenance supervisor, and an approximate 12 person crew at the circulating water intake structure for expected grass intrusions following diurnal tide changes. Fire hoses and shovels were pre-positioned and used to remove grass from the screens during grass intrusions. However, during heavy grass intrusions, as occurred on April 7, a high screen differential pressure rapidly develops and disables the travelling screens by sacrificial failure of the shear pins that connect the screen motor to the screen gear.

The extensive PSE&G efforts at the intake structure had generally positive results in dealing with prior grass intrusions. Management established special work control procedures to facilitate quick restoration of failed circulating water screen shear pins. The special work control procedures allowed the local shift supervisor to approve work and blocking tags during screen repair, thus bypassing normal work control oversight. Records were procedurally required to be maintained by the local shift supervisor for all work performed however, the tagouts and work control history used during the April 7 event were lost and no permanent record was made. The local shift supervisor provided direct continuous communication with both Salem control rooms.

Preparations and Response at the Turbine Hall

Two off-duty shift supervisory personnel were stationed at the water box area during grass intrusion to assist in restoration of circulators to service should trips occur. These individuals were available to assist in pump priming operations. The inspectors learned that shift supervisory personnel would, at times in the past, override the water box priming protective interlock for the circulators by manually lifting contacts. This was found to be the case during the April 7 transient when an attempt to restore the 12A circulator to service was unsuccessful. The on-duty Senior Nuclear Shift Supervisor (SNSS) manually lifted contacts, an action which is not directed in approved operating procedures. This action by an SNSS sets a poor supervisory example for other crew members. As will be described and developed below, the SNSS's presence would have likely been more beneficial in the control room. His absence from the control room was an example of inappropriate prioritization of activities by shift crew management.

In spite of the efforts in planning and guidance outside the control room to effectively respond to grass intrusions, personnel response actions at the circulating water intake structure did not fully meet plant management expectations, and an action in the turbine hall (jumpering a protective interlock) was not procedurally directed and was taken by the senior crew manager.

Preparations and Operator Response In The Control Room (Pre-trip)

Plant and crew management had made no special preparation for control room operator response to routine, expected grass intrusion into circulating water, even though the plant was operating with an important automatic control system in manual. The event revealed weaknesses in the existing procedures and training for control room response that might be required for a significant grass intrusion.

Despite twice daily grass intrusions which caused power reductions and restorations, no compensatory actions had been taken by management to ensure adequate reactor and plant control during the power swings. Automatic rod control was out of service on April 7 due to corrective maintenance. Operators had suspected that the T_{avg} - T_{ref} comparator did not work properly and rods were being manually controlled. No compensatory actions had been established to ensure manual rod control would not adversely hinder rapid power changes, apparently because management did not foresee the potential difficulties that could arise. Crew management expected the two reactor operators to coordinate the reactor transient during the grass intrusion. In particular, crew management foresaw no difficulties with one operator on control rods and boration, controlling reactor power and temperature, while monitoring pressurizer level; and the other operator performing turbine load reduction while monitoring steam generator levels, and controlling balance of plant equipment such as heater drain pumps, feedwater pumps, and circulating pumps and screens.

Review of control room logs revealed some differences between those logs and the final sequence of events which suggested some minor confusion among the crew members. The operator assigned to control the reactor was also assigned to maintain a control room log of activities. Review of the log revealed that all circulator pumps were removed from service or tripped during the event. At the time of the reactor trip, control room logs showed all pumps out of service and none returned. However, subsequent PSE&G review of circulator pump amperage, taken from computer data obtained during the event, reveal that two pumps were running at the time of the reactor trip.

The inspectors considered the alarm response procedures for low vacuum conditions to be weak because no specific turbine trip criteria were provided. Main condenser vacuum is monitored by the operators as turbine last stage back pressure. The operator's attempt to maintain back pressure as low as possible, with annunciator alarms at 25 inches of vacuum (Low alarm) and 23 inches of vacuum (Low-Low Alarm). The abnormal procedure for high backpressure (low vacuum) conditions contained no reactor trip criteria. The setpoint for the low vacuum turbine trip was not specified by the procedure and the procedure stated that the operator should restore vacuum unless a turbine trip occurred between 18 and 22 inches Hg vacuum.

At 10:34 a.m. on April 7, the 12A, and 13A and 13B circulators were out of service. The abnormal procedure for circulating water requires that loss of both 13 pumps in combination with any 12 pump out of service, requires the turbine be taken off line within one hour. It was clear to control room personnel that action was progressing to perform a normal, but rapid,

turbine shutdown until and unless the minimum number of circulators could be returned to service. The rate of turbine load reduction was an attempt by the turbine operator to maintain a minimum backpressure in the main condenser. The operators started the transient with the normal 1 percent per minute load reduction rate. Within a few minutes, an 8 percent per minute rate was used to unload the turbine. The reactor control operator was required to control reactor temperature and power while simultaneously adding boron and inserting control rods while the turbine was being unloaded.

Expectations that circulating water could be returned to service in a short period of time and prior experience in maintaining turbine operations through grass intrusions were contributing factors in the operators continued attempts to maintain turbine operations while progressing to a normal turbine shutdown. The SNSS left the control room during the transient to over-ride a circulator pump permissive interlock and restart the 12A circulator pump in an attempt to maintain condenser vacuum and prevent a turbine trip. The SNSS would normally provide direction to the NSS on when a reactor or turbine trip should be initiated. The actions of the SNSS in combination with the extensive effort undertaken by station personnel to maintain turbine operation at both the circulating water intake and in the turbine hall reflected perceived management expectations that extraordinary effort would be used to overcome grass intrusions; and when viewed in conjunction with the below-described lapses in control of reactor power and coolant temperature, indicate that attention was inappropriately diverted from the primary systems to the balance of plant.

Numerous distractions were present in the control room during the load reduction. Continuing communications with circulating water operators required numerous assessments of plant conditions and restarts or trips of circulators. In the ten minutes prior to the reactor trip, during the cooldown of the reactor; seven circulator pump trips and three restarts occurred on Unit 1. Additionally, the communications included Unit 2 activities as well as repeated circulator screen trips and restarts. During this period, the rod control operator made at least one boron addition and moved control rods nearly 150 steps into the core. At low power, a feedwater pump oscillation occurred and the BOP operator requested and received authorization to idle a feedwater pump. The rod control operator was directed to leave the rod control panel and shift normal plant electrical loads from the main generator to an offsite power source. This evolution required three to five minutes to complete.

The reactor cooled to below the minimum temperature for critical operation. The shift supervisor noted the cooldown and made a reactivity change by personally withdrawing control rods while the rod control operator was shifting normal plant electrical loads. The result of this change could not be determined by the inspectors. The rod control operator returned to the control panel. He was given a direction to raise power to restore plant temperature and began a steady control rod pull. The shift supervisor did not discuss the fact that he had manipulated the control rods with the rod control operator when he returned and his direction to raise power lacked specificity, i.e., how far or how fast to raise power. The reactor trip occurred when power reached the 25 percent power high flux trip. At the time of the reactor trip, the only licensed personnel in the control room were the shift supervisor and the two assigned control operators. Other shift supervisory personnel including an SRO, an SRO-licensed shift technical

advisor, and the SNSS were in the turbine hall attending to water box priming. The AIT concluded that these resources could have been more effectively used for ensuring reactor control and coordination of primary and secondary plant operations.

Summary

PSE&G management's preparation for control room operator response to routine, expected grass intrusion into circulating water was weak. Automatic rod control, an important system for automatic reactivity control during rapid downpower maneuvers, was considered non-functional. This posed an additional burden to the operators. Operator guidance and procedures for rapid downpower maneuvers, loss of circulators, and restoration of T_{avg} below the Technical Specifications minimum were weak or did not exist. This necessitated on-the-spot, subjective decision-making and operator response; rather than a pre-planned, thought out, operator response. The above weaknesses were manifested in poor command and control of control room activities (confusion and lack of supervision of a relatively inexperienced reactor operator) prior to the reactor trip and safety injection. When the operators' efforts were unsuccessful, the resultant plant conditions (Lo-Lo T_{avg}) combined with a long-standing equipment problem (main steam line pressure spiking on turbine trip) to cause the first safety injection. The event suggested training weaknesses associated with the above topics, as well as performance weaknesses (multiple, simultaneous reactivity changes and monitoring of reactor response) and control room supervisory weaknesses associated with supervision of operator activities and resource allocation, e.g., extra licensed operator personnel were used outside the control room for balance of plant equipment, rather than inside the control room to assist with control room activities associated with reactor control.

4.2 Operator Response Following the Plant Trip and Safety Injections

Reactor trip and first safety injection

At 10:47 a.m. on April 7, the reactor tripped on low power high flux (25%) while temperature was below P-12 (543 degrees F). The reactor trip response was as expected. However, momentary main steam flow instrument spikes while in the Low-T_{avg} condition allowed partial actuation of Safety Injection logic. While operators recognized the SI actuation occurrence, no "First Out" alarm indicated the cause. Injection equipment actuated as expected. Other equipment failed to respond as the operators expected when solid state protection system (SSPS) train B did not actuate as described in Section 3 of this report. Emergency Operating Procedures (EOPs) account for SI actuation failures by directing operators to align individual components to the SI position. Ten valves required manual repositioning during sheet 1 of EOP-TRIP-1, the applicable EOP. Operators made one minor error in that they missed one letdown isolation valve during the initial valve alignments. During this time high head safety injection was filling the pressurizer. Prior to reset of safety injection and realignment of charging and letdown, more than thirty minutes had passed, the pressurizer filled solid, and the power operated relief valves had actuated repeatedly.

Operators took approximately 5 minutes to realign valves. Four more minutes were required to complete EOP steps that included control of auxiliary feedwater and isolation of main steam isolation valves (MSIVs). The operators took about seventeen minutes (reset at 11:05 a.m.) to reset from the initial safety injection. In addition, operators needed seventeen more minutes to establish pressure control with letdown and charging.

PSE&G had recognized that safety injection train disagreements were possible occurrences and operator training included diagnosis of train disagreement conditions. However, no procedural actions were specified when train disagreement occurred. During the transient, the operators considered that train B of SSPS did not automatically actuate and took action to manually align the components as specified in the EOPs. Some discussion took place that train B should be declared inoperable due to the failure to actuate. At 11:26 a.m., train B manual actuation was used to insert a safety injection actuation signal during the solid plant cooldown, although automatic actuation occurred prior to the manual actuation. Because train A safety injection had actuated without any apparent coincident logic (as would have been indicated by the "First Out" alarm) in the control room, the operators could not be assured that either train was fully operable.

Solid Pressure Control

The condition of the solid pressurizer should have been anticipated by the operators. The pre-trip cooldown below the minimum temperature had caused a shrink of pressurizer level due to contraction of coolant. The pressurizer level control system attempted to maintain level by limiting letdown and increasing charging into the reactor. The pressurizer level had contracted to less than 17 percent and the pressurizer heaters had cutout as expected on low pressurizer level. The subsequent safety injection added inventory to the reactor coolant system. In addition, the rapid reactor heatup after the first safety injection caused a swelling of reactor coolant making the pressurizer solid. Apparently, none of the operators had predicted the result of the operating sequence although all were trained to do so.

Following the initial safety injection, as they had been trained, the reactor control operator assumed the responsibility for stating the required initial actions of the EOPs. The BOP operator conducted the initial actions as read by the reactor operator. The initial actions were completed in approximately five minutes. Because he was involved in the numerous manual valve alignments needed in this event, the secondary plant operator did not adequately monitor and maintain a stable steam generator pressure, and the automatic feature (steam generator atmospheric steam dumps or MS10's) used to control RCS temperature did not function because of the characteristics of the controller. Section 5 of this report describes this characteristic. Also, the operators not recovering the use of that feature led to the lifting of the steam generator code safety valve.

The operators did not anticipate the effect of the lifted steam generator code safety valve on the solid plant pressure and no attempt was made to control pressure prior to the rapid pressure decrease that led to automatic and manual actuations of the safety injection system.

Although the command and control function during EOP-TRIP-1 was as practiced, the operators neither diagnosed that the post-SI sequence would result in a solid pressurizer nor developed an adequate plan of action for control of solid plant pressure when realized. The secondary plant operator did not establish adequate heat removal using the atmospheric steam dumps.

Second Safety Injection and Continued Solid Plant Pressure Control

After a steam generator code safety lifted, cooldown of the solid plant caused a second, automatic safety injection on low pressure. The operators initiated a manual safety injection about the time when RCS pressure reached the SI setpoint. The second safety injection caused numerous PORV actuations. The PRT rupture disc failed as would be expected during this time.

The rapid pressure reduction was not anticipated by the operators. The operators did not have clear guidance on solid plant pressure control. They did not consider that establishing a bubble in the pressurizer was within the scope of the EOPs. The yellow path for high pressurizer level was not recognized nor used as guidance in drawing a bubble. Although in the Westinghouse system of EOPs, a yellow path represents and optional approach to the event, the licensee did not provide for procedurally-controlled alternatives to it. Thus, the AIT's view is that the correct path would have been identification of coolant inventory yellow path, then use procedure, Functional Recovery Coolant Inventory (FRCI-1) to establish a bubble.

Restoration of Normal Plant Pressure Control

Stable plant conditions were established prior to starting the pressurizer heatup. EOP guidance was adequate in maintaining plant control and although there were numerous technical discussions and distractions in the control room during and subsequent to the safety injections, the operators controlled the plant to a safe endpoint. Event declarations were in accordance with station procedures.

The operators reset the second SI at 11:41 a.m. Operators were controlling RCS temperature by manual control of the MS10s. Earlier, during the response to the opening of the steam generator code safety valve(s), the operators experienced difficulty with the controls for 11MS10 and, as a result, maintained this valve in a manual and closed condition. About an hour after reset, at 12:54 p.m., the 11MS10 opened to about 50% open position, but was immediately closed with no noticeable cooldown. The plant pressure and temperature were then maintained using the other three MS10s with no further difficulties.

Following reset of the second safety injection and establishment of solid plant pressure control using charging and letdown, the operators determined that the action statement of Technical Specification 3.5.2, which required two operable ECCS injection systems (or cooldown to below 350°F within six hours) could not be met. By design, the automatic ECCS actuation capability was not available following the safety injection actuation and would not be re-instated unless reactor trip breakers were cycled after the safety injection was reset. Salem procedures did not include a provision of restoring the automatic functions of the safety injection system from these

conditions. In addition, the operators were not sure if either protection trains were operable based on performance during the preceding events. Since Salem operators had no procedural guidance for re-establishing automatic safety injection capability, and since it was not clear that the automatic logic was operable, and due to the estimated six hours required to re-establish a pressurizer steam bubble, the operators could not complete a reactor cooldown in the time required by the Technical Specification. PSE&G management considered the use of 10 CFR 50.54(x) while the EOPs were in effect. However, later, after restoring normal pressure control and completing the EOPs, PSE&G requested and was granted enforcement discretion by the NRC for the additional time necessary to allow a reactor cooldown in a controlled manner, in accordance with normal cooldown procedures without automatic safety injection capability.

Event Declarations

Declaration of the Notification of the Unusual Event was timely and in accordance with Salem Emergency Action Levels. The decision of the emergency coordinator to declare an Alert to obtain technical assistance when EOPs did not provide clear guidance was prudent.

Summary

Operator response to the reactor trip and safety injection was per the emergency operating procedures. Operators maintained adequate sub-cooling margin throughout the event. Operator control of engineered safeguards equipment was appropriate throughout the event. The post-trip phase of the event revealed weaknesses in operator knowledge, performance, and procedural guidance for: solid plant pressure control; use of functional recovery procedure "yellow paths;" handling of SI train disagreements; and, control of MS10 controllers.

4.3 Procedure Adequacy and Use

Prior to the Reactor Trip

Prior to the reactor trip, direction to the operators for clogging and loss of the circulating water system was provided by procedure, S1-OP-AB.CW-0001(Q), Circulating Water System Malfunction. This procedure directed reduction of load and removal of the turbine from service when a minimum combination of three circulators was not met. The power reduction was conducted using the direction provided by procedure, S1.OP-IO.ZZ-0004(Q), Power Operation. Neither procedure provided management expectations as to when operators should cease the effort to maintain plant operations and instead, stabilize plant conditions by either turbine or reactor trip. As a result of the lack of guidance, operators went to an atypical rate of power reduction (8 percent per minute) in an attempt to maintain main condenser and turbine operation.

The inspectors did not identify procedural expectations for operator action if the plant temperature is not controlled above the minimum temperature for critical operations, except that Technical Specifications require recovery within 15 minutes.

The team identified that the Senior Nuclear Shift Supervisor, instead of directing control room activities during the transient, ignored operations directives for equipment control and manually defeated a circulator start interlock located in the turbine building while attempting to ensure continued plant operation.

Following Reactor Trip

At the time of reactor trip, operators correctly implemented procedure, 1-EOP-TRIP-1, Reactor Trip or Safety Injection. The EOP directs that components not aligned by the automatic actuation be individually aligned to the safety injection position. Manual actuation of safety injection is directed if safety injection is required but not indicated on the control panel indication. In this case, actuation was indicated, but not required, hence no manual actuation was inserted. It was not clear to the AIT, that the operators could specifically associate the failure of the large number of components to respond to the safety injection actuation with a failure of SSPS train B logic. The team noted that no guidance had been provided to the operators on proper response to ECCS train disagreement, which was identified to the operators during the transient by flashing lights on status panel RP-4, on the main control board.

The operators correctly transitioned to procedure, 1-EOP-TRIP-3, Safety Injection Termination, when appropriate plant conditions were established. Following the initial trip and safety injection, operators attempted to establish stable plant conditions but were unable due to the steam generator safety valve actuation and cooldown that resulted in a second safety injection. Quasi-stable conditions were established upon recovery and re-entry into procedure, 1-EOP-TRIP-3, following the second safety injection. At this time, the plant was in solid plant pressure control. Specific control guidance for solid plant control is not provided by the SI termination procedure.

Guidance for re-establishing pressure control with a steam space in the pressurizer was available to the operators by Critical Safety Function; Coolant Inventory Status Tree, yellow path directive, 1-EOP-FRCI-1, Response to High Pressurizer Level. However, this option was not used. Instead, the operators continued through 1-EOP-TRIP-3, and with technical support from the Salem Technical Support Center, re-established the steam space in the pressurizer outside of direct EOP guidance.

As mentioned previously, given the resultant conditions of the transient, and absent procedural guidance to restore the automatic safety injection capability from those conditions, operators could not achieve the shutdown requirements of the plant technical specifications within the time allowed. A Notice of Enforcement Discretion was issued by the NRC to allow the operators to proceed with a normal cooldown.

4.4 Event Classification & Notifications

Event Classifications and Notifications were per procedure. The Alert declaration was particularly prudent, given that the operators felt they wanted or needed additional resources. During the initial notification of the Unusual Event, NRC expectations were not met regarding the level of detail of the telephone reports to the NRC and the ability to discuss the event and answer questions that would enable the NRC to quickly assess the event to determine the appropriate NRC response posture. The initial notification to the NRC did not convey to the NRC information that complications were associated with the event. It was determined that the licensee's Emergency Plan and Event Classification Guide required the licensee's communicator to fill in a data sheet (NRC Data Sheet - Attachment 8 of the ECG) that, if properly completed, would have given the NRC sufficient detail within the required notification time. These problems with level of detail and knowledge of the event were due to the physical location and the pre-event activities of the communicator, combined with the limited background and experience level, in general, of communicators at Salem; and, an apparent lack of oversight by the senior nuclear shift supervisor in approving the information developed for transmission to the NRC.

4.5 Simulator Demonstration

On April 12, 1994, the Salem training department provided a demonstration of the event of April 7, 1994 to AIT team members. The demonstration included an explanation of plant response, indications available to the operators, associated emergency operator procedures, and a walkthrough of the EOP actions. The demonstration provided the inspectors with a good understanding of the event dynamics, man-machine interface, and relevant procedures. The demonstration was valuable in fostering the team's understanding of the event and expected operator response. The team acknowledges the cooperation of site management and the Salem training department in facilitating the simulator demonstration.

4.6 Reactor Vessel Level Indication System (RVLIS) Monitoring

On April 12, 1994, the NRC Senior Resident Inspector noted that the RVLIS indications in the control room were at 93% (indicating that the reactor vessel was not completely full of water) and questioned the operators about the indications. The SRI was told that operators at Salem are not required to monitor RVLIS indications while in cold shutdown. The team reviewed training material associated with RVLIS. This training material indicates that RVLIS provides accurate indication while in cold shutdown.

Assessment of the Gas Bubble in the Reactor Vessel Upper Head

The Salem RVLIS indications are readily visible on a back panel from the normal operator station at the control board. Further, the indication can be displayed on a control board monitor, although, this was not in use when discovered by the SRI. The Senior Resident Inspector

discovered that each of the two RVLIS readings were showing ~ 93% on April 12, 1994. When this was identified to the operators, they were not aware of the indication and initially judged the instrumentation to be incorrect.

As a result, the AIT was concerned with the effectiveness of operator training on this system. In this case, RVLIS was specifically installed to provide an independent indication of water level for events initiating from power operation. A full understanding of shutdown operation would instill the insight that RVLIS is important to shutdown operation as well. Apparently, the licensee did not expect that a gas bubble would form during its shutdown operating conditions.

Ultimately, after much discussion with the NRC, the licensee took the following actions:

a. A sample of the gas bubble was drawn in a careful, well planned manner.

b. Operating plans were changed to avoid plant perturbations until the gas bubble and its implications were understood. For example, the licensee typically switches residual heat removal (RHR) pumps from time to time to equalize use. A planned switch was postponed because the licensee had not yet investigated whether gas bubbles existed at other locations that could impact RHR system operation if the switch were made.

c. An investigation was initiated to identify the source of the bubble. The investigation showed that the reactor coolant system (RCS) letdown, volume control tank (VCT) conditions, and charging were consistent with generating a bubble in the reactor vessel by introducing nitrogen from the VCT via the charging system. (NOTE: During shutdown operations a nitrogen "blanket" is maintained in the VCT to ensure proper pressure for the charging system and minimize the amount of oxygen in the system.)

The AIT judged that the gas bubble was too small to be of immediate safety concern although it would have been a concern if significantly larger. Importantly though, the AIT concluded that the bubble was slowly increasing when discovered. For the bubble to potentially perturb RCS cooling during normal RHR operation, it would have to expand into the hot leg. The most likely expansion process would result in draining all steam generator (SG) tubes, perhaps followed by lowering the pressurizer level, before a loss of RHR would occur due to vortexing at the RHR inlet. Loss of RHR due to the bubble was judged very unlikely based upon the bubble volume and pressure at the time it was discovered.

In addition to being concerned about the apparent lack of operator awareness about the formation of the gas bubble, the AIT was also concerned, however unlikely based on other indicators, whether the gas bubble could have been an indication of fuel damage. The licensee reported an iodine spike following the reactor trip that was expected from its knowledge that one or two fuel pins were leaking. No indications of fuel damage due to the event were evident at the time of discovery of the bubble, nor were any found at any time by the AIT. The licensee obtained a gas sample at approximately 5:30 p.m. on April 13. Analysis showed it to consist of about 96% nitrogen, 3% hydrogen, and minor amounts of other gases. No significant radioactive

components were found. The analysis was as expected for a gas bubble at that location due to nitrogen being introduced from the VCT. The sample was consistent with a conclusion of no fuel damage since no significant quantities of fission product gases were found.

Based on the system operations since the plant shutdown and the evidence gathered through the licensee's sample analysis, the AIT determined that the most likely cause of the bubble is gas transport from the VCT. The composition of the gas sample is consistent with an origin in the VCT. Shortly after discovery of the bubble, the VCT pressure was 38 psig at a temperature of 64 °F, in contrast to essentially atmospheric pressure in the pressurizer gas space (and a higher pressure in the hot leg due to the head of water in the pressurizer) and an RCS temperature of 170 °F. Conditions existed for absorbing nitrogen in the VCT and releasing it in the RCS. Licensee calculations confirmed the plausibility of this behavior. The licensee reduced VCT pressure to 15 psig during the evening of April 12 to reduce gas transport into the RCS.

4.7 Operations Conclusions

The event revealed a number of weaknesses in plant systems, procedures, operator actions and management controls that are normally maintained to assure plant safety:

- Extensive response efforts had been established by plant and crew management for rapid response to grass intrusions, including placing maintenance and operations supervisors in the circulating water structure during periods when grass intrusions occurred, streamlining of work controls including use of on-the-spot tagouts and elimination of individual component work orders, and the use of direct, continual communications between an SRO at the circulating water structure and the control room. However, even the streamlined work controls were not fully adhered to during the April 7 event. Also, CW equipment control was still maintained by the control room operators without assistance, even though the resultant transient conditions were expected.

- The control room operators had not been provided adequate guidance on management expectations for control room activities during grass intrusions. During the rapid power reductions that had become almost routine, circulating water screens, circulating water pumps, main turbine load, steam plant equipment controls, and reactor controls required quick, on-the-spot manipulations to meet all of the guidelines for power reduction. The lack of management guidance was aggravated when rod control was placed in manual instead of the normal automatic condition, requiring direct reactor control and oversight as power was reduced. In spite of the daily power reductions and escalations, and the inoperable automatic feature of rod control, management had not provided additional measures to ensure that the control room operators could successfully respond to a rapid transient condition.

- Pre-trip command and control of operator activities were weak as evidenced by: a poorly controlled rapid downpower with multiple reactivity changes; vague directions from the NSS to the reactor controls operator to "pull rods" to restore T_{avg} above minimum temperature for criticality; an excessive rod pull; an operator being directed to leave the reactor controls console to transfer electrical loads while reactivity was not stable; and, the fact that supervisors did not obtain additional operator(s) in anticipation of the

transient to compensate for having rod control in manual. Additionally, the on-duty Senior Nuclear Shift Supervisor (SNSS) was outside the control room, manually defeating a circulating water protective permissive interlock, when his presence in the control room would have better served nuclear safety.

- The operators had not been provided direction on actions required for operation with reactor temperature below the minimum temperature for critical operations.

- Although the number of CW pumps and screens was below the minimum required for turbine operations, operations efforts were directed toward plant recovery without a trip. This unsuccessful effort resulted in the conditions leading to the safety injections and subsequent loss of the pressurizer steam space.

Post-trip operator performance and command and control were generally good, and in accordance with applicable procedures, although some weaknesses were noted.

- Operators implemented and appropriately followed EOP TRIP-1 and EOP-TRIP-3; with one minor exception, i.e., one letdown isolation valve was missed during the initial valve alignments.

- The MS10 controller characteristics inhibited the control of atmospheric steam dumps. Ineffective direction had been provided to the operators to ensure adequate control of plant temperature following reactor trips without condenser bypass capability. While training included discussion and simulator modeling of the MS10 control problems, the condition remained uncorrected for years. The inability to control the atmospheric dump valves contributed to a steam generator safety valve lifting and the second safety injection during solid plant pressure control.

- The operators had not anticipated that the cooldown and subsequent heatup would fill the pressurizer. No diagnosis of the effect of the open safety valve on the solid plant had been made by the operators until pressure rapidly fell.

- Use and knowledge of functional recovery procedure "yellow paths" was weak. In particular, the availability and applicability of a yellow path to establish a pressurizer bubble was not known by to the operators.

- The operators had not been provided sufficient direction regarding safety injection train logic disagreement, to minimize the recovery actions and possible avoidance of loss of the pressurizer steam space.

- Event Classifications and Notifications were per procedure. The Alert declaration was particularly prudent, given that the operators felt they needed additional resources. NRC

expectations were not met regarding the description of the event with the complications that occurred. Emergency Plan procedures for developing necessary information to be transmitted to the NRC were not fully implemented.

- Operators knowledge and use of RVLIS during cold shutdown conditions was weak.

5.0 EVALUATION OF TROUBLESHOOTING ACTIVITIES

The AIT reviewed the licensee's troubleshooting plans to ensure that the causes of the unexpected plant equipment response would be determined. Also, the review ensured that the cause of any identified malfunction would be corrected. The AIT observed portions of the troubleshooting activities to verify that the activities were appropriately accomplished.

Solid State Protection System

Following the safety injection on April 7, 1994, PSE&G personnel performed extensive testing of the SSPS to determine the root cause of the event and to determine if the system performed as designed. These efforts included visual inspections, performance of established surveillance tests and event specific tests and troubleshooting. These activities included the following:

- A visual inspection of the SSPS components, including the high steam line flow input relays was performed. Discoloration of the relay cases was noted and some relays had a powdery residue on the bottom of the case.

- The response times of the high steam line flow input relays were tested to determine the time from actuating the bistable to input relay contact closure. All relays operated and the drop out times varied from 4.2 to 14.8 milliseconds.

- Surveillance tests S1.IC-ST.SSP-0008(Q)(0009Q), "Solid State Protection System Train A(B) Functional Test," were performed. The test results for both trains were satisfactory.

- Portions of surveillance test S1.OP-ST.SSP-0009(Q), "Engineered Safety Features SSPS Slave Relay Test Train 'A'," were performed to test the operation of slave relays K616 and K621. These relays control the closing of the MSIVs, the feedwater isolation valves and the tripping of the steam generator feed pump turbines and the main turbine. All relay tests were satisfactory. Continuity checks of the release coils for the MSIV control auxiliary relays were also found to be satisfactory.

- Surveillance test S1.IC-TR.SSP-0004(Q), "Response Time of SSPS Logic - Safety Injection Train B," was performed with satisfactory results.

- "Mini SI Test" was developed and performed on each of the SSPS trains to determine how long a safety injection signal must be present to cause the MSIV close circuit latching relays to energize. For this test, one main steam line high flow instrument was placed in a trip condition and a pulse generator was connected to the input of a second. The plant was in a cold shutdown condition resulting in all of the low T_{avg} instruments being in the tripped condition. With these conditions, a pulse signal input to the second high steam line flow instrument completed the trip logic necessary to generate a MSIV isolation and SI protective signal.

  The results of these tests determined that all of the latching relays operated as designed. However, this testing demonstrated that consistent, predictable behavior could not be achieved unless the input signal lasted longer than about 50 milliseconds. Furthermore, the as found condition of the relays associated with Train A actuated faster than those associated with Train B; and therefore, a shorter input pulse duration on Train A would effect valve closure.

- A similar time response test to that for the MSIVs was performed to determine if the feedwater isolation signal would close the four feedwater isolation valves and trip the main feedwater pump turbines. This testing also showed that the equipment actuation was dependent on the duration of the input signal. All components operated as designed.

PSE&G decided to replace the high steam flow input relays based on the results of their visual inspection. A difference in response times of the two trains could also have been caused by differences in the input relay performance. Following the relay replacements, the "Mini SI Test" was reperformed for Train B. The results of this testing determined that the response time for the MSIV closing relays had decreased and the overall response times more closely approximated those for Train A.

Atmospheric Steam Dump Valve Controls

The design function of the air-operated atmospheric dump valves (ADV) is to remove heat from the reactor plant when the main condenser is not available, and to prevent operation of the main steam safety valves (MSSVs) during operating transients. The main steam system pressure is normally approximately 1005 psig at zero power and decreases to approximately 850 psig at full power. The ADV controllers are set to open the valves at 1035 psig (whereas the MSSVs open at 1060 psig). This setting results in a demand signal (actual steam pressure vs. "open" setpoint) that maintains the ADVs closed and charges capacitors in the ADV controllers. When steam pressure rises above the controller setpoint, the capacitors must discharge before the controller can begin providing signals to open the ADV. However, due to the actual pressure being below the controller setpoint for an extended period of time (850 psig vs 1035 psig), the controller output saturates low (a phenomenon called reset wind up) and causes a delay in opening the ADV. Switching the ADV controller to manual will bring it out of saturation in a few seconds.

However, the specific time period required for the controller to be in the manual mode to discharge the internal capacitor, removing the reset wind up, is not known.
The team noted that the operators were trained to use the manual operating mode, however, the emergency operating procedures did not address the use of the manual mode.

The response of the controllers during the testing with a simulated ramp input pressure showed that the ADVs may begin to open before the pressure reaches the MSSV setpoints, but they may not limit the pressure increase to prevent opening the MSSVs.

To minimize the delay in the ADV controller response, PSE&G has installed a clamping circuit to decrease the full power setpoint from 1035 psi to 1015 psi and decreased the controller gain from 12 to 3 and the reset time from 180 seconds to 2 seconds. These changes should improve the response time of the ADV controllers to prevent a rapidly increasing steam pressure from unnecessarily opening the MSSVs.

The reset windup problem associated with atmospheric steam dumps was the result of a plant controls modification implemented in the late 1970's to prevent an inadvertent opening of the valves. The AIT found that PSE&G had recognized this problem for many years, and had intended to address it during a planned design change to the feedwater control system.

Licensee troubleshooting efforts also determined that the problem that occurred with 11MS10 on April 7, was due to a bad servo in the controls, which was then replaced.

Rod Control System

The team reviewed the following two issues related to the rod control system operation: first, why the rod control system was being operated in the manual mode prior to the event; and second, whether the rod control system responded appropriately when it was momentarily switched to automatic control during the event. To address these questions, the team reviewed the following:

- maintenance history of the rod control system prior to the event;
- operation of the rod control system during the event; and
- troubleshooting and testing of the rod control system after the event.

The team reviewed the recent maintenance history of the rod control system to determine why it was in manual control at the time of the event. This review indicated that troubleshooting of the rod control system had begun on February 25, 1994, to investigate three separate instances of unexpected control rod insertion while the system was in automatic control. The results of initial troubleshooting identified multiple grounds within the T_{ave}/T_{ref} recorder, which were corrected. However, on March 14, 1994, the rods again experienced unexpected control rod insertion. Troubleshooting the same day identified noise at the T_{ref} input from isolator

1TM505A. Noise was also identified on the T_{ave} input from isolator 1TM412N. Subsequently, both isolators were replaced and the noise was eliminated. After isolator 1TM412N was replaced, it was found to be drifting. The isolator was recalibrated and PSE&G continued to monitor it to determine if the drift was a problem.

At the onset of the April 7, 1994 event, the rod control system was being operated in the manual mode. During the rapid load reduction the operator switched rod control to automatic with the NSS' approval. The rod speed indicated seven steps per minute and the rods stepped in approximately two steps then stopped. The operator observed the T_{ave} recorder and noticed a five degree temperature error between T_{ave} and T_{ref}, and determined that rod speed should be 72 steps per minute. Therefore, the operator thought that automatic rod control had not responded appropriately and switched back to manual control.

PSE&G performed the troubleshooting to determine whether the rod control system responded appropriately in automatic during the event. This troubleshooting included the satisfactory performance of procedure, SI.IC-CC.RCS-001 (Q), "Rod Control System Automatic Speed Verification," that verified proper rod control system operation at 6 and 72 steps per minute. The rod speed and direction demand are based on a compensated temperature error signal. Temperature error is defined as the difference between T_{ref} and T_{ave} and is compensated by a power mismatch signal. The magnitude of the compensation signal is dependent on the power mismatch between main turbine power and reactor power. Additional troubleshooting was performed to verify the proper operation of the rod control system by varying one input parameter while maintaining the other input parameters constant. The results of these tests indicated proper operation of rod control in the automatic mode.

PSE&G also performed a dynamic test to verify proper operation of automatic rod control. This test established initial conditions where nuclear power, turbine power and T_{ref} were set at 10%, while T_{ave} was set at negative five degree error. Nuclear power was then ramped from 10% to 25% over a one-minute time interval. This test also indicated proper operation of automatic rod control.

PSE&G performed other troubleshooting to confirm that the problems identified prior to the event were adequately resolved. These tests included a verification that the system grounds were removed and that the isolator drift was within specification. Additionally, PSE&G concluded that the T_{ave} recorder should not be used as an indicator of required rod speed during power changes and intended to communicate this to the licensed operators and reinforce it in operator training.

Intermediate Range (IR) Nuclear Instrumentation System (NIS)

In addition to other functions, the IR instrumentation channels provide reactor trip capability and block both automatic and manual withdrawal of control rods (rod block) at 25% reactor thermal power (RTP) and 20% RTP, respectively.

This trip, which provides protection during reactor startup, can be manually bypassed if two-out-of-four power range channels are above approximately 10% of full power. During the event, the reactor tripped at 25% RTP by the power range (PR) NIS low setpoint when the reactor power increased from 7% RTP to 25% RTP under manual control of the control rods. During this power escalation, the IR instrumentation channels 1-out-of-2 logic did not provide either the rod block or the reactor trip functions. It was determined that the IR instruments were indicating a lower power than the PR instruments and never exceeded the IR rod block or reactor trip setpoints.

The licensee stated that the IR rod block and trip function are for startup protection; but, the PR startup trip is used in the safety analysis (and the IR functions are not credited). The licensee's investigation found that the difference between the PR and IR instrument's indicated power was due to the different locations of these two detectors around the core. The IR detectors are in the middle-upper region of the core and thus experience more neutron shielding from the control rods in the core (rod shadowing) than the PR detectors. The PR detectors are located at the upper and lower regions of the core and are, therefore, less affected by the rod positions. For a given reactor power and control rod position, this phenomenon may result in a higher power indication on PR instrumentation channels than on the IR instrumentation channels, as was observed during this event. PSE&G determined that rod shadowing due to the control bank "D" rod position (operator pulled 35 steps, from step 55 to step 90 on control bank D) was responsible for the failure of the IR NIS to provide rod blocks at 20% RTP and reactor trip at 25% RTP. Westinghouse study of this phenomena found that detector IN35 would not initiate signals for rod block and reactor trip until the RTP was 28.1% and 35.1% respectively, while its redundant detector IN36 would not initiate those signals until 25.3% RTP and 31.6% RTP respectively. This translates into a maximum error of 10.1% RTP on IN35 and 6.6% of RTP on IN36.

The existing setpoints of the IR instrumentation channels are based on WCAP-12103, "Westinghouse Setpoint Methodology for Protection Systems, Salem Units 1 & 2." In this analysis the assumed "setpoint uncertainties" used percent span accuracies for various Rack Parameters (RP) and Process Measurement (PM) that were consistent with the standard Westinghouse methodology. This analysis used a combined uncertainty value in terms of percentage RTP for all PM components which contained allowances for power calorimetric, down-comer temperature, radial power redistribution and rod shadowing. A subsequent Westinghouse analysis WCAP-13549 "Setpoint Uncertainties for IR NIS of Salem Units 1&2" separated the rod shadowing from the rest of the PM components and performed calculations to determine the maximum value for rod shadowing that would preserve the total allowance. Total allowance is the difference between the Safety Analysis Limit and the nominal trip setpoint assuming all uncertainties at their maximum values. The new calculation used an uncertainty of 1.8% RTP for rack drift which resulted in an increment of rod shadowing effect from 6.25% RTP to 11.87% RTP. This value is found to encompass the observed error in the setpoint of the IR NIS channels due to the rod shadowing phenomenon (10.1% RTP on IN35 and 6.6%

RTP on IN36) as long as the actual as-found IR NIS Rack Drift is less than 1.8% RTP. The post-incident as-found setpoints of both IN35 and IN36 instrument channels were found to be within this assumed Rack Drift value.

The team observed that the rod shadowing effect was used in the standard Westinghouse instrument setpoint methodology and may have been reevaluated in the plant specific analyses (e.g WCAP-13549) for other Westinghouse Nuclear Power Plants.

High Steam Flow Setpoint Change Circuitry

PSE&G performed testing to determine if the automatic change in the high steam flow setpoint following a reactor trip (P-4) was inducing electrical noise that may have caused momentary high steam low signals.

The results of this test indicated that summator 1PM505B dropped its setpoint slightly below the expected setpoint for a period of time following the reactor trip, while summator 1PM506B responded as expected by going directly to the new setpoint. PSE&G ruled this out as a possible cause of the event since high steam flows were received on both channels and this would require that both summators exhibit the same setpoint drop.

PSE&G continued troubleshooting the high steam flow setpoint circuit to identify the cause of the summator 1PM505B setpoint dropping below the expected setpoint. Initially, PSE&G thought that the summator had failed, however, a replacement module yielded the same test results. Further investigation by PSE&G revealed that both the replacement module and the module that was installed at the time of the event were not the proper module. This module and the one used to replace it during the current troubleshooting were of the proper part number, but did not contain the "special" designation specified by the vendor. This "special" designation was used to identify the incorporation of a capacitor in the summator circuit. Upon determining that the wrong module was installed, the licensee installed the proper module. The test was performed again, and the same results occurred. At the conclusion of this inspection, PSE&G was continuing to investigate the reason for the high steam flow setpoint dropping below the expected setpoint following a reactor trip and how the incorrect module was installed in 1989. The AIT concluded that neither of these two concerns contributed directly to the April 7, 1994 event; but, that the second issue was a potential loss of configuration control.

Conclusion

The AIT closely monitored the licensee's troubleshooting and testing activities. The team found that the planning, control and performance of troubleshooting activities were very good and resulted in the thorough validation of the root causes for the unexpected equipment responses. The results indicated that the plant responded as designed for the conditions present on April 7, 1994. Also, some equipment performed poorly, as a result of pre-existing vulnerabilities or deficiencies such as the CW screen wash system, the high steam flow relays and the MS10 controllers. As described in Section 3.2, the licensee was initially prepared to

accept the pressurizer PORVs without a visual examination of the valve internals. While this activity was noted as weak by the AIT, this was not indicative of the licensee's generally very good troubleshooting efforts.

6.0 OTHER FINDINGS

Condenser Vacuum Alarms and Associated Procedures

The team reviewed the alarm printouts and the SPDS printout of the condenser vacuum values for the April 7, 1994 event. This review revealed the following:

- The vacuum sensed on the west side of the condenser was consistently 2" - 3" Hg lower than that of the east side as recorded by the SPDS;
- The vacuum sensed on the west side of the condenser dropped below 23" Hg at 10:40 a.m. and remained below 23" Hg for approximately three minutes, with the lowest value being 21.67" Hg for over one minute during that time; and
- The condenser vacuum low-low alarm came in at 11:23 a.m., while the condenser vacuum low alarm did not come in during the event.

The condenser vacuum sensed on both the east and west sides of the condenser are used to provide indication. Additionally, the condenser vacuum sensed on the east side is used to provide alarm functions. These alarm functions are a condenser vacuum low alarm with a setpoint of 25" Hg, and a condenser vacuum low-low alarm with a setpoint of 23" Hg. Discussions with PSE&G staff revealed that the condenser is a single-pass condenser, with the circulating water entering on the east side. This design explains the variations between the sensed vacuum for the east and west side.

The team reviewed the alarm response procedure for the condenser vacuum low-low alarm. This procedure described the alarm setpoint, the cause, automatic actions associated with the alarm and operator actions required in response to the alarm. The automatic actions described in the procedure were a turbine trip and reactor trip if power is greater than 49%, and just a turbine trip if power is less than 49%. The team determined this statement is incorrect since the device that trips the turbine is a mechanical device not related to the device actuating the alarm. Additionally, review of the last calibration of the turbine trip device indicated that it was set within its specified range of 18" - 22" Hg, at 18.4" Hg, and would not have actuated at the same time as the alarm. To address this issue PSE&G developed a procedure revision request to revise the alarm response procedure so that it properly reflects that the turbine trip is not an automatic function associated with the condenser vacuum low-low alarm.

SSPS Conformance with IEEE-279

Code of Federal Regulations in 10 CFR 50.55a(h) requires the nuclear power plant protection system to meet the requirements of IEEE Standard 279, "Criteria for Protection Systems for Nuclear Power Generating Stations." As a result of the equipment responses experienced during this event the team reviewed the SSPS design relative to two sections of IEEE-279.

Section 4.16 of IEEE-279, "Completion of Protective Action Once it is Initiated," states that the protection system shall be so designed that, once initiated, a protective action at the system level shall go to completion and return to operation shall require subsequent deliberate operator action.

Section 4.12, "Operating Bypass," which states that where operating requirements necessitate automatic or manual bypass of a protective function, the design shall be such that the bypass will be removed automatically whenever permissive conditions are not met.

The team found that there were latching relays or seal-in features in all of the component control circuitry such that if there were actual conditions requiring an MSIV isolation and safety injection, all actions are designed to go to completion. Also, the team determined that the manual bypass of SI (Auto SI block following reset) in response to an EOP step is not an operating bypass. The blocking of automatic SI following a system reset, permits the operators to take manual control of equipment as necessary to recover from a plant transient or accident. The period of time that the auto SI may be blocked is controlled by plant Technical Specifications.

The team concluded that the SSPS at Salem was in compliance with IEEE-279.

SSPS Modification History

The team reviewed the modification history associated with the SSPS, including changes to the steam flow transmitters. It was determined that the changes made to the system did not have any effect on the April 7, 1994, event. Additionally, the team also reviewed the design specification for the SSPS, and found no specification related to the minimum pulse length required for actuation of the SSPS/ESF systems.

Input Relay Chatter

The team found that the main steam line flow indications have experienced drifting during the operating cycle. The drifting resulted in the instrumentation output reaching the high steam line flow trip setpoint and caused momentary drop out and pick up ("chattering") of the associated input relays. To eliminate the relay chatter the flow instrumentation was periodically recalibrated. As discussed in Section 5 of this report, a visual inspection of the relays indicated some discoloration of the relay cases and the evidence of a powdery residue in the cases. The input relays were subsequently replaced. The response time of the Train B of the SSPS appeared to improve following the installation of new relays, however the team could not

determine if the relays had been degraded by the chattering. The cause of the instrumentation drift had not been identified prior to completing the AIT inspection. The AIT judged that the relay chattering did not play a key role in this event and should be reviewed by NRC as part of routine inspection. NRC inspection in this area was continuing after the AIT effort, as part of the NRC Region I effort to review and assess licensee actions prior to restart. This effort will be documented in a future inspection report.

7.0 SAFETY SIGNIFICANCE AND AIT CONCLUSIONS

7.1 Safety Significance

The AIT found that the event was not a significant threat to the reactor fuel, the fuel cladding or the containment. The RCS pressure boundary was maintained within its design throughout the event; however, the pressurizer PORVs and piping upstream of the PORVs were challenged by frequent cycling of the valves to maintain RCS pressure.

The PORVs functioned as designed to prevent an RCS overpressure although they were damaged in the process. This damage did not appear to affect PORV functionality during or following the event. The licensee did not complete evaluation of piping upstream of the PORVs prior to the AIT exiting the site, and consequently the AIT was unable to complete its assessment of that piping.

The PRT rupture disk relieved to containment as designed during the event. The amount of coolant released to containment was minimal and readily cleaned up following the event. The containment pressure boundary was not challenged.

The most likely complication with significant consequences if further failures had occurred during the event is a small break LOCA. Multiple equipment failures would have been necessary for this to occur, such as: coincident failures to close both a pressurizer PORV and its block valve; or, coincident failures to open both PORVs and a resultant opening of the pressurizer safety valve(s) and a subsequent failure of one or more valves to close. However, initiation of the LOCA would be within the design basis for the plant, and equipment necessary to mitigate such conditions responded as designed to the inadvertent safety injection actuation and hence, would have been available to respond to any further degradation had it occurred.

The Salem April 7 event resulted in no protective barrier failures. However, the event led to a loss of the pressurizer steam space and significantly challenged RCS pressure boundary components.

While, as described above, the safety consequences of the event were minimal, the AIT considered the equipment, personnel performance and procedural problems to be noteworthy and to warrant addressal by the licensee.

7.2 AIT Conclusions

- **No abnormal releases of radiation to the environment occurred during the event.**

The AIT developed an independent sequence of events and performed an assessment of key operating parameters that would indicate a failure to a primary barrier such as fuel cladding, reactor coolant pressure boundary or containment. The AIT determined that the primary boundaries remained intact throughout the event.

The pressurizer PORVs functioned properly on numerous occasions to maintain the RCS pressure boundary within the previously analyzed envelope. As a result of these operations, the pressurizer relief tank (PRT) rupture disk ruptured, as would be expected, to prevent destruction of the tank. As a result, a few gallons of reactor coolant from the PRT were released to the containment floor. The AIT reviewed the radiological surveys of the area near the PRT and concluded that the level of contamination was minor and consistent with the normal activity contained in the PRT.

- **Event challenged RCS pressure boundary resulting in multiple, successful operations of pressurizer PORVS and no operations of the pressurizer safety valves.**

As stated earlier, the AIT findings disclosed that the event sequence provided a challenge to the RCS pressure boundary. As a result of the initial safety injection, the RCS filled with water. Without the normal pressurizer steam space to dampen pressure excursions, the continued injection, both from the initial and second automatic safety injection actuations, resulted in repeated, successful actuations of the pressurizer PORVs to limit the RCS pressure within the analyzed envelope.

The AIT concluded that the event did in fact pose a significant challenge to the pressure boundary by challenging the PORVs; that the pressure boundary protective devices (PORVs and safety valves) functioned properly throughout the event; that no limits were exceeded during the event; and that some equipment degradation resulted.

- **Operator errors occurred which complicated the event.**

The AIT reviewed plant event data and interviewed the operators involved in the event. It was concluded that operator errors occurred throughout the event sequence. However, it was noted that operator performance was better after the reactor trip than prior to the trip.

The operators responded appropriately to the potential loss of condenser circulating water by decreasing reactor and turbine power, ultimately with the intent to remove the turbine-generator unit from service. Power was reduced, using a combination of control rods and boration, to a point that the operators began to switch onsite electrical loads to offsite power supplies in anticipation of removing the turbine from service. The shift supervisor directed the operator on the reactor controls to perform the electrical load swaps. At that time, neither the shift

supervisor nor the reactor operator recognized that the reactivity change, due to borations, was incomplete. In fact, when this was complete, the reactor power was less than the turbine power so that T_{avg} began to decrease. This decreasing T_{avg} was not immediately identified; however, upon discovery the shift supervisor responded to this condition by pulling rods in manual. Thus, the shift supervisor was no longer in a position to properly direct the activities of the reactor operators. The RO completed the electrical load swap, returned to the reactor controls without adequate communications from the shift supervisor regarding the shift supervisor's actions and commenced to raise reactor power. The RO noted that T_{avg} had gone below the Technical Specification minimum temperature for criticality, but failed to effectively communicate such to the senior reactor operator. Also, the shift supervisor directed the RO to raise power, but, was not explicit regarding how far or fast to raise power. Absent such direction, the RO continued to raise reactor power while monitoring T_{avg} for an indication that temperature was recovering and failed to identify that a reactor trip on low power-high flux condition would occur. As a result of the above operator errors, a reactor trip occurred on high flux (25%) and the low T_{avg} condition was still present. The low T_{avg} condition in coincidence with an indicated high steam flow signal initiated the first automatic safety injection.

After the reactor trip and safety injection, the operators appropriately entered the EOPs and successfully completed the required actions. As a result of the unusual equipment response to the initial safety injection system actuation, described previously; numerous valves were not in the expected or required position per the EOPs. The operator responded to these conditions per the EOPs. One letdown isolation valve that was mispositioned was not initially identified and corrected by the operator. This was subsequently discovered by the operators during the termination/recovery actions after identifying that the safety injection was not needed. It is noted by the AIT that a redundant valve for this same isolation line did close.

At about this time in the event sequence at least one steam generator code safety valve lifted causing a rapid secondary and primary cooldown. This cooldown, from the solid RCS condition, induced a very rapid depressurization of the RCS, and ultimately the second safety injection. The AIT concluded that the operators were not properly monitoring the RCS heatup resulting from decay heat and the running Reactor Coolant Pumps, after the initial safety injection. The AIT noted that the automatic steam generator atmospheric relief valves should have lifted before the steam generator code safety valve set point was reached, but due to a characteristic of the controller for the relief valves (reset windup), which the operators were trained to handle, the valves did not open sufficiently to limit the main steam pressure rise.

Following the code safety lift, operators properly responded by taking manual control of the steam generator atmospheric relief valves in order to lower pressure to re-seat the safety(s). The resulting rapid RCS depressurization was observed by the operators and they decided to manually re-initiate safety injection. A second automatic SI occurred prior to the manual operation; however, the operators continued with the manual actuation. The operators then appropriately re-entered their EOPs at this time without further error.

In addition to the above, the AIT also identified the following two concerns regarding operator actions:

During the down power transient, the senior shift supervisor, also SRO-qualified and the senior management representative in the control room, left the control room area to bypass a condenser vacuum permissive switch in an attempt to restart one of the inoperable circulating water pumps, hoping to restore adequate condenser cooling. The AIT concluded that this was an inappropriate work activity and also, poor judgement on the senior shift supervisor's part to leave the control room during the transient.

After the initial safety injection, the senior shift supervisor left the control room proper in order to classify the event and initiate notifications per the emergency plan implementing procedures. While this activity was timely, the initial notification message developed for a communicator provided minimal information to the NRC in that it failed to describe the complications that had occurred.

- **Management allowed equipment problems to exist that made operations difficult for plant operators.**

1. The AIT found that during this event and for about a month prior to the event, that the automatic rod control system was not in service. This led to the operators having to manually control reactor power to maintain RCS T_{avg} within program.

   During the event of April 7, 1994, the operators initially decreased turbine power at 1%/minute, but quickly increased that rate change to a maximum of 8%/minute. At this rate of change, even the automatic rod control system would not have been able to maintain T_{avg} in program without operator action to assist by boration. With the rods in manual, as was the case, operator action in response to the 8%/minute rate of change was very difficult.

   The AIT noted that PSE&G management was addressing the automatic rod control system problem and that, in fact, the control system was available at the time of the event. However, operations management had not yet restored the system to service since a final surveillance test had not been completed. That test had been scheduled for the day of the event.

2. The AIT found that the short duration, high steam flow signal, resulting from the turbine trip, had been previously identified by the licensee following prior post-trip reviews conducted after similar turbine trips in the past. Information provided the AIT indicated this condition had been recognized as early as 1989. The high steam flow signal was of very short duration, on the order of 20 to 30 milliseconds, and appeared about 1 second after the turbine trip. While this condition had been recognized previously, the licensee attributed the cause to be a combination of the logic (the reactor trip automatically reduces the high steam flow setpoint from about 110% to about 40% of rated steam flow)

and the actual decay in steam flow following a reactor trip-turbine trip. Upon closer analysis following this event, the licensee identified that the actual cause of the indicated high steam flow signal following a turbine trip corresponds to a pressure wave initiated by the turbine stop valve closure.

The AIT concluded that this pressure wave did cause the indicated high steam flow, and, coincident with the low T_{avg} condition induced by operator error, resulted in the initial automatic safety injection actuation. The AIT further concluded that earlier licensee assessment of indicated high steam flow after turbine trips was inadequate in that it failed to identify this mechanism and therefore the problem remained uncorrected.

3. The AIT found that the automatic controls for steam generator atmosphere relief valves were not maintained. This, coincident with the operators failure to recognize that RCS and steam generator temperature and pressures were increasing after the initial safety injection, led to the steam generator code safety(s) actuation and resultant second safety injection actuation. The atmospheric relief valves (MS10s) control system had been modified in the late 1970's, which resulted in the controls not responding properly in automatic without operator action. Plant operators had been trained to make up for this deficiency by placing the system in manual for a few seconds and then restoring the system to automatic. This would result in the control system then working properly. During the events of April 7, 1994, the operators failed to take adequate manual control of this system prior to pressure increasing to the lift setpoint of the steam generator code safety(s).

   The AIT determined that the control system for the MS10s was known to be deficient. Modifications had been planned, but never implemented to correct these conditions and operators had been expected, through training, to make up for the control deficiencies by manual actions.

4. The AIT found that the circulating water system was vulnerable to periodic grass intrusions. This had been documented by the licensee for a number of years. Records indicating that this condition was especially aggravated in the spring of 1994 were provided the to AIT. However, the vulnerability had been previously recognized by the licensee and modifications had been planned to make the system less susceptible to grass intrusions. These modifications had not been implemented prior to the event. During the spring of 1994, as the river grass conditions worsened, the licensee began to initiate special work teams and work controls at the circulating water structure in response to the predictable grass intrusions that occurred coincident with daily tide changes. These special practices were quite effective at responding to the degrading circulating water conditions and usually resulted in restoring inoperable traveling screens and circulating water pumps without the need for control room operators tripping the turbine or reactor. The AIT noted that on one occasion prior to the April 7 event, operators had been forced to remove the turbine from service as a result of a grass intrusion; but, the reactor was maintained in low power operation. No further complications had occurred on that

event. It was also noted by the AIT that the event of April 7 was apparently more severe than earlier events, resulting in operators decreasing power at a maximum of 8%/minute. This was done to reduce turbine power fast enough to minimize the increasing back pressure in the condenser. The prior grass intrusion events did result in operators frequently reducing power to maintain condenser vacuum, while the special work activities at the circulating water structure restored inoperable circulators. However, no prior event required such a high rate of change in power to compensate for the loss of circulating water.

The AIT determined that the grass intrusion event of April 7 was very severe; however, the vulnerability of the design was previously recognized and modifications to improve the system had not yet been implemented.

- **Some equipment was degraded by the event, but overall, the plant performed as designed.**

The AIT observed the licensee's troubleshooting efforts. It was noted by the team that certain valves for the safety injection systems, containment isolation systems, feedwater isolation system, and steam line isolation system did not respond in the usual manner to the initial automatic safety injection actuation. This was a result of the short duration of the initiating signal, which was only of sufficient duration for parts of the protection logic to respond, resulting in the unexpected behavior. However, functional testing of the protection logic clearly indicated that it would have performed properly in response to real accident conditions had they been present. The AIT further concluded that licensee troubleshooting methods clearly demonstrated the logic responded as would be expected to the short duration signals. The AIT determined that the plant response to the event was as expected for the conditions that occurred. The troubleshooting efforts clearly demonstrated that the protection logic response, as well as the response of the main steam and feedwater isolation systems, were a direct result of instrument sensitivity and response behavior to short duration signals. Testing demonstrated that consistent, predictable behavior could not be achieved unless the input signal lasted longer than about 50 milliseconds. The vulnerability of the protection system to short duration signals had not been previously identified or evaluated by the licensee prior to the April 7 event.

Due to the repeated operation of the pressurizer PORVs, the AIT requested, and the licensee completed an assessment of the PORVs, pressurizer code safety valves and attendant piping and supports. The licensee and NRC inspected the PORV internals, which exhibited wear requiring further evaluation and corrective action prior to restart.

As a result of the troubleshooting activities, other equipment conditions requiring repairs were also identified, including the PRT rupture disk, main steam high steam flow input relays, and various MS10 control components.

- **Operator use of emergency procedures was good.**

The AIT determined that the operators' use of the EOPs in response to the multiple automatic safety injection actuations was good; however, some errors happened after entry into the EOPs. The AIT found that operators were not specifically knowledgeable in the use of EOP "Yellow Path" procedures for solid plant recovery. "Yellow Path" system function restoration procedures are optional in the Salem EOP scheme; but, for this event and the solid plant condition, no alternative procedures had been provided. Knowledge, training and practice in the use of "Yellow Path" procedures could have aided the operators earlier in the recovery of the pressurizer steam space following the multiple SI actuations.

Operator actions to manually initiate SI on rapidly decreasing RCS pressure and in declaring the Alert to ensure appropriate engineering support for plant recovery from the solid RCS condition were considered appropriate by the AIT.

Prior to entry into the EOPs, the operators committed a number of errors dealing with command control and coordination of the downpower transient. Most of these errors could have been avoided if appropriate guidance had been developed and implemented in the normal integrated operating procedures and in the abnormal or alarm response procedures.

- **Licensee investigations and troubleshooting efforts were good**

The AIT closely monitored the licensee's troubleshooting activities and, to a lesser extent, the licensee's independent investigation. Based on the direct observation of the logic testing and other troubleshooting activities, the AIT determined that the licensee approach was clearly to ascertain the root causes of the events of April 7, identify necessary corrective actions and then implement such measures. However, it was noted by the AIT that the licensee was prepared to accept the operability of the pressurizer PORVs without a visual inspection of the components. The AIT asked for the necessary engineering evaluation of the PORVs upon which the licensee was to base their operability assessment. Prior to developing this evaluation, the licensee then elected to open the components for a visual inspection. This led to the findings of the degraded PORV internals resulting from the event. While this specific activity was not pursued rigorously by the licensee without NRC prompting, this was not indicative of the other troubleshooting activities observed by the AIT.

The AIT met with members of the licensee's investigation team to discuss preliminary findings; and, reviewed the operations post trip report and the investigation report. Information gathered from these reports was useful to the AIT assessment. Further, the licensee's sequence of events and facts supporting the event sequence were found to be consistent with the AIT's. The AIT concluded that there was evidence of noteworthy management oversight and control weaknesses due to the coincidence of equipment issues, both recent and historical, operator errors and procedural guidance deficiencies that all contributed significantly to the April 7 event. In contrast, the licensee's investigations placed a greater emphasis on the operator errors in contributing to the event. The AIT noted that the licensee's investigation did not attempt to

ascertain why the operator errors occurred, but identified the errors as root cause. However, it was also noted by the AIT that licensee's recommended corrective actions clearly addressed the equipment and procedural deficiencies that contributed to the event.

8.0 EXIT MEETING

On April 26, 1994, the AIT conducted a public exit meeting at the site discussing the inspection scope and preliminary findings. The exit meeting slides were provided to the public and made an official record under separate correspondence to the licensee, dated April 26, 1994. The attendees at the exit meeting are listed in Attachment 6. Following the public meeting, the AIT met with and responded to questions from the public and media representatives in attendance.

ATTACHMENT 1
AIT CHARTER

April 8, 1994

MEMORANDUM FOR: Marvin W. Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED TEAM INSPECTION CHARTER FOR THE REVIEW OF THE SALEM UNIT NO.1 REACTOR SCRAM AND LOSS OF PRESSURIZER STEAM BUBBLE

On April 7, 1994, Salem Unit No. 1 reactor scrammed from 25% power during maneuvers to shut the plant down. Subsequent to the reactor scram, the plant experienced a series of safety injections which resulted in loss of the pressurizer steam bubble and normal pressure control. In addition to the reactor trip and safety injection, certain valves that are required to operate, failed to close. Because of multiple failures in safety related systems during the event and possible operator errors, per M.C. 325, Paragraph 05.02, Item a, I have determined that an Augmented Inspection Team (AIT) should be initiated to review the causes and safety implications associated with these malfunctions.

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this augmented inspection. Robert Summers is appointed as the AIT leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects is assigned the responsibility for resident and clerical support as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the AIT and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive 8.3, NRC inspection Manual 0325, inspection Procedure 93800, Regional Office Instruction 1010.1 and this memorandum.

ORIGINAL SIGNED BY:
William F. Kane for
Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Composition

A1-1

ATTACHMENT 1
AIT CHARTER

ENCLOSURE 1

AUGMENTED INSPECTION TEAM CHARTER

The general objectives of this AIT are to:

1. Conduct a thorough and systematic review of the circumstances surrounding the reactor scram at Salem Unit No. 1 on April 7, 1994 and the resulting loss of the pressurizer steam bubble.

2. Assess the operators' actions preceding and subsequent to the reactor scram. Develop a sequence of events and events causal factor analysis for the plant and operators' responses and human factors associated with the event. Compare the expected plant response to the actual plant responses.

3. Review the licensees event classification and notifications for appropriate responses.

4. Assess the safety significance of the event and communicate to the regional and headquarters management the facts and safety concerns related to problem identified.

5. Examine the equipment failures and identify associated root causes.

6. Determine if any design vulnerabilities or deficiencies exist that warrant prompt action.

7. Prepare a report documenting the results of this review for the Regional Administrator within thirty days of the completion of the inspection.

Schedule:

The AIT shall be dispatched to Salem so as to arrive and commence the inspection on April 8, 1994. During the site portion of the inspection resident and clerical support is available.

ATTACHMENT 1
AIT CHARTER

ENCLOSURE 2

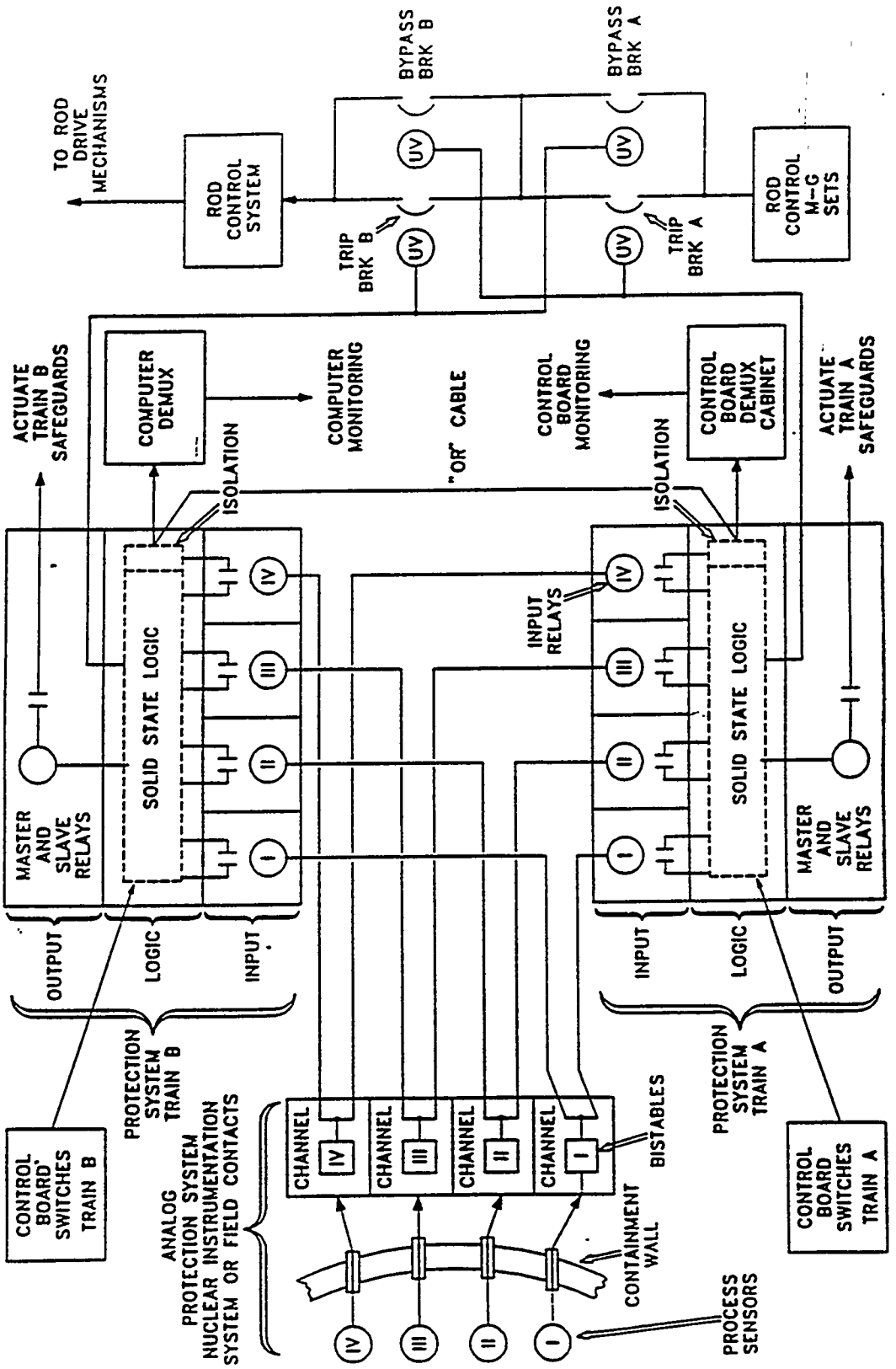
TEAM COMPOSITION

The assigned team members are as follows:

Team Manager:	Wayne Hodges, DRS
Onsite Team Leader:	Robert Summers, DRP
Onsite Team Members:	Steve Barr, DRP
	Scott Stewart, DRS
	Larry Scholl, DRS
	Warren Lyon, NRR
	Iqbal Ahmed, NRR
	John Kauffman, AEOD
	Richard Skokowski, DRS *
	Howard Rathbun, NRR
New Jersey State Observer	Richard Pinney

* added later

ATTACHMENT 2
SAFETY INJECTION SYSTEM LOGIC DIAGRAM



ATTACHMENT 3
CONFIRMATORY ACTION LETTER

April 8, 1994

Docket No. 50-272
License No. DPR-70
CAL No. 1-94-005

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
P.O. Box 236
Hancock's Bridge, New Jersey 08038

Dear Mr. Miltenberger:

SUBJECT: CONFIRMATORY ACTION LETTER 1-94-005

On April 7 and 8, 1994, in telephone discussions, William Kane, Deputy Regional Administrator, informed Mr. Joseph Hagan, Acting General Manager, Salem Nuclear Generating Station, of our decision to dispatch an Augmented Inspection Team (AIT) to review and evaluate the circumstances and safety significance of the Unit 1 reactor trip and safety injection that occurred on April 7, 1994. The event was complex and may have involved personnel error, equipment failure, or a combination of both. The AIT was initiated because of the complexity of the event, the uncertainty of the root causes of some of the conditions and equipment problems encountered during the event, concerns relative to the proper functioning of engineered safety features, and possible generic implications. The AIT, led by Mr. Robert Summers of our office, is expected to commence their activities at the Salem Nuclear Generating Station on April 8, 1994.

In response to our request, Mr. Hagan agreed to place Salem Unit 1 in a cold shutdown condition and maintain that condition until the AIT acquired all the information needed for their assessment and was satisfied that any necessary corrective measures have or would be taken; and that your staff would take actions to:

1. Assure that the AIT Leader is cognizant of, and agrees to, any resumption of activities that involve the operation, testing, maintenance, repair, and surveillance of any equipment, including protection logic or associated components, which failed to properly actuate in response to the reactor trip and safety injection(s) of April 7, 1994.

2. Assemble or otherwise make available for review by the AIT, all documentation

ATTACHMENT 3
CONFIRMATORY ACTION LETTER

(including analyses, assessments, reports, procedures, drawings, personnel training and qualification records, and correspondence) that have pertinence to the equipment problems leading up to the reactor trip and safety injection(s), and subsequent operator response and recovery actions.

3. Assemble or otherwise make available for review by the AIT, all equipment, assemblies, and components that were associated with the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

4. Make available for interview by the AIT, all personnel that were associated with, or have information or knowledge that pertains to the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

5. Gain my agreement prior to commencing any plant startup.

Pursuant to Section 182 of the Atomic Energy Act, 42 U.S.C. 2232, and 10 CFR 2.204, you are hereby required to:

1. Notify me immediately if your understanding differs from that set forth above.

2. Notify me, if for any reason, you require modification of any of these agreements.

Issuance of this Confirmatory Action Letter does not preclude issuance of an Order formalizing the above commitments or requiring other actions on the part of the licensee, nor does it preclude the NRC from taking enforcement action if violations of NRC regulatory requirements are identified through the actions of the AIT. In addition, failure to take the actions addressed in the Confirmatory Action Letter may result in enforcement action.

The responses directed by this letter are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. 96-511. In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter will be placed in the NRC Public Document Room. We appreciate your cooperation in this matter.

Sincerely,
ORIGINAL SIGNED BY:
William F. Kane for:

Thomas T. Martin
Regional Administrator

A3-2

cc:
J.J.Hagan, Acting General Manager - Salem Operations
C. Schaefer, External Operations - Nuclear, Delmarva Power & Light Co.
S. LaBruna, Vice President - Engineering
R. Hovey, General Manager - Hope Creek Operations
F. Thomson, Manager, Licensing and Regulation
R. Swanson, General Manager - QA and Nuclear Safety Review
J. Robb, Director, Joint Owner Affairs
A. Tapert, Program Administrator
R. Fryling, Jr., Esquire
M. Wetterhahn, Esquire
P. J. Curham, Manager, Joint Generation Department,
Atlantic Electric Company
Consumer Advocate, Office of Consumer Advocate
William Conklin, Public Safety Consultant, Lower Alloways Creek Township
K. Abraham, PAO (2)
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of New Jersey

ATTACHMENT 4
SEQUENCE OF EVENTS

DETAILED SEQUENCE OF EVENTS

April 7, 1994

Pre-transient initial conditions: Unit 1 power at 73%, rod control in manual.

0730 12A circulator out of service for waterbox cleaning.

1016 13B circulating water pump emergency trip on travelling screen differential pressure; 13A, 13B and 12B travelling screens all clog and eventually go out of service.

1027 13A circulating water pump trips on high screen differential pressure.

1032 Unit 1 operating crew initiated a plant power reduction from approximately 650 MWe at 1% power per minute initially (up to this point, plant power had decreased from 800 MWe due to an increase in condenser back pressure). Subsequently, operators increased the reduction rate to as high as 8% per minute.

1034 Operators attempt to restart 12A circulating water pump; pump immediately trips due to pump circuit breaker not being fully racked in.

1039 P-8 permissive (reactor trip on low coolant flow in a single loop) reset (blocked) at 36% reactor power.

By this time, all circulating water pumps except 12B have tripped; 13A and 13B are restarted, but by 10:46 they have tripped again, leaving 12B as the only circulator in service.

1043 P-10 permissive (power range low setpoint reactor trip and intermediate range reactor trip and rod stop) reset (reinstalled) at 10% reactor power.

At about this time, the Nuclear Shift Supervisor (NSS) directs the Reactor Operator (RO) at the rod control panel to go to the electrical distribution panel to perform group bus transfers.

1044 Turbine load at 80 MWe, RCS temperature at 531 degrees F. Low-low T_{avg} bistable setpoint Tech Spec allowable value $\geq$ 541 degrees F, therefore low-low T_{avg} bistables trip.

ATTACHMENT 4
SEQUENCE OF EVENTS

1045 The NSS begins to withdraw rods, and then the RO is directed by the NSS to return to the rod control panel and withdraws rods to restore RCS temperature - rods pulled 35 steps, from step 55 to step 90 on control rod bank D.

1047 Reactor power increases from 7% to 25% due to the outward rod motion - reactor trips at 25% power range low setpoint. This is a "reactor startup" nuclear instrument (NI) trip. The NI "intermediate range" 20% power rod stop and 25% power reactor trip did not actuate.

1047 Automatic safety injection (SI) on high steam flow coincident with low-low T_{avg}. All ECCS pumps start, ECCS flow paths functional, main feedwater regulating valves close.

No "first-out" alarm was received for the SI. SI signal received on SSPS logic channel "A" only.

1049 Operators enter EOP-Trip 1 procedure.

1053 Operators manually initiate main feedwater isolation.

1058 Operators manually initiate main steam isolation (only 2 of 4 main steam isolation valves closed at the time of the auto-initiation of SI).

Operators manually trip main feed pumps.

1100 Licensee declared an Unusual Event, based on: "Manual or Auto ECCS actuation with discharge to vessel"

1105 EOP exit-step 36 directs operators to reset SI; operator notices SI logic channel "B" was already reset (indicated that "B" channel had not auto-initiated) and a flashing light on the RP4 panel (indicated SI logic channel disagreement).

1118 Pressurizer PORVs (PR-1 and PR-2) subsequently periodically auto open on high pressurizer pressure (indicated pressurizer was filling to solid condition).

ATTACHMENT 4
SEQUENCE OF EVENTS

During recovery, steam generator atmospheric relief valves open several times to control secondary temperature and pressure.

Number 11 and/or Number 13 steam generator safety valves open, causing RCS cooldown (by this time T_{avg} had increased to about 552 degrees F). This indicated that the steam generator atmospheric relief valves were not properly controlling pressure.

1126 Second actual automatic safety injection - initiated by low pressurizer pressure (low pressurizer pressure trip setpoint=>1765 psig, allowable>=1755 psig). Low pressurizer pressure due to RCS cooldown (due to steam generator code safety valve going open).

Second auto SI received on SSPS logic channel "B" only. Operators initiate a manual SI just after auto SI, in response to the rapidly decreasing RCS pressure.

1141 While resetting the second SI, operator notices that RP4 panel lights indicate SI logic channels in agreement (i.e., light no longer flashing).

Technical Specification Action Statement (TSAS) 3.0.3 entered due to two blocked auto SI trains.

1149 Pressurizer relief tank (PRT) rupture disk ruptures (pressurizer was either solid or nearly solid after the first auto-initiated SI at 1047, and the second auto-initiated SI resulted in sufficient relief of RCS to the PRT to raise level and pressure until rupture disk blew).

1316 Alert declared. This was done to ensure proper technical staff was available. Licensee staff recognized that TSAS 3.0.3 could not be met for inoperable SI logic channels. The operators were also concerned about how to properly restore the pressurizer to normal pressure and level control from solid RCS conditions and wanted sufficient engineering support.

1336 The NRC entered the monitoring phase of the Normal Response Mode of the NRC Incident Response Plan. NRC Region I activated and staffed their Incident Response Center, with support provided by NRC headquarters personnel.

1410 The Technical Support Center was staffed to assist control room operators with recovery of normal RCS pressure and level control.

1511 Operators restore pressurizer bubble.

1630 Pressurizer level restored to 50%, level control returned to auto. EOPs exited, IOP-6

ATTACHMENT 4
SEQUENCE OF EVENTS

(Hot Standby to Cold Shutdown) procedure entered

1715 Plant cooldown initiated.

2020 Alert terminated.

April 8, 1994

0106 Mode 4 (Hot shutdown) entered.

1124 Mode 5 (Cold shutdown) entered.

ATTACHMENT 5
LIST OF ACRONYMS

AIT	Augmented Inspection Team
CDF	core damage frequency
CETPS	core exit thermocouple processing system
CW	circulating water
DNBR	departure from nucleate boiling ratio
EPRI	Electric Power Research Institute
ESF	engineered safety features actuation
FSAR	Final Safety Analysis Report
GL	generic letter
IPE	Individual Plant Evaluation
LOCA	loss of coolant accident
MPA	multi-plant action
NRC	Nuclear Regulatory Commission
NRR	NRC's Office of Nuclear Reactor Regulation
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PORV	pressure operated relief valve
PR...	PR1, PR2 are pressurizer PORVs; PR3 - PR5 are pressurizer safety valves
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RVLIS	Reactor Vessel Level Indication System
RV	reactor vessel
SCM	subcooling margin
SER	safety evaluation report
SG	steam generator
SI	safety injection actuation
SIS	safety injection system
SSPS	solid state protection system
SW	service water
VCT	volume control tank

ATTACHMENT 6
EXIT MEETING ATTENDEES

NAME	TITLE
Nuclear Regulatory Commission (NRC)	
Iqbal Ahmed	Senior Electrical Engineer, NRR
Stephen Barr	AIT Assistant Team Leader, Division of Reactor Projects (DRP)
M. Wayne Hodges	Director, Division of Reactor Safety (DRS)
John Kauffman	Senior Reactor Systems Engineer, AEOD
Warren Lyon	Senior Reactor Systems Engineer, NRR
Larry Scholl	Reactor Engineer, DRS
Richard Skokowski	Reactor Engineer, DRS
J. Scott Stewart	Reactor Engineer - Examiner, DRS
Robert Summers	AIT Team Leader, DRP
Edward Wenzinger	Chief, Projects Branch No. 2, DRP
Public Service Electric and Gas Company (PSE&G)	
R. Dougherty	Senior Vice President - Electrical
J. Hagan	Vice President, Nuclear Operations & General Manager, Salem Operations
S. LaBruna	Vice President, Nuclear Engineering
S. Miltenberger	Vice President and Chief Nuclear Officer
F. Thomas	Manager, Nuclear Licensing

ATTACHMENT 7
FIGURES

FIGURE 1 - PORV Design Drawing

FIGURE 2 - RCS Pressure Response

FIGURE 3 - Salem and Hope Creek CW and SW Layout

FIGURE 4 - Salem CW Drawing

FIGURE 5 - Salem SW Drawing

FIGURE 6 - Hope Creek SW Drawing

ATTACHMENT 7

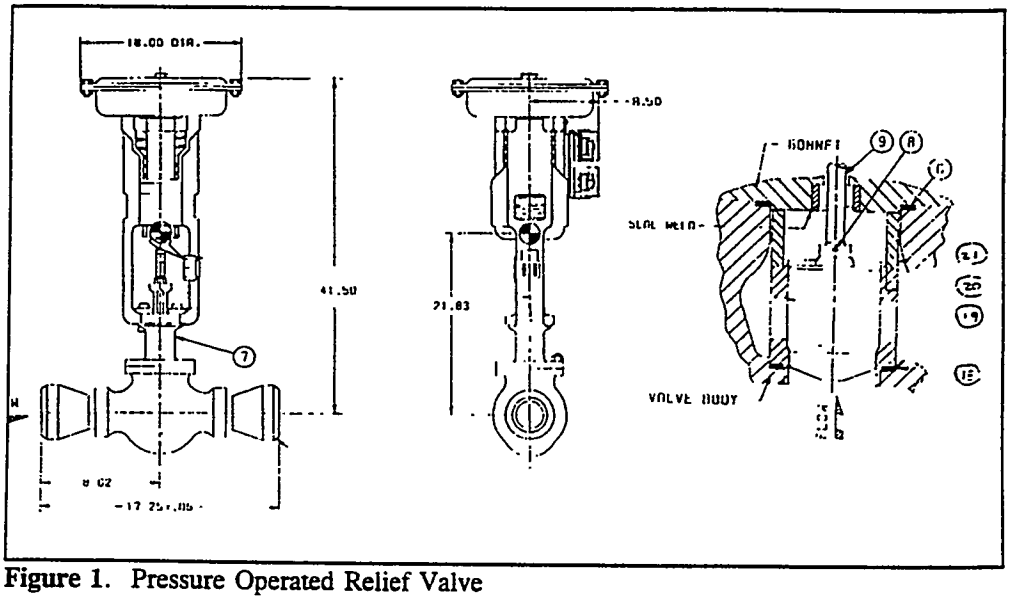


Figure 1. Pressure Operated Relief Valve

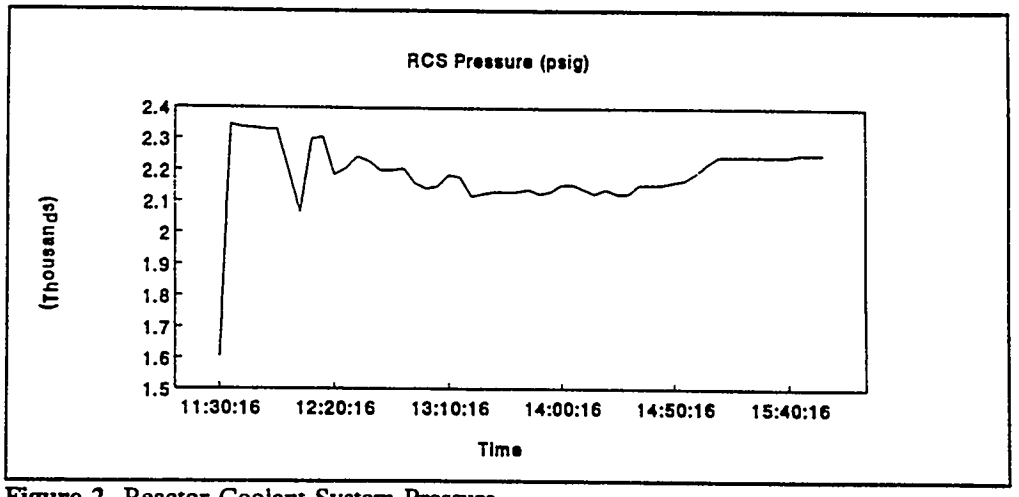


Figure 2. Reactor Coolant System Pressure

ATTACHMENT 7

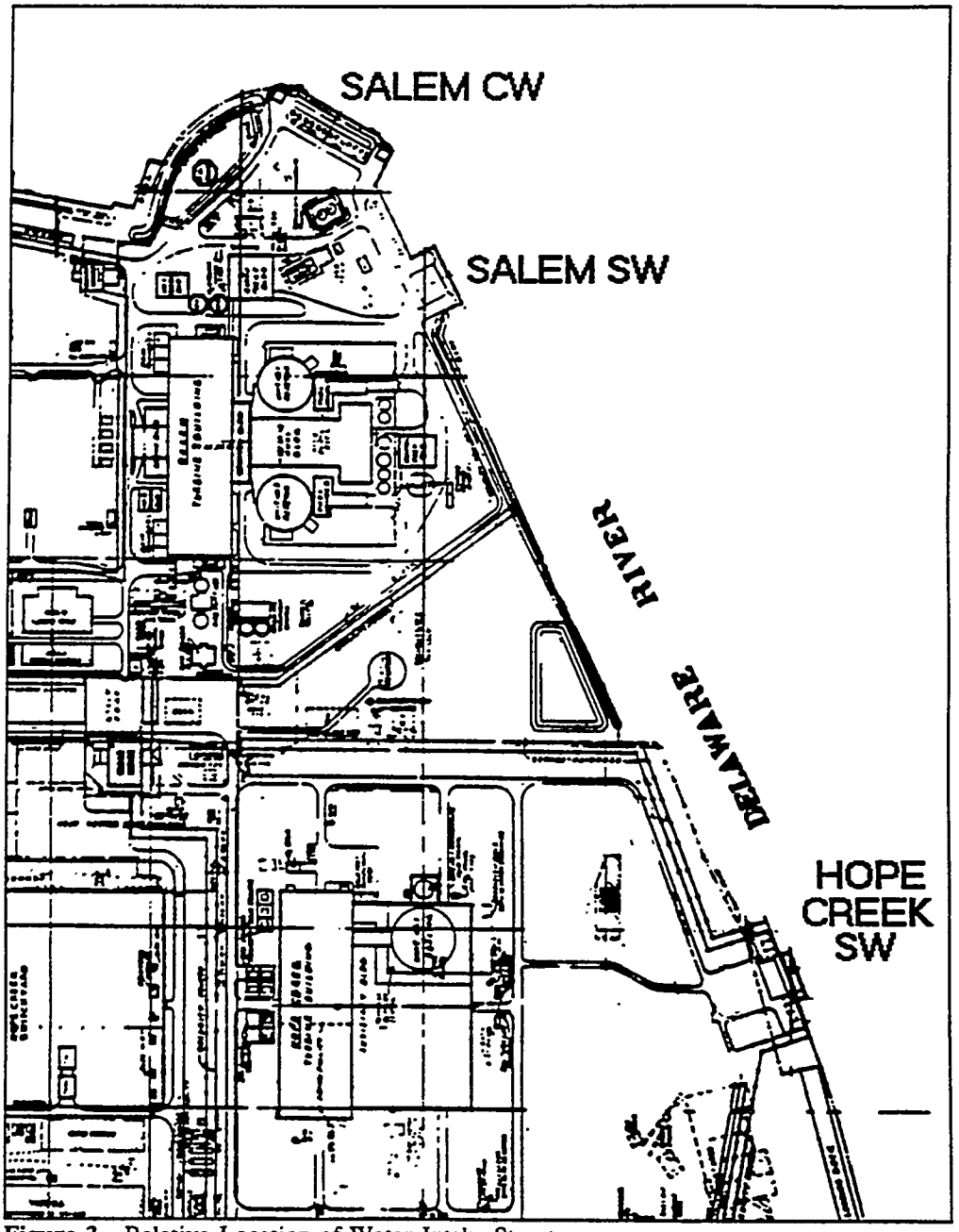


Figure 3. Relative Location of Water Intake Structures

ATTACHMENT 7

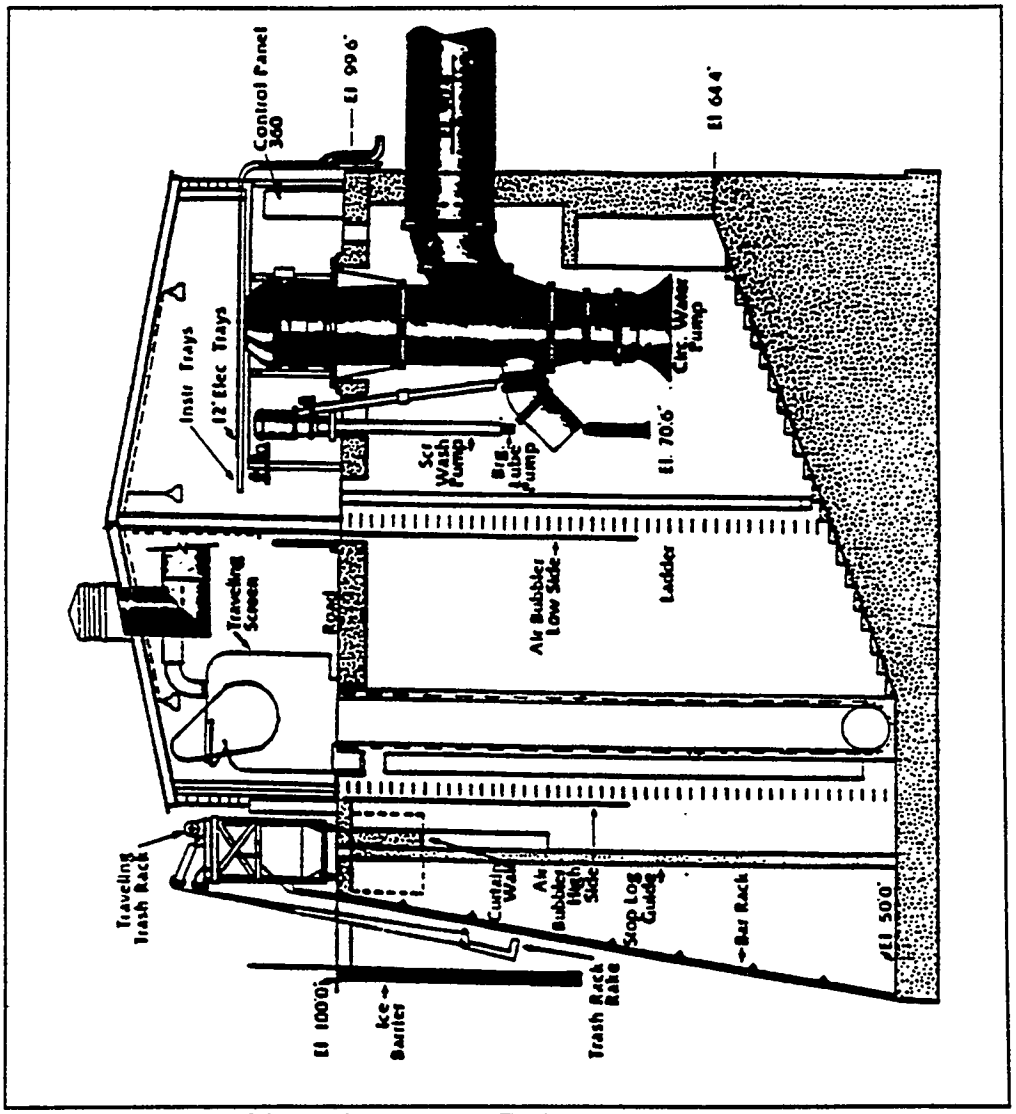


Figure 4. Salem CW Intake Structure and Equipment

ATTACHMENT 7

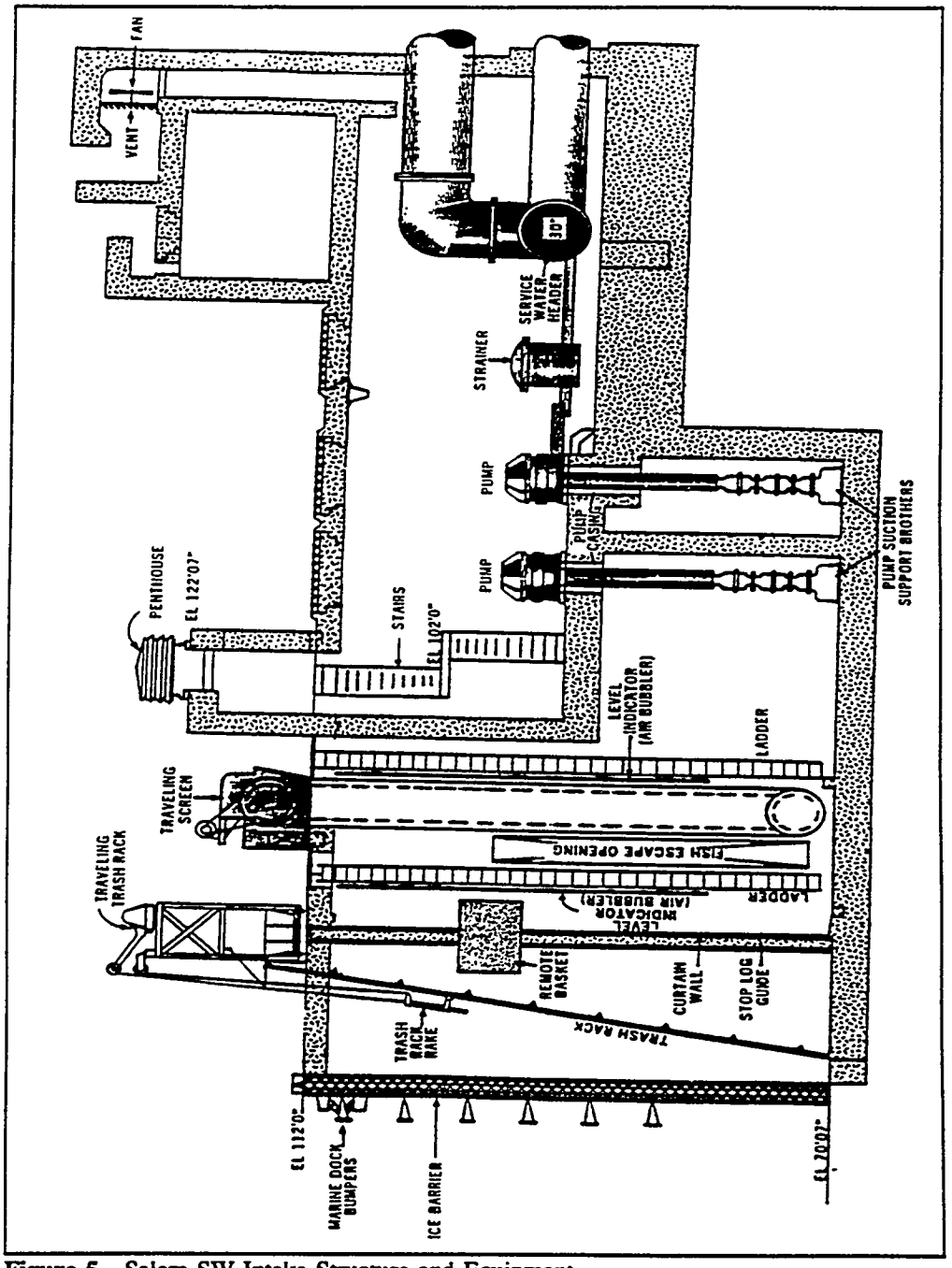


Figure 5. Salem SW Intake Structure and Equipment

ATTACHMENT 7

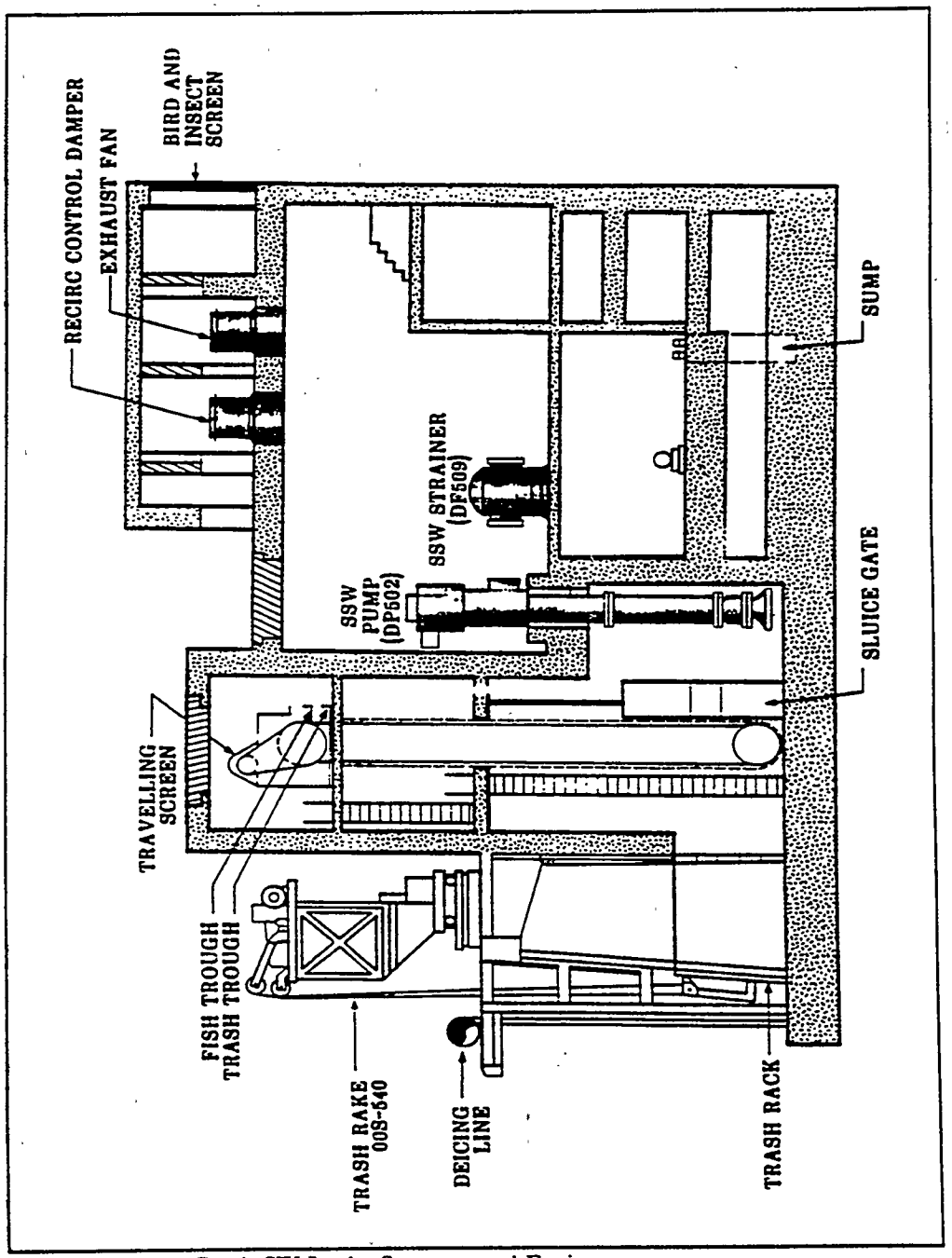


Figure 6. Hope Creek SW Intake Structure and Equipment

ENCLOSURE 2

State of New Jersey
Department of Environmental Protection and Energy
Division of Environmental Safety, Health
and Analytical Programs
Radiation Protection Programs
CN 415
Trenton, N.J. 08625-0415
Tel (609) 987-6389
Fax (609) 987-6390

Robert C. Shinn, Jr.
Commissioner

May 20, 1994

Mr. James T. Wiggins, Acting Director
Division of Reactor Safety
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Dear Mr. Wiggins:

Subject: Salem Unit 1 Augmented Inspection Team

In accordance with the provisions of the July 1987 Memorandum of Understanding between the Nuclear Regulatory Commission (NRC) and the New Jersey Department of Environmental Protection and Energy (DEPE), the DEPE is providing feedback regarding the April 7, 1994 Alert at Salem Unit 1 and the subsequent NRC Augmented Inspection Team (AIT). As you know, the New Jersey DEPE's Bureau of Nuclear Engineering (BNE) observed part of the performance of the AIT. In keeping with the spirit of the agreement between the DEPE and the NRC, the DEPE will not disclose its inspection observations to the public until the NRC releases its final AIT report.

This participation was especially valuable for our nuclear engineering staff. It allowed us to gain immediate understanding of the actual events and plant conditions leading to the Alert declaration on April 7. This information has been shared with DEPE management. Our representatives were impressed with the diligence of the AIT members and their ability to expeditiously sift through a complex series of events. The AIT Team Leader was extremely cooperative and open to our representatives' questions and concerns. All team members had inquisitive attitudes, allowing for effective information gathering from PSE&G and analysis within the team.

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We are continuing to review all available information concerning the Alert. Overall, the information we have seen is consistent with our observations of the AIT. The May 10, 1994 internal memorandum from Mr. Martin, NRC Regional Administrator, to Mr. Taylor, NRC Executive Director of Operations, clearly described the chain of events and the results of the operator interviews. We have two specific subjects we have not seen addressed in the information made available to date and we have one general concern.

First, the NRC and PSE&G have stated that spurious high steam flow signals have been experienced before at Salem Units 1 and 2. We understand that other Westinghouse units have experienced this problem as well. We are concerned that these past spurious signals have not been shared within the industry or if it was shared, there may be a weakness in PSE&G's ability to evaluate industry experience. If the AIT is not assessing this matter, we recommend follow-up through the inspection process.

Second, following the first safety injection on April 7, operators reported that trouble alarms were received on all three diesel-generators and an urgent trouble alarm was received on one of the diesel-generators. An SRO was dispatched to the diesel-generators. He found all diesels operating properly and reset the alarm which was attributed to low starting air pressure. We recognize this is unrelated to the events that led to the declaration of the Alert. However, it may indicate that a problem exists with the diesel-generators that operators have learned to cope with. Certainly, responding to an urgent trouble alarm in an emergency situation is a distraction that should be avoided.

Third, our general concern involves an apparent inconsistency in statements made by NRC senior management and the results of the previous two SALP periods. NRC has expressed concern with long-standing cultural and equipment problems at Salem Units 1 and 2. The results of the previous SALP reports are not consistent with these observations. In fact the latest SALP report indicates some improvement. We are concerned over the effectiveness of the SALP process to reflect the true assessment of this utility's performance. Perhaps we could discuss this issue at an appropriate time.

If you have any questions, please contact me at (609) 987-2189.

Sincerely,

Anthony J. McMahon, Acting SLO
Acting Assistant Director,
Radiation Protection Element,
DEPE

c: Kent Tosch, Manager, DEPE
Dave Chawaga, SLO, NRC

Attachment: DEPE/NRC MOU

ATTACHMENT IV

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
631 PARK AVENUE
KING OF PRUSSIA, PENNSYLVANIA 19406

Richard T. Dewling, Ph.D., P.E.
Commissioner
Department of Environmental
Protection
401 East State Street
CN 402
Trenton, New Jersey 08625

Dear Commissioner Dewling:

This letter is to confirm the general agreement reached as the result of our meetings with Dr. Berkowitz and his staff regarding the surveillance of the nuclear power plants operating in New Jersey. During those meetings we agreed that there was a need to have a more formal way of coordinating NRC and State activities related to plant operations and that the Department of Environmental Protection's Bureau of Nuclear Engineering (BNE) will be the interface with the NRC on a day-to-day basis.

The areas addressed by this letter are:

1. State attendance at NRC meetings with licensees relative to licensee performance, including; enforcement conferences, plant inspections and licensing actions.

2. NRC and BNE exchanges of information regarding plant conditions or events that have the potential for or are of safety significance.

We agree that New Jersey officials may attend, as observers, NRC enforcement conferences and NRC meetings with licensees, including Systematic Assessment of Licensee Performance (SALP) reviews, with respect to nuclear power plants operating in New Jersey (PSE&G, GPUN). We shall give timely notification to the BNE of such meetings, including the issues expected to be addressed. Although I do not expect such cases to arise frequently, we must reserve the right to close any enforcement conference that deals with highly sensitive safeguards material or information that is the subject of an ongoing investigation by the NRC Office of Investigation (OI), where the premature disclosure of information could jeopardize effective regulatory action. In such cases, we would brief you or your staff after the enforcement conference and would expect the State to maintain the confidentiality of the briefing.

With regard to NRC inspections at nuclear power plants in New Jersey, we agree that the BNE staff may accompany NRC inspectors to observe inspections. To the extent practicable, NRC will advise the State sufficiently in advance of our inspections such that State inspectors can make arrangements to attend. In order to assure that those inspections are effective and meet our mutual needs, I suggest the following guidelines:

1. The State of New Jersey will make arrangements with the licensee to have New Jersey participants in NRC inspections trained and badged at each nuclear plant for unescorted access in accordance with utility requirements.

2. The State will give NRC adequate prior notification when planning to accompany NRC inspectors on inspections.

3. Prior to the release of NRC inspection reports, the State will exercise discretion in disclosing to the public its observations during inspections. When the conclusions or observations made by the New Jersey participants are substantially different from those of the NRC inspectors, New Jersey will make their observations available in writing to the NRC and the licensee. It is understood that these communications will become publicly available along with the NRC inspection reports.

With regard to communications, we agree to the following:

1. The NRC shall transmit technical information to BNE relative to plants within New Jersey concerning operations, design, external events, etc.; for issues that either have the potential for or are of safety significance,

2. The NRC shall transmit all Preliminary Notifications related to nuclear plant operations for New Jersey facilities to the BNE routinely.

3. The BNE shall communicate to the NRC any concern or question regarding plant conditions or events, and any State information about nuclear power plants.

Please let me know if these agreements are satisfactory to you.

Sincerely,

W.T. Russell

William T. Russell
Regional Administrator

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

ENCLOSURE 3

Docket No. 50-272

JUN 24 1994

Mr. Anthony J. McMahon
Acting Assistant Director
Radiation Protection Element
State of New Jersey Department
of Environmental Protection and Energy
CN 415
Trenton, N.J. 08625-0415

Dear Mr. McMahon:

SUBJECT: CORRESPONDENCE DATED MAY 20, 1994 REGARDING SALEM UNIT 1 AUGMENTED INSPECTION TEAM

The purpose of this letter is to thank you for forwarding the assessment of the AIT activities that were observed by your representatives and to address the concerns you raise in the subject letter. We were pleased with the generally favorable remarks you made regarding the conduct of the AIT.

Your letter provided three issues for our consideration, which you did not believe were being addressed at the time of the AIT. You are correct in that the AIT did not address these issues. Our plans are outlined below.

Your first issue addressed past industry experience related to spurious high steam flow signals and raised a concern about PSE&G's ability to evaluate such industry experience. In reply, the AIT did not assess this issue directly. Also, while the PSE&G independent investigation did address operating experience feedback, no assessment of this specific issue was made. Therefore, NRC will follow up on this issue during a future inspection and will ensure that the findings are documented in an inspection report. More generally, the AIT finding regarding the vulnerability of the high steam flow instruments is being reviewed by NRC management for possible generic communications to the industry.

Your second issue addressed the trouble and urgent trouble alarms received on the emergency diesel generator (EDG) following the first safety injection actuation on April 7, 1994, and raised two concerns regarding: operators learning to cope with existing problems; and, distraction of operators by nuisance alarms during emergency situations. In reply, the AIT did not specifically review the causes of the EDG alarms. The alarms were investigated by the licensee and the findings of that investigation were discussed with the NRC. The cause of the urgent trouble alarm was a defective air receiver outlet low pressure switch, which was replaced. The cause(s) of the other trouble alarms was not identified; but, additional future monitoring of these alarms during EDG starts is planned. Future NRC inspections will evaluate the licensee efforts to identify the specific cause(s) of the trouble alarms. Regarding your concern about operators

JUN 24 1994

learning to cope with existing problems, the AIT does address this issue for different examples of pre-existing equipment problems. This matter will be followed up as a result of the AIT findings. Regarding your other concern about the potential distraction of operators during emergency conditions, NRC agrees that this should be avoided, if possible. Our view is that all indicators, including alarms, should be assumed to be correct and appropriately responded to. If the alarming condition is subsequently found to be defective, then appropriate corrective actions should be taken. In this case, corrective actions have been taken for the urgent trouble alarm. If future testing identifies the cause(s) of the other trouble alarms, we will ensure appropriate corrective actions by the licensee are taken.

Your final issue addressed a perception involving an apparent inconsistency in statements made by NRC senior management regarding "long-standing cultural and equipment problems at Salem Units 1 and 2," and the results of the previous two SALPs. The NRC reviews licensee performance on a continual basis. This is accomplished through SALP, through routine assessments in support of NRC Senior Management Meetings and through inspections. The SALP, by its nature is a very broad and performance-based assessment, but is focused on performance observed during the SALP period. The conclusions drawn in the SALPs were based on information gathered during their respective SALP periods. Recent NRC findings, including the AIT findings, and discussions by NRC management are factors that are considered in our current assessment. These findings, as well as other information that NRC management gathers through inspection and licensing activities and management reviews that occur periodically, are all appropriately considered in the continual NRC assessment of performance. We would expect to include the results of our current assessment in the next SALP report. We understand how your review of the past SALP reports can lead to the perception you developed. Although infrequent, it is not uncommon that we would also see differences between past SALP assessments and current performance of licensees. Those differences have typically resulted either from significant changes in the licensee's processes or organization, or from more defined insights gained by us through our ongoing programs. In the case of Salem, I suggest both circumstances were at work. If you would like to discuss this process further, we would be glad to do so.

Both this letter and your letter, dated May 20, 1994, will be enclosed with the transmittal letter forwarding the results of the AIT inspection to PSE&G. In accordance with the provision of the MOU between NRC and the State of New Jersey, both these letters will be placed in the Public Document Room.

Once again, thank you for your assessment and observations. If you have any questions, please contact me at (610) 337-5080 or Mr. Edward Wenzinger at (610) 337-5225.

Sincerely,

James T. Wiggins, Acting Director
Division of Reactor Safety

LER No. 275/94-020
Diablo Canyon, Unit 1

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Diablo Canyon Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 2 7 5

PAGE (3): 1 OF 8

TITLE (4): Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage that Resulted from an Electrical System Disturbance External to the PG&E System

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YR	FACILITY NAMES	DOCKET NUMBER (S)
12	14	94	94	- 0 2 0 -	0 0	01	13	95	Diablo Canyon Unit 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

X 10 CFR 10 CFR 50.73(a)(2)(iv)

OTHER - (Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	TELEPHONE NUMBER
David P. Sisk - Senior Regulatory Compliance Engineer	805	545-4420

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

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

ABSTRACT (16)

On December 14, 1994, at 0026 PST, with Unit 1 and Unit 2 in Mode 1 (Power Operation) at 100 percent power, both units experienced reactor trips. Both units were stabilized in Mode 3 (Hot Standby) in accordance with plant emergency procedures. A four-hour, non-emergency report was made at 0131 PST in accordance with 10 CFR 50.72(b)(2)(ii).

The reactor trips were due to an undervoltage on the auxiliary power bus that provides power to the reactor coolant pumps. The undervoltage condition was due to a system disturbance external to the PG&E system.

Due to the circumstances of the event, no corrective actions were deemed necessary. However, the Western System Coordinating Council, a utility coordination group composed of the eleven western states and British Columbia that are interconnected through the 500 kV Pacific Intertie, will study the transient and a formal report should be available in several months. If PG&E determines that any corrective actions are necessary as a result of this final report, a supplement to this LER will be issued.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	2 OF 8

TEXT (17)

I. Plant Conditions

Unit 1 and Unit 2 were in Mode 1 (Power Operation) at 100 percent power.

II. Description of Problem

A. Summary

On December 14, 1994, at 0026 PST, with Unit 1 and Unit 2 in Mode 1 at 100 percent power, both units experienced reactor trips [AB][RCT] due to a 12 kV auxiliary power system (reactor coolant pump (RCP) [AB][P] feeder bus [EA][BU]) undervoltage. The units were stabilized in Mode 3 (Hot Standby) in accordance with plant emergency procedures. A four-hour, non-emergency report was made at 0131 PST in accordance with 10 CFR 50.72(b)(2)(ii).

B. Background

PG&E has transmission systems operating at several voltage levels. The Diablo Canyon Power Plant (DCPP) is connected to the 230 kV system [FK] for startup and standby power and to the 500 kV system [FK] for transmission of the plant's power output. The 500 kV system is further connected through the 500 kV Pacific Intertie to the Western Systems Coordinating Council (WSCC) network covering the eleven western states plus British Columbia.

The DCPP electrical systems generate and transmit power to the high-voltage (500 kV) system, distribute power to the auxiliary loads, and provide control, protection, instrumentation, and annunciation power supplies for the units.

FSAR Update Section 15.3.4, "Complete Loss of Forced Reactor Coolant Flow," states that a reactor trip on RCP bus undervoltage is provided to protect against conditions that can cause a loss of voltage to all RCPs, i.e., loss of offsite power. In addition, a reactor trip on low primary coolant loop flow is provided to protect against loss-of-flow conditions that affect only one RCP and also serves as a backup to the undervoltage trip.

C. Event Description

On December 14, 1994, prior to 0026 PST, the PG&E 500 kV system configuration was normal, except for one section of 500 kV line that had its backup relays in service (the primary relays were out-of-service for testing). At 0026 PST a 500 kV network fault and system separation occurred in

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	3 OF 8

TEXT (17)

Idaho. The fault/separation voltage surge affected Nevada, Arizona, Southern California, and Northern California.

On December 14, 1994, at 0026 PST, with Unit 1 and Unit 2 in Mode 1 (Power Operation) at 100 percent power, both units experienced reactor trips due to RCP bus feeder undervoltage. Licensed plant operators in the control room [NA] responded in accordance with established emergency procedures, confirmed the reactor trip, verified proper engineered safety features (ESF) actuations, and initiated manual actions to stabilize the units in Mode 3 (Hot Standby). At this time, the instrument AC uninterruptable power supply common trouble alarm annunciated.

At approximately 0027 PST, a unit trip automatically initiated and all 12 and 4 kV buses, except 4 kV vital Bus 1-F, transferred to startup power. Vital Bus 1-F was paralleled to both the auxiliary power system and its associated diesel generator (DG 1-3)[EK][DG] for routine surveillance testing at the time of the event, and upon receipt of the automatic bus transfer signal, DG 1-3 picked up the bus load as per design (i.e., auxiliary power breaker opened). At approximately the same time, DG 1-1 and 2-2 started automatically, and, per design, all containment fan cooler units (CFCU), except CFCU 1-5, started.

In response to the reactor trip, both units experienced reactor coolant system temperature decreases. A centrifugal charging pump was started for Unit 1 and the turbine-driven auxiliary feedwater (AFW) pumps [BA][TRB][P] were throttled for both units. The RCS temperature recovered following these activities. Unit 1 reached 520 °F prior to recovery and Unit 2 reached 525 °F prior to recovery.

At approximately 0100, a manual transfer of vital Bus 1-F to startup power was attempted. During the manual transfer to startup power, the DG 1-3 tripped on phase-A overcurrent and DG 1-3 was declared inoperable.

Also, at approximately 0100, Unit 1 normal letdown could not be re-established due to the failure of valve 1-LCV-460 to open, and excess letdown was placed in service.

In addition, at approximately 0100, a loss of vacuum was experienced on Unit 1. The condenser air ejectors were realigned and the condenser vacuum pump was started.

A four-hour, non-emergency report was made at 0131 PST in accordance with 10 CFR 50.72(b)(2)(ii).

At 0345 PST, excess letdown was removed from service and normal letdown was re-established.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	4 OF 8

TEXT (17)

At 0428 PST, due to continuing decreasing condenser vacuum, the Unit 1 main steam isolation valves were shut and the vacuum was broken.

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

Prior to the system disturbance, the PG&E 500 kV system configuration was normal, except for one section of 500 kV that had its backup relays in service (the primary relays were out-of-service for testing).

E. Dates and Approximate Times for Major Occurrences

1. December 14, 1994, at 0026 PST: Event/Discovery Date: Automatic unit trip initiated following 500 kV system disturbance.

2. December 14, 1994, at 0131 PST: A four-hour, non-emergency report was made to the NRC in accordance with 10CFR50.72(b)(2)(ii).

F. Other Systems or Secondary Functions Affected

1. Diesel Generator 1-3

DG 1-3 testing was in progress at the time of the reactor trip. After the reactor trip, DG 1-3 was observed to be providing power to Bus F. During the manual attempt to transfer Bus F to startup power, an A-phase overcurrent tripped the feeder breaker. The cause of the overcurrent trip is being investigated and if any valid failures are identified, a separate special report will be submitted.

2. Letdown Isolation

Letdown isolated as required, but 1-LCV-460 could not be re-opened. Excess letdown was placed in service until the failure to re-open 1-LCV-460 could be investigated. The valve was subsequently opened using the control board switch following operators exercising valve position switches locally at the valve. The position switches were adjusted and the valve tested satisfactorily.

3. Loss of Vacuum

A loss of vacuum was experienced on Unit 1 approximately 30 minutes into the event. The air ejectors were realigned and the

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	5 OF 8

TEXT (17)

NASH vacuum pump was started. Subsequent investigation determined that there was leakage through two moisture separator heater relief valves. The open relief valves were successfully reseated prior to returning Unit 1 to power operations.

4. Instrument AC Uninterruptable Power Supply Trouble Alarm

Instrument AC uninterruptable power supply 2-2 experienced a failed AC input. The failure was due to a previously documented rectifier control board sensitivity to voltage transients. The rectifier, as an equipment protection design feature, shuts down during voltage transients of 30 percent below and 20 percent above nominal. To reset the control board, the ac input breaker was cycled open and closed.

G. Method of Discovery

The event was immediately apparent to plant operators due to alarms and indications received in the control room.

H. Operator Actions

Licensed plant operators in the control room responded in accordance with established emergency procedures, confirmed the reactor trip, verified proper ESF actuations, and initiated manual actions to stabilize the units in Mode 3.

Approximately 5 minutes after the trip, plant operators secured the turbine-driven AFW pump for each unit in accordance with Emergency Procedure EOP E-0.1, "Reactor Trip Response," in response to an RCS pressure and temperature decrease. This manual action was successful in stopping the cooldown and recovering the RCS pressure.

I. Safety System Responses

1. The reactor trip breakers (JC)(BKR) opened.

2. The main turbine [TA][TRB] tripped (turbine stop valves closed).

3. The control rod drive mechanism [AA][DRIV] allowed the control rods to drop into the core.

4. The motor-driven AFW pumps and the turbine-driven AFW pump started automatically and delivered water to all steam generators as required.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	6 OF 8

TEXT (17)

5. DGs 1-1 and 2-2, due to light bus loading conditions, started on momentary bus undervoltage but, by design, did not close on their 4 kV bus since startup power was available.

6. All CFCUs, except for CFCU 1-5, started as expected on transfer to startup power. An investigation determined that the low speed timing relay failed on CFCU 1-5. The relay was replaced and the CFCU tested satisfactorily.

III. Cause of the Problem

A. Immediate Cause

As a result of a transient on the 500 kV system, the Unit 1 and Unit 2 RCP feeder buses experienced undervoltage, resulting in the initiation of a reactor trip signal.

B. Root Cause

The event was due to a 500 kV system disturbance due to a transmission line fault external to the PG&E system.

IV. Analysis of the Event

A reactor trip from 100 percent power is a previously analyzed FSAR Update, Chapter 15, Condition II event. The reactor protection system (RPS) responded as designed and initiated a reactor trip on low RCP bus voltage. The units were stabilized in Mode 3. Due to the momentary nature of the transient, and the availability of the standby 230 kV system power supply, the RCPs remained in operation throughout the event.

At the time of the reactor trip, Unit 2 was operating with a known fuel defect. Prior to the unit trip, RCS dose equivalent iodine (DEI) activity was below 0.1 micro-curie/gram (uc/g). After the reactor trip, the RCS DEI activity peaked at 0.9 uc/g approximately 4 hours after shutdown. Subsequent samples taken after shutdown showed declining RCS DEI activity. The low value of the DEI spike and short duration indicates no further fuel degradation due to the trip. The conditions of the fuel and the absence of primary to secondary leakage supported restart of Unit 2 as soon as practical (i.e., the fuel condition was not viewed as a constraint). An iodine spike is anticipated during restart, but it will not be as high as the spike after the trip. Therefore, the restart would not be expected to exceed the steady-state Technical Specification limit.

An engineering evaluation was performed with regard to the voltage transients experienced by the plant equipment. Based on the voltage plots recorded for Unit 2, a momentary overvoltage condition, lasting less than one second, was

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	7 OF 8

TEXT (17)

experienced prior to the reactor trip. The magnitude of the overvoltage condition was found to be within industry standards for all potentially affected equipment.

Initial concerns were raised that the cooldown was higher than expected for both units. After a review of previous reactor trip data, PG&E determined that the plant cooldowns were consistent with several past unit trips. An investigation concluded that the cooldown was due to a combination of AFW flow and, to a lesser extent, to steam dump operation due to controls sensitivity (a cooldown factor above 543 °F only). In addition, Unit 1 experienced a larger cooldown because Unit 1 was aligned as the normal source for common unit auxiliary steam.

The health and safety of the public were not affected by these events.

V. Corrective Actions

A. Immediate Corrective Actions

Electrical equipment inspections were performed before allowing the plant to restart. No evidence of any adverse effects was found.

B. Corrective Actions to Prevent Recurrence

No corrective actions were deemed necessary since the RPS performed its intended function.

The WSCC will study the transient and a formal report should be available in several months. If PG&E determines that any corrective actions are necessary as a result of this final report, then PG&E will submit a supplement to this LER.

In addition, as a prudent measure, PG&E is evaluating the RCS cooldown to determine if there are any lessons to be learned and whether operational enhancements can be made to provide better RCS temperature control during plant transients.

VI. Additional Information

A. Failed Components

None.

B. Previous LERs on Similar Problems

LER 1-87-004-00, "Reactor Trip on Low Reactor Coolant Pump Bus Voltage Due to a 500 kV System Disturbance." On March 15, 1987, with Unit 1 in Mode 1, a reactor trip occurred when an airplane crashed into the Diablo Canyon-Gates 500

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Diablo Canyon Unit 1	0 5 0 0 0 2 7 5	94	- 0 2 0	- 0 0	8 OF 8

TEXT (17)

kV transmission line approximately 50 miles from the plant site. At the time of the event, Unit 1 main generator voltage regulation was in manual control, awaiting adjustments. The root cause of the reactor trip was the inability of the unit to withstand a major 500 kV voltage transient with the main generator voltage regulation in manual control. Based on the circumstances of the event, no corrective actions were deemed necessary. For the present event, the voltage regulation was in automatic mode and the plant responded as expected to the external system disturbance. Therefore, lessons learned from the 1987 event could not have prevented the present event.

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Appendix I

LER No. 293/94-004
Pilgrim, Unit 1

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
PILGRIM NUCLEAR POWER STATION	05000 - 293	1 of 6

TITLE (4)

Automatic Closing of the Reactor Core Isolation Cooling System Turbine Steam Supply Isolation Valves Due to High Steam Flow Signal During Surveillance Testing

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									N/A	05000
08	03	94	94	--004--	01				FACILITY NAME: N/A	DOCKET NUMBER: 05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)					
POWER LEVEL (10)	100	20.402(b)	20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X	50.73(a)(2)(v)(D)		73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)		50.73(a)(2)(vii)		OTHER
		20.405(a)(1)(iii)	50.73(a)(2)(i)B		50.73(a)(2)(viii)(A)		(Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iv)	50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
		20.405(a)(1)(v)	50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Robert L. Cannon - Senior Compliance Engineer	(508) 830-8321

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
D	BN	SCV	T147	Y						

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On August 3, 1994, at 1122 hours, an automatic Primary Containment Isolation Control System (PCIS) group 5 actuation occurred during performance of the Reactor Core Isolation Cooling (RCIC) System quarterly surveillance test. The actuation resulted in the closing of the RCIC turbine steam supply isolation valves. This caused the RCIC system to become inoperable. The isolation resulted from a high steam flow isolation signal. Investigation revealed the direct cause for the isolation signal was the governor control valve failed to respond to the control system demand due to valve binding. Further investigation into the cause of the control valve binding determined the fulcrum dowel pins were not properly aligned. Subsequent investigation determined the maintenance procedure did not provide sufficient guidance regarding alignment of the dowel pins. Utilizing guidance provided in the vendor technical manual, the valve was rebuilt and properly aligned. The maintenance procedure will be revised to included adequate guidance for dowel pin alignment. During post work testing on August 5, 1994, the turbine had been running for approximately fifteen (15) minutes when the turbine speed began to oscillate. At this time, oil began to spray from the governor end bearing cover, oil level on the coupling end bearing housing dropped below the sight glass level and oil was observed on the skid. The turbine was manually tripped at this time to investigate the cause of these problems. The cause for the oil level change was determined to be due to air becoming entrained in the oil. Vents were added to the oil sump and system oil pressure was reduced to correct the problem. This event occurred during plant operation while at 100 percent reactor power. The reactor mode selector switch was in the RUN position. The Reactor Vessel (RV) pressure was approximately 1030 psig with RV temperature at saturation. The RCIC System was returned to operable status on August 12, 1994. The High Pressure Coolant Injection System was operable during the period the RCIC was inoperable.

NRC FORM 366A (5-92)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
PILGRIM NUCLEAR POWER STATION	05000 - 293	2 of 6

REASON FOR SUPPLEMENT

This supplemental report includes the results of the root cause investigation regarding the improper alignment of the Reactor Core Isolation Cooling (RCIC) turbine steam governor control valve fulcrum alignment pins. The investigation had not been completed when the initial report was submitted.

BACKGROUND

The Reactor Core Isolation Cooling (RCIC) System turbine steam supply piping is equipped with differential pressure sensors (DPIS 1360-1A and -1B) that provide a steam line break detection function. A high steam flow signal in one or both logic channels functions to close the RCIC turbine steam supply piping isolation valves to limit the release of steam if a break in the RCIC Turbine steam supply piping occurs. The Group 5 portion of the Primary Containment Isolation Control System (PCIS) closes the RCIC turbine steam supply valves MO-1301-16 and -17 and initiates an automatic RCIC turbine trip when an isolation signal is present.

EVENT DESCRIPTION

On August 3, 1994, at 1122 hours, an automatic Primary Containment Isolation Control System (PCIS) group 5 actuation occurred during performance of surveillance procedure 8.5.5.1, Rev. 36, "Reactor Core Isolation Cooling (RCIC) Pump Operability Flow Rate and Valve Test at approximately 1000 psig." The actuation resulted in the closure of RCIC turbine steam isolation valves MO-1301-16 and 17 due to a high steam flow signal. The RCIC turbine tripped when MO-1301-16 and 17 closed. RCIC was declared inoperable and Limiting Condition for Operation (LCO) A94-176 was entered. The NRC Operations Center was notified at 1204 hours per 10CFR50.72.B.2.ii for the RCIC isolation (Engineered Safety Feature (ESF) actuation), and per 10CFR50.72.B.2.iii for the RCIC system being inoperable. Problem Report (PR) 94.9313 was issued to document the group 5 PCIS isolation, and PR94.9314 was issued to document oil identified on the turbine skid.

This event occurred during plant operation while at 100 percent reactor power. The reactor mode selector switch was in the RUN position. The Reactor Vessel (RV) pressure was approximately 1030 psig with RV temperature at saturation.

ROOT CAUSE

Subsequent investigation determined the cause for the high steam flow signal to be binding of the RCIC turbine steam governor control valve (HO-1301-159). Investigation into the binding of the governor control valve determined the direct cause to be improper alignment of the control valve fulcrum alignment pins. The alignment pins were not fully seated in the alignment holes. Investigation into the improperly aligned fulcrum dowel pins determined the root cause to be an inadequate maintenance procedure. Maintenance Procedure 3.M.4-78, Rev. 0, "RCIC Turbine 5-year Preventive Maintenance Inspection", does not provide sufficient guidance for proper alignment of the fulcrum dowel pins during governor control valve reassembly. The root cause investigation also identified that the dowel pins are not shown on Terry Turbine Drawing No. E4747 (our Drawing No. 2059-12-6). The governor control valve was supplied by Terry Turbine Company as a part of the turbine unit.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
PILGRIM NUCLEAR POWER STATION	05000-293	94	-004-	00	3 of 6

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

At approximately 0400 hours on 8/5/94, the RCIC system was started for post work test (PWT) using procedure 8.5.5.11, Rev. 0, "Manual Start of the RCIC Turbine for Maintenance Activity", followed by the operability surveillance procedure 8.5.5.1, Rev. 36. During the post work testing evolution, the turbine had been running for approximately fifteen (15) minutes when turbine speed began to oscillate. At this time, oil began to spray from the governor end bearing cover, oil level on the coupling end bearing housing decreased below the sight glass level and oil was observed on the skid. The turbine was manually tripped at this time to investigate the cause of these problems. Based on discussions with the vendor (Dresser Rand) and troubleshooting observations, the cause for the oil level changes was due to air becoming entrained in the system lubricating oil. The air formed a bubble in the drain line from the governor end bearing, preventing the oil from properly draining, resulting in an increase in bearing oil level. Since the oil was not fully draining from the governor end bearing, the major source of oil to the sump and oil pump was from the coupling end bearing. This resulted in a lower oil level in the coupling end bearing. Dresser Rand stated the most probable cause was the pumping action of the turbine mechanical trip disk which aerated the oil; however, other sources such as pump suction piping leaks could have been the cause.

CORRECTIVE ACTION

The governor control valve was rebuilt, properly aligned using the alignment pins, and successfully post work tested on August 5, 1994. Maintenance Procedure 3.M.4-78, Rev. 0, will be revised to include guidance from the vendor technical manual for alignment of the dowel pins during governor control valve reassembly. A Document Change Notice will be issued to revise Drawing 2059-12-6, "RCIC Turbine Longitudinal Drawing", to include the dowel pins which currently are not shown.

Several actions were taken to identify the source of the entrained air. These actions included sealing the joints on the oil pump suction tubing followed by replacement with piping to eliminate any potential sources of air in-leakage at the pump suction. Verification of oil level was performed to ensure the oil was not being agitated/aerated by the pumping action of the trip disk, and the oil was replaced with oil of the type used prior to RF09 to identify if the new oil was the cause of the foaming. The oil pump was also replaced and a new oil pump (regulator) relief valve was installed. A vent line was installed on the governor end and coupling end bearing oil drain return lines to the oil sump. After each of these actions RCIC was operated, and in each case the same symptoms occurred approximately 15 to 20 minutes into the test run, with the exception of the initial run following installation of a temporary vent line on the governor end bearing oil return drain line to the oil sump. This installation was temporary for testing purposes, and it contained non-Q parts. During this test run tygon tubing was still connected to the thermocouple wells on the bearing oil drain lines. These served two purposes: first, it allowed a path for the entrapped air to vent from and also allowed observation of the entrained air phenomenon as it occurred. From these observations, during a test run of the turbine, it was noted that at turbine speeds less than rated (4500 rpm) the oil aeration could be significantly reduced and even stopped. When the permanent vent assembly was installed, the tygon tubing was removed and the thermocouples were replaced. The subsequent test failed. The vent path provided by the tygon tubing

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
PILGRIM NUCLEAR POWER STATION	05000-293	94	--004--	00	4 of 6

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

appeared to have contributed to the successful test run with the temporary vent assembly installed on the governor end bearing oil drain line. A permanent vent line assembly was also installed on the coupling end bearing drain line. Subsequent testing indicated the aeration and foaming of the oil had minimal improvement.

Oil discharge pressure is proportional to turbine speed as the pump is driven from the turbine shaft through a worm gear arrangement. In addition, there is a relief/pressure control valve which is adjusted to maintain proper system operating pressure. Based on observation from testing and concurrence from the turbine manufacturer, the relief valve setpoint was reduced from 12-15 psig to 8-10 psig with significant results. With the slightly reduced header pressure oil aeration was significantly reduced with no adverse effect on turbine operation. This condition is believed to be inherent in the design of the system. It had gone undetected because it requires at least fifteen (15) minutes of continuous operation at rated speed, flow and pressure to manifest itself. Surveillance testing, although routinely performed at these operating parameters, rarely lasted fifteen minutes. In addition, review of historical plant computer data indicates that when RCIC was actually called upon by Operations personnel, it was typically run at less than rated speed which would result in oil pressure less than 12 psig. Operability testing was performed and the RCIC System was returned to operable status on August 12, 1994, at 0320. Any further evaluation regarding the oil aeration is being addressed as part of our operating experience program review of Information Notice 94-84, "Air Entrainment in Terry Turbine Lubricating Oil System".

REQUEST FOR ENFORCEMENT DISCRETION

On August 10, 1994, Boston Edison Company requested (Ref. BECo Ltr. 94-086) the NRC to exercise enforcement discretion in granting a one time out-of-service (OOS) extension of the RCIC System Technical Specification 3.5.D.2 from 7 days to 14 days. The extension provided needed additional time to implement corrective actions to restore the RCIC system to Operable status.

The request for a 14 day out-of-service (OOS) reflected the Standard Technical Specification allowed RCIC system OOS time, and is consistent with Boston Edison Company's June 9, 1994 (Ref. BECo Ltr. 94-068) proposed Technical Specification change submittal that would increase Pilgrim's RCIC OOS time from 7 to 14 days.

The NRC granted enforcement discretion verbally on August 10, 1994 and documented it in an NRC letter dated August 12, 1994. On August 11, 1994, repairs to the RCIC System were completed and satisfactorily post work tested. Operability testing was satisfactorily conducted in accordance with Procedure 8.5.5.1 and the RCIC System was returned to operable status on August 12, 1994, at 0320 hours and the enforcement discretion was terminated.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
PILGRIM NUCLEAR POWER STATION	05000-293	94	--004--	00	5 of 6

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

OTHER ACTION TAKEN

The high steam flow trip setpoint was set conservatively low at Pilgrim Station. On August 3, 1994, the negative trip for differential pressure sensors DPIS 1360-1A and -1B was removed in accordance with PDC-94-06 and the positive trip was changed from 105 inches to 180 inches of water pressure and incorporated in revision 21 of procedure 8.M.2-2.6.1, "RCIC Steam Line High Flow." Although this action would not have precluded this event, it will help to preclude future spurious high steam flow trips.

SAFETY CONSEQUENCES

This event posed no threat to the public health and safety.

The group 5 high steam flow isolation is designed to mitigate the consequences of a break in the RCIC system turbine steam supply line. The automatic closing of the RCIC turbine steam supply isolation valves prevents excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier if a pipe break occurs. For this event, no break in the RCICS turbine steam line occurred.

The High Pressure Coolant Injection System was operable during the period the RCICS was inoperable as required by Technical Specifications.

This report is submitted in accordance with 10CFR50.73(a)(2)(iv) because the PCIS actuation was not a planned part of the surveillance test. This report is also submitted in accordance with 10CFR50.73(a)(2)(v)(D) because the RCIC system became inoperable.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) submitted since January 1984. The review was focused on LERs submitted in accordance with 10CFR50.73(a)(2)(iv) involving a similar group 5 isolation due to high steam flow signals. The review identified LER 91-001-00, LER 93-007-01 and LER 93-021-00.

LER 91-001-00 reported an event on January 25, 1991, at 0956 hours and at 1407 hours, involving an automatic closing of valves MO-1301-16 and -17 during a surveillance test. The cause was a sensed RCIC turbine steam supply line high flow condition. The high steam flow condition occurred due to a failed transistor in the system's turbine speed control electric governor (EG-M). An exact cause of the transistor failure could not be identified. However, the signal cable connecting the EG-M to the turbine control valve hydraulic actuator (EG-R) was found to be degraded. This degradation could have led to the transistor failure. The transistor and cable were replaced.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
PILGRIM NUCLEAR POWER STATION	05000-293	94	--004--	00	6 of 6

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

LER 93-007-01 reported an event on March 17, 1993, at 0024 hours, involving an automatic Primary Containment Isolation Control System (PCIS) group 5 actuation that occurred while attempting to place the Reactor Core Isolation (RCIC) cooling system in standby service during the performance of procedure 2.1.1, "Startup from Shutdown". The actuation closed RCIC turbine steam supply isolation valves MO-1301-16 and 17. The isolation resulted from a high steam flow isolation signal while attempting to jog open the RCIC turbine steam supply valve MO-1301-16. After several attempts, valve MO-1301-16 was opened. The opening of the valve resulted in a rapid steam line pressurization and actuation of the steam flow sensors upstream of valve MO-1301-16. The inability to open MO-1301-16 on initial attempts was caused by a missing jumper that bypasses the torque switch in the opening circuit.

LER 93-021-00 reported an event on August 24, 1993, at 1329 hours, involving an automatic Primary Containment Isolation Control System group 5 actuation that occurred while operators were using the Reactor Core Isolation Cooling System for reactor vessel pressure control in accordance with procedure. The actuation resulted in the closing of the RCIC turbine steam supply isolation valves MO-1301-16 and -17 and inoperability of the RCIC system. The isolation resulted from a high steam flow signal following a reduction in RCIC test return flow by throttling Condensate Storage Tank (CST) return valve MO-1301-53. An increase in turbine steam flow and turbine speed resulted as the RCIC control system attempted to maintain CST return flow. The steam flow increase eventually caused one high flow sensor to trip and initiate the event.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Valve, Isolation (MO-1301-16 and -17)	ISV
Valve, Control, Speed (HO-1301-159)	SCV
Transmitter, Differential, Pressure (DPIS 1360-1A/1B)	PDT

SYSTEMS	CODES
Engineered Safety Features Actuation System (PCIS)	JE
Reactor Core Isolation Cooling System (RCICS)	BN
High Pressure Coolant Injection System (HPCIS)	BJ

LER No. 295/94-003
Zion, Unit 1

LICENSEE EVENT REPORT (LER)

Form Rev 3.0

Facility Name (1)	Docket Number (2)	Page (3)
Zion Unit 1	0 5 0 0 0 2 9 5	1 of 0 8

Title (4)

Containment Pressure Sensing Lines Were Inadvertently Capped During Containment Close Out

Event Date (5)			LER Number (6)				Report Date (7)				Other Facilities Involved (8)	
Month	Day	Year	Year	///	Sequential Number	///	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 3	2 3	9 4	9 4	---	0 0 3	---	0 0	0 4	2 2	9 4	Zion Unit 2	0 5 0 0 0 3 0 4

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0	___ 20.402(b)	___ 20.405(c)	_X_ 50.73(a)(2)(iv)	___ 73.71(b)
		___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
		___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify
		___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	in Abstract
		___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	below and in
		___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	Text)

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
	AREA CODE
Jerry Marsh, Mechanical Maintenance ext. 2942	7 0 8 7 4 6 - 2 0 8 4

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E				N					

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
___ YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On March 23, 1994 at 1754, the Operating Department was attempting to vent containment. Pressure indications were not lowering, so a Shift Foreman was dispatched to investigate. He found that the sensing lines on all of the safety related containment pressure transmitters were capped off inside containment.

The cause of this event was management/QA deficiency. Containment Penetrations inside containment are not labeled.

As a result of the inoperability of these instruments, there was not an accurate indication of containment pressure in the control room and the following automatic actuation functions of Engineered Safeguard Features, (ESF) were also inoperable: Safety Injection on a Containment High Pressure Signal at 4.5 psig. Containment Spray Initiation (CS). Phase B Containment Isolation and Main Steam Isolation Valve (MSIV) Isolation on a containment high high pressure signal at 23 psig. Updated Final Safety Analysis Report (UFSAR) transients which generate a containment pressure increase were evaluated to identify the safety significance of this event. Specifically, the Main Steam Line Break (MSLB) and Loss of Coolant Accident (LOCA) were reviewed and determined not to have been adversely affected.

Immediate corrective actions included removing the pipe caps that were found and verifying that lines required to be open to containment pressure for both units were open. Additional corrective actions will include labeling penetrations inside containment for both units, changing GOP-0, Checklist G, "Containment Closeout," to verify penetrations are open before plant heatup, and incorporating lessons learned from this event.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																				Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)										Page (3)	
									Year	/// /// ///	Sequential Number	/// /// ///	Revision Number							
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-	0	0	3	-	0	0	0	2	OF	0	8

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

A. CONDITION PRIOR TO EVENT

MODE 3 - Hot Shutdown RX Power 0 % RCS [AB] Temperature/ Pressure 538 / 2235 psig

B. DESCRIPTION OF EVENT

On March 23, 1994 Unit 1 was in Hot Shut Down (Mode 3) and plant heat-up was underway. Between 0022 and 0512 the Operating Department attempted to vent containment several times, but the indicated pressure on 1PI-RV85 did not decrease as expected. The valve lineups were verified and the vent lines were drained in efforts to lower containment pressure. On the following shift, the venting problem persisted so operators expanded the troubleshooting efforts. At 1445 the containment pressure and vacuum reliefs were verified to be open. At about 1630, 1PI-CS19 was reading about 1.5 psig with the redundant pressure channels showing no elevation in pressure. With 1PI-RV85 and 1PI-CS19 both indicating a high pressure, Operations dispatched a Shift Foreman to Containment to investigate further. The Shift Foreman found a newly installed pipe cap on the sensing line for 1PI-CS19 at containment penetration P-41 and reported this finding to the Control Room. The shift determined that this installation was improper and the cap was removed. Pressure indication on 1PICS19 dropped in response to the now open penetration. The Shift Foreman then inspected the other penetrations which support containment pressure indications. He found newly installed pipe caps on the three other sensing lines for Unit 1 containment pressure. These were also determined to be improper and were removed. Upon removing the cap from the line that supplied 1PI-RV85, indicated pressure dropped.

A total of four pipe caps were removed from instrumentation sensing lines (penetration numbers P-41, P-54, P-78, P-82). These caps had rendered inoperable 8 containment pressure instruments. The affected main control board indicators were:

Instrument No.	Description
1PI-CS19	CONTAINMENT PRESSURE - ESF ACTUATION
1PI-CS20	CONTAINMENT PRESSURE - ESF ACTUATION
1PI-CS21	CONTAINMENT PRESSURE - ESF ACTUATION
1PI-CS22	CONTAINMENT PRESSURE - ESF ACTUATION
1PI-RV85	CONTAINMENT PRESSURE INDICATION
1PI-CS50	CONTAINMENT PRESSURE WIDE RANGE INDICATION
1PI-CS51	CONTAINMENT PRESSURE WIDE RANGE INDICATION
1PR-CS50	CONTAINMENT OVER PRESSURE RECORDER

Investigation has positively established that the caps were installed on the afternoon of March 19, 1994 with the unit in Cold Shut Down (Mode 5). However, prior to discovery of this condition, Unit 1 transitioned into Mode 3.

All instrumentation, alarm, and protective features normally afforded by these transmitters were unavailable from the time of cap installation until the condition was discovered and immediately corrected by 1754 on March 23, 1994.

An ENS red phone call was made at 1806 to the NRC to report the inoperability of the containment pressure transmitters.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																								Form Rev 3.0	
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)															Page (3)	
									Year			/// /// ///	Sequential Number			/// /// ///	Revision Number							
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-		0	0	3	-		0	0	0	3	OF	0	8	

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

C. APPARENT CAUSE OF THE EVENT

The cause of this event was management/QA deficiency. Containment penetrations inside containment are not labeled. These penetrations are identified by using a penetration grid map (M print) showing how the penetrations are laid out from the vertical pipe chase side of the containment wall. The map must be transposed when looking at the penetrations from inside containment. When containment closeout was being performed, the map was incorrectly read and the wrong penetration number (P-86) was given to System Engineering to determine if it was acceptable to cap the penetration. P-82 was the correct penetration number. System Engineering determined that P-86 could be capped.

ZAP 400-01, "Station Material Condition Program", Appendix A "Examples of Minor Maintenance" states that minor maintenance activities on station components shall not involve temporary or permanent alteration to plant equipment, components or systems. ZAP 400-02, "Initiating and Processing a Work Request", Appendix AJ, "Examples of Minor Maintenance", states that minor maintenance activities on station components shall not result in a permanent configuration change of the plant. Adding caps to these lines was a configuration change to the plant, however it was not recognized as such.

Also, communications between the maintenance work crew and two supervisors about extra lines they had found without caps were not clear. The crew perceived that they were authorized to install caps on these extra lines and expanded their work scope to include the extra caps. No follow-up was performed on the extra caps by either supervisor after the job to identify what extra penetrations had been capped.

In addition, the work list for capping the open lines was not accurately prepared. The list identified four open abandoned lines and a spare containment penetration needing to be capped for FME purposes. The list should have only identified two open lines as needing caps and no penetrations needing caps.

D. SAFETY ANALYSIS OF EVENT

Due to the inoperable transmitters, the Engineer Safeguard Feature (ESF) automatic actuation functions based on the containment pressure signal were also inoperable. The affected ESF functions were:

Safety Injection on a Containment Hi Pressure Signal
Containment Spray (CS) Actuation, Phase B containment isolation and MSIV isolation on a Containment Hi Hi Pressure Signal.

An evaluation was performed which demonstrated that based on the less limiting actual plant conditions (e.g. minimal core decay heat, lower containment temperature) existing during the event, the inoperable containment pressure transmitters did not have an adverse safety significance. That evaluation follows.

The inoperable containment pressure signal ESF functions could only affect those UFSAR transients which generate a containment pressure increase. Therefore, the following UFSAR transients required evaluation:

Main Steam Line Break (MSLB) (UFSAR Section 15.1.5)
Loss of Coolant Accident (LOCA) (UFSAR Section 15.6.5)

It should be noted that the rupture of a Control Rod Drive Mechanism (CRDM) housing (UFSAR Section 15.4.3) could also generate a containment pressure increase, however, the containment pressure effects of this event are bounded by the LOCA. Therefore, this UFSAR accident does not require evaluation for this event. It should also be noted that the automatic ESF actuation functions derived from the containment pressure signal (except for the CS actuation and Phase B isolation) are redundant to other ESF actuation signals as follows:

ESF Function	Actuation Signals
Safety Injection	Low Pressurizer Pressure Steam Line Differential Pressure High Steam Line Flow with Low Steam Pressure or Low Low Tavg
Main Steam Line Isolation	High Steam Line Flow with Low Steam Pressure or Low Low Tavg

These redundant protection signals were operable during the time that the containment pressure signals were inoperable. Also, all of the ESF functions including containment spray and Phase B isolation were available for manual actuation.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			Page (3)
		Year	Sequential Number	Revision Number	
Zion Unit 1	0 5 0 0 0 2 9 5	9 4	- 0 0 3	- 0 0	0 4 OF 0 8

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

Loss of Coolant Accident (LOCA)

Peak Clad Temperature (PCT)

The LOCA PCT results must be evaluated since the containment pressure response, which affects the RCS blowdown and reflood phases, will be changed due to the loss of the automatic containment spray function. It should be noted that the LOCA PCT analysis assumes a different containment pressure response than that used to establish containment integrity. Since the PCT results become less severe with increased containment pressure, the loss of containment spray would result in a lower PCT than for the current UFSAR LOCA case. In addition, Zion Unit 1 was at much less limiting initial conditions than analyzed in the UFSAR full power case. These initial conditions included being in the hot shutdown mode with only approximately 0.1% rated thermal power of core decay heat and a lower RCS temperature. Consequently, the loss of containment spray automatic actuation had no safety significance on the LOCA PCT analysis results.

Containment Integrity

The containment integrity analysis consists of two separate calculations which must be evaluated. The first calculation generates the conservative maximum mass and energy (M/E) released into containment during a LOCA event. This LOCA M/E data is then used as input into a computer code containment model which conservatively models the heat removal systems and calculates the resulting pressure and temperature response. Therefore, NFS has performed separate evaluations of the potential effects due to the loss of automatic CS actuation on the LOCA M/E and the containment response.

LOCA Mass and Energy Release (M/E)

The limiting LOCA M/E is the double-ended pump suction (DEPS) case as documented in the Westinghouse analysis results. However, Commonwealth Edison Nuclear Fuel Services Department (NFS) has assumed the LOCA M/E data for the blowdown phase reflood phase is based on an 8 ft. quench front (listed in UFSAR Tables 15.6-18 and 15.6-19) instead of the 10 foot quench front used in the UFSAR case. This assumption is acceptable since Westinghouse identified the 10 foot quench front data to be extremely conservative.

NFS has evaluated the LOCA M/E by quantifying the net effect on each major energy source during the blowdown and reflood phases due to the actual Mode 3 plant conditions during the event as compared to the limiting hot full power values assumed in the UFSAR case. The net blowdown and reflood phase energy effects are then combined to determine the overall effect on the total LOCA energy released during the blowdown and reflood phases by adjusting each source by the estimated change. This evaluation is based on the assumption that if the UFSAR identified source energy is changed by a certain percentage based on actual plant conditions, then the net energy released from that source would also change by the same percentage. NFS has conservatively assumed that the LOCA mass release is unchanged, even though it is expected to be less for the actual conditions as compared to the UFSAR case. Also, NFS has not credited any interactive effects between the revised containment pressure response due to the loss of CS, and the M/E release as a function of time.

UFSAR Tables 15.6-23 and 15.6-24 list the various energy sources for the blowdown and reflood phases of the event, which are also summarized in Table 1 along with their individual percentage contribution of the total energy available. The blowdown energy sources will be affected by the reduced RCS temperature, the reduced core stored energy, and the zero core power generation based on Mode 3 operation. The reflood energy sources will be affected by the reduced core stored energy and the minimal core decay heat (approximately 0.1% rated thermal power) based on the unit being shutdown for almost six months. In addition, the reflood Steam Generator (SG) energy is affected by the actual plant SG liquid mass and temperature. The following paragraphs briefly summarize the quantified effects on these energy sources as summarized in Table 1.

LOCA M/E Blowdown Phase

Because the evaluated RCS Tavg of 540.0°F is less than the UFSAR case of 562.2°F, the NFS calculations determined there is a decrease in the available coolant energy. Consequently, it is conservatively estimated that there will be a decrease of 1.9% in the reactor coolant energy source for the blowdown phase. Since Unit 1 was in Mode 3 operation with 0% core power, and since the core decay heat is accounted for in the reflood phase, NFS determined that there is no net contribution from core power generation to the blowdown phase. Thus, it is conservatively estimated that there will be a decrease of 100% in the core power generation for the blowdown phase.

NFS quantified net effect on the core stored energy based on the assumption that the calculated stored energy is proportional to the average fuel temperature. Consequently, the UFSAR LOCA case would have an average fuel temperature corresponding to 100% power, while Zion Unit 1 actually had an average fuel temperature corresponding to 0% power. In addition, the Zion Unit 1 startup core had 76 fresh assemblies whose only stored energy would be due to the RCS average temperature. Therefore, NFS conservatively calculated that there would be a net decrease of 53.3% in the core stored energy for the blowdown phase. This calculation is also applicable to the core stored energy for the reflood phase.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																								Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)															Page (3)
									Year	/// /// ///	Sequential Number	/// /// ///	Revision Number											
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-	0	0	3	-	0	0	0	5	OF	0	8		

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

LOCA M/E Reflood Phase

The core decay heat is a significant energy source for the reflood phase M/E release. Based on the estimated actual Zion Unit 1 decay heat at 6 months, it is conservatively estimated that there will be a decrease of 98.5% in the decay heat energy of the reflood phase.

The available steam generator energy source for the reflood phase will increase due to the increased SG mass and pressure (and therefore saturation temperature) at the actual HSD conditions compared to the UFSAR full power case.

Therefore, NFS calculated that SG source energy would increase by approximately 46.8% for the reflood phase.

Net Energy Change for LOCA M/E Blowdown and Reflood

Based on the individual energy source effects summarized in Table 1, the estimated Zion Unit 1 blowdown and reflood energy is only 94.0% of the original total energy generated for the limiting UFSAR case. In addition, an explicit M/E calculation based on the plant Mode 3 conditions would be expected to generate an even larger energy reduction. Consequently, NFS has determined that the loss of the automatic CS actuation function did not have any adverse safety significance on the Zion LOCA M/E analysis.

LOCA Containment Pressure Response

As discussed previously, Westinghouse established the current bounding containment peak pressure case as a Double Ended Pump Suction (DEPS) LOCA. Consequently, NFS performed an analysis using a CONTEMPT4 mod5 computer model of the Zion containment, to quantify the effects due to the loss of automatic CS function. The evaluation analysis was performed assuming no CS, but using initial conditions based on plant data obtained during the loss of containment pressure indication event, and some more realistic assumptions than credited in the UFSAR case. These analysis inputs are summarized in Table 2 and discussed in the following paragraphs.

The initial containment air temperature was reduced from the UFSAR value of 120°F to 85°F, since this conservatively bounds the plant data. Although the plant containment pressure data is invalid due to the inoperable transmitters, the site System Engineering Primary Group established that a value of 2 psig was conservatively bounding. The 2 psig value is also conservatively greater than the initial 1.0 psig assumed in the UFSAR case.

NFS credited four RCFCs available for heat removal since the plant actually had all five RCFCs operable during the event (minus one for assumed single failure). NFS also credited a lower service water temperature compared to the 80°F assumed in the UFSAR case. The 50°F service water temperature assumed by NFS conservatively bounds the plant data during the event, but still has the effect of increasing the RCFC heat removal capability compared to the UFSAR case.

NFS also assumed an 8 foot quench front (as defined in UFSAR Tables 15.6-18 and 15.6-19) which generates less mass and energy than the 10 foot quench front used in the UFSAR case. This is acceptable since Westinghouse identified the 10 foot quench front as overly conservative.

The calculated LOCA peak pressure results for the evaluation case was 44.94 psig at 123.4 seconds. This value is less than the containment peak pressure calculated in the UFSAR LOCA case, and well below the design limit pressure of 47.0 psig. Therefore, this analysis demonstrates that the inoperable containment pressure transmitters did not have any adverse safety significance for the LOCA containment integrity analysis.

Offsite Dose

The UFSAR LOCA case is the bounding event for offsite dose since it generates significant fuel cladding damage and some fuel failure. However, this UFSAR case is based on extended full power operation, while Zion Unit 1 was starting up from a refueling and in the HSD mode during the event. Consequently, about one third of the Zion core was new fuel with zero residual decay heat and with no fuel cladding degradation in the event of a LOCA at the plant HSD conditions.

The Zion Unit 1 decay heat at the time of interest was calculated to be about 0.1% rated thermal power (RTP). Therefore, NFS performed a simplified and conservative calculation to determine the fuel rod heatup which would occur during a LOCA. The calculation was performed with the RETRAN02 computer code model of a OFA/VANTAGE5 fuel pin in a time dependent volume representing the surrounding core coolant.

The fuel pin was assumed to have a decay heat rate twice that of the calculated core average to conservatively bound the maximum to average core burnup ratio. The fuel pin was initialized at steady state conditions with the core coolant at 547°F and 2250 psig. The core coolant conditions were then modified to achieve steam conditions at 300°F to be conservative with the peak calculated containment air temperature. The fuel pin was then allowed to heat up assuming a conservatively low steam convection heat transfer coefficient. The heat up continued until 350 seconds, which is much longer than the time until reflood quenching occurs (<200 seconds) per the UFSAR Table 15.6-19.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			Page (3)
		Year	Sequential Number	Revision Number	
Zion Unit 1	0 5 0 0 0 2 9 5	9 4	- 0 0 3	- 0 0	0 6 OF 0 8

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

The NFS calculations demonstrated that the fuel pin cladding temperature would not exceed 1200°F while the fuel temperature did not exceed 1250°F by 350 seconds. These temperatures are well below the values where fuel integrity is a concern, such that no fuel failures would occur and no fuel gap activity would be released to the containment atmosphere. Consequently, the loss of containment spray automatic actuation and the Phase B isolation had no adverse safety significance on the LOCA dose results.

Main Steam Line Break (MSLB)

The consequence of the MSLB event are mitigated by the Safety Injection (SI), main steam line isolation, and the containment heat removal protection functions. As discussed in Zion UFSAR Section 15.1.5, the MSLB core response event is analyzed both inside and outside of containment. The MSLB cases outside containment do not affect containment pressure, and therefore, do not require any evaluation.

The MSLB event results in a rapid cooldown and depressurization of the RCS. Consequently, the Zion UFSAR MSLB core response analysis generates a SI signal on low pressurizer pressure, and the inoperable containment pressure SI function had no safety significance for this event.

The MSLB event also requires a main steam line isolation in order to prevent the simultaneous uncontrolled blowdown of more than one steam generator. Although the MSLB inside containment would not have generated a steam line isolation signal due to the Inoperable containment pressure transmitters, the check valves would have provided steam line isolation protection. Therefore, the loss of the main steam line isolation derived from the containment pressure signal did not have any safety significance for the MSLB event.

The containment cooling actuation is required to provide sufficient heat removal in order to ensure a postulated event does not exceed the peak containment pressure design limit. The MSLB pressure effects on containment are bounded by the LOCA peak pressure case which has already been evaluated not to be adversely affected. Therefore, the loss of containment spray actuation peak pressure did not have any adverse safety significance on the MSLB peak pressure analysis.

Equipment Qualification (EQ)

The Zion EQ bounding pressure and temperature profiles for inside containment are shown in UFSAR Figure 6.2-1 and Figure 6.2-2, respectively. NFS has already demonstrated in the previous LOCA containment integrity section that the loss of automatic CS had no adverse safety significance on the containment pressure analysis and therefore, the EQ pressure profile is still bounding. However, NFS still had to evaluate the potential effects due to the loss of automatic CS on the Zion EQ temperature profile to ensure it is still bounding.

The same Zion CONTEMPT4 mod5 containment model described in the previous LOCA containment integrity section, was used to evaluate the MSLB inside containment cases. NFS evaluated all twelve of the Double Ended (DE) zero power MSLB break cases. Most of these cases did not require explicit evaluation since based on the actual Zion conditions, they involved either a physically incredible single failure, or they were obviously bounded by other zero power cases. As a result, the following four zero power DE MSLB cases were evaluated:

Full DE break with FWIV failure
Full DE break with containment safeguards failure
0.2ft^2 DE Break with FWIV failure
0.2ft^2 DE Break with containment safeguards failure

These cases were all calculated assuming no automatic containment spray (CS) actuation but crediting the same initial conditions and performance assumptions discussed in the previous LOCA containment integrity evaluation.

The calculated peak containment atmosphere temperature is 321.12°F at 600.5 seconds. Since this temperature exceeds the EQ curve in Figure 6.2-1, an additional evaluation was performed to model the temperature of an EQ component. Therefore, and additional small heat structure was added to the containment model, consisting of a 1ft^2 carbon steel slab in order to estimate the EQ component transient temperature. This additional heat structure was modeled small enough to ensure there was not an inadvertent effect on the overall containment temperature response. The calculated surface temperature of the simulated EQ component metal surface did not exceed the 271.0°F limit. Consequently, the lower peak EQ component surface temperature provides assurance that the loss of automatic CS actuation did not have an adverse safety significance on the Zion EQ temperature envelope.

Conclusion

Based upon the preceding evaluations, Zion Unit 1 inoperable containment pressure transmitters did not have an adverse impact on the safety analysis acceptance criteria.

ZLER\94007.ler(7)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION Form Rev 3.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)							Page (3)		
		Year	/// /// ///	Sequential Number	/// /// ///	Revision Number					
Zion Unit 1	0 5 0 0 0 2 9 5	9 4	-	0 0 3	-	0 0	0 7	OF	0 8		

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

Table 1 - Net Energy Effects for Blowdown and Reflood

Source	UFSAR Case (% Total Energy)	Initial Condition Multiplier (Fraction of UFSAR)	Zion Unit 1 Evaluated Case (% Total Energy)
BLOWDOWN			
Reactor Coolant	89.2%	1.004	89.6%
Accumulators (4 of 4)	1.4%	1.0	1.4%
Initial Core Stored Energy	5.8%	0.467	2.7%
Thin Metal Stored Energy	1.3%	1.0	1.3%
Thick Metal Stored Energy	0.0%	1.0	0.0%
Core Power Generation (to the end blowdown)	2.3%	0.000	0.0%
Blowdown Total	100.0%		95.0%
REFLOOD			
Core Stored Energy	14.1%	0.467	6.6%
Decay Heat	19.2%	0.015	0.3%
Thin Metal	9.9%	1.0	9.9%
Thick Metal	5.1%	1.0	5.1
Steam Generators	51.6%	1.429	73.7%
Reflood Total	99.9%		95.6%

Table 2 - Containment Response Initial Condition Comparison

Input Parameter/Assumption	UFSAR Case	Zion Unit 1 Evaluation
Initial Containment Air Temperature	120°F	85.0°F
Initial Containment Pressure	1.0 psig	2.0 psig
RCFCs Available	3/5	4/5
Service Water Temperature	80.0°F	50.0°F
Reflood Quench Front Height Case	10 ft.	8 ft.

ZLER\94007.1er(8)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																								Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)															Page (3)
									Year			/// /// ///	Sequential Number			/// /// ///	Revision Number						
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-		0	0	3	-	0	0		0	8	OF		0	8

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

E. CORRECTIVE ACTIONS

The following are the immediate actions that were taken to correct the incorrectly capped piping:

1. The pipe caps were removed from the Unit 1 containment pressure sensing lines. (P-41, P-54, P-78, P-82)
2. The Unit 2 containment pressure sensing lines were inspected.
3. Both units were inspected, and lines in systems that are required to be open to containment pressure were verified to be open. Penetrations specifically inspected included the following:
   a. containment pressure and vacuum relief (P-60)
   b. accumulator nitrogen vent (P-76)
   c. hydrogen recombiner outlet (P-56)
   d. hydrogen recombiner inlet (P-15)
   e. containment air monitoring outlet (P-44)
   f. containment air monitoring inlet (P-44)
4. Interviews were conducted to determine the number and locations of the caps that were installed by the involved work group. It was determined that no additional caps were incorrectly installed.
5. Maintenance work activities were restricted to the formal work request process in the Auxiliary Building and both Containments as an interim action.
6. System Engineering requested that an evaluation of the containment pressure condition during the event with respect to FSAR design assumptions be performed by Nuclear Fuel Services.
7. The event was discussed with the individuals involved in regards to the lack of follow-up, the inaccurate work list and poor work practice.

The following are the long term corrective actions:

1. Labeling of penetrations inside Unit 1 and Unit 2 containments will be reviewed. All penetrations will be verified to have appropriate labeling. (295-180-94-00701)
2. Operating department will initiate a procedure change to GOP-0, Checklist E, "Containment Close Out", to verify penetrations or associated lines P-41, P-54, P-78, P-82, P-60, P-76, P-56, P-15, and P-44 are open/uncapped before plant heat-up. (295-180-94-00702)
3. Maintenance Staff will review ZAP 400-01 and 400-02 to clarify and strengthen the minor maintenance restrictions on plant changes. (295-180-94-00703)
4. This event and Appendix A of ZAP 400-01 will be tailgated to the Maintenance Departments. (295-180-94-00704)

ZLER\94007.ler(9)

Appendix I

LER No. 295/94-011
Zion, Unit 1

LICENSEE EVENT REPORT (LER)

Form Rev 3.0

Facility Name (1)	Docket Number (2)	Page (3)
Zion Unit 1	0 5 0 0 0 2 9 5	1 of 0 3

Title (4)

Violation of the 10CFR50 Appendix R Analysis Separation Criteria in Fire Zone 18.6.A-1

Event Date (5)			LER Number (6)			Report Date (7)				Other Facilities Involved (8)	
Month	Day	Year	Year	///	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 7	1 4	9 4	9 4	---	0 1 1	0 0	0 8	1 2	9 4	Zion Unit 2	0 5 0 0 0 3 0 4

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	___ 20.402(b)	___ 20.405(c)	___ 50.73(a)(2)(iv)	___ 73.71(b)
		___ 20.405(a)(1)(i)	___ 50.36(c)(1)	X 50.73(a)(2)(v)	___ 73.71(c)
		___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify in Abstract below and in Text)
		___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
		___ 20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
		___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
Art Campos, System Engineering ext. 2146	AREA CODE 7 0 8 7 4 6 - 2 0 8 4

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E				N					

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On July 14, 1994, while preparing Exempt Change (EC), No. E22-0-93-255 (Work Request Z32800) to replace Thermo-Lag fire wrap with an approved material for a conduit in Fire Zone 18.6.A-1, it was discovered that an adjacent conduit, which is not fire wrapped, or part of the EC scope, created a discrepancy in the 10CFR50, Appendix R analysis currently on record. This discovery indicates that a failure scenario exists that could render the 0 Emergency Diesel Generator (EDG) inoperable for both units, and disable both the 1A and 1B centrifugal charging pumps. This means that the necessary equipment for reaching hot shutdown would not be available in the event of a fire in Zone 18.6.A-1, concurrent with a loss of offsite power.

The cause of this event is management deficiency. The engineering review that was performed for the original 10CFR50, Appendix R analysis did not realize that the 1B Cent. Charging Pump could be affected by a Unit 2 cable.

The corrective actions include verifying that the existing continuous fire watch was still in place, and ensuring that no other 10CFR50, Appendix R discrepancies on common unit cables for the 0 EDG existed.

ZLER/94019.1er(2)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																					Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)												Page (3)
									Year		/// /// ///	Sequential Number			/// /// ///	Revision Number					
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-	0	1	1	-	0	0	0	2	OF	0	3

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

A. CONDITION PRIOR TO EVENT

MODE 3 - Hot Shutdown RX Power 0% RCS [AB] Temperature/ Pressure 545°F/2235 psig

B. DESCRIPTION OF EVENT

NRC IE Information Bulletin 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage", required that all installations of Thermo-Lag 330 be identified. One of the conduits identified is associated with the 0 Emergency Diesel Generator (EDG) [EK] , and is located in Fire Zone 18.6.A-1. This conduit houses cabling for the 0 EDG fuel transfer pump and air compressor control circuitry.

On July 14, 1994, preparation of an Exempt Change (EC), No. E22-0-93-255 (Work Request Z32800) to replace Thermo-Lag 330 fire wrap with an approved material for this conduit was underway, when it was discovered that an adjacent conduit, which is not fire wrapped, or part of the EC scope, could create a discrepancy in the 10CFR50, Appendix R analysis currently on record. The unwrapped adjacent conduit provides the 0 EDG power feed to Unit 2 Bus 247, and is on the 0 EDG side of the Bus 247 feed breaker 2473 (see figure 1).

This discovery indicates that a failure scenario exists that could render the 0 EDG inoperable for both units, and disable both the 1A and 1B Centrifugal (Cent.) Charging Pumps [CB]. This means that the necessary equipment for reaching hot shutdown would not be available in the event of a fire in Fire Zone 18.6.A-1, concurrent with a loss of offsite power.

This scenario assumes that the conduit containing the power feed cables to the Unit 2 0 EDG output breaker faults in the event of a fire, as do all the other cables in the fire zone. Since there is no isolation device between the 0 EDG output and the fault (section of cable in zone 18.6.A-1), the 0 EDG would be faulted and would be rendered inoperable. Since the 1B Cent. Charging pump is fed by the Unit 1 emergency feed breaker 1473, and the 1A Cent. charging pump cable is also routed through Fire Zone 18.6.A-1, both pumps would be rendered inoperable.

A continuous fire watch has been established in Fire Zone 18.6.A-1 since 1992 when the NRC bulletin identified that Thermo-Lag 330 would not provide adequate fire protection.

C. APPARENT CAUSE OF EVENT

The cause for this event is management deficiency. The 1A Cent. Charging Pump cable conduit was relocated in Fourth Quarter 1984 into Fire Zone 18.6.A-1 under a modification to resolve separation criteria issues in another Fire Zone. The engineering review that was performed for the original 10CFR50, Appendix R analysis did not realize that the 1B Cent. Charging Pump could be affected by a Unit 2 cable. This type of situation is unique to the 0 EDG design.

D. SAFETY ANALYSIS OF EVENT

The 10CFR50, Appendix R Safe Shutdown Analysis indicates that at least one train of the Chemical and Volume Control System (CVCS) is necessary to reach hot shutdown. This analysis assumes a scenario that includes a fire in Fire Zone 18.6.A-1 that faults all cables in that zone, and a loss of all offsite power. In such a scenario, a reactor trip would occur immediately following a loss of offsite power. The loss of both trains of the Chemical and Volume Control System (1A and 1B Cent. Charging Pumps), would disable seal injection flow to the Reactor Coolant Pump (RCP) Labyrinth seals. However, since Component Cooling water is assumed to still be available, adequate cooling would be provided to preclude an uncontrolled Loss of Coolant Accident through the RCP seals. Furthermore, the Safety Injection Pumps fed off buses 148 and 149 would be available for local operation for responding to a loss of coolant through the RCP seals or for make-up of controlled seal leakoff.

The subject zone has been under a continuous fire watch since 1992, and no fires have occurred in this area. This area is a stairwell and contains little or no combustibles.

Since the proper compensatory measures were taken when the Thermo-Lag 330 deficiency was discovered, and no events involving fire in this Fire Zone have occurred, this event is of minimal safety significance.

ZLER/94019.ler(3)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																					Form Rev 3.0
FACILITY NAME (1)	DOCKET NUMBER (2)								LER NUMBER (6)												Page (3)
									Year	/// /// ///	Sequential Number			/// /// ///	Revision Number						
Zion Unit 1	0	5	0	0	0	2	9	5	9	4	-	0	1	1	-	0	0	0	3	OF	0	3

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

E. CORRECTIVE ACTIONS

1. The immediate corrective action for this finding was to ensure that the continuous fire watch, that was established in 1992, is still being performed.

2. An engineering review to determine if similar discrepancies exists was performed. This review was limited in scope to the 0 EDG power output cables, because the 1A, 1B, 2A, and 2B EDG's provide direct feed from their respective EDG room Fire Zones, into their respective switchgear room Fire Zones. This eliminates the possibility of cross unit interaction. The 0 EDG is unique in that a feed to Bus 247 must be routed through multiple Fire Zones.

   The conclusions of this limited scope evaluation was that, with the exception of Fire Zone 18.6.A-1, no other errors resulting in incorrect overall conclusions affecting plant operating conditions were identified. In addition, no indication of programmatic deficiencies were revealed through this limited scope review.

3. Several potential corrective actions are being analyzed for feasibility by Modification Design Engineering, such as fire wrapping additional conduits with an approved material. (295-180-94-01901)

F. PREVIOUS EVENTS

Licensee Event Report 2-92-003, documented another event identifying cables associated with redundant channels of Wide Range Reactor Coolant System Temperature loops not being fire wrapped. Corrective actions from LER 2-92-003 would not have prevented LER 1-94-011, because this situation already existed when LER 2-92-003 occurred.

G. COMPONENT FAILURE DATA

None

ZLER/94019.1er(4)

LER 1-94-011

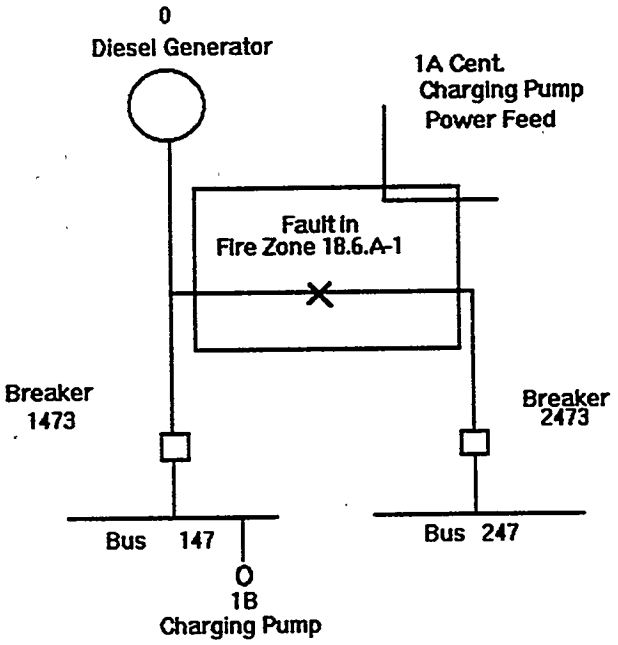

FIGURE 1

LER No. 298/94-010
Cooper

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
COOPER NUCLEAR STATION	05000298	1 OF 5

TITLE (4) Closure of Shutdown Cooling Suction Isolation Valves While Warming the Residual Heat Removal System Due to Leakage Through the Minimum Flow Valve.

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
05	26	94	94	--010--	01	11	14	94	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)		20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Gautam Sen, Senior Staff Nuclear Licensing & Safety Engineer	(402) 825-3811

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	BO	V	A395	Y					

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

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

On May 26, 1994, at 09:44 am, and again at 11:57 am and 12:06 pm, Residual Heat Removal (RHR) shutdown cooling isolation valves RHR-MOV-M017 and RHR-MOV-M018 closed as a result of actuation of one or both of the shutdown cooling suction high pressure switches RHR-PS-128A and RHR-PS-128B. These isolations occurred during heatup and flushing of RHR subsystem B loop piping which was being conducted in order to place the subsystem in the Shutdown Cooling mode of operation. At the time when these isolations occured, reactor pressure and temperature was approximately 40 psig and 280 degrees F, respectively. The turbine bypass valves were controlling RPV pressure, rejecting decay heat to the main condenser.

Subsequent to these isolations, leakage was audibly detected through RHR-MOV-M016B (RHR pump B minimum flow valve) to the suppression pool (torus). At 12:30 pm, RHR-MOV-M016B was closed manually with less than one hand wheel turn of the motor operator. Leakage through the valve was determined to have caused the rapid depressurization of the shutdown cooling suction line, creating steam voids in that section of piping, which led to hydraulic instability (pressure spiking) upon admittance of fluid to the suction piping. Per NUREG-1022, the root cause of this event is "Other," attributed to the lack of a Foreign Material Exclusion (FME) program at CNS.

NRC FORM 366 (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
COOPER NUCLEAR STATION	05000298	94	-- 010 --	01	2 OF 5

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

A. Plant Status

The plant was shutdown and preparations were being made to place the RHR System in the Shutdown Cooling mode of operation. Reactor pressure and temperature was approximately 40 psig and 280 degrees F, respectively, throughout the duration of this event. The turbine bypass valves were controlling RPV pressure, rejecting decay heat to the main condenser.

B. Event Description

On May 26, 1994, at 09:44 am, and again at 11:57 am and 12:06 pm, Residual Heat Removal (RHR) shutdown cooling isolation valves RHR-MOV-M017 and RHR-MOV-M018 closed as a result of actuation of one or both of the shutdown cooling suction high pressure switches RHR-PS-128A and RHR-PS-128B. Prior to receipt of the first isolation, heatup and flushing of RHR subsystem B loop piping was in progress in preparation for placing the subsystem in the Shutdown Cooling mode of operation. When RHR-MOV-M015B and RHR-MOV-M015D (RHR pump shutdown cooling suction valves) were opened, RHR-MOV-M017 and RHR-MOV-M018 closed. Indications of a pressure perturbation were observed and RPV level dropped approximately 4.5 inches (minimum level for the event was approximately 210 inches above TAF). Other indications included annunciation of both the RHR SDC suction header pressure high alarm and the Automatic Depressurization System (ADS) auxiliary cooling interlock alarm.

A preliminary evaluation of the data on the isolation indicated that a steam void had formed and subsequently collapsed in the RHR suction piping downstream of RHR-MOV-M015B & D causing a pressure perturbation which actuated one or both of the shutdown cooling suction high pressure switches RHR-PS-128A and 128B. A walkdown of accessible RHR piping was performed and no damage to system piping or components was found. No evidence of system leakage was observed during the system walkdown. Prior to attempting to re-open RHR-MOV-M017 and 18, it was noted that because the heated water (approximately 250 degrees F) had been static in the suction piping for more than two hours, a void could be present. As such, it was understood that there was a potential for a second isolation, and that in this event, the valves should be re-opened as soon as possible afterward to prevent a void from reforming. At 11:00 am the intermediate elevation RHR suction pressure gauge was indicating 28 psig.

At 11:57 am, the group 2 logic was reset and RHR-MOV-M017 and 18 were opened. The isolation was again received with indications of a pressure perturbation and an RPV level decrease of approximately 13.5 inches (minimum level for the event was approximately 200 inches above TAF). However, the actual setpoint of 72.5 psig (shutdown cooling high suction pressure interlock), which provides overpressure protection for the shutdown system piping, was not reached.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
COOPER NUCLEAR STATION	05000298	94	-- 010 --	01	3 OF 5

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

B. Event Description (continued)

At 12:06 pm, the Group 2 logic was reset and RHR-MOV-M017 and 18 were re-opened. The isolation was again received with indications of a pressure perturbation and RPV level decrease of approximately 16.5 inches (minimum level for the event was approximately 200 inches above TAF). Subsequent to the event, the system engineer, who was in the vicinity of RHR pumps B and D, audibly detected leakage through RHR-MOV-M016B (RHR pump B minimum flow valve) to the suppression pool (torus). In a parallel investigation, it had been noted that suppression pool level had been increasing slowly since approximately 5:00 am, which corresponded with the commencement of subsystem flushing operation. At 12:30 pm, with less than one hand wheel turn, RHR-MOV-M016B was manually closed and was subsequently declared inoperable.

Over the time period of flushing and heatup operations (seven hours), RHR pump B minimum flow valve RHR-MOV-M016B had been leaking into the torus. The leakage through RHR-MOV-M016B was the cause of both the torus level increase and the rapid depressurization of the shutdown cooling suction line. The multiple isolations of RHR shutdown cooling isolation valves RHR-MOV-M017 and M018 were caused by pressure perturbations (water hammer) in the RHR shutdown cooling suction line.

At 1:10 pm, the intermediate level RHR suction pressure gauge, which was indicating 28 psig prior to closing M016B, was found to be indicating 38 psig.

At 3:30 pm, based on pump suction pressures and gauge elevations, it was determined that no void could exist in the suction piping. In addition, it was noted that the increase in torus level had ceased since RHR-MOV-M016B was closed. A systematic walkdown of accessible piping was again performed and no damage to system piping or components was found. At 5:25 pm, RHR-MPOV-M017 and 18 were opened and Procedure 2.2.69.2 was re-initiated. Shutdown cooling was established at 9:35 pm without further incident.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (4)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
COOPER NUCLEAR STATION	05000298	94	-- 010 --	01	4 OF 5

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

C. Cause

Leakage through RHR-MOV-MO16B caused depressurization and flashing of hot fluid (approximately 250°F) in the suction line and led to steam void formation in the line. The rapid repressurization of the suction line, when RHR-MOV-MO15B and 15D (first attempt) and RHR-MOV-MO17 and MO18 (second and third attempts) were opened, collapsed the steam voids which resulted in a water hammer. The engineering and operations personnel did not develop pre-planned actions to eliminate the steam void. This resulted in multiple unsuccessful attempts to establish shutdown cooling.

The failure of RHR-MOV-MO16B to fully close was caused by foreign particles on one of the two torque switch contacts. When the control switch for the valve was taken to CLOSED, the limit switch (LS8) bypassed the torque switch and allowed the motor operator to operate up to 97% fully closed position.

The root cause of this event is lack of a Foreign Material Exclusion (FME) program at CNS.

D. Safety Significance

The failure of RHR pump B minimum flow valve, RHR-MOV-MO16B, to fully close was caused by foreign particles on one of the two torque switch closed contacts. The leakage path past the seat of RHR-MOV-MO16B valve provides a source of vessel inventory loss into the torus. Based on the estimate of total leakage to the torus (8000 gallons) over the time frame of flushing and heat up operations (seven hours), the leakage rate would have been approximately 50 gpm through RHR-MOV-MO16B valve during shutdown cooling. It is not a significant impact on available system flow from either the main condensate system during normal operations, or low pressure ECCS pumps during faulted conditions. Shutdown cooling is the only mode of concern during which the leak path is isolable (either by RHR-MOV-MO17 and MO18 or RHR-MOV-MO15B and 15D from the suction side, and by MO27B and pump discharge check valve form the discharge side). The effects of this leak would raise the torus water level and it is well monitored in the Control Room via high level alarm annunciators. If RHR-MOV-MO16B valve failure would have occurred coincident with a LOCA, then it would be considered as the single failure and the redundant A-train of RHR system would provide the required cooling. Also, containment integrity is assured because this is a closed system outside containment.

Based on the probable impact of the leakage of RHR-MOV-MO16B valve on the plant during operation, shutdown and LOCA conditions, it can be concluded that the safety significance of this event is minimal.

.NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
COOPER NUCLEAR STATION	05000298	94	-- 010 --	01	5 OF 5

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

E. Corrective Action

As part of the short-term corrective action for eliminating the root cause of this event, appropriate safety related motor operated valves (MOV) will be checked for torque-in current during MOV operability surveillances.

In order to prevent recurrence of this type of event, a Foreign Material Exclusion (FME) program will be developed and implemented at CNS and a motor operated valve compartment cleanliness program will be incorporated into the MOV surveillance procedures.

Also, throughout flushing and heatup evolutions, per RHR System Operations Procedure 2.2.69.2, it will be ensured that RHR suction and discharge piping is filled and pressurized.

F. Similar Events

LER 92-007 Actuation of shutdown cooling isolation valves due to low reactor pressure while warming the Residual Heat Removal System.

LER 94-005 Actuation of shutdown cooling isolation valves due to a pressure perturbation caused by void collapse in the Residual Heat Removal System.

NRC FORM 366A (5-92)

LER No. 304/94-002
Zion, Unit 2

LICENSEE EVENT REPORT (LER)

FACILITY NAME: ZION NUCLEAR POWER STATION UNIT 2 | DOCKET NUMBER: 0 5 0 0 0 3 0 4 | PAGE: 1 OF 0 5

TITLE: Exceeded Limiting Condition of Operation 3.7.2 Action e for Placing Unit 2 in Mode 4 with a Turbine-Driven and Motor-Driven AFW Pump Inoperable

EVENT DATE			LER NUMBER			REPORT DATE			OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQ. NUMBER	REVISION	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 3	0 7	9 4	9 4	- 0 0 2	- 0 1	0 9	2 8	9 5	Zion Unit 1	0 5 0 0 0 2 9 5

OPERATING MODE		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (CHECK ONE OR MORE OF THE FOLLOWING)			
	3	20.402(b)	20.405(a)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL	0	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER
Dwight Vorpahl, System Engineering ext. 2315	7 0 8 7 4 6 - 2 0 8 4

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
D				N		X	E K	F U	L 2 2 3	Y	
X	B A	R U F	W 2 9 0	Y							

SUPPLEMENTAL REPORT EXPECTED

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

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

On March 7, 1994, Unit 2 was in Mode 3, performing Technical Staff Surveillance (TSS) 15.6.43, "Endurance Testing of Diesel Generators During Refueling" on the 2B Emergency Diesel Generator (EK) (EDG). During TSS 15.6.43, the 2A Auxiliary Feedwater Pump (BA) (AFW) received a start signal and subsequently tripped due to overspeed. At 0533 hours, the 2A AFW pump was declared inoperable per Technical Specification 3.7.2 Action c and a Periodic Test (PT)-14, "Technical Specification Related Inoperable Equipment Test Sheet," was initiated. At 0618 hours, the 2B EDG began experiencing frequency swings and was manually tripped. The 2B DG was also declared inoperable per Technical Specifications 3.15 and a PT-14 was initiated. On March 8, 1994, it was determined that Technical Specification LCO 3.7.2 Action e should have been entered at 0618 hours on March 7, 1994 which requires the Unit to be placed in Hot Shutdown (Mode 4) within 20 hours. A unit cooldown was commenced and Unit 2 entered Mode 4 on 03/09/94 at 0130 hours.

The cause of this event is procedural deficiency. PT-14 which is utilized to status and track inoperable equipment did not require reviewing Technical Specification 3.0.5 for applicability or referencing the Zion Operability Determination Manual. The cause of the 2A AFW pump trip was determined to be an improper buffer spring in the governor. The cause of the 2B EDG failure was a Potential Transformer fuse that was found to have loose end caps which in turn produced intermittent continuity and resulted in voltage and frequency fluctuations. Zebra Mussels and corrosion nodules fouling the 2B EDG Lube Oil and Jacket Water heat exchangers were discovered. This fouling did not cause this failure, but would have forced the EDG to be declared inoperable due to lube oil and jacket water temperatures exceeding their limits if the EDG had continued to run.

Corrective Actions include revising PT-14, replacing the buffer springs in the governor on the 2A AFW pump, removing the zebra mussel shells, and replacing the defective fuses.

ZLER/94002S.ler(3)

| LICENSEE EVENT REPORT (LER) TEXT CONTINUATION | | |

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION				
FACILITY NAME	DOCKET NUMBER	LER NUMBER		PAGE
		YEAR	SEQ. NUMBER / REVISION	
ZION NUCLEAR POWER STATION UNIT 2	0 5 0 0 0 3 0 4	9 4	- 0 0 2 - 0 1	0 3 OF 0 5

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

C. APPARENT CAUSE OF EVENT (Continued)

The cause of the 2B EDG frequency swings was component failure. Two problems occurred simultaneously on the 2B EDG. The first problem was that zebra mussel shells and corrosion nodules were found in the lube oil cooler and jacket water cooler. This debris blocked the flow through the coolers and caused the increase in lube oil and jacket water temperatures that were seen by the equipment operator before the EDG was manually tripped. The jacket water cooler was heavily fouled with a mat of zebra mussel shells and corrosion nodules approximately 1/2" thick against the inlet tube sheet. Approximately 50% of the tubes in the lube oil cooler were partially plugged with a combination of zebra mussel shells and corrosion nodules, and there were several corrosion nodules in the inlet channel head. Based on these results both turbocharger intercoolers were opened, inspected and cleaned. The results of this inspection revealed approximately 50% and 100% partial tube blockage with silt, zebra mussel shells, and corrosion nodules with the same type of debris in the channel heads. These dead zebra mussel shells were from the fire protection header that was used for EDG temporary cooling water during the Fall 1993/Winter 1994 dual unit service water outage.

The second problem was the failure of a potential transformer (PT) fuse. The PT fuse that failed was found to have loose end caps causing intermittent continuity thus causing the voltage regulator to sense a fluctuating (erratic) reference signal which produced voltage fluctuations. The frequency indication was fluctuating due to the effects on the metering circuit by the PT fuse. The EDG speed was not oscillating, only the frequency indication.

The problem with the lube oil and jacket water heat exchanger tube fouling was discovered due to an increase in temperatures monitored during the running of the EDG. The EDG did not trip or experience voltage and frequency fluctuations due to the fouling of these heat exchangers.

D. SAFETY ANALYSIS OF EVENT

The AFW system provides a reliable source of water to the steam generators for decay heat removal. The turbine driven AFW or one of the two motor driven AFW pumps are capable of meeting the decay heat removal demands for the unit during accident conditions. Although the margin of safety was impacted, there was no safety significance during this event because one motor driven AFW pump was available. The Zion Individual Plant Examination (IPE) shows that the turbine driven AFW pump is especially important because of its ability to function for loss-of-offsite power scenarios in which all diesel generators have failed. However, the situation which is the subject of this LER occurred in Mode 3, after a very long shutdown period for the Zion dual unit Service Water (SW) outage. The resultant significantly lower decay heat level dramatically reduced the importance of AFW, compared to what is modeled in the IPE, which is based on full power conditions.

The worst situation is one in which there has been a loss of off-site power and either the 2C AFW pump or its respective EDG (i.e., 2A), fails. For this situation, reactor coolant pumps would be tripped by the initiating event, minimizing the heat transferred into the reactor coolant system. Given the decay heat levels during this particular event and normal steam generator water inventory, calculations show that with no AFW operating, the steam generator inventory would last at least 36 hours. This provides a considerable amount of time for recovery of off-site power, AFW, EDGs or other necessary actions.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION				
FACILITY NAME	DOCKET NUMBER	LER NUMBER		PAGE
		YEAR / SEQ. NUMBER / REVISION		
ZION NUCLEAR POWER STATION UNIT 2	0 5 0 0 0 3 0 4	9 4 - 0 0 2 - 0 1		0 4 OF 0 5

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

E. CORRECTIVE ACTIONS

1. PT-14 was revised to require a Licensed Shift Supervisor review of Technical Specification 3.0.5 applicability and ZODM review for each PT-14 initiated.

2. The buffer springs in the 1A and 2A AFW pump turbine governor were replaced with the proper buffer springs. This greatly increased the stability of the governor and no overspeed trips have occurred since. The governor data sheet to which new governors are ordered as well as the governor specifications have been revised to specify the correct buffer spring type. This will ensure that any new governors ordered or old governors sent for refurbishment will contain the correct size buffer springs.

3. The Potential Transformer fuses on all 5 EDGs were replaced with sand filled fuses. The sand filled fuses are an improved design for the environment that they function in.

4. In November of 1992, the 10" Fire Protection (FP) header that supplies a backup water supply to each EDG heat exchanger was flushed out to the forebay. This flush was performed by PT-218D, "Fire Suppression Water System Flush of the Indoor and Underground 10 inch Header". This flush is performed on a yearly frequency.

5. The 2B EDG lube oil cooler, jacket water cooler, and both turbocharger intercoolers were cleaned and the 2B EDG was returned to service.

6. The 1B EDG lube oil and jacket water cooler had been opened, inspected, and cleaned on February 14, 1994. This inspection occurred after the 1B EDG had been supplied with temporary cooling water from the FP system throughout the dual unit outage. Both coolers had zero tubes plugged and small amounts of shells in the inlet channel heads. Based on the cleanliness of the lube oil and jacket water cooler, it was decided that an inspection of the intercoolers was not warranted.

7. The 2A EDG jacket water cooler, lube oil cooler, and both intercoolers were opened, inspected, and cleaned on March 9, 1994. The coolers had up to approximately 50% partial tube blockage and varying amounts of zebra mussel shells and corrosion nodules in the inlet channel heads.

8. The 0 EDG jacket water cooler, lube oil cooler, and the 0-2 intercooler were opened, inspected, and cleaned on March 12, 1994. The coolers had very small amounts of partial tube blockage and small amounts of zebra mussel shells and corrosion nodules in the inlet channel heads. Based on the cleanliness of the 0-2 intercooler, it was decided that an inspection of the 0-1 intercooler was not warranted.

9. The 1A EDG was the only EDG that did not have its heat exchangers being supplied with temporary water from the FP system during the dual unit outage. Therefore, the 1A EDG heat exchangers have been evaluated as not containing the same type of fouling discovered in the other EDG heat exchangers. Work request 940029217 was written to flush the small section of 4" fire protection backup supply piping for the 1A EDG from the 10" fire protection supply header to the pressure control valve. This flush is scheduled to be performed during the Unit 1 Refueling Outage (Z1R14) which began on September 9, 1995. (304-180-94-0020101)

10. Engineering Request ER9500308 has been sent to design engineering to evaluate installing flush taps in the fire protection backup supply lines to the EDG heat exchangers for periodically flushing these sections of piping. (304-180-94-0020102)

| LICENSEE EVENT REPORT (LER) TEXT CONTINUATION | | |

LER No. 318/94-001
Calvert Cliffs, Unit 2

NRC FORM 366 (5-92) U. S. NUCLEAR REGULATORY COMMISSION

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

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Calvert Cliffs, Unit 2	05000 318	1 OF 09

TITLE (4)
Reactor Trip Due to Opening of 13.8 Kilovolt Feeder Breaker

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBERS(S)
01	12	94	94	- 001 -	01	03	16	94	CC, Unit 1	05000 317
										05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR :(Check one or more) (11)							
POWER LEVEL (10)	100		20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
			20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (include Area Code)
R. Cary Gradle, Compliance Engineer	410-260-3738

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

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

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

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

On January 12, 1994 at 0552, Calvert Cliffs Unit 2 tripped when an electrical protective relay actuated in the 13.8 kv voltage regulator (2H2103) for Unit Service Transformer (UST) U-4000-22. This actuation caused the loss of 4 kv Busses 22, 23, and Safety Bus 24. Both control element drive mechanism motor generator sets lost power, causing a reactor trip from loss of power to the control element drive assemblies and a main turbine trip.

The cause of the 13.8 kv feeder breakers opening was the actuation of the sudden pressure trip circuit for the 13.8 kv voltage regulators due to intermittent grounds on their associated 125 VDC bus.

A Significant Incident Finding Team was appointed by the Plant General Manager to investigate the event. The results of this investigation and associated corrective actions are included in this supplemental report.

NRC Form 366 (5-92)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	02 OF 09

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

I. DESCRIPTION OF EVENT

On January 12, 1994 at 0552, Calvert Cliffs Unit 2 tripped when an electrical protective relay actuated in the 13.8 kv voltage regulator (2H2103) for Unit Service Transformer (UST) U-4000-22. This actuation caused the loss of 4 kv Busses 22, 23, and Safety Bus 24. Both control element drive mechanism motor generator sets lost power, causing a reactor trip from loss of power to the control element drive assemblies and a main turbine trip.

Subsequently, similar protective relaying for UST U-4000-21, which supplies the redundant Unit 1 4 kv Safety Bus 14, actuated resulting in a loss of normal power supply to Bus 14. At the time of the event, both units were operating at 100 percent power.

At the time of the event, a modification was under construction which installs six 13.8 kv voltage regulators (three per Unit). Each regulator has manual transfer switches located between the respective UST 13.8 kv supply feeder breaker and the UST. On the morning of January 12, 1994, all six voltage regulators and transfer switch assemblies were mounted in place, but their 13.8 kv cables were not connected to existing plant equipment. Their annunciation circuits were tagged out with fuses removed. The voltage regulator protective trip circuits to the respective 13.8 kv supply feeder breaker control circuit had been connected earlier in the construction sequence. The project team members incorrectly believed these protective trip circuits were functionally isolated from existing plant equipment. At the time of the event, construction personnel were working on top of Unit 2 voltage regulator 2H2101 and inside each of the three Unit 2 voltage regulator transfer switch assembly cabinets. They were preparing 13.8 kv cable ends for termination during future planned 13.8 kv bus outages.

Each voltage regulator protective circuit consists of two parallel circuits sensing a sudden pressure increase in either of two separate compartments. Each circuit consists of a bellows-type sensor switch and solid-state seal-in relay circuit card which is connected to the trip circuit of the associated 13.8 kv UST feeder breaker. The circuit is designed to open the breaker and deenergize the regulator/transformer combination in the event of a sudden pressure increase from a fault inside a winding compartment.

Figure 1 provides a schematic of the power supply scheme discussed in this Licensee Event Report (LER).

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	03 OF 09

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

At 0552, a Sudden Pressure Trip Relay actuated in voltage regulator 2H2103, tripping open 13.8 kv feeder breaker (252-2103) to UST U-4000-22. 4 kv Busses 22, 23, and 24 feeder breakers (152-2201, 152-2311, and 152-2401, respectively) also tripped open, as designed, on undervoltage and Unit 2 tripped. Control Room operators implemented appropriate post-trip Emergency Operating Procedures. Auxiliary feedwater flow was initiated at 0556. Emergency Diesel Generator (EDG) 21 started and loaded as designed.

A Plant Watch Supervisor was dispatched to inspect the 13.8 kv electrical components for anomalies. He found UST U-4000-22 feeder breaker 252-2103 open. There was no local indication of any breaker protective devices tripped, but the breaker's lockout device was tripped. The Unit 1 13 kv switchgear house was inspected and all breaker conditions were normal.

At 0617 the 13.8 kv feeder breaker (252-2102) to UST U-4000-21 tripped open, with a subsequent undervoltage trip of Unit 1 4 kv Bus 14 feeder breaker 152-1414. No. 12 EDG started upon loss of power to 4 kv Bus 14. Unit 1 Control Room operators implemented appropriate procedures and took actions to close alternate feeder breaker 152-1401, which reenergized 4 kv Bus 14.

At 0619, the 13.8 kv feeder breaker (252-2101) to UST U-4000-23 tripped open, resulting in a loss of Unit 2 4 kv Busses 25 and 26. At 0628, the Control Room staff had determined that the spurious 13.8 kv breaker trips were isolated to 13.8 kv Bus 21 and opened the 13.8 kv Service Bus 21 feeder breaker 252-2104, deenergizing 13.8 kv Service Bus 21.

At approximately 0630 plant electricians verified a ground on Unit 2 125 VDC Bus 21. Using schematic drawings of the voltage regulator they identified the sudden pressure trip protective circuit, investigated, and found a sudden pressure seal-in relay actuated for each of the three Unit 2 voltage regulators. Subsequent troubleshooting isolated the DC ground to voltage regulator 2H2102. Plant electricians discovered that all three voltage regulator protective trip circuits were connected to the breaker control circuits.

The sudden pressure trip circuits for the breakers associated with the Unit 2 13.8 kv voltage regulators were disconnected. The three Unit 2 voltage regulator transfer switch assemblies were then tagged and locked in the bypass mode.

At 1535, Unit 2 13.8 kv Bus 21 was reenergized. At 1550, the other Unit 2 4 kv busses were restored to a normal lineup. Similarly, Unit 1 4 kv busses

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	04 OF 09

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

were restored to a normal electrical lineup with the voltage regulators isolated and the trip circuits removed, at about 1845.

II. CAUSE OF EVENT

The immediate cause of the 13.8 kv feeder breakers opening was the actuation of the sudden pressure trip circuit for 13.8 kv voltage regulators due to intermittent grounds on their associated 125 VDC bus. Extensive electrical bench testing confirmed that the circuit would actuate in the presence of a DC ground in the specific condition that the circuit was in at the time. An actuation did not occur if the circuit was in its final designed configuration. The designed circuit is reliable if it is properly connected. However, if the sensor device is disconnected (and a ground occurs), we have shown that the solid-state seal-in relay will actuate. Opportunities were missed to detect the sensitivity of the solid-state seal-in relay during the design review phase of the project.

A Significant Incident Finding Team (SIFT) was appointed by the Plant General Manager to investigate the event. The SIFT determined the actuations were caused by intermittent grounds on the DC control power circuits interacting with the plant's DC ground detection system. The grounds actuated the sensitive solid-state relay because its sensor device was not connected. The intermittent nature of the electrical ground in the system was most likely due to loose leads from a terminal block in the 2H2102 bypass transfer switch cabinet coming into contact with the inner cabinet door. The leads were not taped and minor movement of the door or the leads could have resulted in their contact.

A detailed analysis of this event has identified the following root causes.

A. Our control of new equipment while under construction was less than adequate. The 50.59 safety evaluation required the sudden pressure trip protective circuit to be disabled. This circuit was energized and enabled prematurely. The Design Instructions did not adequately implement the requirements of the 50.59 safety evaluation as required by our modification procedures. This inadequate design control carried through the implementing work package.

B. The modification process did not adequately require testing to be integrated with work in progress. The 50.59 safety evaluation specified the required voltage regulator transfer switches' positions to disable the trip circuit. The voltage regulator bypass

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	05 OF 09

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

transfer switch auxiliary contacts were assumed, but not verified, to be functional. Sensor devices were not detected disconnected.

C. Less than adequate communications existed between project team members. After many of the project meetings, there were conflicting views of the planned approach to ensure the protective circuits were disabled. Imprecise communications confused 13.8 kv and 125 VDC work and misleading statements existed about "associated DC circuits" and "breaker control wiring."

D. The design review conducted by personnel involved with this modification was less than adequate. The specified sudden pressure increase seal-in relay circuit is susceptible to inadvertent actuation when its sensor is disconnected. The designated method for enabling and disabling the protective circuit (auxiliary switches) was less than adequate. Opportunities were missed by our design personnel to detect the sensitivity of the solid-state seal-in relay during the design review phase of the project.

III. ANALYSIS OF EVENT

A loss of non-emergency AC power (LOAC) event is defined in the Updated Final Safety Analysis Report (UFSAR) as a loss of the plant's 500 kv/13 kv service transformers. A loss of load to one unit's turbine-generator with offsite power unavailable and the other unit's turbine-generator unavailable would result in a LOAC event. In this context, a loss of offsite power (LOOP) means a loss of the main power grid (500 kv ring bus) in conjunction with the loss of the other unit's turbine-generator; in other words, a loss of all non-emergency power with the EDGs supplying AC emergency power to all of the plant's vital electrical loads.

The most limiting LOAC event described in the UFSAR assumes a loss of turbine load on a unit operating at 100 percent power with offsite AC power unavailable and concludes that no significant safety consequences will result from this event. The UFSAR scenario bounds this actual event.

At the time of the event, Unit 1 was fully capable of being safely shutdown and maintained in a safe shutdown condition in the event of a LOOP. No. 12 EDG was OPERABLE and available to provide AC emergency power to Unit 1 safety-related equipment.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	06 OF 09

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

At 0405 on January 12, 1994, No. 11 EDG and No. 11 saltwater loop for Unit 1 were removed from service for scheduled maintenance. The next planned 13.8 kv service bus outage for continued modification installation was to occur the following morning on January 13, 1994. Approximately 25 minutes after the start of the event, at 0617, flow was lost through Unit 1 No. 12 saltwater loop when No. 12 saltwater pump stopped due to loss of Unit 1 4 kv Bus 14. Since there is no ACTION statement for two inoperable saltwater loops, Unit 1 was placed in a condition not covered by the plants Technical Specification. Power was promptly restored to 4 kv Bus 14 by closing its alternate feeder breaker, No. 12 saltwater pump was started and saltwater flow was restored through No. 12 saltwater loop. There were no significant safety consequences resulting from the approximately two minutes that flow was lost through No. 12 saltwater loop.

This event is considered reportable under the provisions of the following 10 CFR 50.73 reporting criteria:

A. 50.73(a)(2)(i)(B); Any operation or condition prohibited by the plants Technical Specifications.

B. 50.73(a)(2)(iv); Any event that results in a manual or automatic actuation of any ESF, including the RPS.

C. 50.73(a)(2)(v); Any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems needed to; (b) remove residual heat; and (d) mitigate the consequences of an accident.

IV. CORRECTIVE ACTIONS

Immediate Corrective Actions:

A. The immediate construction areas around the Unit 1 and 2 voltage regulator project were physically posted and quarantined.

B. The Plant General Manager directed that a SIFT assess the event.

C. Each voltage regulator sudden pressure trip circuit was disconnected from its respective 13 kv feeder breaker.

D. The Unit 1 and Unit 2 voltage regulator transfer switch assemblies were tagged and locked in the bypass mode.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	07 OF 09

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

E. All work associated with the voltage regulator project that could affect operable plant systems has been stopped, pending Plant General Manager approval.

Preventive Actions:

A. We are currently reviewing the 50.59 safety evaluation, design instructions, and associated implementing procedures for this modification. They will be revised, as necessary, to ensure they are consistent with each other.

B. We are developing an integrated test plan for the 13.8 kv voltage regulator project. The project implementation plan will be presented to the Plant Operations and Safety Review Committee and the Plant General Manager.

C. We will require minutes for project meetings to document concurrence on agreements.

D. We plan to replace the solid-state seal-in relay with a design that is less susceptible to spurious actuation. We plan to remove the auxiliary contacts from the sudden pressure trip circuit and install new test switches.

E. This event has been reviewed with the involved design engineering personnel.

F. We are proceduralizing guidance for review and control of "potential high risk" construction activities.

G. We will develop guidance on how and when to defeat and enable protective circuits.

H. We are developing procedural guidance for integrated work/testing requirements for modifications.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	08 OF 09

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

V. ADDITIONAL INFORMATION

A. Affected Component Identification

Component or System	IEEE 803 EIIS Funct	IEEE 805 System ID
Electrical Protective Relay	94	EA
13.8 kv Voltage Regulator	90	EA
13.8 kv Breaker	BKR	EA
Motor Generator Sets	MG	AA
Saltwater System Pump	P	BI
Emergency Diesel Generator	DG	EK
125 VDC System	N/A	EI
Unit Service Transformer	XFMR	EB

B. Previous Similar Events.

Both LER 50-317/93-003 and this event involve actuation of unnecessarily enabled breaker protection circuits leading to partial losses of offsite power and reactor trips. These events do not have similar casual factors, however. One of the causal factors identified in LER 50-317/93-003 was that isolating the protective circuit was not recognized as a means to avoid an unnecessary reactor trip hazard. In this case, the need to isolate the protective circuit was recognized and planned as part of the modification process. However, in this case, the implementation of the plan did not result in an effective circuit isolation. Thus, while some similarities exist between these events, we have concluded the underlying casual factors of these events are different.

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

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (3)	PAGE (4)
Calvert Cliffs, Unit 2	05000 3 1 8	94 - 001 - 01	09 OF 09

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

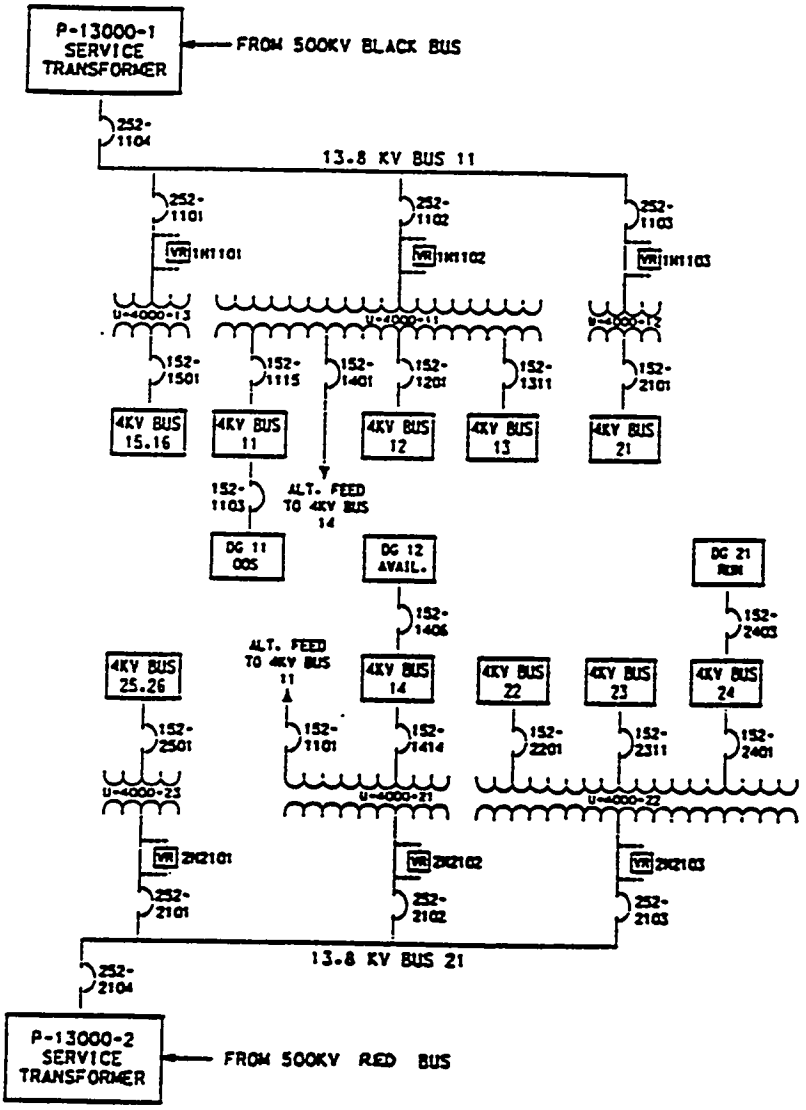

FIGURE 1

LER No. 324/94-008
Brunswick, Unit 2

NRC FORM 366 (5/92) U.S. NUCLEAR REGULATORY COMMISSION

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

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant, Unit 2	05000324	1 of 4

TITLE (4)
Dispatcher Switching Evolution Results in Loss of Offsite Power to Unit 2

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
05	21	94	94	- 08 -	00	06	09	94	Brunswick Unit 1	05000325
									FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	5
POWER LEVEL (10)	0

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Jeanne F. McGowan, Regulatory Affairs Specialist	(910) 457-2136

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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

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

On May 21, 1994, Unit 2 was in a Refuel Outage. The Unit 2 Startup Auxiliary Transformer (SAT) was being supplied from Switchyard Bus 2B. At 1442 hours, the system dispatcher notified the Brunswick Control Room that maintenance had been completed on the Whiteville 230 kV line and that the circuit breakers would be restored to service. Testing of the Whiteville breakers would involve opening one breaker on Switchyard bus 2B and two breakers on Switchyard Bus 2A. At 1509 hours, the dispatcher opened the one breaker on Bus 2B. He then opened the remaining two breakers feeding bus 2B (the two breakers feeding Bus 2A should have been opened). Opening the remaining two breakers to Bus 2B caused a Loss of Offsite Power to Unit 2. All four Diesel Generators (DGs) started and DG 3 and 4 auto loaded to their respective Emergency Buses. Engineered Safety Feature Systems actuated as required. The Reactor Building Ventilation inboard dampers failed to automatically isolate due to a failed relay. The dampers were manually closed from the Control Room. All other systems operated as designed. The cause of the event was personnel error. Corrective actions include requiring dual verification for switching evolutions at nuclear power plants and reviewing the event with appropriate operations personnel. The safety significance was minimal. All DGs auto started and DGs 3 and 4 loaded to their respective Emergency Buses.
The cause classification for this event per the criteria of NUREG-1022 is personnel error.

NRC FORM 366A (5/92) U. S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 5/31/95
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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	05000324	94	- 08 -	00	2 of 4

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

TITLE

Dispatcher Switching Evolution Results in Loss of Offsite Power to Unit 2

INITIAL CONDITIONS

On May 21, 1994, Unit 2 was in a Refuel Outage. The Unit 2 Start-up Auxiliary Transformer (SAT) and the Caswell Beach Pumping Station Transformer were being supplied from Switchyard Bus 2B.

EVENT NARRATIVE

On May 20, 1994, a line clearance from the System Dispatcher had been placed on the Unit 2 Whiteville 230 kV Line to apply Room Temperature Vulcanized (RTV) Silicone coating to the bus insulators. On May 21, 1994, Carolina Power & Light Substation Maintenance personnel canceled the line clearance on the Unit 2 Whiteville 230 kV line. The system dispatcher informed the Brunswick Nuclear Plant (BNP) Control Room that the Whiteville circuit breakers were going to be returned to service. The switching instructions were written to test and restore the section of the Whiteville 230 kV line to service. The Wallace (28B), the Castle Hayne (27A), and the Delco West (30A) circuit breakers would be opened to isolate the 2B bus from any possible fault, and the Whiteville 230 kV line would be tested from the Wallace 230 kV line through the 2A bus.

The Unit 2 230 kV electrical system configuration (see attachment) has four incoming feeders from the grid (Whiteville, Delco West, Wallace, and Castle Hayne West). The feeders can be lined up to either the 2A or 2B Bus. The Unit Main Transformers, the Startup Auxiliary Transformer (SAT), and the Unit Auxiliary Transformer (UAT) also supply either the 2A or the 2B Bus. The SAT supplies power to the plant during shutdown conditions. During power operations the SAT feeds the Reactor Recirculating Pumps and the UAT supplies all other plant loads. At the time of the switching evolution the SAT was being supplied from the Switchyard 2B Bus with the Delco West, the Castle Hayne West and the Wallace circuit breakers feeding the bus.

On May 21, 1994, at 1442 hours, the dispatcher notified the BNP Control Room that they were commencing the switching evolution to return the Whiteville 230 kV line to service. At 1505 hours, the dispatcher confirmed with the BNP Unit 2 Control Room that the SAT was being supplied from Switchyard Bus 2B. The procedure instructs the dispatcher to "go to manual control and open the Wallace 28B 230 kV CB, the Castle Hayne West 27A 230 kV CB, and the Delco West 30A 230 kV CB". There is a manual selection for each of the circuit breakers on the 230 kV line and at 1508 hours, the dispatcher placed the Delco West 30B, Wallace 28B, and Castle Hayne West 27B circuit breakers in manual. At 1509 hours, he opened the Wallace 28B, Delco West 30B, and Castle Hayne 27B circuit breakers de-energizing Bus 2B and causing a loss of power to the SAT. All four Diesel Generators (DGs) auto started and DG 3 and DG 4 loaded to their respective Emergency Buses. The Reactor Protection System (RPS) motor generators "A" and "B" tripped. The spent fuel pool cooling pumps and supplemental spent fuel pool cooling pumps tripped and the "2A" nuclear service water pump auto started. There was an isolation of Reactor Building Ventilation System and an auto start of the Standby Gas Treatment System (SBGT). The Reactor Building Ventilation system inboard dampers did not automatically isolate due to a relay failure in the SBGT control relay logic. The following Primary Containment Isolation System (PCIS) isolations occurred:

PCIS Group 2, Drywell Floor and Equipment Drains,

NRC FORM 366A (5/92) U. S. NUCLEAR REGULATORY COMMISSION

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

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	05000324	94	- 08 -	00	3 of 4

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

PCIS Group 3, Reactor Water Cleanup System,

PCIS Group 6, Containment Atmospheric Control System,

PCIS Group 10, Pneumatic Nitrogen System

Unit 1 experienced an isolation of the PCIS Group 6 (CAC) valves, a Reactor Building isolation and a SBGT auto start, loss of two drywell coolers, a Conventional Service Water (CSW) pump trip and an auto start of a standby CSW pump, and the Unit 1 Hydrogen Water Chemistry System trip.

The Unit 2 Reactor Operator informed the dispatcher that there had been an auto start of the diesel generators. The dispatcher realized that the "B" breakers had been opened rather than the "A" breakers and notified Brunswick of the error. At 1511 hours the "B" circuit breakers were closed and power was restored to the Unit 2 SAT.

Subsequent recovery actions were in accordance with the plant Abnormal Operating Procedures. At 1551 hours, Buses 2B, 2C, and 2D were re-energized from the SAT. Emergency Bus E4 was re-energized from bus 2C at 1613 hours, and Bus E3 was re-energized from Bus 2D at 1618 hours. All four diesel generators were secured and placed in standby. All switching operations were completed at 1828 hours, with the switchyard 230 kV buses in normal configuration.

CAUSE OF EVENT

The cause of the event was personnel error. The dispatcher executed the actions specified in the switching instructions too rapidly. The switching instruction contained six actions in one step, allowing the performance of multiple actions without referencing the procedure. All six actions were completed in 52 seconds which did not allow time for self-checking. Additionally, the time between actions did not allow communications (intended action and feedback) with the BNP Control Room which should have identified that the intended action was incorrect.

The switching instructions contained actions for both the "A" and "B" bus in one step. The dispatcher had previously reviewed the switching instructions and noted that actions were required on both "A" and "B" buses. He had underlined the differences, yet when referencing the step prior to execution, only "B" registered in his mind.

A contributing factor was the BNP review of the switching instructions prior to the evolution. The review did not identify that the instructions were not written to the same standard as BNP procedures nor that a high risk potential existed with incorrect execution of the switching instructions.

CORRECTIVE ACTIONS

1. Appropriate controls were established to ensure that switching instructions follow established plant procedure format.

2. The event was reviewed by appropriate system dispatchers.

3. Pre-job briefings will be required for all planned switching activities involving nuclear power plants.

NRC FORM 366A (5/92) U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	05000324	94	- 08 -	00	4 of 4

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

4. Instructions for any planned switching activity at a nuclear power plant will require dual verification ensuring that the correct device has been selected.

5. Senior Reactor Operator review of switching instructions will be documented on the BNP Control Room copy prior to authorization of planned switching activities.

6. The event will be reviewed by appropriate BNP operations personnel.

7. System dispatchers will be trained on the STAR (Stop, Think, Act, Review) method of self-checking.

SAFETY ASSESSMENT

The safety significance was minimal. All four diesel generators auto started with diesels 3 and 4 auto loading to their respective emergency buses. All Engineered Safety Feature systems operated as designed with the exception of the Reactor Building inboard supply and exhaust dampers failing to auto close. The failure was due to a relay failure in the Standby Gas Treatment System control relay logic. The dampers were manually closed from the Control Room at 1608 hours. The relay was replaced on May 28, 1994. Switchyard bus 2B was restored within 4 minutes and bus 2A remained energized and available throughout the event.

PREVIOUS SIMILAR EVENTS

Previous events involving a Loss of Offsite Power are discussed in LERs 1-93-008 and 2-91-016.

EIIS COMPONENT IDENTIFICATION

System/Component	EIIS Code
Containment Atmospheric Control System	IK
Primary Containment Isolation System	JM
Reactor Protection System	JD
Standby Gas Treatment System	BH
Switchyard System	FK

LER No. 336/94-040
Millstone, Unit 2

NRC Form 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES: 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Millstone Nuclear Power Station Unit 2	05000336	1 OF 3

TITLE (4): Ventilation Design Deficiency Affecting Enclosure Building Integrity

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
12	6	94	94	- 040 -	00	12	28	94		05000
									FACILITY NAME	DOCKET NUMBER
										05000

OPERATING MODE (9)	*	THIS REPORT IS BEING SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)	0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	(Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Philip J. Lutzi, Nuclear Licensing	(203) 440-2072

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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

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

On December 6, 1994, at 2223 hours, with the plant defueled, it was determined that a release path existed from the Enclosure Building that would allow for a direct discharge to atmosphere following a Loss of Coolant Accident (LOCA) that would not receive charcoal filtration.

The root cause is a deficiency in the original design.

NRC Form 366 (5-92)

NRC Form 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 2	05000336	94	- 040 -	00	02 OF 03

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

I. Description of Event

On December 6, 1994, at 2223 hours, with the plant at 0% power with the core offloaded, it was determined that a release path existed from the Enclosure Building that would allow a direct discharge to the atmosphere during a Loss of Coolant Accident (LOCA) that would not receive charcoal filtration. The cause of this event has been determined to be an oversight in the original design of the discharge flow path for the Hydrogen analyzers. With the establishment of the system engineering program, the engineer reviewing a work package immediately identified the discrepancy in this non-safety related system and initiated an investigation.

The design basis of the Enclosure Building Filtration System is to collect any leakage from the Containment Structure during a LOCA and process the leakage through a High Efficiency Particulate (HEPA) and Charcoal Filtration system. This method of discharge minimizes the publics exposure to Iodine and maintains off site dose less than 10CFR100 limits.

A hydrogen analyzer cabinet and sample hood exhaust fan was found to take a suction on the enclosure building and discharge approximately 1000 cfm out the Unit 2 Main Exhaust stack. This flow path has HEPA filters but does not have any Charcoal Adsorber filtration. This non-safety related exhaust fan normally runs to maintain a negative pressure on the sample hood to prevent technicians from being exposed to gas while obtaining routine chemistry samples. The fan has no automatic shut off feature and there are no isolation dampers in the line to prevent a release during an event that would actuate the Enclosure Building Filtration System.

The Radiological Assessment branch performed an evaluation to determine the effects of this condition. Their analysis was based upon a major accident assuming a substantial meltdown of the core with subsequent release of appreciable quantities of fission products as identified in 10CFR100.11 and concluded that the calculated site boundary thyroid dose would exceed 10CFR100.11 limits.

Following the discovery of this condition on December 6, 1994, immediate corrective action was to declare the enclosure building integrity inoperable. The plant was in an undefined mode due to the core being off loaded when the discrepancy was found and declared inoperable. Enclosure Building integrity is not required in Mode 5 or 6, therefore, no additional operator actions were required.

There were no automatic or manually initiated safety systems actuated as a result of the event.

II. Cause of Event

The root cause of this event is the design and installation of the hydrogen analyzer cabinet ventilation system.

III. Analysis of Event

Based on event investigation, this event is reportable under the criteria of 10CFR50.73(a)(2)(v), "Any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to Mitigate the consequences of an accident."

The Radiological Assessment branch performed an evaluation to determine the effects of this condition. Their analysis was based upon a major accident assuming a substantial meltdown of the core with subsequent release of appreciable quantities of fission products as identified in 10CFR100.11 and concluded that the calculated site boundary thyroid dose would exceed 10CFR100.11 limits. This has been a configuration that has been in service since initial installation.

NRC Form 366A (5-92)

NRC Form 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Millstone Nuclear Power Station Unit 2	05000336	94	- 040 -	00	03 OF 03

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

IV. Corrective Action

Following the event discovery on December 6, 1994, immediate corrective action was to declare the Enclosure Building integrity inoperable. Since the plant was defueled when the discrepancy was found and declared inoperable and Enclosure Building integrity is not required in Mode 5 or 6, no additional immediate actions were required.

Work is in progress to redesign the hydrogen analyzer and sample sink ventilation systems to correct this deficiency prior to Mode 4 when enclosure building integrity is required.

V. Additional Information

Similar LERs: None

EIIS Codes

Enclosure Building	BD
Hydrogen Analyzer Cabinet	IK-CAB
Hydrogen Analyzer Cabinet Fan	IK-FAN

NRC Form 366A (5-92)

LER No. 366/94-003
Hatch, Unit 2

NRC FORM 366 (5-92) U.S.NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Edwin I. Hatch Nuclear Plant - Unit 2

DOCKET NUMBER (2): 0 5 0 0 0 3 6 6 | PAGE (3): 1 OF 8

TITLE (4): Fuse Actuation Results in ESF Actuation and Interruption in Shutdown Cooling Flow

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

OPERATING MODE (9)	4
POWER LEVEL (10)	0 0 0

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME: Steven B. Tipps, Nuclear Safety & Compliance Manager

TELEPHONE NUMBER (include area code): AREA CODE 9 1 2 3 6 7 - 7 8 5 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

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

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

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

On 3/17/94, at 1131 EST, Unit 2 was in the Cold Shutdown mode, one day into a scheduled refueling outage. Reactor coolant temperature was 168 degrees Fahrenheit. The "B" loop of the Residual Heat Removal (RHR) System was in operation in the Shutdown Cooling (SDC) mode. At that time, a non-licensed engineer was tracing the routing of a control wire in a Control Room panel when he observed an arc in the panel and heard several relays actuate. He notified the licensed Shift Supervisor. Subsequent walkdown of the control room panels revealed that the loop "B" SDC discharge valve, 2E11-F015B, was closed and SDC flow was zero. An operator attempted to open the valve with the control switch but was unsuccessful. Shift personnel then entered procedure 34AB-E11-001-2S, "Loss of Shutdown Cooling," and began, with engineers' assistance, to investigate the cause of the valve isolation. At 1202 EST, the cause of the event had not been determined, and it was decided to place the "A" loop of RHR in the SDC mode. By 1250 EST, SDC flow had been restored via the "A" loop of the RHR system. Bulk average reactor coolant temperature did not exceed 212 degrees Fahrenheit throughout the event. However, investigation showed that the reactor vessel pressurized to approximately 9 psig during the event. The cause of the event was inadvertent grounding of a Primary Containment Isolation System logic circuit resulting in a fuse actuation and isolation of the SDC discharge valve. Corrective actions include replacing the fuse, repairing a wire termination, revising procedures, changing an alarm setpoint and training personnel.

NRC Form 366 (5-92)

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL YEAR	REVISION NUMBER	PAGE (3)
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	– 0 0 3	– 0 0	2 OF 8

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

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System Codes are identified in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 3/17/94, at 1131 EST, Unit 2 was in the Cold Shutdown mode, one day into a scheduled refueling outage. Reactor coolant temperature was 168 degrees Fahrenheit as measured at the inlet to the Reactor Water Cleanup System (RWCU, EIIS Code CE). The "B" loop of the Residual Heat Removal System (RHR, EIIS Code BO) was in operation in the Shutdown Cooling (SDC) mode. The "A" loop of RHR was aligned to the Low Pressure Coolant Injection (LPCI) mode. The "A" and "B" loops of Core Spray were operable. The 2A, 1B, and 2C Emergency Diesel Generators (EDG, EIIS Code EK) were operable. The reactor vessel was vented to the Unit 2 Drywell via the reactor head vent line. The Unit 2 Drywell head had been removed; thus, Unit 2 Primary Containment was communicating with Unit 1 Secondary Containment. (The two units share a common refueling floor which is part of Unit 1 Secondary Containment.) Unit 1 Secondary Containment was intact but the Unit 2 Secondary Containment (Reactor Building) was not intact. All Drywell penetrations which allow communication between Unit 2 Primary Containment and Unit 2 Secondary Containment were isolated.

Prior to the event, it had been determined that several control circuit relay coils needed replacement. In support of the replacement effort, a nonlicensed engineer was tasked with physically verifying the wiring configuration of the relays. At 1131 EST, the engineer was tracing the routing of a control wire in Main Control Room panel 2H11-P623 when he observed an arc in the panel and heard several relays actuate. After being notified of the arc, the Shift Supervisor inspected the panel and directed the licensed operators to walk down the control panels, noting any unusual conditions that may have resulted from the arcing incident. At approximately 1140 EST, an operator walking down the panels discovered that the loop "B" SDC discharge valve, 2E11-F015B, was closed and that SDC flow was zero. The operator notified the Shift Supervisor. No plant conditions existed that would necessitate closure of the valve; therefore, the operator attempted to open the valve with the control switch. The valve cycled open and then automatically closed indicating that a Primary Containment Isolation System (PCIS, EIIS Code JM) signal was in effect on the valve control logic. This valve is a dual function valve providing Primary Containment isolation capability as well as injection capability for the SDC and the Low Pressure Coolant Injection (LPCI) modes of the RHR system. The operator then reset the PCIS signal and attempted to open the valve. Again, the valve cycled open and then automatically closed, indicating that an invalid PCIS signal was sealed in. The operating RHR pump was then secured and the discharge throttle valve, 2E11-F017B, was closed.

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	– 0 0 3	– 0 0	3 OF 8

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

Shift personnel then entered procedure 34AB-E11-001-2S, "Loss of Shutdown Cooling," and began, with engineers' assistance, to investigate the cause of the PCIS signal. Procedure 34AB-E11-001-2S requires increased monitoring (i.e., every 15 minutes) of the reactor coolant temperature and the reactor vessel pressure, as well as other plant parameters. The procedure also requires that reactor water level be raised to greater than 53 inches above instrument zero, if SDC flow is not restored immediately, in order to induce natural circulation in the reactor vessel. Prior to the event, the reactor water level was 37 inches above instrument zero (195 inches above the top of the active fuel) and was therefore raised to 57 inches above instrument zero.

Procedure 34AB-E11-001-2S requires that if reactor coolant temperature approaches 212 degrees Fahrenheit an alternate means of SDC should be established. The "A" loop of RHR was operable and capable of being aligned to the SDC mode if necessary. However, since temperature as measured at the RWCU system inlet was essentially constant at 168 degrees Fahrenheit, placing the "A" loop of RHR in the SDC mode was not immediately pursued and activities focused on monitoring plant parameters and identifying and correcting the cause for the invalid PCIS signal.

At approximately 1202 EST, licensed personnel saw reactor coolant temperature as measured at the RWCU inlet begin increasing. At this point, the cause of the event had not been determined and it was decided to place the "A" loop of RHR in operation in the SDC mode. By 1250 EST, reactor coolant temperature as measured at the RWCU inlet had increased to 185 degrees Fahrenheit and SDC flow had been restored via the "A" loop of the RHR system. Forced circulation was thus restored and the higher temperature coolant in and above the reactor core region was being moved into the annulus region. Consequently, RWCU inlet temperature initially increased, reaching a maximum of 194.8 degrees at 1255 EST, before it began to decrease.

By 1325 EST, a blown fuse in a Group 2 PCIS initiation circuit had been found and replaced. Subsequently, the PCIS signal was reset and the 2E11-F015B valve was cycled to ensure its operability.

An Event Review Team was established to fully investigate the event. In reviewing strip charts and process computer printouts after the event, the team determined that the reactor pressure had reached a maximum of approximately 9 psig during the interruption in SDC flow. Pressure was greater than atmospheric for approximately 3 hours. Because of the apparent pressurization of the reactor vessel, there was concern that the plant had gone from the cold shutdown condition, to hot shutdown. Analysis of the event by General Electric, however, showed that the bulk average

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

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Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	– 0 0 3	– 0 0	4 OF 8

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

temperature was less than 212 degrees Fahrenheit throughout the event, indicating that the Hot Shutdown mode had not been entered. (By definition, the plant is in the hot shutdown mode when the average reactor coolant temperature is above 212 degrees Fahrenheit).

CAUSE OF EVENT

The cause of the interruption in SDC flow was inadvertent grounding of a PCIS initiation circuit. Specifically, an engineer, in attempting to identify control wiring, slightly moved a bundle of control wires in a control panel to view a wire label. One of the wires in the bundle that was landed to a nearby relay terminal contacted a metal cable raceway when the bundle was moved, grounding the circuit. This wire is a multi-strand wire and is attached to the relay with a compression fitting. One of the strands of the wire had been separated from the other strands apparently during installation and was not held by the compression fitting. When the bundle was moved, the wire moved enough to bring the strand into contact with an adjacent metal raceway, grounding the associated circuit. The grounding incident caused the circuit fuse to actuate and the circuit to de-energize. The wire was part of a PCIS initiation logic circuit which is of a fail-safe design in that it de-energizes to initiate an actuation. Consequently, when the fuse actuated, a PCIS signal was generated and several outboard PCIS valves including valve 2E11-F015B automatically closed.

Pressurization of the reactor vessel was caused by several factors. First, the reactor had been shutdown approximately 34 hours before the event; thus, decay heat load was relatively high. Therefore, with the interruption in SDC flow, localized boiling occurred in the reactor core and steam was generated and emitted into the steam dome area of the reactor vessel. The reactor head vent line was open at the time of the event. However, the 1/2 inch line was not of sufficient capacity to totally vent off the steam being generated, resulting in slight pressurization of the reactor vessel.

An additional factor contributing to the event was that licensed personnel believed that with the reactor head vent open, pressurization of the reactor vessel was not possible for the conditions existing at the time of the event. Procedure 34AB-E11-001-2S also contained wording that implied that pressurization was not possible with the head vent open. However, a review of design documentation for the vent line showed that the purpose for the vent was to provide a path for noncondensibles when flooding up the vessel for hydrostatic testing, not to prevent pressurization due to localized boiling.

Procedure 34GO-OPS-015-2S, "Maintaining Cold Shutdown," was less than adequate in that it specified inappropriate instrumentation for monitoring reactor pressure in low pressure conditions. Specifically, the procedure directed licensed personnel to use reactor pressure indicators 2C32-

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

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		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	- 0 0 3	- 0 0	5 OF 8

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R605A, B, or C or the Process Computer for monitoring reactor pressure in the Cold Shutdown mode. The scale of the pressure indicators is 0 - 1200 psig and the smallest graduation is 20 psig on a spacing of 3/16-inch. Consequently, a pressure increase of the magnitude occurring in this event would be difficult if not impossible to discern on these indicators. The Process Computer, however, provides a digital output that is accurate at low pressures. In this event, licensed personnel, given the option to use the indicators or the Process Computer, used the indicators and, therefore, did not see the rise in reactor pressure during the event.

A Process Computer alarm for low core flow that had recently been installed did not annunciate during the event. The alarm was designed to annunciate when jet pump flow decreased below the level expected with SDC in service, providing an indirect indication for an interruption of SDC flow. However, when the interruption in SDC flow occurred, the alarm did not annunciate. It was later determined that indicated jet pump flow did not decrease with the interruption in SDC flow. This was because the jet pump flow instrumentation is calibrated under high temperature conditions. Without density compensation integrated into the instrumentation, indicated flow increases as temperature of the coolant decreases even when actual flow remains constant. At the time of the event, the reactor coolant temperature was substantially less than that during normal operation. Therefore, due to the higher density of the lower temperature coolant, the indicated flow of the jet pumps did not decrease sufficiently to trip the alarm. Had the alarm functioned in this event, licensed personnel would have been made aware of the interruption in SDC flow approximately eight minutes earlier; the eight minute delay was, however, inconsequential in this event.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required pursuant to 10 CFR 50.73(a)(2)(iv) because an unplanned Engineered Safety Feature (ESF) actuation occurred resulting in the automatic closure of Group 2 PCIS valves. Additionally, the event resulted in an interruption of SDC flow which further resulted in relatively low pressurization of the reactor pressure vessel. This aspect of the event is not reportable, however, is being included in the report since it was a consequence of the ESF actuation and may be of industry interest.

The Primary Containment Isolation System provides automatic isolation capability of Primary Containment penetrations to preclude the release of radioactive material and the loss of reactor coolant inventory in the unlikely event of an accident. In this event, inadvertent grounding of a control circuit resulted in a loss of power to a PCIS initiation circuit which is of a fail-safe design in that, upon a loss of power to the circuit, an isolation signal is generated. Consequently, a partial

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

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Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	- 0 0 3	- 0 0	6 OF 8

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

PCIS isolation occurred resulting in several PCIS valves automatically closing. With the unit in an outage, many of the valves were already closed prior to the event. Had the event occurred coincident with an accident, the valves would still have closed as required, isolating the associated Primary Containment penetration.

One of the PCIS valves that closed as a result of the fuse actuation was valve 2E11-F015B. As stated previously, this valve is a dual function valve providing Primary Containment isolation in the closed position and SDC/LPCI injection capability in the open position. Consequently, when the valve automatically closed in this event, SDC flow was interrupted. The purpose of the SDC mode of the RHR system is to provide adequate cooling to the reactor core while the reactor is shutdown in order to reduce the reactor coolant temperature to and/or maintain it below 212 degrees Fahrenheit. In this event, SDC flow was interrupted for approximately one hour and twenty minutes. At the time of the event several backup systems, each of which are capable of maintaining adequate reactor core cooling, were available. The "A" loop of RHR-SDC was available and was ultimately used to re-establish cooling flow to the reactor core. Had the "A" loop of RHR not been available, either of the "A" or "B" loops of Core Spray (CS, EIIS Code BM), which were both available, could have been used for alternate shutdown cooling. In this mode of operation, the RHR System is aligned to the Suppression Pool Cooling mode. When reactor pressure reaches approximately 50 psig, a Safety Relief Valve (SRV, EIIS Code SB) would be opened providing a flow path from the reactor vessel to the Suppression Pool. A Core Spray pump would then be started taking suction from the Suppression Pool. Reactor water level would then be raised to the level of the Main Steam lines and flow would be established through the SRV to the Suppression Pool.

During the event, the interruption in SDC flow resulted in heatup of the reactor coolant. An analysis performed by General Electric showed that the bulk average temperature of the reactor coolant did not exceed 212 degrees Fahrenheit. Therefore, based on the Technical Specification criteria for entering the Hot Shutdown mode, a mode change to Hot Shutdown did not occur as a result of this event. However, the reactor vessel did pressurize to approximately 9 psig during the event. The General Electric Evaluation also determined that the noted pressure increase was credible.

Had the Hot Shutdown mode been reached during the event, the requisite conditions of Primary Containment and Secondary Containment would not have existed. Specifically, Unit 2 Primary Containment was not intact. The Drywell head had been removed prior to the event and Unit 2 Primary Containment was communicating with Unit 1 Secondary Containment. (The two units share a common refueling floor which is part of Unit 1 Secondary Containment.) The penetrations

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 6/31/95
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	– 0 0 3	– 0 0	7 OF 8

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

between Unit 2 Primary Containment and Unit 2 Secondary Containment were isolated; therefore, Unit 2 Primary Containment was not in communication with Unit 2 Secondary Containment. Unit 2 Secondary Containment was not intact in that the Reactor Building equipment door was open to support outage activities. Had the Hot Shutdown mode been reached, Unit 2 Secondary Containment could have been established quickly by closing the equipment door. Unit 2 Primary Containment could not have been established expeditiously due to the Drywell head being removed. However, due to the fact that no gross fuel failures existed, any radioactive releases into Unit 1 Secondary Containment would be minimal and would be processed by the Standby Gas Treatment system (SGT, EIIS Code BH) and released via an elevated release path. Consequently, 10 CFR 100 limits would not have been exceeded.

Based on the above information, it was concluded that this event had no adverse impact on nuclear safety. This assessment applies to all operating conditions.

CORRECTIVE ACTIONS

The fuse was replaced and the operability of the 2E11-F015B valve was verified.

The wire involved in the grounding incident was reterminated with all of the strands landed in the compression fitting.

The Process Computer alarm setpoint problem has been corrected.

Procedure 34GO-OPS-015-2S will be revised to specify the Process Computer as the primary means for monitoring reactor pressure in low pressure conditions. Other operations procedures will be reviewed for this problem and revised as necessary. This action will be completed by 7/29/94.

Procedure 34AB-E11-001-2S will be revised to state that the potential exists for pressurization of the reactor vessel upon interruption in SDC flow even if the reactor head vent is open. Other operations procedures will be reviewed for this problem and revised as necessary. This action will be completed by 7/29/94.

An engineering evaluation will be completed by 6/30/94 to determine if the reactor head vent line size should be increased.

The outage planning and scheduling philosophy has been revised to require that both loops of RHR be available until the reactor cavity is flooded.

NRC FORM 366A (5-92) U.S.NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 5/31/95
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Edwin I. Hatch Nuclear Plant - Unit 2	0 5 0 0 0 3 6 6	9 4	– 0 0 3	– 0 0	8 OF 8

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

Operations licensed shift personnel have been trained on this event with special emphasis on the potential for pressurizing the reactor vessel even with the head vent open.

ADDITIONAL INFORMATION

No systems other than those previously identified in this report were affected by this event.

One event has occurred in the previous two years in which SDC flow was interrupted. The event was reported in LER 50-321/93-004, dated 5/14/93. In that event, a PCIS logic circuit fuse actuated when the circuit was inadvertently grounded during a wiring modification. The condition went unnoticed for approximately one and a half hours. Corrective actions for the event included increasing the frequency of checking critical plant parameters, including SDC flow, during Cold Shutdown and issuing a plantwide directive informing plant personnel of the possible consequences of grounding incidents and the need to aggressively investigate incidents to determine their effect on the plant. These corrective actions were not intended to prevent future interruptions in SDC flow. No reasonable actions can be taken to completely eliminate the potential for such events. These corrective actions were intended to prevent prolonged interruptions in SDC flow by helping to ensure that licensed personnel became aware of such interruptions as soon as possible. One of the corrective actions was instrumental in this manner. Specifically, the individual seeing the arcing in this event knew of the potential consequences of such arcing events because of previous training and notified the shift supervisor of the event almost immediately after it had occurred.

The frequency of SDC flow checks had been increased from once every four hours to once every hour as a result of the previous event. It had been performed thirty minutes prior to the event and was not scheduled to be performed for another thirty minutes when the event occurred. Had the interruption in SDC flow gone unnoticed for another thirty minutes, placing the "A" loop of SDC in service would most likely not have been delayed since the decision to do so was based on RWCU inlet temperature increasing which did not occur until approximately thirty minutes after the interruption occurred.

No failed components contributed to this event.

Appendix I

LER No. 382/94-004
Waterford, Unit 3

NRC FORM 366 5-92 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Waterford Steam Electric Station Unit 3	05000 382	1 OF 8

TITLE (4)
Degraded CCW Heat Exchanger Discovered While Shutdown, Due to Biological Fouling

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									n/a	05000
03	07	94	94	-- 004 --	00	04	05	94	FACILITY NAME: n/a	DOCKET NUMBER: 05000

OPERATING MODE (9)	5
POWER LEVEL (10)	0

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

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

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
P.A. Gropp, Systems Engineering Supervisor	(504) 739-6652

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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

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

On March 7, 1994, during plant shutdown for Refuel 6, it was determined that Component Cooling Water (CCW) Heat Exchanger 'A' was degraded according to performance testing conducted in response to Generic Letter 89-13. The CCW system is designed to provide cooling water to safety-related components at a maximum temperature of 115 degrees F under accident conditions. Evaluation of test results, extrapolated to design accident conditions, predicted a CCW outlet temperature of 117.2 degrees F. The degraded condition of CCW Heat Exchanger A is believed to be outside the design basis of the system in that the required capacity of the heat exchanger may not have been available for maximum design accident conditions. The root cause of the degradation is biological fouling of the heat exchanger. Corrective actions included chemical cleaning of CCW Heat Exchangers 'A' and 'B'. An engineering review concluded that the heat exchanger would have fulfilled its intended safety function prior to shutdown because the heat removal capacity of the degraded CCW Heat Exchanger would have been adequate to remove accident heat loads. Therefore, this event did not compromise the health and safety of the general public or plant personnel.

NRC FORM 366 (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	2 OF 8

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

REPORTABLE OCCURRENCE

On March 6, 1994, during cooldown to begin Refueling Outage 6, Special Test Procedure 01120153 was conducted to collect performance data on Component Cooling Water (CCW) Heat Exchanger 'A' (EIIS Identifier CC-HX) in accordance with the recommendations of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." Evaluation of test results, extrapolated to design accident conditions, predicted a CCW Heat Exchanger outlet temperature of 117.2 degrees F, which would exceed the design outlet temperature of 115 degrees F.

The CCW system (EIIS Identifier CC) is a closed water system designed to remove heat from safety-related components. Two trains of dry and wet cooling towers, along with the water stored in the wet cooling tower basins (EIIS Identifier BS), constitute the ultimate heat sink (EIIS Identifier BS) at Waterford 3. The function of the ultimate heat sink is to dissipate the heat removed from the reactor and its auxiliaries during normal unit operation, during refueling, or after a design basis accident. Ultimate heat sink dissipation is accomplished jointly by the dry and wet cooling towers and is highly dependent upon meteorological conditions.

Each dry cooling tower (EIIS Identifier CC-CTW) is sized to dissipate to atmosphere approximately 60 percent of heat removed by the CCW system after a LOCA assuming a historically highest ambient dry bulb temperature of 102 degrees F. The wet cooling towers (EIIS Identifier BS-CTW) remove heat from the CCW system via a separate Auxiliary Component Cooling Water (ACCW) system (EIIS Identifier BI). The ACCW system uses water from the wet cooling tower basin and pumps it through the CCW Heat Exchanger where its temperature is raised, and then to the wet cooling tower for heat dissipation to the atmosphere. Each wet cooling tower is sized to dissipate to atmosphere

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	3 OF 8

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

approximately 40 percent of heat removed by the CCW system after a LOCA, assuming the historically highest ambient wet bulb temperature of 83 degrees F.

With a degraded CCW Heat Exchanger, heat transfer to the wet cooling tower is diminished. The design basis maximum CCW Heat Exchanger outlet temperature is 115 degrees F under maximum post-accident heat loads. Evaluation of special test results on March 7, 1994, indicated that the design basis maximum CCW Heat Exchanger outlet temperature could have been exceeded, resulting in the discovery of a degraded condition while shutdown. This condition would have resulted in operation outside of the plant design basis and is reportable as a 30 day LER per 10CFR50.73(a)(2)(ii)(B).

INITIAL CONDITIONS

Plant Power	0
Plant Operating Mode	Mode 5
Procedures Being Performed Specific to this Event	Special Test Procedure 01120153
Technical Specification LCO's in Effect Specific to this Event	None
Major Equipment Out of Service Specific to this Event	CCW Heat Exchangers 'A' and 'B'

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	4 OF 8

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

EVENT SEQUENCE

(Times are approximate)

On March 6, 1994, at 1500 hours, Special Test Procedure 01120153 was initiated in Mode 5 during cooldown to begin Refueling Outage 6. The purpose of the Special Test Procedure was to collect performance data for the CCW Heat Exchanger 'A', in response to recommendations of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment". At 1955 hours the data collection was completed and the affected systems were secured from testing.

On March 7, Engineering completed a preliminary evaluation of the performance test results and extrapolation of those results to design accident conditions predicted a CCW Heat Exchanger outlet temperature of 118.2 degrees F, which would have exceeded the design outlet temperature of 115 degrees F. At 1645 hours, a four hour notification was provided to the NRC in accordance with 10CFR50.72 (b)(2) for the discovery of a degraded condition while shutdown. In addition, Condition Report (CR) 94-174 was initiated to document the degraded condition of the CCW Heat Exchanger in the corrective action program.

On March 13, a borescopic examination was performed on CCW Heat Exchanger 'B'. The borescopic examination revealed deposits and microbiological activity on the outside diameter of the tubes. Chemical cleaning of CCW Heat Exchanger 'B' was completed and the results of the chemical cleaning were verified by an additional borescopic examination on March 18.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	5 OF 8

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

On March 21, Engineering completed the formal evaluation of the performance test results and extrapolation of those results to maximum design accident conditions predicted a revised CCW Heat Exchanger outlet temperature of 117.2 degrees F.

On March 25, a borescopic examination was performed on CCW Heat Exchanger 'A'. The borescopic inspection revealed similar fouling conditions to those found in CCW Heat Exchanger 'B'. Chemical cleaning of CCW Heat Exchanger 'A' was completed and the results of chemical cleaning were verified by an additional borescopic examination on March 28.

CAUSAL FACTORS

The root cause of this event is biological fouling of the CCW Heat Exchanger tubes, which degraded the heat transfer capability required to dissipate heat to the wet cooling tower under maximum accident conditions. Borescopic examination of both CCW Heat Exchangers 'A' and 'B' revealed deposits and microbiological activity on the outside diameter of the tubes. It is believed that the microbiological activity in the wet cooling tower basins contributed to the biological fouling of the heat exchanger tubes.

IMMEDIATE CORRECTIVE MEASURES

Corrective measures included the performance of a borescopic examination on both CCW Heat Exchangers 'A' and 'B'. The borescopic examination revealed deposits and microbiological activity on the heat exchanger tubes. Chemical cleaning was conducted and the results of the chemical cleaning were verified by a post cleaning borescopic examination.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	6 OF 8

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

The post-cleaning borescopic examination revealed that the deposits and microbiological activity were removed from the outside of the heat exchanger tubes. Engineering concluded that the thermal performance of the CCW Heat Exchangers has been restored to the design condition.

ACTIONS TO PREVENT RECURRENCE

In addition to the current performance trending and testing of CCW Heat Exchangers, periodic borescopic examinations of the heat exchangers will be performed during Cycle 7 as plant conditions permit, during system outages. Findings will be reported to the Chemistry Department. Condition Report (CR) 94-174 was initiated to document the degradation of the CCW Heat Exchanger and track associated corrective actions.

Furthermore, the Chemistry Department will evaluate the current sampling and treatment program as defined in Technical Procedure CE-002-003, "Maintaining Wet Cooling Tower Chemistry." Technical Procedure CE-002-003 will be revised based on the results of that evaluation by August 31, 1994, to prevent the conditions which contributed to the degradation of the CCW Heat Exchangers. Condition Report (CR) 94-217 was initiated to document the condition of the wet cooling tower basin and track associated corrective actions.

NRC FORM 366A (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	7 OF 8

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

SAFETY SIGNIFICANCE

Engineering performed a review to determine if degraded CCW Heat Exchanger would have fulfilled its intended safety function prior to shutdown. The engineering review concluded that the heat removal capacity of the degraded CCW Heat Exchanger would have been adequate to remove accident heat loads.

The function of the ultimate heat sink is to dissipate the heat removed from the reactor and its auxiliaries during normal unit operation, during refueling, or after a design basis accident. The ultimate heat sink is required to have sufficient capacity to dissipate heat removed by the CCW and ACCW systems:

- after a design basis accident, assuming a single active failure coincident with a loss of offsite power and the historically highest dry bulb temperature of 102 degrees F and the historically highest wet bulb temperature of 83 degrees F, and;

- to permit safe shutdown of the unit coincident with a loss of offsite power, multiple tornado missiles and single active failure.

The ultimate heat sink consists of dry and wet cooling towers and water stored in the wet cooling tower basins. Each dry cooling tower has been sized to dissipate to the atmosphere approximately 60 percent of heat removed by the CCW system after a Loss of Coolant Accident (LOCA) assuming the historically highest ambient dry bulb temperature.

NRC FORM 366A (5-92)

NRC FORM 366A :5-92 U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Waterford Steam Electric Station Unit 3	05000 382	94	- 004 -	00	8 OF 8

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

Wet cooling towers remove heat from the CCW system via the separate ACCW system. The ACCW system takes water from the wet cooling tower basin, pumps it through the component cooling water heat exchanger where its temperature is raised, and then to the wet cooling tower for heat dissipation to the atmosphere. Each wet cooling tower is sized to dissipate to the atmosphere approximately 40 percent of heat removed by the CCW system after a LOCA, assuming the historically highest ambient wet bulb temperature.

The dry and wet cooling tower design heat removal is based on the maximum historical one hour average dry bulb temperature of 102 degrees F, and the maximum historical one hour average wet bulb temperature of 83 degrees F. The ultimate heat sink heat dissipation is a collaborative effort of the wet and dry cooling towers and the heat sink capacity is highly dependent upon meteorological conditions. When meteorological conditions more favorable than the historical maximums exist, heat dissipation capacity margin is created. With a degraded CCW Heat Exchanger, heat transfer to the wet cooling tower is diminished. Meteorological conditions permitting however, the dry cooling tower capacity will increase and attempt to compensate.

An engineering review concluded that, given the degraded capacity of the CCW Heat Exchanger, the ultimate heat sink was capable of dissipating the peak LOCA heat load coincident with the highest recorded hourly temperature during Cycle 6. Therefore, the degraded condition of the CCW Heat Exchanger did not compromise the health and safety of the general public or plant personnel.

SIMILAR EVENTS

There have been no similar events reported as LERs.

NRC FORM 366A (5-92)

Appendix I

LER No. 454/94-003
Byron, Unit 1

LICENSEE EVENT REPORT (LER)

FACILITY NAME	DOCKET NUMBER	PAGE
BYRON NUCLEAR POWER STATION	0 5 0 0 0 4 5 4	1 OF 0 4

TITLE: AUXILIARY FEEDWATER ISOLATION VALVE EXPOSURE TO POTENTIALLY HARSH ENVIRONMENT DUE TO FLOOD SEAL REMOVAL

EVENT DATE			LER NUMBER			REPORT DATE			OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQ. NUMBER	REVISION	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 3	1 4	9 4	9 4	- 0 0 3	- 0 0	0 4	1 3	9 4	BYRON, UNIT 2	0 5 0 0 0 4 5 5
										0 5 0 0 0

OPERATING MODE		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (CHECK ONE OR MORE OF THE FOLLOWING)			
	1	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL	0 9 9	20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER
LAUREL ZECH, LICENSING GROUP LEADER, EXT. 2825	8 1 5 2 3 4 - 5 4 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED		EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
X YES. (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 7	1 3	9 4

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

On 03/14/94, the design bases of the Flood Seal Openings (FSO) located between the Main Steam Tunnel (MS)[SB] and the Auxiliary Feedwater (AF)[BA] Tunnel was questioned since these flood seal openings have been occasionally removed during operation to allow access to the AF tunnel. Byron Station's Safety Evaluation Report (SER) states that the flood seal opening plates between the Main Steam tunnel and the Auxiliary Feedwater tunnel separate equipment in the AF tunnel from the environment created in the event of a main steamline break (MSLB) in the MS safety valve room or steam pipe tunnel and ensure a watertight environment in the AF tunnel in the event of turbine building flooding due to a circulating water pipe break. The AF isolation valves in the AF tunnel are not in the Equipment Qualification (EQ) Program since the environment is considered mild, and therefore, since they have not been analyzed for a harsh environment they cannot be relied upon to mitigate consequences of an event occurring while the FSO plates are removed. However, the plates have been removed for periods of time during plant operations which exposed the equipment in the AF tunnel to potentially harsh environments.

Immediate corrective actions included verifying that the AF tunnel FSO plates were in place on both units and requiring the FSO plates to remain in place until this issue has been evaluated and acceptable resolution achieved.

This event is reportable per 10CFR50.73(a)(2)(v) any condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident.

(9953R/WPF/041294/2)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION				
FACILITY NAME	DOCKET NUMBER	LER NUMBER		PAGE
		YEAR	SEQ. NUMBER / REVISION	
BYRON NUCLEAR POWER STATION	0 5 0 0 0 4 5 4	9 4	- 0 0 3 - 0 0	0 2 OF 0 4

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

A. PLANT CONDITIONS PRIOR TO EVENT:

Event Date/Time 03-14-94 / 12:30

Unit 1 MODE 1 - Power Operation Rx Power 99% RCS [AB] Temperature/Pressure NOT/NOP

Unit 2 MODE 1 - Power Operation Rx Power 99% RCS [AB] Temperature/Pressure NOT/NOP

B. DESCRIPTION OF EVENT:

On 03/14/94, during a review of plant documentation following a routine plant walkdown, an operator noted that the Updated Final Safety Analysis Report (UFSAR) identifies a maximum normal temperature for the auxiliary feedwater (AF) [BA] tunnel of 100 degrees F and a maximum accident temperature of 419 degrees F for the main steam (MS) [SB] tunnel. The difference in the temperature values prompted the operator to question what allowed removal of the FSO plates during operation since they provide the isolation between the MS tunnel and the AF tunnel. These plates have been removed for periods of time during power operations to accommodate maintenance and surveillance activities in the AF tunnel (see Attachment A) in accordance with Byron Administrative Procedures in existence since 1985. The equipment located in the AF tunnel, both trains of steam generator (SG) AF isolation valves (1/2AF013A through H) and supporting electrical equipment, is not included in the Environmental Qualification (EQ) Program since the AF tunnel is considered a mild environment.

Upon further investigation by Regulatory Assurance, it was determined on 03/29/94 that closure of the FSO plates is required for compliance with General Design Criteria (GDC) 4. As documented in the Byron SER and SSER-2, the FSO plates are relied upon to separate equipment in the AF tunnel from the environment created in the event of a main steamline break (MSLB) in the MS safety valve room or steam pipe tunnel and to ensure a watertight environment in the AF tunnel in the event of turbine building flooding due to a circulating water pipe break. As noted above, the equipment in the AF tunnel is not in the EQ Program, and therefore, since they have not been analyzed for a harsh environment they could not be relied upon to mitigate consequences of an event occurring while the FSO plates are removed. Specifically, the AF isolation valves in the AF tunnel may not provide isolation of a faulted SG following exposure to the environment created by a MSLB or flooding event. Reportability consistent with 10CFR50.72, a condition which alone could have prevented the fulfillment of a safety function needed to mitigate the consequences of an accident, was determined at 1430 CST on 03/29/94. NRC was notified via the Event Notification System of this condition at 1510 CST (1610 EST) on 03/29/94. At the time of notification, all AF tunnel FSO plates were in place.

This event is reportable per 10CFR50.73(a)(2)(v) any condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident.

C. CAUSE OF EVENT:

The removal of the flood seals was performed in accordance with our current procedures; however, the bases for removal of the flood seal openings during operation requires further investigation. A Root Cause investigation is in progress. The results of this investigation will be reported in a supplemental LER.

(9953R/WPF/041294/3)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION				
FACILITY NAME	DOCKET NUMBER	LER NUMBER		PAGE
		YEAR / SEQ. NUMBER / REVISION		
BYRON NUCLEAR POWER STATION	0 5 0 0 0 4 5 4	9 4 - 0 0 3 - 0 0		0 3 OF 0 4

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

D. SAFETY ANALYSIS:

The safety consequences of this event were minimal. During the time periods when the FSO plates were removed, no incidence of MSLB or turbine building flooding occurred. Had such an event occurred, current Byron Emergency Operating Procedures address alternate equipment and methods which could have been used to provide isolation of AF to the steam generators, if needed.

Electrical cable for equipment other than the AF isolation valves passes through the AF tunnel, but no safety related terminations for these cables are present in the tunnel. The cables are qualified and purchased to the same specifications as other safety related cable used in harsh environmental applications. Since the plant cable qualification envelopes the MS tunnel conditions during a MSLB, there would be no adverse affects on the cable in the AF tunnel should an event occur while the FSO plates are removed.

E. CORRECTIVE ACTIONS:

Immediate corrective actions included verifying that the AF tunnel FSO plates were in place on both units and requiring the FSO plates to remain in place until this issue has been evaluated and acceptable resolution achieved. Additionally, the AF tunnel FSO plates were tagged to alert personnel to not remove them without Shift Engineer approval.

Activities currently in progress to determine appropriate long term corrective actions include the following:

1. Evaluation of ability to qualify/document other equipment available to achieve isolation of the SGs in the event of a MSLB in the steam tunnel with the AF tunnel FSO plates removed.

2. Evaluation of an appropriate time period for which the FSO plates can be removed for maintenance and surveillance activities without significantly increasing the risk of core damage and/or offsite release.

3. Evaluation of procedural enhancements based on results of 1 and 2.

The above activities are being tracked via commitments 454-180-94-00300-01 through 03 respectively. When final corrective actions are determined, a supplemental report will be submitted (454-180-94-00300S1).

F. RECURRING EVENTS SEARCH AND ANALYSIS:

SOER 85-05 and NRC Information Notices No. 87-49 and No. 92-52 addressed industry flooding concerns. Byron responded with administrative controls and training related to the flood seals. These actions are not directly related to the concerns in this event.

An event concerning design inadequacy of the AF discharge isolation valves was reported as Byron LER 90-012. This inadequacy rendered the AF013 valves potentially incapable of being closed within the specified time frames of the analysis for a MSLB inside containment. Although the condition was different than considered in this LER (94-003), the corrective actions, enhancing procedures to provide alternatives to operators for isolating flow to a faulted steam generator, served to mitigate consequences of the current event.

(9953R/WPF/041294/4)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION				
FACILITY NAME	DOCKET NUMBER	LER NUMBER		PAGE
		YEAR / SEQ. NUMBER / REVISION		
BYRON NUCLEAR POWER STATION	0 5 0 0 0 4 5 4	9 4 - 0 0 3 - 0 0		0 4 OF 0 4

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

G. COMPONENT FAILURE DATA:

No component failure occurred during this event.

(9953R/WPF/041294/5)

LER 94-003

Attachment A
History of AF Tunnel Flood Seal Opening Plate Removal
for previous 12 months (03/29/93 - 03/29/94)

DATE REMOVED	DATE REPLACED	REASON FOR REMOVAL
11/17/92	04/27/93	Flood seal #1-9 removed for EM surveillance.
01/29/93	04/27/93	Flood seal #1-7 removed to support outage activities.
01/29/93	04/27/93	Flood seal #1-8 removed to support outage activities.
03/09/93	03/29/93	Flood seal #2-8 removed for EM surveillance.
05/25/93	05/29/93	Flood seal #2-8 removed.
06/21/93	07/07/93	Flood seal #1-8 removed for EM access to Unit 1 Tunnel.
07/13/93	07/16/93	Flood seal #2-8 removed for EM access to AF Tunnel.
08/24/93	09/02/93	Flood seal #1-8 removed for access to AF Tunnel.
09/01/93	10/25/93	Flood seal #2-8 removed.
10/13/93	10/19/93	Flood seal #1-8 removed for inspection support.
11/15/93	02/23/94	Flood seal #1-8 removed for EM access to AF Tunnel.
12/15/93	03/14/94	Flood seal #2-8 removed for Teledyne surveillance.
03/16/94	03/25/94	Flood seal #2-8 removed to inspect pipe hangers.
03/16/94	03/25/94	Flood seal #1-8 removed to inspect/repair AF line pipe hangers.

(9953R/WPF/041294/6)

LER No. 458/94-023
River Bend

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

LICENSEE EVENT REPORT (LER)

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
River Bend Station	05000-458	1 of 18

TITLE (4)
REACTOR SCRAM DUE TO SPURIOUS SIGNALS FROM UNDAMPED ROSEMOUNT MODEL 1153 TRANSMITTERS

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									N/A	05000
09	08	94	94	023	01	12	12	94	FACILITY NAME: N/A	DOCKET NUMBER: 05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more (11))							
POWER LEVEL (10)	97	20.402(b)		20.405(c)		X	50.73(a)(2)(iv)		73.71(b)
		20.405(a)(1)(i)		50.36(c)(1)			50.73(a)(2)(v)		73.71(c)
		20.405(a)(1)(ii)		50.36(c)(2)			50.73(a)(2)(vii)	X	OTHER
		20.405(a)(1)(iii)	X	50.73(a)(2)(i)			50.73(a)(2)(viii)(A)	(Specify in abstract below and in text, NRC Form 366A)	
		20.405(a)(1)(iv)		50.73(a)(2)(ii)			50.73(a)(2)(viii)(B)	10CFR21	
		20.405(a)(1)(v)		50.73(a)(2)(iii)			50.73(a)(2)(x)	SPL. RPT: T.S.3.5.1	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
T.W. Gates, Supervisor - Nuclear Licensing	504-381-4866

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	JC	LT	R370	Y						
B	BN	TRB	D245	Y						

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

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

On September 8, 1994 at 8:28 PM, with the reactor at 97 percent power, an automatic reactor scram occurred due to a false high reactor water level condition sensed on channels C and D of the reactor water level instrumentation. During this event, the RCIC turbine tripped due to binding of the turbine governor valve. The conditions leading to this failure have been determined to be reportable pursuant to 10CFR21. Since the HPCS system was manually operated during this event, this supplement also finalizes the Special Report required by Technical Specification 3.5.1 concerning emergency core cooling system (ECCS) injections.

The cause of this event is spurious signals from undamped Rosemount model 1153 transmitters in response to process noise. The model 1153 transmitters that were in service in the reactor water level instrumentation application have been replaced with Rosemount model 1152s. Extensive monitoring was conducted as a conservative measure during the startup from the forced outage and continuing into power operation for a limited period of time.

The investigation of transmitter performance revealed that the model 1153 susceptibility to process noise would not have prevented the transmitters from functioning properly in an actual event. Equipment and radiological issues, including reactor vessel cooldown and the Technical Specification surveillance time limit non-compliances for radiological and chemistry sampling were evaluated and determined not to be safety significant. Therefore, this event did not compromise the health and safety of the public.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 2 OF 18

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

1.0 REPORTED CONDITION

On September 8, 1994 at 8:28 PM, with the reactor at 97 percent power, an automatic reactor scram occurred due to a false high reactor water level condition sensed on channels C and D of the narrow range reactor water level instrumentation (*JC-LT*). During the course of the event, surveillance time limits requiring sampling of noble gases, tritium, and reactor coolant conductivity were not met. Therefore, this event is reported pursuant to 10CFR50.73(a)(2)(iv), to document the reactor scram, and 10CFR50.73(a)(2)(i)(B) to document the non-compliances with the Technical Specifications.

2.0 INVESTIGATION

2.1 Initial Conditions

The plant was at 97 percent power with power ascension in progress to 100 percent power at a rate of 1 percent per hour. During the previous shift, power had been reduced to 76 percent in response to loss of a non-safety-related chiller. No surveillance test procedures were being performed and no maintenance was in progress in the containment.

2.2 Event Description

On September 8, 1994, at 8:28 PM, an automatic reactor scram occurred due to a false high reactor water level condition, sensed by the C and D channels of the narrow range reactor water level instrumentation. The control room operators had no indication of the origin of the scram at the time it occurred. There was no control room indication of a reactor water level increase or a feedwater level excursion. Operators initiated recovery procedures.

By design, the reactor scram did not result in an automatic trip of the main turbine (*TA*) or electric generator (*TB*) or the reactor feed pumps (*SJ-P*). During the process of completing AOP-0002, "Turbine/Generator Trip," the unit operator (UO) recognized that the turbine had not tripped. Recognizing that the normal trip for this condition would be the generator trip on reverse power, the operator attempted to determine if a reverse power condition actually existed. The digital generator load indicator was alternately indicating 5 and 6 MW. The analog generator load indicator had decreased to 0 MW, but the generator output breakers (*TB-BKR*) had not opened on reverse power as expected by the operator. The UO immediately reported to the Control Room Supervisor (CRS) that the turbine was still on-line.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION			APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 3 OF 18

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

Since reactor pressure was continuing to drop, the crew felt that some action was required to take the turbine off-line regardless of whether or not a reverse power condition existed. After evaluating the condition, the CRS directed the crew to manually trip the turbine, intending to intentionally arm the generator anti-motoring trip function, so that the generator output breakers would automatically open.

Following the turbine trip, the main generator failed to trip on reverse power and was manually tripped at 8:40 PM, approximately twelve minutes after the reactor scram. The manual trip of the generator resulted in a slow bus transfer of non-safety related station services, as designed.

The slow bus transfer resulted in the de-energization of non-safety related loads as the bus supply source was shifted from the normal station service transformers (*XFMR*) to the preferred station service transformers (*XFMR*) (i.e., off-site power). The de-energization of the non-safety related buses resulted in the loss of power to all condensate pumps (*SD-P*), all feedwater pumps (*SJ-P*), reactor recirculation pumps (*AD-P*), and both Reactor Protection System (RPS) (*JC-BU*) buses. Loss of normal power to the RPS buses caused a balance of plant isolation and main steam isolation valve (*ISV*) closure. This loss of electrical power also caused a failure of the Safety Parameter Display System (SPDS) (*IU*) and the Emergency Response Information System (ERIS) (*IQ*) computers.

The Reactor Core Isolation Cooling (RCIC) (*BN*) system was manually started to provide make-up to the reactor pressure vessel, but tripped on a mechanical overspeed condition. The High Pressure Core Spray (HPCS) pump (*BG-P*) was then manually started and used to raise Reactor Pressure Vessel (RPV) level and maintain adequate core cooling. Main steam safety-relief valves (*SB-RV*) were cycled by the operators, as required by procedures, to control RPV pressure. During the event, an automatic transfer of the HPCS suction source, from the condensate storage tank (CST) (*TK*) to the suppression pool, occurred on high suppression pool water level. After due consideration, the HPCS system was manually transferred back to the CST, as directed by EOP-0001 "RPV Control."

Emergency procedures were utilized to assure control of RPV and containment parameters. On three occasions, SRVs automatically actuated at the relief setpoint. At 10:09 PM, the Shift Superintendent declared a Notification Of Unusual Event (NOUE) at his discretion to mobilize assistance to maintain the plant in a stable condition. There were no unmonitored radiological releases and all effluents remained within established limits.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 4 OF 18

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

At 11:21 PM, reactor feedwater was restored to service. Restoration of other plant systems was proceeding in accordance with plant procedures. At 12:30 AM on September 9, all Emergency Operating Procedures were exited and the NOUE was terminated.

2.3 SEQUENCE OF EVENTS

20:28 Automatic reactor scram (Initiating signal: RPV Water Level 8 signals to RPS channels C and D.).

Recirculation pumps transferred to slow speed automatically.

20:38 Manual trip of main turbine.

20:40 Manual trip of Main Generator output breakers.

Normal (13.8 kV) station service buses NPS-SWG1A and NPS-SWG1B "slow transfer" from the normal station service transformers to the preferred station service transformers. Non-safety related plant equipment was deenergized as follows:

- Condensate and feedwater pumps (loss of normal high pressure makeup to the reactor vessel).
- RPS A and B (results in a full MSIV and BOP isolation). (Normal power supply to safety related RPS busses is via non-safety related motor generator sets. RPS fails safe on loss of power.)
- Reactor recirculation pumps.
- Circulating water pumps A & C.
- Instrument Air Compressor B
- One Normal Service Water pump.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 5 OF 18

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

-	Emergency Response Information System (ERIS) computer.
-	Safety Parameter Display System (SPDS) computer.
20:41	RPS A&B manually transferred to alternate supply.
20:44	Operators attempted to provide coolant makeup water to the reactor via the Reactor Core Isolation Cooling (RCIC) System. The RCIC turbine trips on overspeed and cannot be reset from the Main Control Room. Safety Relief Valves used to manually control reactor pressure.
20:49	Restored Drywell Cooling.
20:57	High Pressure Core Spray (HPCS) pump started manually to provide coolant makeup water to the reactor. Level at 0" (wide range) and lowering (Note: Normal operating water level is +35 inches, auto-initiation setpoint is -43 inches, and the top of the active fuel is -162 inches).
21:18	Opened B21*MOVF019 (*SB-20*), Main Steam Drain Outboard Isolation Valve, establishing a vent path from the reactor vessel to the main condenser to assist in reactor pressure control.
21:20	Restored Turbine Building Chillers (*NM-CHU*) to service.
21:27	Started Residual Heat Removal System in Suppression Pool Cooling Mode.
21:38	Valve 1CNS-MOV112 (*SD-20*) could not be opened during condensate fill and venting
21:56	Reset Reactor Scram.
22:03	Re-inserted one-half scram on Division I to comply with Technical Specification 3.3.1, "Reactor Protection System Instrumentation."
22:09	Notification of Unusual Event declared.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 6 OF 18

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

22:20 Restarted Condensate Pump CNM-P1A (*SD-P*).

23:21 Started Main Feed Pump A (*SJ-P*).

23:51 Re-opened Main Steam Isolation Valves (*SB-ISV*) after chillers reduced area temperatures below the isolation setpoint.

00:17 Secured HPCS. Reactor water level maintained with main feed pump.

00:30 Exited Emergency Operating Procedures and terminated Notice of Unusual Event.

2.4 Turbine Response

As designed the reactor scram did not result in an automatic trip of the main turbine. Instead, operators manually tripped the turbine at 2238, ten minutes after the scram. Operators manually tripped the generator breakers at 2040. The manual trip of the generator resulted in a slow bus transfer of nonsafety-related station services, as designed.

The feedwater control system reactor vessel level transmitters are used to sense reactor water level and trip the main turbine and feedwater pumps on high water level. The nuclear boiler instrumentation reactor vessel level transmitters sense reactor water level and trip the reactor on high water level. In this case, since two level transmitters in the nuclear boiler instrumentation system sensed the high reactor water level, an automatic scram resulted. However, since only one level transmitter in the feedwater control system sensed a high reactor water level, the main turbine and feedwater pumps did not automatically trip. Process computer data indicate that the scram was caused by level 8 signals from narrow range reactor water level instrumentation channels C and D. ERIS data indicates that narrow range feedwater level transmitter 4C reached the level 8 setpoint and that 4A and 4B did not. The two-out-of-three logic required to produce a turbine trip was not satisfied since only one of three channels reached the level 8 setpoint. Therefore, with regard to the reactor vessel high water level signals, the main turbine trip logic functioned as designed.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 7 OF 18

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

2.5 Generator Response

By design, the reactor scram did not result in an automatic trip of the main turbine or generator. Operators inserted a manual trip of the turbine approximately 10 minutes after the reactor trip. The manual turbine trip resulted in turbine stop valve closure. Following the turbine trip, the main generator did not trip on reverse power. Normally, the generator output breakers are expected to open upon reverse power to the generator following a reactor scram. The generator output breakers were manually opened at 2040, approximately twelve minutes after the reactor scram, since the reverse power trip function had not initiated. The manual trip of the generator resulted in a slow bus transfer of non-safety related station services, as designed.

The investigation revealed that the failure of the reverse power trip to initiate as expected was due to common mode calibration inaccuracies in the reverse power relays, 32G and 32G1, combined with a very low power factor (i.e., high reactive load). The generator was operating under a large reactive load at a very low power factor which resulted in an extreme phase angle at the relay. The relays were found to have been misadjusted by 2 degrees for relay 32G1 and 4 degrees for relay 32G. This combined with inherent relay inaccuracy, resulted in the failure of the relays to actuate because the generator was operating within the error band of the relay trip point. This is the root cause of the failure of the generator output breakers to open on reverse power.

2.6 Transfer to Offsite Power

During a main turbine trip, the main generator should trip after reverse power occurs. Two automatic transfer schemes ("fast" and "slow") are provided to transfer station electrical loads from the main generator to off-site power. In accordance with the system design, a slow, instead of a fast, transfer occurred during this event. A slow bus transfer provides a protective function for station equipment and differs from a fast transfer in that it results in the tripping of all bus loads. Manual restoration of those loads is required following a slow transfer.

The slow transfer of 1NPS-SWG1A and 1B was not anticipated by Operations personnel, but the evaluation revealed that it occurred correctly. Since the generator output breakers were manually tripped prior to the reverse power trip occurring, relay logic blocked the fast transfer

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
River Bend Station	05000-458	94-023-01	8 OF 18

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

from occurring. Thus, the prerequisites for the fast transfer were not met. With regard to the function of the fast/slow transfer circuits, no corrective action is required. However, the indications available to the operators could be improved to allow evaluation of the reverse power condition and support operators' decision when to trip the generator output breakers.

2.7 RCIC Turbine Trip

On September 8, 1994, subsequent to the manual opening of the generator output breakers after the scram, the slow transfer to the preferred offsite power resulted in a loss of normal feedwater.

Upon the loss of feedwater, the operators initiated actions to manually start the RCIC turbine in anticipation that it may be needed to help control reactor vessel coolant level and reactor pressure. The RCIC turbine tripped when steam was admitted to the turbine. The operator could not reset the RCIC turbine from the control room and the indications that he had were consistent with a mechanical overspeed trip which by design must be reset locally. Subsequent field investigation verified that the mechanical overspeed trip device was actuated and had caused the RCIC turbine to trip. The cause of the RCIC pump turbine overspeed was found to be binding of the turbine governor valve due to accelerated corrosion of the valve stem. The root cause of the accelerated corrosion is the combined effect of problems with the surface treatment of the governor valve stem, improper washer material in the valve gland area and characteristics of the carbon spacers in the gland area (i.e., porosity and the presence of sulfur). The investigation revealed that the surface treatment of the stem was non-uniform, with variations in thickness and defects present. The sulfur in the carbon spacers can leach out in a moist environment and create an electrolytic solution to support galvanic corrosion. The improper washer material can also promote galvanic corrosion. EOI has determined that this condition is reportable pursuant to 10CFR21. The stem, washers and spacers were manufactured by Terry Steam Turbine Company. Dresser-Rand Steam Turbines is the current vendor. The stem, spacers, and washers were new equipment installed during refueling outage 5.

The washers supplied in 1984 were installed during refueling outage 5. One of these washers was selected for analysis which revealed that it was made out of 300 series stainless steel instead of 410 stainless. Another group of washers was supplied in 1985. Of the 21 washers in the 1985 order, 20 of them were 300 series stainless steel, and one was 400 series stainless steel. The part number of the washers supplied in 1984 and 1985 was the same, P/N#54846.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION			APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 9 OF 18

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

2.8 MOV Issues

The post-scram investigation revealed that SWP*MOV40A (*BS-20*) failed during midstroke due to a short in one of its control cables. The safety function of 1SWP*MOV40A is to open during a standby service water initiation. Valve 1SWP*MOV40A was approximately 30% open when it failed during mid-stroke. A generic design vulnerability applicable only to Limitorque SMB-00 actuators was identified and measures have been implemented to prevent recurrence.

In addition, several non-safety power operated valves (MOVs and SOVs) also failed to respond as expected. These valves were in balance-of-plant (BOP) systems and had no impact on the ability to safely shut down the reactor and maintain it in a safe shutdown condition.

The root cause for the problems associated with the non-safety related valves is the lack of a preventive maintenance program.

2.9 Event Response Information System and Safety Parameter Display System

During the plant transient, the normal power supply to the Safety Parameter Display System (SPDS), transient analysis computers which is part of the Emergency Response Information System (ERIS) and Digital Radiation Monitoring System (DRMS) was lost. Upon discovering that the computer systems were inoperable, the system engineer attempted to archive any available data, then restarted the computer systems and restored them to their normal display and data collection functions. The cause of the failure was that the power inverter (*INVT*), 1BYS-INV06, which supplies power to these systems, was unavailable. The inverter was in bypass for maintenance.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION			APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 10 OF 18

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

2.10 Reactor Vessel Stratification, Cooldown, Pressure/Temperature Limits

The investigation included evaluation of reactor vessel stratification, cooldown, and the effect on pressure and temperature limits. The cooldown rate exceeded the Technical Specification limit of 100 degrees F per hour. The evaluations to address these issues revealed that in each case, the thermal transient effects were bounded by previous analyses, including the thermal transient effects due to the cooldown rate. Usage factors for the HPCS nozzle, piping, and recirculation system piping and components were determined to be within the design values. The total accumulated actuation cycles for the HPCS nozzle was calculated to be 15. The circumstances that led to the initiation of the HPCS system are described in Section 2.2, Event Description. This report provides the information required for the Special Report pursuant to T.S. 3.5.1.

2.11 Noble Gas and Tritium Samples

After the reactor scram, Chemistry did not obtain samples of main plant noble gas and tritium within one hour even though the dose equivalent I-131 concentration exceeded three times normal. The tritium and noble gas samples were taken approximately one hour late.

Following the event, an investigation of the TS requirements was conducted. This investigation found that the TS wording changed prior to issue of the initial low power operating license to add the one hour time limit for sampling tritium and noble gases following thermal transients. The change created a time requirement that is inconsistent with the other licensing basis documents reviewed and the TS from the other operating boiling water reactor (BWR) 6 plants in the United States. The one hour limit following reactor thermal transients cannot be fulfilled following a reactor scram due to time requirements for sampling and analysis. While the surveillance was not performed within one hour, the requirements of the action statement of TS 3.11.2.1 were not violated. The dose rate due to radioactive effluents was always within the TS limits.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION			APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 11 OF 18

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

The missed sample was a recurrence of a previous event, documented in LER 87-013 and Condition Report (CR) 87-962, in which the same TS samples were missed following a reactor scram. In that event, the root cause was failure of control room personnel to notify chemistry personnel that the plant had scrammed. The corrective actions for that event included adjusting the volume on the plant paging system in the chemistry lab and investigating a possible change to the TS. The response from that investigation stated that there was inadequate justification to request a change. The corrective actions for LER 87-013 were not sufficient to prevent recurrence and are considered part of the cause of the missed chemistry sample.

Contributing factors included absence of the sample pump at 1RMS*RE125, and delays entering the Auxiliary Building due to operation of the SGTS.

2.12 Conductivity Sample

Following the reactor scram, chemistry failed to obtain the reactor coolant conductivity analysis once per every four hours after a loss of continuous conductivity recording. Prior to the reactor scram only the Reactor Water Cleanup System (*CE*) (WCS) influent conductivity monitor was operable in accordance with TS 3/4.4.4. The recorder in the control room for the reactor recirculation conductivity monitor had been determined to be inoperable earlier that day by the on-shift chemistry technician. While obtaining the dose equivalent I-131 samples at 0206 of that same night the on-shift chemistry technician observed flow from the WCS sample line, although at a reduced rate. Communications with control room personnel at 0230 informed him that the WCS pumps had tripped following the scram; however, he was unaware that containment isolation valves for this system had closed and that the reactor recirculation conductivity recorder was not operable.

The root cause of the missed conductivity sample was determined to be the lack of timely communications between control room and chemistry personnel regarding status of the reactor water cleanup system. Chemistry personnel were also unaware that the reactor recirculation conductivity recorder was inoperable.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 12 OF 18

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

2.13 Radiological Impact

Two radiological transients occurred subsequent to the scram. A transient in the turbine building ventilation system resulted in a build-up of noble gases in the turbine building. After the ventilation system was restored to service, noble gas levels rapidly decreased to normal. In addition, a radiological transient in the containment building occurred subsequent to safety relief valve actuation which resulted in an increase in containment building activity. An evaluation and off-site dose calculation was performed prior to initiating a reactor building purge. As a result, radiological conditions in containment stabilized and returned to normal.

The contribution of these transients to the off-site dose was below TS and 10CFR off-site radiological limits. A review of the events determined that the radiological procedures utilized during the event were adequate for transient events. The review also concluded that communication and staffing (including augmented staffing) were adequate to perform the required RP activities. No corrective actions are required.

3.0 Root Cause Evaluation

All available data associated with reactor operation that could potentially affect reactor water level instrumentation was reviewed and all potential failure modes were identified using event and causal factors charts, Kepner-Tregoe (K-T) analysis, and failure mode analysis.

Two major paths were considered in the investigation of the level 8 signal. One of these paths considered an actual change in reactor vessel level. The other path considered was an indicated level transient. The analysis of the events in the indicated level transient path led to the conclusion that the probable cause of the event was process noise resulting in a large amplitude trip signal on the RPS C and D level transmitters and feedwater level transmitter C. The investigation included in-vessel-visual-inspections (IVVI). The information gained from these inspections was evaluated and resulted in ruling out many theorized causes.

The cause of this event is spurious signals from undamped Rosemount model 1153 transmitters in response to process noise. All three of these transmitters are Rosemount model 1153 transmitters. Rosemount model 1152 transmitters were used for RPS channels A and B and these channels did not initiate a level 8 signal. The investigation revealed that all three of the model 1153 transmitters had been installed as replacements for Rosemount model 1152s.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 13 OF 18

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

The three affected 1153s had minimum damping; two were set at minimum damping and one had no damping card installed. The investigation of the damping issue revealed that the time response testing requirements for the transmitters results in minimal damping.

The investigation also revealed deficiencies in the maintenance of these transmitters. While these issues did not contribute to the root cause, they are being addressed. A damping card was not installed on RPS level channel C and feedwater level transmitter C was undamped. However, if the damping card had been installed on RPS channel C, it would probably have been set to minimum damping, and the scram would still have occurred. The minimization of damping was permissible given the design guidance available to maintenance personnel; however, improvements in the areas of generic modification guidance and maintenance planning will be evaluated.

Based on testing that was performed, engineering personnel concluded that the transmitters would have functioned properly during an actual level transient. The investigation also revealed that no electrical or significant hydraulic transient existed.

4.0 Corrective Action

As a result of the September 8 event, Entergy Operations promptly formed a "Significant Event Response Team" (SERT) to investigate the event and develop appropriate corrective actions. The SERT team was authorized by the plant manager and its membership included a high level of management from multiple departments. The team's function was to investigate root cause and provide corrective actions for all deficiencies identified during the September 8 event. Management oversight was provided by members of the executive staff led by John McGaha, Vice President - Operations.

The event response organization was supplemented by offsite Entergy Operations personnel and nuclear industry expertise, including General Electric and root cause analysis experts from Failure Prevention International (FPI). An assist team from the Institute of Nuclear Power Operations (INPO) was also onsite to investigate the event.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 14 OF 18

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

Review of selected condition reports associated with this event was conducted by the Corrective Action Review Board (CARB). This board is comprised of the direct reports to the Vice President - Operations, the General Manager - Plant Operations and his direct reports, Manager, Nuclear Safety and Assessment, and the QA Manager. This review is conducted to assure proper root cause determination and development of effective corrective actions for events determined to be significant by the criteria of River Bend Nuclear Procedure RBNP-030, "Initiation and Processing of Condition Reports."

The sections below document the current status of the primary corrective actions for the issues identified in this event.

4.1 Rosemount Model 1153 Transmitters and Backfill System

- The Rosemount 1153 transmitters that were in service in the reactor water level instrumentation and feedwater level applications have been replaced with Rosemount model 1152s which do not have the same sensitivity to process noise.
- A verification of all aspects of the configuration of all safety related Rosemount transmitters was performed prior to startup. Plant walkdowns were used to baseline the configuration and verify the transmitters based on model number, required damping, and mounting.
- Time response testing methodology will be reviewed with a focus on industry practices.
- Generic modifications for changeouts of equipment and the maintenance planning process will be evaluated.
- To address a potential vulnerability identified by the investigation, the backfill system has been modified to relocate the orifices downstream of the check valves.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 15 OF 18

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

- EOI developed a monitoring program to track important process parameters during the startup from the forced outage and following this for a limited time during power operation. The objective of this program was to identify operational anomalies to minimize the risk of recurrence, as a conservative measure. The monitoring program was completed with no unusual events or anomalies detected.

4.2 Operations

With respect to operator performance, several lines of investigation are being pursued as a result of this event. The goal of this investigation is to identify areas where enhancements will result in improved operator performance. Specific areas of interest include:

- Event Reconstruction. In the interest of obtaining a complete, clear understanding of a significant plant event, Operators should be debriefed as soon as possible. Although individual debriefings were conducted by operations management, a full crew debriefing was not conducted in a timely manner. The delay in conducting a full crew debriefing will be evaluated and appropriate guidance developed regarding the timeliness of these interviews.

- Procedures. The AOP for turbine and generator trip contains requirements related to verification of generator trip. This procedure, AOP-0002, has been revised to improve the procedural guidance for positive verification of reverse power conditions. Procedure Enhancements identified during review included revision of AOP-0001, "Reactor Scram," to improve the turbine trip verification, and SOP-0080, "Turbine Generator Operation," to provide a caution on turbine/generator motoring.

- Training. The crew's understanding of the issue of the fast/slow transfer of station loads was not clear and the simulator modeling and associated training was incorrect. Simulator modifications have been implemented to correct deficiencies. Training has been provided during the last licensed operator requalification module concerning the procedure changes to AOP -0001 and AOP-0002. In addition, a simulator scenario has been developed which requires operator action to manually open the generator output breakers following failure of the generator reverse power/anti-motoring trips.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 16 OF 18

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

4.3 Generator Response

Both reverse power relays were recalibrated to maintain the phase angle of each at its setpoint with the tightest tolerance attainable. Improvements in the applicable maintenance procedure, MCP-1005, are being considered.

4.4 Transfer to Offsite Power

To improve the indications available to the operators for evaluation of the reverse power condition and determining when to trip the generator output breakers, the SPDS system graphic display in the control room has been upgraded to indicate negative megawatts. This display will allow operators to monitor reverse power conditions.

4.5 RCIC Turbine Trip

The governor valve stem has been replaced with a new stem having an aluminized coating for increased corrosion resistance. Washers of the proper material have been installed, and periodic monitoring of the stem resistance is being performed, pending further evaluation of monitoring data.

4.6 Motor Operated Valves

Corrective actions being implemented for SWP*MOV40A are:

- The damaged wire and lug were replaced and repositioned to avoid rubbing.
- Nine (9) additional SMB-00 actuators were identified and have been inspected for similar lug configurations on contacts LS-1 and LS-9. No additional problems were identified.
- Maintenance procedures will be revised to include guidance on proper positioning of wires landed on contacts LS-1 and LS-9.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95		
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503		
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 17 OF 18

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

River Bend Station is implementing a preventive maintenance program action plan with a focus on reliability centered maintenance (RCM), and prioritization by Maintenance Rule system and component importance. The predictive and preventive maintenance tasks for non-safety related valves will be addressed in the context of this program.

4.7 ERIS and SPDS

The services building power inverter, 1BYS-INV06 has been restored to service. Replacement of the ERIS system is being evaluated. This evaluation will also address concerns with the ease of retrieval of historical data from past events.

4.8 Noble Gas and Tritium Sampling

To prevent recurrence, Technical Specifications 3/4.11.2.1.2, Table 4.11.2.1.2-1 will be revised to remove the one hour sampling and analysis requirement for noble gases, and the tritium sampling requirements. License Amendment Request (LAR) 94-11, "Gaseous Effluents," was submitted to the NRC on October 4, 1994 (RBG-40919). Other corrective actions include changes to operations announcement practices, revision of SOP-0043 to provide safe access to the auxiliary building when the standby gas treatment system is in operation, and ensuring the proper equipment is dedicated and staged for ready access near 1RMS*RE125. These actions have been implemented.

4.9 Conductivity Sample

Chemistry Procedure, CSP-0101, has been revised to incorporate a shutdown enclosure in the procedure. Corrective actions have also been implemented to address timeliness of required chemistry actions and assure that chemistry personnel coming on-shift will be cognizant of current equipment status.

5.0 Safety Assessment

Based on testing that was performed, engineering personnel concluded that the transmitters would have functioned properly during an actual level transient. The investigation also revealed that no electrical or significant hydraulic transient existed.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION			APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503
FACILITY NAME (1) River Bend Station	DOCKET NUMBER (2) 05000-458	LER NUMBER (6) 94-023-01	PAGE (3) 18 OF 18

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

The evaluation of other equipment related issues revealed the following:

- The reactor scram did not result in an automatic trip of the main turbine or electric generator, by design. The "two out of three" logic required to produce an automatic turbine trip was not satisfied since only one of three feedwater level transmitter channels provided a level 8 signal.
- The slow transfer was also determined to have occurred as designed. The conditions required for a fast transfer to occur were not satisfied.
- The HPCS system was available throughout this event and was operated manually to provide makeup to the reactor vessel following the trip of the RCIC turbine.
- The reactor vessel cooldown rate has been evaluated and the thermal transient effects were bounded by previous analyses. Other thermal effects, such as thermal stratification, were also shown to be bounded by previous analyses.
- The contribution to offsite dose as a result of this event was analyzed and determined to be below Technical Specification limits and other regulatory limits.

Operator actions were correctly prioritized throughout the event. While they did encounter unexpected responses from some plant equipment, the operators effectively utilized the available resources to diagnose and respond to reactor and plant system indications. They focused on reactor safety and took actions to manually control reactor water level and pressure. Based on the above considerations, EOI concludes that this event did not compromise the health and safety of the public.

Note: Energy Industry Identification System (EIIS) Codes are identified in the text as (*XX*).

AIT No. 458/94-20
River Bend

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/94-20

License: NPF-47

Licensee: Entergy Operations Incorporated
P.O. Box 220
St. Francisville, Louisiana 70775-0220

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: September 8-15, 1994

Team Members: M. Runyan, Reactor Inspector, Division of Reactor Safety

D. Loveless, Senior Resident Inspector, South Texas Project, Division of Reactor Projects

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Team Leader: _____ 10/19/94
Thomas F. Stetka, Team Leader
Division of Reactor Safety
Date

Approved: _____ 10/19/94
Thomas P. Gwynn, Director
Division of Reactor Safety
Date

TABLE OF CONTENTS

1 INTRODUCTION (93800) 1

1.1 General Description of the Event 1
1.2 AIT Formation and Tasks 2

2 AIT INSPECTION 3

2.1 Sequence of Events 4
2.2 Operator Response 9

2.2.1 Reactor Trip Response 9
2.2.2 Reactor Vessel Water Level Response 11
2.2.3 Use of the Emergency Operating Procedures (EOPs) . . . 11
2.2.4 Operator Command, Control, and Communication 12
2.2.5 Use of Main Steam Line Drains To Control Reactor Pressure 13

2.3 Operator Overtime/Fatigue Considerations 13
2.4 Operator Training 13
2.5 Control Room Indications and Operating Procedures 14
2.6 Control Rod Drive (CRD) Hydraulic System Fuse Failure 14
2.7 Plant Radiation Levels 15
2.8 Delayed Chemistry Sample 15
2.9 High Reactor Vessel Water Level (Level 8) Reactor Trip 16

2.9.1 Background 16
2.9.2 Potential Causes 17

2.9.2.1 Reactor Vessel Water Level Transmitter Reference Leg Backfill System Induced Transient 17
2.9.2.2 Electrical Fault/Grounding/Radio Interference 19
2.9.2.3 Spurious Transmitter Trip 20
2.9.2.4 Mechanical Shock 21
2.9.2.5 Feedwater Excursion 21
2.9.2.6 Reactor Recirculation Flow Excursion 22

2.9.3 Additional Potential Causes of the Sensed High Water Level Condition 22

2.10 Main Turbine/Generator System Response and Slow Power Transfer 23

2.10.1 Background 23
2.10.2 Effect of Main Turbine/Generator 24
2.10.3 Failure of the Reverse Power Relays to Actuate . . . 25
2.10.4 Slow Transfer to Preferred Power Supply 26

2.11 Bus Transfer Induced Equipment Anomalies 26

2.12 Valve Failures 27

2.12.1 Failure of Vavle SWP*MOV40A to Open 27
2.12.2 Apparent Failure of Valve B21*MOVF016 28
2.12.3 Failures of Balance-of-Plant Motor-Operated Valves and Air Operated Valves 29

2.13 Reactor Core Isolation Cooling (RCIC) Turbine Trip 30
2.14 Management Response 31

3 FINDINGS AND CONCLUSIONS 32

4 CORRECTIVE ACTIONS 33

ATTACHMENT A - Persons Contacted and Exit Meeting
ATTACHMENT B - Event and Causal Factors Charts
ATTACHMENT C - NRC Public Meeting Attendance List and Briefing Handout

DETAILS

1 INTRODUCTION (93800)

The NRC has established a policy to provide for the timely, thorough, and systematic inspection of significant operational events at nuclear power plants. This includes the use of an augmented inspection team to determine the causes, conditions, and circumstances relevant to an event and to communicate its findings, safety concerns, and recommendations to NRC management. In accordance with NRC Inspection Manual Chapter 0325, an AIT was dispatched to the River Bend Station (RBS) on September 9, 1994, to review the circumstances surrounding the reactor trip and unusual plant response following this trip that occurred on September 8, 1994.

1.1 General Description of the Event

On September 8, 1994, the RBS was operating at 97 percent of full power. At approximately 8:28 p.m., a reactor trip occurred. The plant operators responded to the trip by entering their abnormal operating procedures (AOPs) for a reactor trip and emergency operating procedures (EOPs) due to a low water level in the reactor vessel. Approximately 7 minutes after the reactor trip, with the at-the-controls operator controlling reactor vessel water level as directed by the AOPs, the unit control operator had completed his AOP and began to assist the at-the-control operator with her AOP when he noted that the main turbine had not tripped. This observation was discussed with the control room supervisor and the decision was made to manually trip the main turbine.

Following the manual trip of the main turbine, the operators observed the main generator operation and expected the main generator output breakers to automatically open. When the crew decided that the main generator output breakers would not open, further discussions occurred between the unit operator and shift supervision. The supervisor then directed the unit operator to manually open the generator output breakers.

When the main generator output breakers were manually opened, the plant responded differently than the operators were trained to expect. The operators did not expect the power transfer to result in the loss of nonsafety-related balance-of-plant (BOP) electrical loads. However, the delayed power transfer did result in the loss of the nonsafety-related electrical loads which than required the operators to manually restore power to these affected loads.

The power transfer delay caused loss of the feedwater pumps, condensate pumps, reactor protection system (RPS) power, reactor recirculating pumps, and turbine building ventilation. The transfer delay did not affect the safety-

related electrical buses (because they are normally powered from a different power source). Since no safety-related loads were lost, the emergency diesel generators did not get a signal to start. The loss of the BOP loads caused the loss of the normal heat sink for reactor decay heat removal.

To compensate for these conditions, the operators followed their EOPs and attempted to establish makeup water to the reactor using the reactor core isolation cooling (RCIC) pump. However, when this turbine-driven pump was manually started, the turbine tripped on an overspeed condition and this condition could not be reset. The operators then started the high pressure core spray (HPCS) pump to inject water into the reactor vessel. The operators also manually opened the safety relief valves (SRVs), as required, to control reactor pressure.

While taking these compensating actions, the operators were also taking actions to return power to the RPS (this was restored within about 3 minutes) and to restore the feedwater system, condensate system, and turbine building ventilation. The turbine building ventilation needed to be restored because the lack of ventilation caused an increase in airborne radioactivity within the turbine building and, due to increased temperatures in the main steam tunnel, prevented reopening of the main steam isolation valves (MSIVs).

To help control the reactor pressure and water level, the operators opened valves in the main steam drain system (a 3-inch pipe) to both provide equalization of pressures around the MSIVs and to assist with pressure control by dumping steam to the condenser.

At approximately 10:09 p.m., the shift superintendent declared a notification of unusual event. While there was no requirement to declare a notification of unusual event, the shift superintendent made the declaration because there was only one makeup water source to the reactor, the event had the possibility of degrading, and additional personnel were needed to assist in returning the BOP systems to service.

At approximately 10:20 p.m., the condensate system was restored to service and at approximately 11:21 p.m., the feedwater system was restored to service. The MSIVs were then opened, and the operators verified that reactor water level and pressure were being properly controlled. They then secured the HPCS pump, exited the notification of unusual event, and continued to cool down the reactor to the cold shutdown condition.

1.2 AIT Formation and Tasks

Region IV, in consultation with the Office of Nuclear Reactor Regulation (NRR) and the Office for Analysis and Evaluation of Operational Data, formed an augmented inspection team (AIT) on September 9, 1994. The AIT, which was led by a team leader from Region IV and which was composed of a reactor inspector from Region IV, the South Texas Project senior resident inspector, a human factors engineer from the Office of Nuclear Reactor Regulation (NRR), and a

senior electrical engineer from NRR, was sent to RBS to gather information regarding licensee actions and to review plant response to this event. The AIT members began to arrive onsite on Friday, September 9, and initiated on-site inspection activities on September 10, 1994.

The AIT tasks, which were specified in a Charter dated September 9, 1994, to Mr. T. F. Stetka from Mr. L. J. Callan were:

(1) A complete review and documentation of the initial conditions and sequence of events through the initiation of shutdown cooling;

(2) A review of the plant structures, systems, procedures, and components that caused, or contributed to the cause, of the event. This should include a review of the licensee's root cause determination as well as the corrective actions that have been or will be taken;

(3) A review of plant equipment that did not respond as expected, including, but not limited to, the reactor protection system, turbine and generator output breaker trip functions, other electrical system equipment, the reactor core isolation cooling system, certain nonsafety-related mechanical equipment, and motor-operated valves and the resulting safety impact;

(4) A review of operator response to the event, including the decision to use the main steamline drains to control reactor pressure; and

(5) An evaluation of management response to the event.

2 AIT INSPECTION

The inspection effort began with a briefing by a licensee senior management response team. The briefing included the licensee's investigation into the events and their findings to date. The AIT found this briefing to be comprehensive and highly beneficial. In addition to this management response, which also included around-the-clock senior management presence, the licensee established a significant event review team, which conducted its investigation in parallel with the AIT's activities. Senior management and the significant event review team kept the AIT informed of their findings throughout the inspection.

The AIT inspection included a review of plant logs; numerous interviews with personnel, including interviews of the operators who were on shift at the time of the reactor trip; a review of plant procedures and maintenance records, a review of pertinent vendor information; walkdowns of selected equipment and control panels; and observations of ongoing maintenance and testing activities. The team also independently developed an event and causal factors chart that was then used to judge the depth and breadth of the licensee's own investigation.

2.1 Sequence of Events

The AIT developed the following sequence of events based upon review of the licensee's documentation, personnel interviews, and briefings by plant management personnel. Times marked with a "*" are approximations. (Attachment B provides the event and causal factors chart developed by the AIT.)

September 8, 1994

6 p.m.* Night shift operators assumed the watch. Reactor power was at 96 percent.

7 p.m.* The shift crew briefing was completed and operators began the following routine night shift duties:

- Nuclear equipment operators began performing rounds in the plant in accordance with building logs.
- A low volume containment purge was established.
- Operators began flushing a reactor water cleanup demineralizer.

8 p.m.* Reactor at 97 percent power, operators were increasing power at approximately 1 percent per hour.

8:28 p.m. The reactor tripped (scrammed) when two of four reactor vessel water level channels indicated high level (Level 8). The operators in the control room entered the following procedures:

- Abnormal Operating Procedure AOP-0001, "Reactor Scram," Revision 9; and
- Abnormal Operating Procedure AOP-0003, "Automatic Isolations," Revision 7.

As expected, reactor vessel water level immediately began decreasing to the low level setpoint (Level 3). The control room supervisor entered Emergency Operating Procedure EOP-0001, "Reactor Pressure Vessel Control," Revision 11.

The at-the-controls operator began performing the immediate actions of AOP-0001. The operator actuated a manual reactor trip, placed the reactor mode switch in the shutdown position, verified that the control rods were fully inserted, verified that reactor power was lowering, and began to control the feedwater system to restore reactor vessel water level.

8:30 p.m. Main generator output indicated zero megawatts.

8:32 p.m. The unit operator completed the actions of AOP-0003. All required isolations actuated as designed.

8:35 p.m. The shift superintendent ordered a precautionary reactor building evacuation. Security personnel determined that no one was in the building at the time of the reactor trip.

8:36 p.m. The at-the-controls operator established the condensate/feedwater systems on long cycle recirculation to better control reactor vessel water level.

8:38 p.m. The unit operator, assisting in the performance of AOP-0001, identified that the main turbine had failed to trip as expected. After a discussion with the control room supervisor and a determination that the main generator output megawatt meter was reading "0" (which indicated a motoring condition), the turbine was manually tripped.

The main generator was still motoring, using approximately 10 megawatts of power by backfeeding through the main generator output breakers.

8:40 p.m. The main generator output breakers did not open as expected following the turbine trip. Discussions were held among the operators, the control room supervisor, and the shift superintendent. The output breakers were then manually opened.

When the breakers were opened, the main generator began backfeeding the still connected plant switchgear. The main generator low voltage annunciator alarmed. A main generator load of approximately 30 megawatts was present immediately after the breakers opened.

8:41 p.m. Plant switchgear transferred to the preferred power supply as undervoltage conditions occurred on each switchgear unit. As designed, the following equipment was lost:

- All main feedwater pumps,
- All condensate pumps,
- Both trains of the RPS,
- A and C main circulating water pumps,
- One of the two running normal service water pumps,
- Both reactor recirculation pumps,
- One instrument air compressor,
- The safety parameter display system, and
- The emergency response information system.

As a result of these losses, the following engineered safety features actuations occurred as designed:

- Closure of the MSIVs,
- A BOP equipment containment isolation, and
- Automatic start of the standby service water system.

Operators responded by entering the following procedures:

- AOP-0003 (Reentered);
- AOP-0005, "Loss of Main Condenser Vacuum/Trip of Circulating Water Pump," Revision 8;
- AOP-0006, "Condensate/Feedwater Failures," Revision 8;
- AOP-0008, "Loss of Instrument Air," Revision 7;
- AOP-0009, "Loss of Normal Service Water," Revision 7;
- AOP-0010, "Loss of One RPS Bus," Revision 8; and
- AOP-0053, "Initiation of Standby Service Water," Revision 1.

EOP-0001 was reentered on decreasing water level (Level 3) in the reactor vessel, and EOP-0002, "Primary Containment Control," Revision 9, was entered for high primary containment pressure, which were expected conditions, given the actuations listed above.

The Standby Service Water Pump 2A Discharge Valve 1-SWP*MOV40A did not fully open upon pump start.

8:41 p.m. Operators restored the RPS to service on the preferred power supply and began verification and recovery from the associated isolations.

8:42 p.m. The main generator reverse power relay tripped. Normal Service Water Pump 1B tripped on low surge tank level.

8:44 p.m. Operators manually started the RCIC system pump to establish reactor water level and pressure control. The pump immediately tripped on overspeed. The operators made several unsuccessful attempts to relatch the turbine trip and throttle valve.

8:45 p.m. The control room supervisor asked the at-the-controls operator about the availability of the condensate and feedwater systems. They determined that the system needed to be vented prior to restarting the condensate pumps.

The control room supervisor directed that the high pressure core spray (HPCS) system be manually started when needed to provide makeup water to the reactor.

The shift superintendent determined that the manual initiation of the HPCS system did not require declaration of an emergency.

8:46 p.m. Operators manually opened one main steam safety-relief valve (SRV) for reactor vessel pressure control.

8:49 p.m. Operators reestablished drywell cooling.

8:50 p.m. Primary containment radiation high alarm received on the digital radiation monitoring system.

8:51 p.m. Reactor vessel water level swelled to Level 8 during manipulation of the SRV.

8:57 p.m.* Operators manually started the HPCS system pump, after aligning the flowpath, to provide makeup water to the reactor.

The control room supervisor directed operators to maintain reactor pressure at 600-800 psig.

The control room supervisor increased the pressure control band and allowed pressure to increase to 1040 psig before opening an SRV.

9 p.m.* A nuclear equipment operator and a chemistry technician could not open the door to enter the auxiliary building to respond to the reactor trip because of differential pressures caused by both fans running in the standby gas treatment system.

9:02 p.m. SRVs lifted automatically at 1105 psig. EOP-0001 had directed the operators to stabilize pressure below 1064.7 psig.

9:05 p.m. Nuclear equipment operators began locally venting the condensate system.

9:06 p.m. Reactor vessel level control was established with HPCS by routing excess flow through the system full flow test return line to the condensate storage tank.

9:17 p.m. HPCS isolation valve closed when reactor vessel water level swelled to Level 8 during manipulation of safety-relief valves. This occurred four additional times during the event.

9:30 p.m. Nuclear equipment operators restored the turbine building chillers to service.

9:27 p.m. Operators placed Residual Heat Removal Train A in suppression pool cooling mode in accordance with System Operating Procedure SOP-0031, "Residual Heat Removal," Revision 12.

9:30 p.m. SRVs again lifted automatically at 1105 psig.

9:36 p.m. The main plant exhaust radiation monitor alarmed high.

9:37 p.m. Operators aligned the suppression pool reject to radwaste in accordance with SOP-0031, as directed by EOP-0002.

9:38 p.m. Nuclear equipment operators reported that Valve CNS-CV0112 would not open to provide fill water to the condensate system.

9:40 p.m. The HPCS pump suction automatically transferred from the condensate storage tank to the suppression pool because of high suppression pool water level.

9:41 p.m. After starting Iodine Removal Filter Train 6, operators started a condenser air removal compressor. The lowest vacuum observed was approximately 7 inches of mercury.

9:48 p.m. Nuclear equipment operators manually opened Valve CNS-CV0112 and began filling and venting the condensate system.

9:46 p.m. Operators reset the reactor trip.

10 p.m. The standby gas treatment system was secured by the operators.

10:09 p.m. The shift superintendent declared a notification of unusual event because only one source of high pressure water to the reactor was available, the event had the possibility to degrade, and additional support was needed to help return the condensate and feedwater systems to service.

10:20 p.m. Operators reestablished condensate system flow.

10:30 p.m. Operators attempted to equalize pressure across the MSIVs and provide additional reactor pressure control by opening steam drains in accordance with EOP-0001.

11 p.m.* Operators identified that the control rod drive hydraulic system parameters were not reading correctly. The only available indication was pump current.

11:19 p.m. Nuclear equipment operators responded to manually open Discharge Valve 1-SWP-MOV040A on Standby Service Water Pump 2A.

11:21 p.m. Operators started Feedwater Pump 1A in accordance with System Operating Procedures SOP-0009, "Reactor Feedwater System," Revision 10, and SOP-0007, "Condensate System," Revision 9.

11:40 p.m. Operators secured suppression pool reject to radwaste.

11:51 p.m. An operator rapidly reduced reactor pressure to 600 psig, utilizing an SRV to equalize pressure across the MSIVs. The MSIVs were then opened.

11:55 p.m. Operators replaced the blown fuse in the control rod drive hydraulic system circuitry and returned the system to service.

September 9, 1994

12:17 a.m. After verifying that the feedwater system was maintaining reactor vessel water level, the operators secured the HPCS system.

12:20 a.m. The emergency response information system and safety parameter display system was returned to service.

1:22 a.m. Operators established a low volume purge of primary containment to reduce containment pressure in accordance with EOP-0002. Health Physics personnel had determined that limits would not be exceeded if purge was established through the containment purge filter train.

12:30 a.m. The shift superintendent exited the notification of unusual event after the control room supervisor exited the emergency operating procedures. The reactor was stable, the feedwater system was supplying water to the reactor vessel, and the main steam bypass valves were controlling reactor vessel pressure.

2:53 a.m. Operators began raising reactor water level to greater than 75 inches to meet the administrative limits for low temperature natural circulation.

3:14 a.m. Reactor vessel water level reached at 75 inches.

3 a.m. Operators secured the residual heat removal system from suppression pool cooling.

:8 a.m. Operators started warming up the residual heat removal system for shutdown cooling.

4:53 a.m. Operators started Residual Heat Removal Pump A, and placed the system in shutdown cooling mode in accordance with SOP-0031.

2 Operator Response

2.1 Reactor Team Response

The team interviewed the shift superintendent, the control room supervisor, and the three reactor operators that were on shift at the time of the reactor

trip. These interviews provided additional insight into what took place in the control room during the September 8 event.

Prior to the event, the operators had completed shift turnover activities and had sufficient time to become familiar with the control panel status. Three operators, the at-the-controls operator, the unit operator, and the control room supervisor were in the control room at the time of the event. The reactor pressure vessel water level was in its normal band at approximately 35 inches on the narrow range level instruments.

The first indication the operators had of a plant problem was the reactor trip. The operators did not initially realize that the reactor trip was caused by a Level 8 trip signal. They responded to the reactor trip and the resultant low reactor vessel water level condition (Level 3) by performing the actions required by their abnormal operating procedures (AOPs) and emergency operating procedures (EOPs).

Reactor water level recovered rapidly and the at-the-controls operator began taking feedwater pumps off line to prevent overfilling the vessel. Approximately 8 minutes after the trip, reactor vessel water level began to stabilize.

At this time, the unit operator who had been verifying that the required isolations had occurred, began to assist in the completion of the AOP immediate actions. He noticed that the main turbine/generator had not tripped as expected. Procedure AOP-0001 directed the operator to "Verify turbine is tripped." He consulted with the control room supervisor about the condition, and they decided to manually trip the main turbine.

Following the main turbine trip, the operators noted that the main generator output breakers had not opened (due to failure of the reverse power relays to actuate) as they had anticipated. The operators requested the shift superintendent's assistance. The shift superintendent was concerned that opening the main generator output breakers too early could cause the turbine to overspeed. During interviews, the operators stated that they had some concern that a delayed transfer from the normal to the preferred power supply could cause a loss of electrical loads. However, neither voiced their concerns because they had been trained to expect a power supply transfer to occur that would not have resulted in a loss of loads.

The team questioned the operators about the indications that they had used to determine that the main generator was motoring and needed to be tripped. The operators responded that they had used the main control panel generator output meters and elapsed time. None of the operators indicated that main turbine control valve position or main turbine first stage pressure had been utilized to determine if steam was still available to the main turbine. These indications would have assured the operators that all steam to the main turbine was secured and, therefore, that an overspeed condition would not occur when the main generator output breakers were opened. However, the operating crew did make the decision to manually open the main generator output breakers.

2.2.2 Reactor Vessel Water Level Response

The team reviewed the operators' response to the decreasing water level in the reactor vessel following the loss of the condensate and feedwater systems. The team determined that use of the RCIC turbine would have helped control reactor pressure by utilizing this steam as a motive force while also providing reactor vessel makeup water. The team also verified that the condensate storage tank and suppression pool levels, as well as primary containment pressure, were within appropriate limits for operating the RCIC system.

Through interviews, the team determined that the operators properly attempted the RCIC system initiation. Operator actions could not have caused the turbine overspeed event. In addition, following the mechanical overspeed trip, system design would not have allowed operators to relatch the turbine's trip and throttle valve from the main control room.

Following the loss of the RCIC system, Procedure EOP-0001, Step RL-4, directed the operators to utilize the high pressure core spray system to maintain reactor vessel water level with a suction from the condensate storage tank, if possible. The operators aligned the system in accordance with System Operating Procedure SOP-0030, "High Pressure Core Spray," Revision 11, and reestablished water level. Operators stated that they then opened the full flow test return line to the condensate storage tank to control the flow rate to the reactor as they had been trained. The team noted that this response was not documented in Procedure SOP-0030. The system remained available and maintained water level for approximately 3 hours until secured when the feedwater system was made available and controlling reactor vessel level.

2.2.3 Use of the Emergency Operating Procedures (EOPs)

The team determined that, in general, the operators followed the requirements and guidelines of the EOPs. The team noted, however, several occasions throughout the event where operators failed to maintain reactor vessel pressure and water level below the limits required by Procedure EOP-0001. Following the loss of power to the normal switchgear, reactor operators took manual control of the safety relief valves (SRVs) to control reactor pressure.

Step RP-8 of EOP-0001 requires the operators to stabilize reactor pressure below 1064.7 psig. However, on two occasions during the event, operators allowed pressure to increase to the lift setpoint of the SRVs of 1105 psig. The control room supervisor initially directed operators to reduce pressure to 900 psig; however, due to the coarse pressure control that occurred when the SRVs were used to control pressure, it was difficult to maintain the 900 psig pressure. As a result, the control room supervisor revised his direction to now maintain pressure in a 600-800 psig band. Shortly thereafter, however, the control room supervisor again revised the control band and requested that pressure be allowed to increase to 1040 psig prior to opening a SRV and that he be kept informed of the reactor pressure so that he could direct the operators to open the SRVs when necessary. This supervisory direction limited the operator's discretion with the operation of the SRVs.

The EOP bases for Step RP-8 states that the operator be given a desired pressure control value to maintain. The intent of maintaining the reactor pressure below 1064.7 psig would allow the reactor trip to be reset and provide sufficient margin to prevent the SRVs from automatically opening. During the event, the operators stated that the reactor trip had not been reset and, therefore, was not of concern. However, allowing the SRVs to open automatically at the lift setpoint clearly did not meet the intent of the pressure control band required by Procedure EOP-0001.

Similarly, Step RL-4 required the operator to restore and maintain reactor vessel water level between 9.7 and 51 inches. However, on numerous occasions, operators maintained water level high enough, so that upon operation of a SRV, the water level swelled to greater than 51 inches. This caused the high pressure core spray (HPCS) system isolation valve to close automatically.

The EOP bases document stated that Step RL-4 defines the preferred range in which reactor vessel water level should be established and maintained. The upper water level limit prevented a main turbine trip, feedwater pump trips, HPCS injection valve closure, and RCIC shutdown. The operator's failure to control the reactor vessel water level below Level 8 did not meet the intent of the bases because closure of the HPCS injection valve was not prevented.

Although the team considered the plant conditions and operator responses that caused reactor vessel pressure and water level to increase above the Procedure EOP-0001 control bands, the team also noted that operator distractions were low at the time, a different dedicated operator was assigned to pressure and level control operations, and the plant responses were similar to those seen by the operators during training.

2.2.4 Operator Command, Control, and Communication

The team reviewed the licensee's command and control of the event by interviewing the operators involved to ensure that adequate staffing and oversight was provided to mitigate the transient. The team determined that the crew appeared to adequately control the transient and that control room supervision was responsive, e.g., issuing the notification of unusual event to ensure appropriate operations staff was available to support the recovery efforts. Additionally, it appeared that crew members were kept appraised of major evolutions and focused on their responsibilities assigned by the control room supervisor. However, the team noted several communication weaknesses which may have contributed to operator difficulties during event recovery. These included: (1) lack of clear direction to maintain reactor pressure below 1064.7 psig using SRVs per EOP-0001, which resulted in several automatic SRV actuations and HPCS isolations on level 8 during event recovery; and (2) failure of operators to communicate their concerns about a possible delayed bus transfer prior to manually opening the main generator output breakers.

2.2.5 Use of Main Steam Line Drains To Control Reactor Pressure

Approximately 2 hours after the reactor trip, operators attempted to equalize pressure across the main steam isolation valves (MSIVs) and provide for additional reactor pressure control by opening steam drains in the main steam system. This was as directed by Step RP-8 in Procedure EOP-0001.

Opening the main steam line drain caused a discharge of steam to the main condenser. Main turbine gland seal steam was available and there was a vacuum in the condenser. The team determined that the increased airborne radioactivity levels in the turbine building were caused by the loss of ventilation and not by operating the main steam system without gland seals.

2.3 Operator Overtime/Fatigue Considerations

The team reviewed the operations department biweekly time sheets to determine if operator fatigue may have been a contributing factor to the transient response. The crew on shift Thursday, September 8, during the event was in their second night of rotation, having previously worked day shift on Sunday, September 4, followed by 2 consecutive days off. The crew had completed their normal 12-hour rotation on Wednesday, September 7, and had completed shift turnover at 7 p.m. on Thursday, September 8, approximately 1.5 hours prior to the reactor trip. From the records reviewed and interviews with the crew members involved with the event, there was no evidence that fatigue was a factor in the operators' transient response.

2.4 Operator Training

The team reviewed the licensee's training program to determine if operator training may have been a factor that affected the ability of the operators to mitigate the event. A sample of lesson plans related to abnormal and emergency operations were reviewed with particular emphasis on reactor trip, main turbine/generator trip, and EOP implementation guidance. Additionally, the team observed several short simulator scenarios of reactor trips, manual and automatic main turbine/generator trips, and a simulated slow transfer of power to the 13.5kV non-vital buses.

From this review, the team determined that the licensee's simulator did not adequately reflect the actual plant response including: (1) slow transfer of non-vital power following manual opening of the main generator output breakers, (2) failure of the main turbine/generator to automatically trip on motoring of the main generator, and (3) non-simultaneous trip of the main generator output breakers following a manual main turbine trip. Additionally, lesson plans associated with main turbine/generator trip focused on verifying main turbine trip based solely on main generator electrical output indication trending towards zero without further analysis of other main turbine parameters, such as control valve position and main turbine impulse pressure that was available at the main control panel. These weaknesses in simulator fidelity and training contributed to the operators' lack of understanding of main turbine/generator operation and response during the event and subsequent loss of plant equipment, as a result of the transfer of electrical power following the manual opening of the main generator output breakers.

2.5 Control Room Indications and Operating Procedures

The team reviewed key control board indications, controls, and abnormal and emergency operating procedures during simulator exercises, control room walkdown, and desktop review. The team determined that the operators had sufficient indication and control to adequately mitigate the transient. However, the team noted several areas where lack of direct control board indication and vague procedural guidance may have contributed to operator difficulties during the event recovery. These included a lack of: (1) direct indication of motoring of the main turbine/generator; and (2) explicit procedural guidance for verifying main turbine trips and transferring plant loads from normal to the preferred power supply prior to manually opening the main generator output breakers.

2.6 Control Rod Drive (CRD) Hydraulic System Fuse Failure

A fuse to Power Supply 1C11B-K600 and to the indicating lights of Flow Control Valves 1C11-FVF002A and -B in the CRD hydraulic system failed after the reactor trip. Emergency response information system data indicated that the fuse blew approximately 12 minutes after the reactor trip. The team's review of this failure indicated that the fuse failed due to an overcurrent condition. The team concluded that the voltage transient that occurred after the load transfer produced a current surge that was sufficient to cause the fuse to blow.

The team reviewed the impact of the blown fuse in the CRD hydraulic system on plant operations. The blown fuse caused a loss of most control room indication of the CRD system status and caused the CRD flow control valves to fail shut. Charging water was available to the hydraulic control units, allowing them to be repressurized and the reactor trip to be reset.

Since cooling water was no longer available to the control rod drives, an additional source of high pressure water to the reactor was lost. Step RL-14 in Procedure EOP-0001 directed the operators to maximize control rod drive hydraulic flow when the condensate and feedwater systems were not available. This source of water was unavailable, and due to the failed fuse, insufficient indication was available in the control room for operators to be aware of this system's status.

The team discussed the issue of water stratification within the reactor vessel with the licensee. The team determined that since the high pressure core spray system was available and injecting water into the core, the failure of the CRD hydraulic system may have been of benefit. With the reactor in natural circulation following the loss of the recirculation pumps, cold water entering the bottom head of the reactor vessel, as would occur with the CRD system in operation, would tend to stratify and cause additional stresses in the vessel walls. The loss of the CRD system did not make this a factor during this event.

Another issue identified by the team involving the loss of the CRD cooling flows was the effect of increased temperatures on the CRD seals. Degradation in these seals could result in longer insertion times for the control rods.

On September 14, General Electric, the reactor designer, provided the licensee with a letter stating that the short-term control rod drive operations at higher than normal temperatures would not have caused significant damage to the CRD seals.

2.7 Plant Radiation Levels

One of the balance-of-plant (BOP) systems lost following the main generator trip was the turbine building main ventilation system. With the shutdown of this ventilation system, removal of any radioactive gases from the turbine building ceased while several sources of noble gas leakage into the turbine building were occurring. At 9:41 p.m., operators started a condenser air removal compressor so that condenser vacuum would be maintained. Although the discharge from this compressor was routed through the iodine removal filter train, leakage from the compressor seals caused increasing airborne radioactivity levels and minor contamination in the vicinity of the compressors. A temporary loss of loop seals in the offgas system piping also caused increasing airborne levels in the offgas building.

During the condensate system venting process, additional radioactive gases were released. A nuclear equipment operator involved in venting the system alarmed the personnel contamination monitor when exiting the area. Approximately 90,000 counts per minute of contamination were detected on this operator. The contamination was determined to be caused by the released noble gases.

At 11:10 p.m., radiological protection technicians declared the turbine building, offgas building and auxiliary building to be airborne radioactivity areas. General area surveys of these buildings indicated no increase in radiation levels or loose contamination, with the exception of certain equipment filters (that ranged from 6 to 8 mRem per hour). As a result, personnel stay-time records were used for all building entries after this time. The team noted that building airborne radiation levels decreased rapidly once the turbine building ventilation system was returned to service.

The team reviewed the radiological effluents released following the reactor trip and during the low volume containment purge. An offsite dose projection was performed to determine the potential dose rates that a purge would cause. The highest recorded main plant exhaust release rate was 38,400 microcuries per second. Licensee personnel calculated that had this release continued, this release rate would have caused a dose rate of 118 mRem per year to a member of the public at the site boundary. This represented approximately 25 percent of the Technical Specification limits. The inspectors also received the licensee's analysis of main plant exhaust grab samples. This analysis corroborated the release rate data.

2.8 Delayed Chemistry Sample

The team reviewed the events surrounding the failure of licensee personnel to obtain and analyze a main plant exhaust noble gas and tritium sample within 1 hour of the reactor trip. This sample was required by the Technical Specifications. Upon loss of the reactor protection system, both trains of

the standby gas treatment system started. The resulting pressure differentials made entry into and out of the auxiliary building difficult. Although a chemistry technician and a nuclear equipment operator gained access to the building, they determined that the necessary equipment was not available to obtain the required sample. Additionally, the shift superintendent directed that no other entries into the building be made, while the standby gas treatment system was running, for personnel safety reasons.

The team interviewed the chemistry technicians on shift following the reactor trip. These personnel stated that communications were less than adequate. The control room operators apparently failed to understand that the Technical Specification required sampling and analysis would be missed.

During these interviews with the chemistry technicians, the team determined that the procedure for obtaining and analyzing the main plant exhaust grab samples did not fully implement Technical Specification requirements. Chemistry Surveillance Procedure CSP-0100, "Chemical/Radiochemical Technical Specifications Surveillances," Revision 14, required the technicians to take the sample within 1 hour, and then analyze the sample. This activity was required following reactor power changes exceeding 15 percent of rated thermal power. However, Technical Specification 4.11.2.1.2, Table 4.11.2.1.2-1 requires that the sample be obtained and analyzed within 1 hour following such reactor power changes. The technicians stated that, based on the requirements of Chemistry Surveillance Procedures CSP-0050, "Grab Sampling Gaseous Streams," Revision 6, and CSP-0303, "Operation of the Canberra Multi-Channel Analyzer, Series 90," Revision 4, it would be impossible to obtain and analyze the samples within 1 hour. The licensee planned to review this issue to determine what training, procedure and/or equipment changes may be required. It appeared to the team that a Technical Specification revision may be required.

The team was concerned that the standby gas treatment system operation could prevent normal access to and egress from the auxiliary building. This concern was discussed with the licensee. As the result of these discussions, the licensee planned to review auxiliary building accessibility to ensure that required entries into the auxiliary building could physically be performed under accident conditions.

2.9 High Reactor Vessel Water Level (Level 8) Reactor Trip

2.9.1 Background

This event was initiated by a sensed high reactor vessel water level condition. An automatic reactor trip would occur when water level in the reactor vessel reaches +51 inches (Level 8). A trip of the main turbine/generator and feedwater pumps would also occur at this level.

There are four sensors (channels) in the reactor protection system (RPS) used to detect a Level 8 condition. The channels, identified as A, B, C, and D, were arranged in a one-out-of-two-taken-twice logic. A high water level has to be detected by either Sensor A Level Transmitter 1B21*LTN080A or C Level Transmitter 1B21*LTN080C, and must also be detected by either Sensor B Level

Transmitter 1B21*LTN080B or D Level Transmitter 1B21*LTN080D before an automatic reactor trip would occur. RPS Sensor Channels C and D sensed a Level 8 condition that initiated the trip. The RPS Channel C trip came in slightly ahead of the RPS Channel D trip. RPS Channels A and B did not trip.

There are three sensors (channels) in the feedwater control system that were used to sense reactor vessel water level and trip the main turbine/generator and feedwater pumps on high water level. The channels, identified as A, B, and C, were arranged in a two-out-of-three logic. A high water level had to be detected by any two out of the three sensors before an automatic trip of the main turbine/generator and feedwater pumps would occur. During the event, only Channel C Level Transmitter 1C33*LTN004C sensed a Level 8 condition. The A and B feedwater level transmitters showed only a very slight and gradual level change and did not trip. Therefore, the main turbine/generator and feedwater pumps did not trip. The Channel C Feedwater Level Transmitter 1C33*LTN004C had a reference leg and condensing chamber, instrument rack, and variable leg instrument line that were common with the RPS Channel C Level Transmitter 1B21*LTN080C.

2.9.2 Potential Causes

The potential causes of the high reactor vessel water level reactor trip were identified by the licensee and reviewed by the team. The following causes were systematically eliminated from consideration as a likely cause of the event:

- Reactor vessel water level transmitter reference leg backfill system induced transient,
- Electrical fault/grounding/radio interference,
- Spurious transmitter trip,
- Mechanical shock,
- Feedwater excursion, and
- Reactor recirculation flow excursion.

The following sections briefly summarize the licensee's investigation and disposition of the above items. This information was reviewed by the team during the inspection.

2.9.2.1 Reactor Vessel Water Level Transmitter Reference Leg Backfill System Induced Transient

The water level transmitter reference leg backfill system was installed during refueling Outage 5 in response to Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54f," and NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs." The generic letter and bulletin addressed a concern that noncondensible gases dissolved in the reference legs of boiling water reactor (BWR) vessel water level instrumentation would result in level indication errors. The backfill system pipes relatively cool CRD water to the reference legs of the water level instrumentation. The licensee considered this system to have the potential of

being a common cause of the high water level signals. The following is a summary of the considerations used by the licensee and reviewed by the team that resulted in the elimination of this system as a potential cause of the Level 8 high water level reactor trip.

- No CRD system evolutions were being conducted just prior to the reactor trip.
- The CRD flow control valve fuse failure occurred approximately 13 minutes after the reactor trip.
- Emergency response information system computer data for reactor water level and CRD flow showed no evidence that a water hammer event occurred.
- Wide range water level transmitters showed no large or sudden level changes.
- Only two RPS narrow range water level transmitters and one feedwater water level transmitter exhibited large level increases.
- The transmitters affected (C and D) were physically located 145° apart on the reactor vessel. The C transmitter was relatively close physically to the CRD system and was on the west ring header of the backfill system, while the D transmitter was much farther physically (3 or 4 times) from the CRD system and was on the east ring header of the backfill system.
- The A and B narrow range feedwater level transmitters showed only a very slight and gradual level change of about 1 inch. No RPS trips on Channels A and B occurred.
- Level responses observed were not typical of CRD backfill system transient test data that had been accumulated by the BWR Owners' Group and other BWR type plants.
- Mechanical impact on the piping and transmitters was discounted based on 2.9.2.4 the physical locations of the backfill system piping and the transmitters, ERIS computer transient data, and computer security logs (no one was inside the containment building at time of the event).
- The pressure wave generated by the CRD system would result in a time difference between the C and D transmitters of only 0.02 seconds, whereas the observed time was 0.2 seconds.
- The reactor pressure transmitter data available on the ERIS computer did not indicate any pressure perturbations prior to the trip. These transmitters were common to the reference legs to which Level Transmitters C and D were connected.

2.9.2.2 Electrical Fault/Grounding/Radio Interference

Electrical faults (ground fault, power supply noise, cross channel communication, etc.) resulting in, or causing a spurious high water level trip on the three level transmitters (RPS C and D and feedwater C) were investigated by the licensee and reviewed by the team. They were eliminated as a possible cause of the high water level signals for the following reasons.

- The affected RPS transmitters were powered from different sources. RPS Transmitters C and D were powered from RPS Bus A and RPS Bus B, respectively. Feedwater Transmitter C was powered from the 125 vdc distribution system.

- RPS Transmitter C and D cables were verified to be routed through penetrations which enter the Fuel Building, while the feedwater Transmitter C cable was routed through a penetration which enters the Auxiliary Building.

- Transmitter inspections were performed to detect loose terminations or signal wires and any unusual or abnormal indications in the grounding buses of RPS Transmitters C and D. Divisional wiring in the vicinity of these cables was also inspected. No problems were identified.

- Transmitters powered by the high pressure core spray (HPCS) power supply ran through the same panels as the C reference leg transmitters; however, they did not run into the same panels that the D reference leg transmitters ran into. The two sets of cables ran through separate cable trays and conduit. If the event was induced by the HPCS power supply system, a transient on the HPCS level transmitter (wide range) would have been seen.

- The observed signals on RPS Transmitters C and D that occurred during the event were not typical of an electrical spike.

- While lightning was observed in the area, none was occurring in close proximity to the plant. A lightning strike would be expected to have caused a more random effect on various types of instrumentation, rather than on just the three narrow range water level transmitters. Equipment that was typically more sensitive to the effects of lightning than these level transmitters did not exhibit any of the usual lightning-induced characteristics.

- Radio interference was eliminated based on a review of security printouts of personnel in the plant, personnel interviews, and the physical locations of radio-equipped personnel in the plant.

2.9.2.3 Spurious Transmitter Trip

The licensee investigated the possibility of a transmitter or associated trip unit spurious actuation due to calibration drift that could have caused a premature reactor trip (C and D instruments) or prevented a reactor trip from occurring (A and B instruments). The team reviewed the licensee's investigation and noted that this possibility was eliminated, based upon the following information:

- Surveillance Test Procedures (STPs) 051-4205 through 051-4208, for RPS level Transmitters A through D, were performed during the last refueling outage to calibrate the entire instrument loop from the transmitter to the trip unit. Also, STP's 051-4505 through 4508 were performed on a monthly basis to ensure correct actuation of the trip units for each instrument loop. Each STP was recently completed with satisfactory results.

- The applicable portions of STP 051-4206 and STP 051-4207 were performed on RPS level Transmitter B (1B21*LTN080B) and C (1B21*LTN080C) following the event, in order to verify the accuracy of the transmitter outputs. RPS Transmitter C had an as-found error of +0.2" and RPS Transmitter B had no error. While the small amount of error found on Transmitter C was not within the acceptance criteria of the procedure, it was considered to be of no consequence with respect to the amount of level change detected on the C and D instruments during the transient event.

- Temperature-related effects on the transmitters were discounted because the containment temperatures remained constant, both prior to and following the reactor trip.

The team also reviewed Condition Reports (CRs) that identified previous spurious operation of these RPS level transmitters to determine if there was a history of spurious transmitter trips that could have been a precursor to the September 8 event. As the result of this review, the team noted that CR 91-0015, that was issued on January 11, 1991, identified that a Level 8 half reactor trip had occurred on RPS Channel D. The half reactor trip (or half scram) meant that one-half of the RPS had tripped and that if the other half of the RPS were to receive a trip signal, a full reactor trip would occur.

The licensee's corrective actions from this event were to recheck the calibration of the trip units (they were found to be in calibration), determine if any other activates were in progress that would have effected this unit (none were identified), and to install a recorder on these trip units so that any anomalous operation could be detected (none was). As a precautionary measure, the licensee replaced the suspect trip units. The licensee considered the root cause of this trip to be indeterminate.

The team concluded that this January 11, 1991, event was unrelated to the September 8 event. (Note: Subsequent to this inspection, the team was

informed that the transmitter that tripped on January 11 was a Rosemount Model 1152 - see Section 2.9.3 of this report.)

2.9.2.4 Mechanical Shock

The licensee investigated the possibility that a physical shock to the instrument tubing or transmitters might have resulted in a spurious high water level trip on the three level transmitters (RPS C and D and feedwater C). The team reviewed the licensee's investigation and noted that this possibility was eliminated based upon the following information:

- The physical location of the transmitters and the actual routing of the instrument tubing prevented the possibility of a single physical shock affecting all three transmitters.
- No damage was detected on the instrument tubing inside containment.
- No personnel were present within the containment at the time of the reactor trip.

2.9.2.5 Feedwater Excursion

The licensee investigated the possibility that the Level 8 reactor trip was caused by a feedwater excursion. The team reviewed the licensee's investigation and noted that this possibility was eliminated based upon the following information:

- ERIS computer data indicates that feedwater regulating Valves A and C remained at the steady state value of about 80 percent open prior to and immediately following the trip. The B feedwater regulating valve's position indication was not operative at the time of the reactor trip; however, there was no indication, based upon feed flow, that an increase occurred prior to the reactor trip.
- The feedwater system master controller output and reactor vessel level setpoint showed no change on ERIS prior to the reactor trip.
- ERIS data indicated that, subsequent to the reactor trip, the feedwater level control system responded, as designed, to control reactor vessel water level.
- ERIS data indicated that main steam line flow and feedwater flow remained constant prior to the reactor trip.
- The accuracy of the ERIS data was checked and confirmed, by comparison to control room recorders, for feedwater flow and for reactor vessel water level indication.
- All three feedwater pumps were running at the time of the reactor trip. Feedwater flow response was compatible with this condition.

- Feedwater level control Channel A was selected at the time of the reactor trip. Both the A and B narrow range reactor vessel water level indication showed no significant level increase prior to the reactor trip.

- The two-out-of-three logic for Level 8 feedwater pump and main turbine/generator trips did not occur, indicating that only Channel C of the trip circuitry experienced a high level condition.

- Wide range water level transmitters showed no level increases prior to the reactor trip.

2.9.2.6 Reactor Recirculation Flow Excursion

The licensee investigated the possibility that a reactor recirculation flow excursion might have caused the Level 8 reactor trip. The team reviewed the licensee's investigation and noted that this possibility was eliminated based upon the following information:

- Pressure across the reactor core plate remained relatively constant up to the time of the reactor trip.

- Recirculation pump differential pressures and total recirculation flow remained constant up to the time of the reactor trip.

- All jet pump differential pressures remained relatively constant up to the time of the reactor trip.

- No recirculation loop flow oscillations were observed and no change in recirculation flow controller output signals were observed.

- Changes in the flow through the reactor core can usually be observed by changes in neutron flux indications. The average power range monitors showed no sudden or prompt changes in neutron flux magnitude just prior to the reactor trip.

- A jet pump failure similar to that which occurred at other BWR type plants caused a sufficient perturbation to the water level sensing transmitters such that HPCS was initiated. River Bend Station's wide range water level indication was unaffected prior to the event. This fact, when considered in addition to the constant jet pump differential pressures, indicated that jet pump failure did not occur.

2.9.3 Additional Potential Causes of the Sensed High Water Level Condition

Based on the elimination of the above potential causes and on a review of the signals received from the reactor vessel narrow range water level instrumentation, the licensee postulated that a cause of the sensed reactor vessel high water level change could have been a hydraulic wave phenomena that occurred within the reactor vessel. The scenarios investigated were those that could have caused a hydraulic wave to be formed in the vicinity of the

C narrow range variable leg tap due to a sudden influx of flow or flow redistribution in the reactor vessel annulus region above the reactor core. It was postulated that such a wave, initially sensed at Channel C, could have resulted in two symmetric waves that moved around the reactor vessel annulus and collided at approximately 180° apart, resulting in a level change such as that sensed at Channel D (Channel D water level sensing is 145° apart from Channel C on the reactor vessel). This scenario was supported by data from the event (Channel C high water level signal came in slightly ahead of the Channel D signal, and Channels A and B showed a small and gradual water level rise).

A feedwater sparger break, shroud crack/shroud head bolting failure, or jet pump mounting plate manhole cover failure were some of the possible causes of a hydraulic condition that could have led to this event. Subsequent to the completion of this inspection on September 15, 1994, the licensee opened up the reactor vessel and conducted a detailed inspection of the reactor vessel internals. The licensee reported that no failures of reactor vessel internals had occurred.

On September 29, 1994, the licensee reported that they had identified the root cause of the reactor trip. They reported that the trip occurred due to the use of more sensitive water level transmitters (Rosemount Model 1153) on RPS level sensing Channels C and D and on feedwater level sensing Channel C. The use of these more sensitive transmitters without either properly adjusting the damping circuitry or installing the damping circuitry (which reduced the transmitter's sensitivity) made them subject to spurious trips, due to normal process flow noises. The other RPS and feedwater level transmitters were of the less sensitive Rosemount Model 1152 variety.

The licensee presented this information to the NRC staff in a public meeting conducted at the Region IV office on October 4, 1994. Details of this meeting are included as Attachment C to this report.

2.10 Main Turbine/Generator System Response and Slow Power Transfer

2.10.1 Background

Following the high reactor vessel water level (Level 8) trip of the reactor, the main turbine/generator and feedwater pumps failed to trip. As described in Section 2.9.1 of this report, the reason for this was due to the fact that a high water level condition was only sensed by the Channel C Feedwater Level Sensor 1C33*LTN004C. The A and B feedwater level transmitters showed only a very slight and gradual level change of about 1 inch. Because only one of the three feedwater system level transmitters sensed a high water level condition that was sufficient to trip its channel, the required two-out-of-three logic necessary to trip the main turbine/generator and feedwater pumps was not satisfied.

When the operators observed that the main turbine/generator did not trip following the reactor trip, they waited for a period of time to allow the main generator's reverse power protection relays to automatically trip the main turbine and open the main generator output breakers. The plant loads are

designed to automatically fast transfer from the normal station service power (powered from the output of the main generator) to the preferred station service power (powered from the grid) when this occurs.

When the reverse power protection relays had not tripped the main turbine/ generator within approximately 10 minutes following the reactor trip, the operators manually tripped the main turbine and waited for the reverse power protection circuitry to trip the main generator output breakers. The plant loads are designed to fast transfer as indicated above when the reverse power protection actuates.

After waiting approximately 1 minute 43 seconds, the operators then manually tripped the main generator output breakers when it appeared that the reverse power protection circuitry was not going to automatically open these breakers. The operators expected the plant loads to automatically fast transfer to the preferred station service power when they manually opened the main generator output breakers. However, the load transfer occurred slowly resulting in a significant amount of balance of plant equipment tripping on undervoltage which than required operator action to restart this equipment.

2.10.2 Effect of Main Turbine/Generator Operation on Bus Transfers

Just prior to the high water level reactor trip, the main generator was providing power of approximately 955 megawatts real power and 200 megavars reactive power (supplying real power and reactive power to the grid). Following the reactor vessel high water level reactor trip, the main generator power output decayed from the initial value of approximately 955 megawatts down to approximately 0 megawatts in about 80 seconds. The main generator power than became negative, which was indicative of a motoring condition. The main generator power continued to increase in the negative direction for about an additional 4 to 6 minutes and then stabilized at approximately -10 megawatts. Within an additional 2 to 4 minutes of this condition, the operators tripped the main turbine. This was approximately 10 minutes after the reactor trip and about 8.5 minutes following indication of initial main generator motoring. The operators had no direct indication of a main generator motoring condition in the main control room. At the time the main turbine was tripped, the main generator output analog meter was indicating 0 megawatts and the digital meter was alternating between +5 and +6 megawatts.

Following the manual trip of the main turbine, there was little additional change in main generator negative power, indicating that the main turbine was already at or near a zero steam flow condition prior to the trip. Approximately 1 minute 43 seconds after the manual trip of the main turbine, the operators manually opened the main generator output breakers. When these breakers were opened, an abrupt change of main generator output occurred in which main generators output changed from approximately -10 megawatts (motoring) to about +30 megawatts (generating). Over the next 43 seconds the main generator output decayed from approximately +30 megawatts to approximately +14 megawatts. This indicated that upon tripping the main generator output breakers, the plant loads remained connected to the main generator output through the normal station service power supply, as designed. Following the opening of the main generator output breakers, the speed of the

main turbine/generator dropped from 1800 rpm to approximately 1580 RPM in 40 seconds and the main generator exciter and voltage regulator remained operational. However, when the exciter and voltage regulator reached their maximum field forcing limit, the slowdown of the main generator subjected the connected loads to a decaying voltage and frequency over the period of time they remained connected to the output of the main generator. It appeared that the main generator supplied power to the loads due to its rotating inertia and whatever small amount of steam was still available to the turbine.

Approximately 11 seconds after the opening of the main generator output breakers, numerous main steamline isolation trip signals and neutron monitoring trip signals and related alarms occurred. These were due to the loss of the power from the RPS motor-generator sets. This trip occurred while the plant loads, including the RPS motor-generator sets, were still connected to the output of the main generator, but were experiencing decaying frequency and voltage.

Approximately 28 seconds after opening of the main generator output breakers, the first main generator low voltage alarm came in. At approximately 1 minute, 16 seconds, the 13.8 kV Bus 1A undervoltage protection actuated and then reset about 2 seconds later and at approximately 1 minute, 23 seconds the 13.8 kV Bus 1B undervoltage protection actuated and reset about 1 second later. These reset times indicated the time at which the 13.8 kV A and B plant buses were transferred to the preferred power supply. The plant buses (and associated equipment), therefore, remained connected to the output of the main generator for about 1.3 minutes following the trip of the main generator output breakers. As the main generator output voltage and frequency decayed, the plant equipment tripped on undervoltage and as designed, initiated the slow transfer to the preferred power supply. This transfer scenario correlated well with the transfer circuitry electrical schematics reviewed by the team.

2.10.3 Failure of the Reverse Power Relays to Actuate

There are two reverse power relays (32G1 and 32G) that were expected to trip during this event. The 32G1 relay is set at approximately 3 megawatts (at a 0° power factor angle) with a 5-second time delay and is enabled only if the main turbine stop valves are closed or the main turbine control valves and the intermediate/intercept valves are closed, as is the case if a main turbine trip occurs before a reactor trip. The 32G relay is also set at approximately 3 megawatts (also at a 0° power factor) with a 30-second time delay and requires no turbine permissives to trip, as would be the case if the reactor tripped prior to the main turbine. The purpose of the 30-second time delay was to insure that the main generator was motoring prior to opening the main generator output breakers; thus, preventing a main turbine overspeed condition. Following the event, the relay calibration was checked and found to be acceptable; however, it was also noted that the relays were sensitive to large power factor angles such as the power factor angle that existed when the main generator was motoring. With the main generator initially at approximately 955 megawatts and 200 megavars just prior to the event, the reactor trip and subsequent loss of steam to the main turbine resulted in the

decay of power output from the main generator as described; but with the main generator exciter and voltage regulator still operative the megavar output remained high and maintained a large power factor angle. The team's data review indicated that the main generator was operating during the motoring state at an angle of about 84°-87° (approximately 200 megavars onto the grid and 10 megawatts into the main generator).

Subsequent testing of the reverse power relays by the licensee indicated that with a power factor angle in that range, the 32G1 relay would require approximately 9.2-12.8 megawatts to operate and the 32G relay would require approximately 20.4-30.8 megawatts to operate. Since the main generator was motoring with a power input of approximately 9-10 megawatts, it appeared that a reverse power trip was unlikely.

2.10.4 Slow Transfer to Preferred Power Supply

As described previously, had the reverse power relays actuated as intended, the transfer of the plant loads to offsite power would have been a fast transfer (typically less than 10 milliseconds), and the main turbine and main generator would have tripped automatically. Because the main generator output breakers were opened manually, the prerequisites for the fast transfer were not met, and the only action that occurred was the opening of the breakers. This was consistent with the design of the manual trip circuitry. The slowed transfer subsequently occurred due to actuation of the 13.8 kV bus load undervoltage relays.

2.11 Bus Transfer Induced Equipment Anomalies

As discussed in Section 2.1, the slow bus transfer caused the loss of a number of electrical loads. Based on the events that occurred and the electrical system lineup prior to the event, these losses were expected. The only exception to these losses involved the nonsafety-related reactor protection system (RPS) motor-generator sets. The team reviewed the loss of these motor-generator sets, since such motor-generator sets are designed to coast through a short duration power interruption. To further investigate this aspect, the team reviewed a condition report that involved a previous slow transfer event to determine how the motor-generator sets responded. During an event on February 15, 1992, the slow transfer occurred because the closing circuit breaker operation was slowed due to a dried and hardened grease condition. There was no indication that the RPS motor-generator sets had been lost during these slow transfer conditions. The team concluded that the RPS motor-generator sets would probably not trip on a normal slow transfer. In the September 8 event, however, the decaying conditions on the output of the generator caused a slower than normal loss of bus voltage, resulting in the loss of the RPS motor-generator sets.

During the event, circulating water Pumps B and D and normal service water Pump B should also have tripped. This equipment, however, continued to run. The cause was determined by the licensee to be a failed bus undervoltage relay. A review of the failure history for the Type KV-1 relay did not indicate past problems with this type relay nor a potential generic concern. The faulty relay was subsequently replaced.

2.12 Valve Failures

2.12.1 Failure of Vavle SWP*MOV40A to Open

During the event, the control room operators started Standby Service Water Pumps 2A and 2C to provide cooling to safety-related loads. The pump discharge valves, motor-operated valves (MOVs) 1SWP*MOV40A (MOV 40A) and 1SWP*MOV40C (MOV 40C), respectively, were designed to automatically open when the pumps are started. Contrary to this design, MOV 40A failed to open fully. Control room position indication for MOV 40A was lost. MOV 40A is an 18-inch butterfly valve with a Limitorque SMB-00 actuator. Pumps 2A and 2C and MOV 40C operated properly and the combined flow through this division of standby service water was sufficient to provide the design cooling loads. Later in the event, an auxiliary operator manually opened MOV 40A, thus restoring the normal system configuration.

Upon investigation, the licensee determined that the control power fuse on MOV 40A had blown, a condition sufficient by itself to prevent remote operation of the valve and cause a loss of control room indication, as observed. The locking gear set prevented the valve from subsequently drifting in either direction. Inspection of the actuator revealed that arcing had occurred between the limit switch compartment cover and a wire landed to limit switch contact point LS-1. The wire was routed in a configuration that caused it to be bent back sharply from the lug. The small bend radius in contact with the cover had resulted in abrasion of the insulation jacket, especially from the vibration present during valve strokes. A single strand of bare wire was exposed. A ground between this wire and the compartment cover was thought to have caused the overcurrent condition that blew the control fuse. The team examined the exposed wire in the actuator and concluded that it was the probable cause of the valve failure.

The only information available to determine the position at which the valve failed was the recollection of the nuclear equipment operator who manually opened the valve during the event. The operator stated that the local valve position indicator dial was slightly above horizontal, corresponding to a valve position of approximately 10 percent open. Because of the lack of evidence establishing the position at which the valve failed, the team considered the possibility that the valve may have failed to stroke at all during the event. However, the licensee provided an evaluation based on fluid dynamics that satisfactorily demonstrated that MOV 40A was open and passing an appreciable amount of flow at the time of failure.

To determine the generic implications of the MOV 40A failure, the licensee examined the clearances between limit switch terminals and compartment covers for all sizes of installed actuators. The licensee determined that only SMB-00 actuators with wires connected to limit switch Terminals LS-1 or LS-9 were susceptible to the failure mechanism observed in MOV 40A. All other actuators and terminal points were determined to provide adequate clearances.

The team examined sample SMB-00 and SMB-000 actuators and concurred with the licensee that the SMB-000 actuator (the smallest of the Limitorque actuators) could be eliminated from the scope of corrective actions. The licensee developed plans to inspect nine additional safety-related SMB-00 actuators that were identified to have wires attached on Terminals LS-1 or LS-9.

The licensee stated that there had been previous occurrences of crushed or damaged wires in limit switch compartments, but that these problems had always been discovered during the post-maintenance valve stroke test that was performed after any work was performed in the limit switch compartment. What made the failure of MOV 40A unusual was that this valve had passed its last post-maintenance valve stroke test. Evidently, the loss of wire insulation was progressive over time and the ground that developed was intermittent in nature. The previous failures had occurred on all sizes of Limitorque actuators. The licensee considered inspection of only SMB-00 actuators to be adequate by reasoning that wire damage, if sufficient to cause problems, would be successfully discovered during the post-maintenance stroke testing. Continuing degradation would occur only in those cases where the wire was held firmly in place while in contact with the compartment cover. The team considered this position to be reasonable. Based on the measurements reported by the licensee, only the SMB-00 actuators with wires landed to LS-1 and LS-9 would be subject to progressive vibratory deterioration.

The team witnessed inspections of three of the nine SMB-00 actuators that had been identified to have wires landed to LS-1 or LS-9 (1E12*MOVF068A, 1SWP*MOV40C, and 1SWP*MOV 55A). The wires landed to LS-1 and LS-9 in these actuators were in good condition and were routed in configurations that did not result in high bend radii or contact with the compartment cover. One discrepancy was noted. A control wire in 1SWP*MOV40C was damaged and had evidently been crushed at some prior time when the cover was installed. Some bare wire was evident. In discussions on this subject, the team agreed with the licensee that the damaged wire found in 1SWP*MOV40C would not have been subject to further deterioration from vibration since the wire was free to move inside the compartment (unlike the condition in MOV 40A where the wire was held in place against the cover).

2.12.2 Apparent Failure of Valve B21*MOVF016

Valve B21*MOVF016 (MOV 016) is the inboard containment isolation steam line drain valve. This valve is designed to close automatically in response to a low condenser vacuum. During the event, a low condenser vacuum alarm was received in the control room. The operators noted that MOV 016 did not close. Based on these facts, the licensee initially believed that MOV 016 had failed to perform as designed.

During investigation, the licensee determined that MOV 016 had not malfunctioned. The MOV and the control circuit were tested and determined to be operating properly. The licensee determined that the low vacuum condition lasted for a short duration and was close to the valve's setpoint value. Since the annunciator and valve isolation circuitry are derived from separate pressure transmitters, the annunciator transmitter could have reached its trip setpoint, whereas one or both of the transmitters that must trip to send a

close signal to MOV 016 could have remained above the setpoint. The team concurred with the licensee's conclusion that MOV 016 did not malfunction during the event.

2.12.3 Failures of Balance-of-Plant Motor-Operated Valves and Air Operated Valves

During the event, several nonsafety-related balance-of-plant MOVs and air-operated valves (AOVs) failed to perform as expected. Although these valves were not needed to safely shut down the reactor or prevent the release of radioactive material, their failure to perform as expected complicated recovery efforts and distracted control room operators. The team reviewed the licensee's investigation of these valves. A summary of the valve failures is presented below:

- CNS-MOV112 (condensate transfer line to condensate system supply valve) failed to open.
- CNM-MOV136 (low pressure feedwater heater bypass) failed to open.
- 1FWS-MOV34A (1st point feedwater heater bypass valve) failed to open.
- FWS-MOV26A (feedwater Pump 1A discharge valve) failed to close.
- MSS-MOV106 (steam jet air ejector bypass valve) handswitch broke, but could still be operated from the control room.
- SVH-AOV25B (3rd point feedwater heater vent) and SVH-AOV41B (5th point feedwater heater vent) stroked satisfactorily during the event. However, they indicated closed in the control room when, in fact, they were open.

The licensee had not completed evaluations of these valve failures, but some preliminary information was available. The team was particularly interested in the three MOVs that failed to open and the one MOV that failed to close.

Valve CNS-MOV112 stopped after opening approximately three percent of the full stroke. This was the point in the stroke where the open torque switch was enabled in the control circuit. The contacts on the open torque switch were not closed. Further inspection revealed that the power termination screws, leaf contacts (SMB-000 actuator), and bridge contact screws were all loose. The licensee postulated that the torque switch components had loosened over time as a result of vibration experienced during operating flow conditions. A further complication was that the open torque switch bypass, which shared a limit switch rotor with the valve position limit switch, was not properly set to bypass the unseating loads experienced under full flow conditions. The licensee replaced the torque switch and the valve was tested satisfactorily. The licensee intended to increase the open torque switch bypass setting by using a spare rotor.

Valve CNM-MOV136, which had failed to open during the event, was found to have been heavily damaged. Limit switch decks were sheared, rotors were cracked, screws were loose, the motor was twisted, and the stem appeared to be bent. Causal factors had not been determined at the conclusion of this inspection.

Valve 1FWS-MOV34A, which failed to open during the event, was found to have incurred hydraulic lock of the actuator springpack. The licensee postulated that during the preceding closing stroke, the close torque switch did not make up, the motor stalled, and the thermal overloads tripped. No remote indication of the thermal overload trip was available (though all safety-related MOVs have control room indication of tripped thermal overloads). As a result of the tripped overloads, the MOV could not be opened remotely.

In an attempt to close, Valve FWS-MOV26A experienced a torque switch trip at a valve position of approximately 95 percent closed. The valve was closing against a differential pressure of 1400 psid and a line pressure of 2000 psi. The torque switch tripped because its setting was based on a valve factor of 0.3 and a stem friction coefficient of 0.15, whereas actual values for these parameters were probably higher. After the pressure had decayed, the control room operators were able to remotely close the valve, apparently because the springpack or torque switch gearing relaxed slightly, allowing the torque switch to reset.

In response to the multiple failure of balance of plant MOVs, the licensee developed a plan to inspect 38 MOVs that the operations department had designated as being the most important nonsafety-related valves. An additional criteria in the selection process was the lack of recent preventive maintenance.

The team witnessed the inspection of Valve 1FW-MOV26B, which was one of the 38 balance of plant MOVs selected for examination. The inspection met the stated objectives and, overall, the condition of this MOV appeared good.

2.13 Reactor Core Isolation Cooling (RCIC) Turbine Trip

During the event, the RCIC pump turbine tripped on mechanical overspeed. The turbine, which was supplied by Dresser-Rand Steam Turbines, could not be reset remotely. Therefore, the RCIC pump could not be used during the recovery efforts.

The licensee determined that the cause of the overspeed trip was that the normally-open governor valve was stuck in the open direction. This was confirmed by the fact that the valve could not be manually stroked. Once steam was admitted to the turbine, rotor speed was uncontrolled and continued to increase until the mechanical overspeed device activated.

The team witnessed the removal of the RCIC governor valve. No obstructions were found in the area of the valve seat that would have prevented the valve from closing.

The licensee disassembled the governor valve and discovered that the valve stem was excessively corroded in the gland area where the stem interfaces with carbon spacers and stainless steel washers. Corrosion products had migrated into fractures in the carbon spacers. The corrosion caused the valve stem to stick and resist the hydraulic pressure that otherwise would have repositioned the valve so that turbine speed was controlled.

During the previous refueling outage (Refueling Outage 5, Spring 1994), the governor valve was observed to be difficult to move. As a preventive measure, the licensee replaced the valve stem, carbon spacers, and washers. The old stem exhibited some corrosion, though not to the same extent that the new stem incurred after less than three months of standby service. From these facts, the primary failure mechanism was believed to be accelerated corrosion. Similar incidents of accelerated corrosion of turbine governor valves have been reported in the nuclear industry. The most recent occurrence was reported in a 10 CFR Part 21 report, by Virginia Electric and Power Company, dated September 2, 1994. Accelerated corrosion of governor valve stems appears to occur most often in the first weeks or months after a new stem is installed. Some recent information has suggested that sulfur contamination in the carbon spacers may accelerate the corrosion process.

The RCIC pump was tested on a quarterly surveillance interval. The pump was last tested following the governor valve rebuild in Refueling Outage 5 and had not yet reached the quarterly testing interval where periodic testing was required. Therefore, this failure was the first time the RCIC pump was called on to start since the conclusion of the refueling outage.

The licensee sent the valve stem and some of the carbon spacers and stainless washers to a laboratory for analysis. The results of this testing were not available during the inspection. Once the specific failure mechanism is established, the licensee will determine the corrective actions to be taken. During the inspection, the licensee discussed several possible courses of action. These included the coating of the valve stem and washers, using a nickel-zinc plating process. As an alternative, the licensee was also considering the use of a chrome plated valve stem.

2.14 Management Response

The team considered the management response to this event to be adequate and appropriate. It was observed that senior management was involved with the event soon after the reactor trip as evidenced by plant management responding to the control room within approximately 30 minutes of the event to assist the operators with their event response activities. In addition, the team observed continued strong management oversight of activities as evidenced by the rapid development of the Significant Event Response Team (SERT) that was manned by plant management personnel and around the clock coverage of activities by senior management personnel.

When the team was assembled at the site on Saturday, September 10, 1994, senior management personnel provided a briefing for the team. This briefing was detailed and comprehensive and demonstrated that senior management was fully involved with the event and its consequences.

3 FINDINGS AND CONCLUSIONS

The AIT had the following findings and conclusions:

- The licensee's development of a sequence of events from just prior to the reactor trip through the initiation of shutdown cooling was in good agreement with the sequence of events independently developed by the team. In addition, the event and causal factors chart that was developed by the licensee also demonstrated good agreement with that independently developed by the team.

- The team agreed with the licensee's initial assessment that the most likely cause of the reactor trip was the postulated hydraulic wave within the reactor vessel. However, subsequent to the conclusion of the AIT, the licensee completed a thorough examination of the reactor vessel internals and did not detect any failures. In addition, it appears that the licensee has identified the root cause of the reactor trip to be sensitivity of the Rosemount Model 1153 level transmitters to process noise. This information was presented to the NRC staff in a public meeting at the Region IV office on October 4, 1994. This meeting confirmed that the licensee has identified the root cause of the reactor trip. Details of this meeting are contained as Attachment C to this report.

- The team reviewed the radiological releases that resulted from the event and confirmed that the releases were small in comparison to the license limits.

- The team considered the operators' responses to the event to be adequate and appropriate. Nevertheless, the team noted the following apparent weaknesses:

  - The operators' knowledge of the main turbine/generator operation was weak, as evidenced by their lack of knowledge that a slow electrical bus transfer would occur following a manual main generator output breaker trip. The team attributed this to training weaknesses and a lack of simulator fidelity to actual plant operation.

  - Communications between the operators and other plant personnel were lacking in certain areas. This was exhibited by the operators' failures to:

    * Communicate their concerns about the possibility of a slow bus transfer occurring,

    * Prevent the safety relief valves from cycling automatically at a pressure that was higher than specified in the emergency operating procedure,

* Control reactor vessel level within specified limits resulting in the actuation of a Level 8 signal during high pressure core spray operation causing the high pressure core spray injection valve to close, and

* Take action to allow the chemistry technicians to take required Technical Specification samples in a timely fashion.

The team considered these communication weaknesses to have complicated the operators' response to the event.

- The team considered the use of the main steam line drains to control reactor pressure to be appropriate and in accordance with the emergency operating procedure.

- The team noted a conflict between the Technical Specifications and the plant procedure regarding the noble gas sampling of the plant exhaust effluent following a reactor trip. This appears to be a Technical Specification problem in that the Technical Specifications required actions that could not be completed within the allotted time.

- The team agreed with the licensee's conclusions that the RCIC turbine overspeed condition was caused by a sticking turbine governor valve. The team also agreed that this sticking was caused by a corrosion condition which existed between the valve stem and packing. The team concluded that the licensee had established a satisfactory plan of action to identify and correct the specific failure mechanisms.

- The team agreed with the licensee's conclusions regarding the postulated failures of two safety-related MOVs to operate when required. The team concluded that Valve B21*MOVF016, a main steam line drain isolation valve, did not fail and that Valve 1SWP*MOV40A, a standby service water pump discharge isolation valve, did fail to stroke open as required. The team also concluded that the failure of Valve 1SWP*MOV40A was caused by a pinched wire within the motor operator's limit switch compartment and that the problem had potential generic implications.

- The team considered the licensee's inspection plan of nonsafety-related valves to be a satisfactory response to the balance-of-plant valve failures experienced during the event.

- The team agreed with the licensee's conclusions that the cause of the main turbine/generator trip anomalies was the result of the reverse-power relay operation.

4 CORRECTIVE ACTIONS

The team reviewed the licensee's planned corrective actions. It is the team's understanding that the following corrective actions are being considered:

- Improve the operators' knowledge of the main turbine/generator operation through the use of additional operator training and improved simulator fidelity.

- Review the abnormal operations procedure that addresses the main turbine/generator trips and consider enhancements to this procedure.

- Analyze the valve stem and packing for the RCIC turbine governor valve to confirm the failure mechanism. To reduce corrosion of this valve stem, evaluate the replacement of the existing stem with a valve stem that is more corrosion resistant.

- Review the preventative maintenance procedure for testing the RCIC turbine and consider enhancements to this procedure to ensure proper governor valve operation.

- Inspect an additional nine Limitorque Type SMB-00 safety-related actuators with similar wire lug configurations to check for a shorting potential.

- Provide additional training of maintenance personnel and procedure enhancements that will address work that is conducted in MOV limit switch compartments.

- To improve main generator operation and indication by:

  - Positive indication in the main control room of a main generator motoring condition.

  - Additional instructions in the procedures regarding a manual main generator trip.

  - Replacement of existing reverse power relays with relays that have improved tripping characteristics.

- Inspect 38 balance of plant MOVs recommended by the operations department as being important for event recovery actions prior to plant restart. For each MOV, the licensee plans to:

  - Inspect limit switch housing for crimped or loose wires,
  - Relubricate the valve stems,
  - Check grease condition, and
  - Perform a valve stroke test.

  If an MOV was found to have significant discrepancies, additional refurbishment efforts would be performed.

- Review auxiliary building accessibility issues such as procedures and equipment lineups to assure that required access is available when needed.

- Reevaluate chemistry department training and procedures to assure that chemistry technicians are prepared to take samples under varying plant conditions.

ATTACHMENT A

1 ENTERGY OPERATIONS INC., PERSONNEL

** R. Bigg, Supervisor, Quality Assurance
***O. Bulich, Manager, Licensing
** B. Burke, Corporate Chemist
* J. Burton, Manager, Mechanical Engineering and Safety Analysis/Grand Gulf
***T. Davey, Manager, Electrical Instrumentation and Control
***W. Day, Cajun Site Representative
* D. Derbonne, Technical Assistant to the General Manager
***D. Dormady, Manager, Mechanical/Civil
* R. Douet, Director, Plans, Projects & Support
** K. Dreher, Communications Specialist
***E. Ewing, Maintenance Manager
* J. Fisicaro, Director, Nuclear Safety
** K. Giadrosich, Manager, Quality Assurance
** L. Grant Lewis, Manager, Training
***J. Holmes, Superintendent, Chemistry
** C. Hurst, Secretary, Nuclear Safety
** H. Hutchens, Superintendent, Plant Security
** H. Keiser, Executive Vice President
***M. Krupa, Manager, System Engineering
** J. Leavines, Manager, Nuclear Safety and Assessment
***T. Leonard, Director, Engineering
***D. Lorfing, Supervisor, Licensing
***J. McGaha, Vice President, River Bend
* J. McGhee, Operations Technical Assistant
***B. Odell, Superintendent, Radiation Control
** C. Odom, Site Administrative Program Coordinator
** S. Radelbaugh, Senior Oversight Specialist
** J. Roberts, Director, Central Licensing
** J. Russell, Steno, Licensing
* M. Sellman, General Manager
** W. Short, Onsite Engineering
** B. Smith, Manager, Emergency Preparedness
** J. Somerindyke, Supervisor, Security Operations
** J. Sutherland, Project Manager
** F. Titus, Vice President, Engineering
***J. Venable, Operations Manager
** T. Young, Manager, Communications
***K. Zimmerman, Communications
* G. Zinke, Technical Coordinator, Nuclear Safety

2 NRC PERSONNEL

** L. Callan, Regional Administrator
* G. Galletti, Human Factors Engineer, Office of Nuclear Reactor Regulation
** J. Gilliland, Public Affairs Officer
** T. Gwynn, Director, Division of Reactor Safety
** C. Skinner, River Bend Resident Inspector

* J. Lazevnick, Senior Electrical Engineer, Office of Nuclear Reactor Regulation
* D. Loveless, Senior Resident Inspector, South Texas Project
* M. Runyan, Reactor Inspector
* W. Smith, Senior Resident Inspector

3 OTHER PERSONNEL

** J. Connelly, WBRZ
** M. Goldsby, Channel 9
** L. Kettl, Public
** M. McGraw, WBRZ
** J. Minton, Morning Advocate
** A. Plettinger, Public
** L. Zganjar, Associated Press

The AIT contacted the following personnel during this inspection. In addition to these personnel, the AIT contacted other licensee personnel during this inspection.

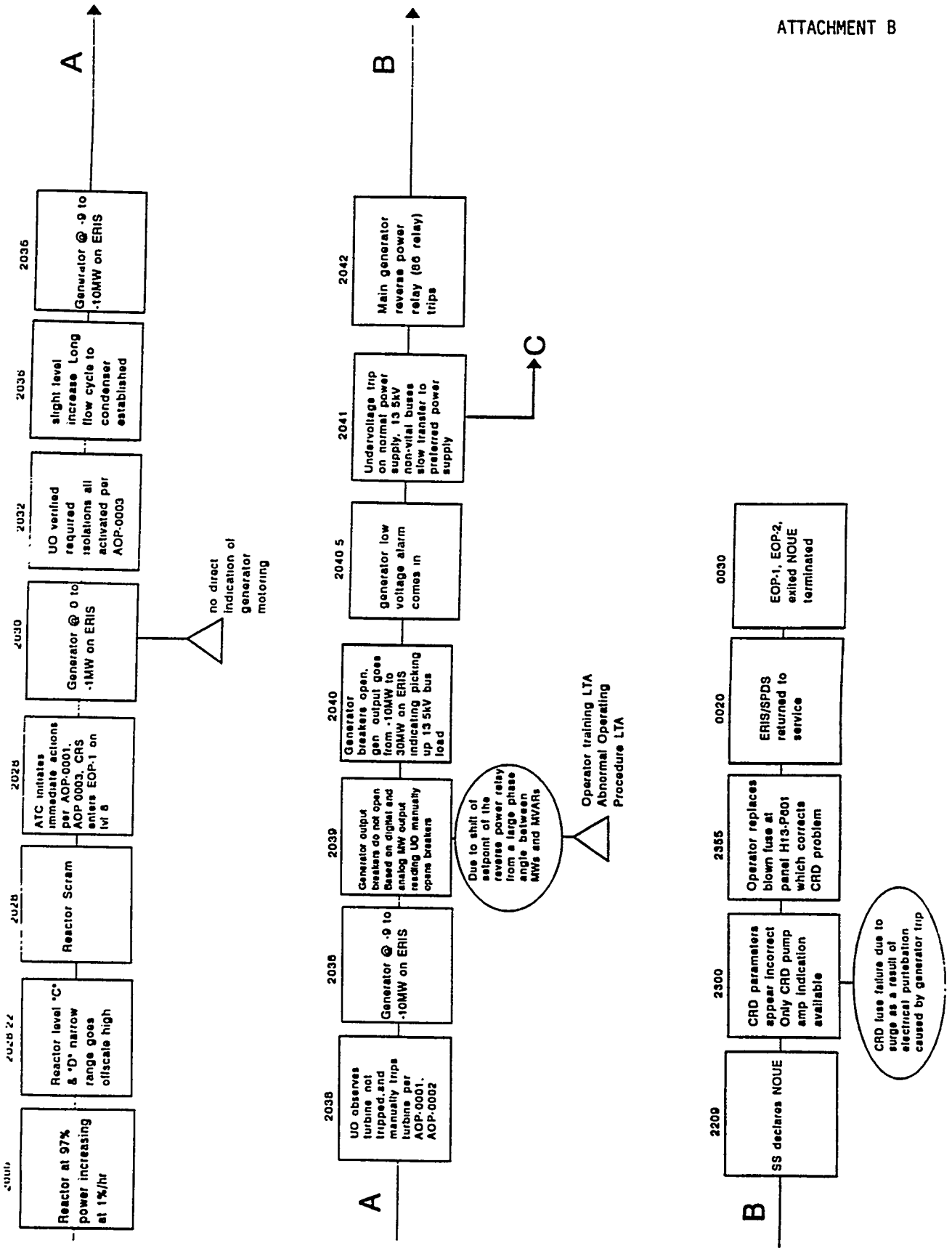
*Denotes personnel that attended the interim exit meeting held on September 15, 1994.

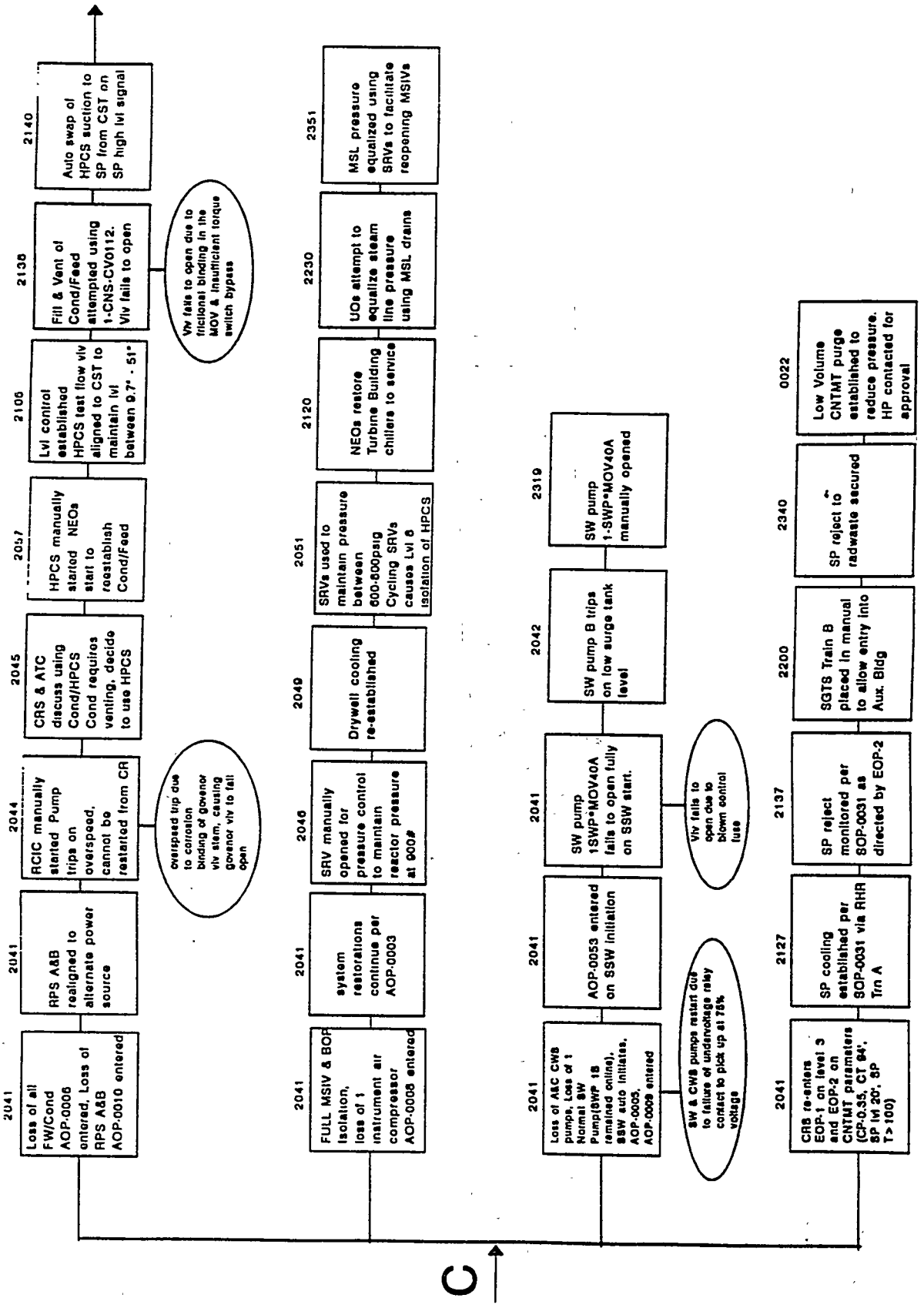
**Denotes personnel that attended the public exit meeting held on September 22, 1994.

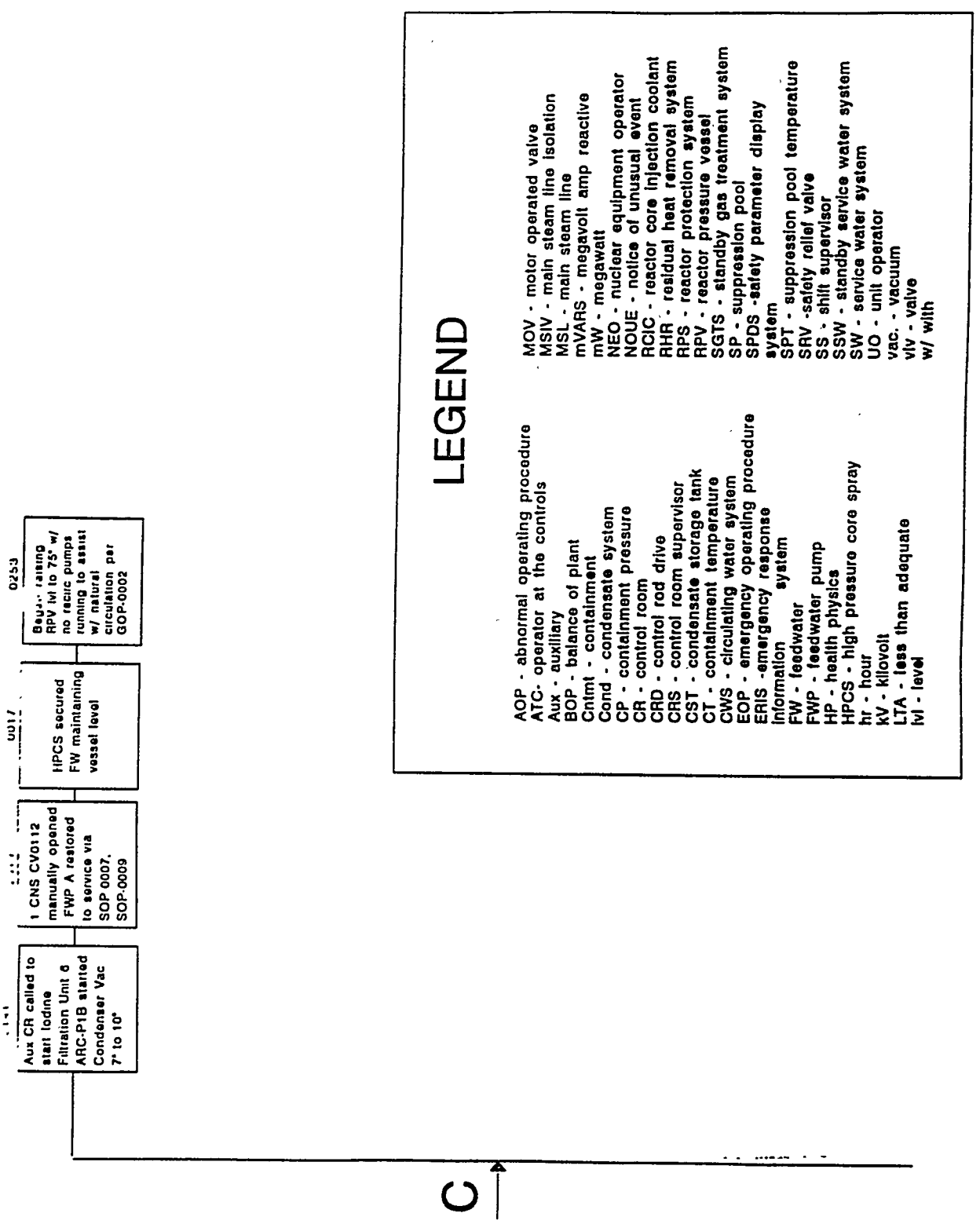
***Denotes personnel that attended both the interim exit meeting held on September 15, 1994, and the public exit meeting held on September 22, 1994.

EXIT MEETING

An interim exit meeting was conducted at the end of the onsite inspection on September 15, 1994. A final exit meeting open to public observation was conducted on September 22, 1994. The personnel that attended these exit meetings are listed above. During the September 22 meeting, the team leader summarized the scope and findings of this inspection, as delineated in this report. The licensee acknowledged the inspection findings and did not express a position on the inspection findings. The licensee did not identify as proprietary any information used in the performance of this inspection.


Reactor at 97% power increasing at 1%/hr
Reactor level 'C' & 'D' narrow range goes offscale high
Reactor Scram
ATC initiates immediate actions per AOP-0001. AOP 0003, CRS enters EOP-1 on lvl 8
Generator @ 0 to -1MW on ERIS
no direct indication of generator motoring
UO verified required isolations all activated per AOP-0003
slight level increase Long flow cycle to condenser established
Generator @ -9 to -10MW on ERIS
A
UO observes turbine not tripped and manually trips turbine per AOP-0001. AOP-0002
Generator @ -9 to -10MW on ERIS
Generator output breakers do not open Based on digital and analog MW output reading UO manually opens breakers
Due to shift of setpoint of the reverse power relay from a large phase angle between MWs and MVARs
Operator training LTA
Abnormal Operating Procedure LTA
Generator breakers open, gen output goes from -10MW to 30MW on ERIS indicating picking up 13.5kV bus load
generator low voltage alarm comes in
Undervoltage trip on normal power supply, 13.5kV non-vital buses slow transfer to preferred power supply
Main generator reverse power relay (86 relay) trips
B
C
B
SS declares NOUE
CRD parameters appear incorrect Only CRD pump amp indication available
CRD fuse failure due to surge as a result of electrical puriebation caused by generator trip
Operator replaces blown fuse at panel H13-P601 which corrects CRD problem
ERIS/SPDS returned to service
EOP-1, EOP-2, exited NOUE terminated


2041
Loss of all FW/Cond AOP-0006 entered, Loss of RPS A&B AOP-0010 entered
2041
RPS A&B realigned to alternate power source
2044
RCIC manually started Pump trips on overspeed, cannot be restarted from CR
overspeed trip due to corrosion binding of governor v/v stem, causing governor v/v to fail open
2045
CRS & ATC discuss using Cond/HPCS Cond requires venting, decide to use HPCS
2057
HPCS manually started NEOs start to reestablish Cond/Feed
2106
Lvl control established HPCS test flow v/v aligned to CST to maintain lvl between 9.7" - 51"
2136
Fill & Vent of Cond/Feed attempted using 1-CNS-CV0112. V/v fails to open
V/v fails to open due to frictional binding in the MOV & insufficient torque switch bypass
2140
Auto swap of HPCS suction to SP from CST on SP high lvl signal
2041
FULL MSIV & BOP Isolation, loss of 1 instrument air compressor AOP-0008 entered
2041
system restorations continue per AOP-0003
2046
SRV manually opened for pressure control to maintain reactor pressure at 900#
2049
Drywell cooling re-established
2051
SRVs used to maintain pressure between 600-800psig Cycling SRVs causes Lvl 8 isolation of HPCS
2120
NEOs restore Turbine Building chillers to service
2230
UOs attempt to equalize steam line pressure using MSL drains
2351
MSL pressure equalized using SRVs to facilitate reopening MSIVs
2041
Loss of A&C CWS pumps. Loss of 1 Normal SW Pump(SWP 1B remained online). SSW auto initiates. AOP-0053, AOP-0008 entered
2041
AOP-0053 entered on SSW initiation
2041
SW pump 1SWP*MOV40A fails to open fully on SSW start.
2042
SW pump B trips on low surge tank level
2319
SW pump 1-SWP*MOV40A manually opened
SW & CWS pumps restart due to failure of undervoltage relay contact to pick up at 75% voltage
V/v fails to open due to blown control fuse
2041
CRS re-enters EOP-1 on level 3 and EOP-2 on CNTMT parameters (CP-0.35, CT 84', SP lvl 20', SP T>100)
2127
SP cooling established per SOP-0031 via RHR Trn A
2137
SP reject monitored per SOP-0031 as directed by EOP-2
2200
SGTS Train B placed in manual to allow entry into Aux. Bldg
2340
SP reject to radwaste secured
0022
Low Volume CNTMT purge established to reduce pressure. HP contacted for approval
C


Aux CR called to start Iodine Filtration Unit & ARC-P1B started Condenser Vac 7" to 10"
1 CNS CV0112 manually opened FWP A restored to service via SOP 0007, SOP-0009
HPCS secured FW maintaining vessel level
Begin raising RPV lvl to 75" w/ no recirc pumps running to assist w/ natural circulation per GOP-0002
C
LEGEND
AOP - abnormal operating procedure
ATC- operator at the controls
Aux - auxiliary
BOP - balance of plant
Cntmt - containment
Cond - condensate system
CP - containment pressure
CR - control room
CRD - control rod drive
CRS - control room supervisor
CST - condensate storage tank
CT - containment temperature
CWS - circulating water system
EOP - emergency operating procedure
ERIS -emergency response information system
FW - feedwater
FWP - feedwater pump
HP - health physics
HPCS - high pressure core spray
hr - hour
kV - kilovolt
LTA - less than adequate
lvl - level
MOV - motor operated valve
MSIV - main steam line isolation
MSL - main steam line
mVARS - megavolt amp reactive
mW - megawatt
NEO - nuclear equipment operator
NOUE - notice of unusual event
RCIC - reactor core injection coolant
RHR - residual heat removal system
RPS - reactor protection system
RPV - reactor pressure vessel
SGTS - standby gas treatment system
SP - suppression pool
SPDS -safety parameter display system
SPT - suppression pool temperature
SRV -safety relief valve
SS - shift supervisor
SSW - standby service water system
SW - service water system
UO - unit operator
vac. - vacuum
vlv - valve
w/ with

ATTACHMENT C

NRC Public Meeting Attendance List and Briefing Handout

On October 4, 1994, a management meeting that was open to the public was conducted in the NRC Region IV office in Arlington, Texas. During this meeting, the root cause and corrective actions for the September 8, 1994, reactor trip was discussed. The following personnel attended this meeting:

1 ENTERGY OPERATIONS, INC.

T. Davey, Manager, Electrical Instrumentation and Control
T. Dickson, Public Information Officer
E. Ewing, Maintenance Manager
J. Fisicaro, Director, Nuclear Safety
H. Keiser, Executive Vice President
M. Krupa, Manager, System Engineering
T. Leonard, Director, Engineering
J. McGaha, Vice President, River Bend
M. Sellman, General Manager

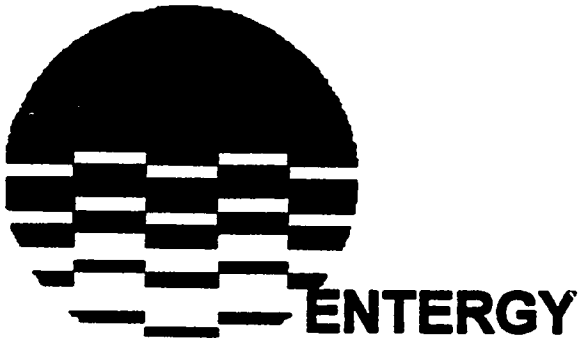
2 NRC

A. Beach, Director, Division of Reactor Projects (DRP)
L. Callan, Regional Administrator
J. Gilliland, Public Affairs Officer
B. Henderson, Public Affairs Officer
J. Pellet, Acting Deputy Director, Division of Reactor Safety (DRS)
D. Powers, Chief, Maintenance Branch, DRS
T. Stetka, Team Leader, DRS
C. VanDenburgh, Chief, Projects Branch D, DRP
D. Wigginton, Licensing Project Manager, Office of Nuclear Reactor Regulation

RBS / NRC

MANAGEMENT

MEETING



OCTOBER 4, 1994

MANAGEMENT MEETING AGENDA

I.	OPENING REMARKS	JOHN McGAHA Vice President - Operations
II.	SUMMARY OF SCRAM ROOT CAUSE	MIKE SELLMAN General Manager Plant Operations
III.	INVESTIGATION RESULTS	MIKE KRUPA Manager - System Engineering
IV.	CORRECTIVE ACTIONS AND START-UP MONITORING PLAN	TED LEONARD Director - Engineering
V.	CORRECTIVE ACTIONS DAMPING	EARLY EWING Manager - Maintenance
VI.	SUMMARY AND CONCLUSIONS	MIKE SELLMAN General Manager Plant Operations

PAGE 2

OPENING REMARKS

- PURPOSE OF MEETING

JOHN McGAHA
Vice President - Operations

PAGE 3

PURPOSE OF MEETING

- EXPLAIN CAUSE OF SCRAM
- PROVIDE SUMMARY OF SCRAM CAUSE INVESTIGATION
- DISCUSS INVESTIGATION RESULTS
- PRESENT CORRECTIVE ACTION AND START-UP MONITORING PLAN

PAGE 4

SUMMARY OF SCRAM CAUSE

- EVENT OVERVIEW
- STAFF RESPONSE
- INVESTIGATION PROCESS
- ROOT CAUSE SUMMARY
- SCRAM CORRECTIVE ACTIONS

MIKE SELLMAN
General Manager
Plant Operations

PAGE 5

EVENT OVERVIEW

- AUTOMATIC REACTOR SCRAM OCCURRED ON SEPTEMBER 8, 1994 AT 2028
- NO INDICATION OF FEEDWATER LEVEL EXCURSION
- CAUSE DETERMINED TO BE
  - UNDAMPED ROSEMOUNT MODEL 1153 TRANSMITTERS ON RPS NARROW RANGE CHANNEL C AND D REACTOR WATER LEVEL RESPONDED TO PROCESS SYSTEM NOISE

PAGE 6

STAFF RESPONSE

- STAFF SUPPORT BEGAN IMMEDIATE INVESTIGATION OF ROOT CAUSES
- TECHNICAL EXPERTS BROUGHT IN FROM OTHER EOI PLANTS AND CORPORATE OFFICE
- INDUSTRY EXPERTS TO ASSIST INVESTIGATION
  - GENERAL ELECTRIC
  - BABCOCK & WILCOX
  - FAILURE PREVENTION INTERNATIONAL
  - ROSEMOUNT
  - INPO
- SPECIAL INVESTIGATION TEAM ESTABLISHED TO FOCUS ON SCRAM ROOT CAUSE

PAGE 7

INVESTIGATION PROCESS

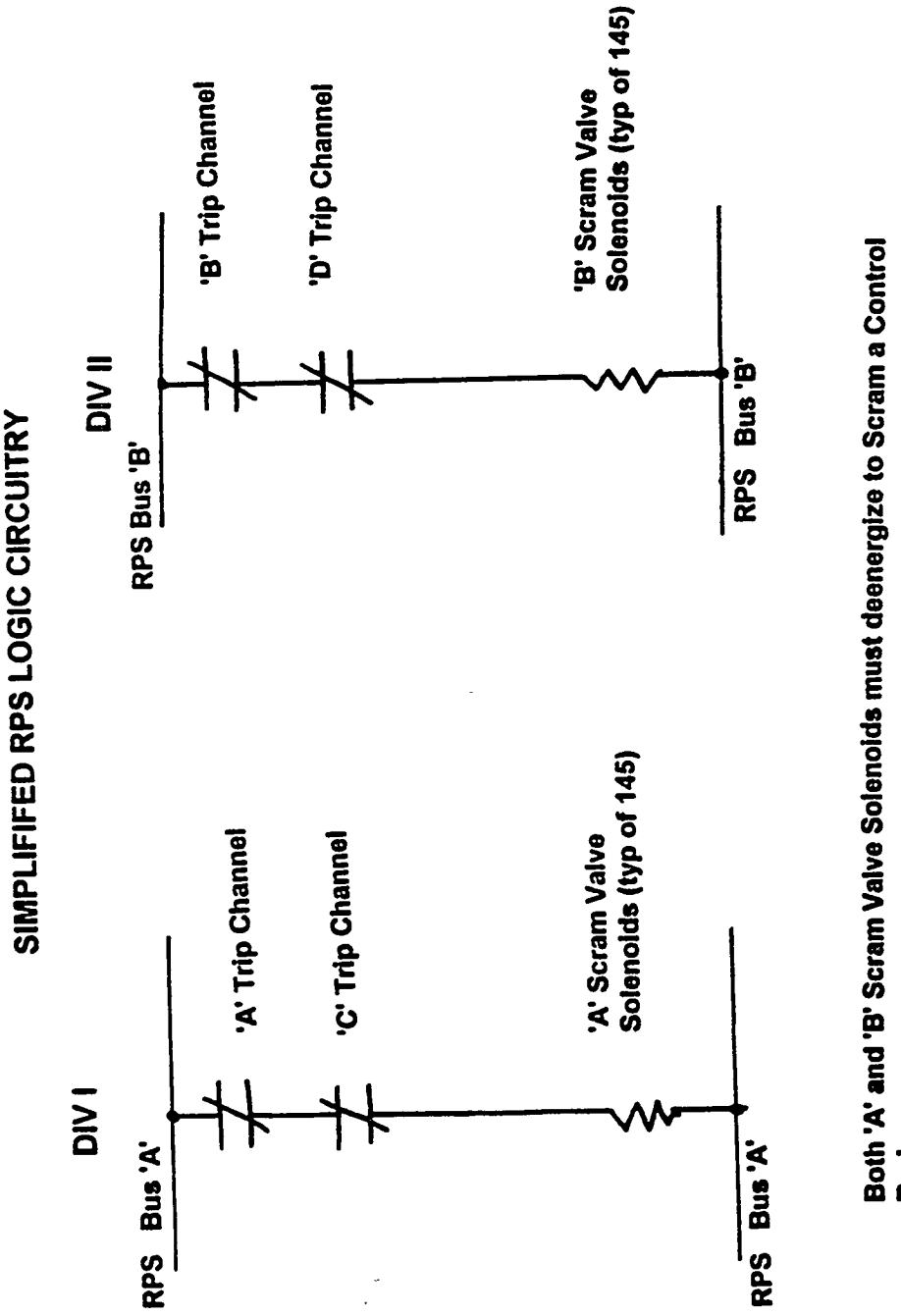
- IDENTIFIED 37 POTENTIAL FAILURE SCENARIOS FOR INVESTIGATION
- INVESTIGATION EXPLORED ALL PLAUSIBLE EVENT INITIATORS
- UTILIZED RIGOROUS METHODOLOGY FOR EVALUATION
  - POTENTIAL ISSUES EVALUATED IN PARALLEL
  - ISSUES RULED OUT BASED ON FACTS AND EVIDENCE
- ESTABLISHED MOST PROBABLE CAUSES
- CORRECTIVE ACTIONS ESTABLISHED TO ADDRESS THESE CAUSES

PAGE 8

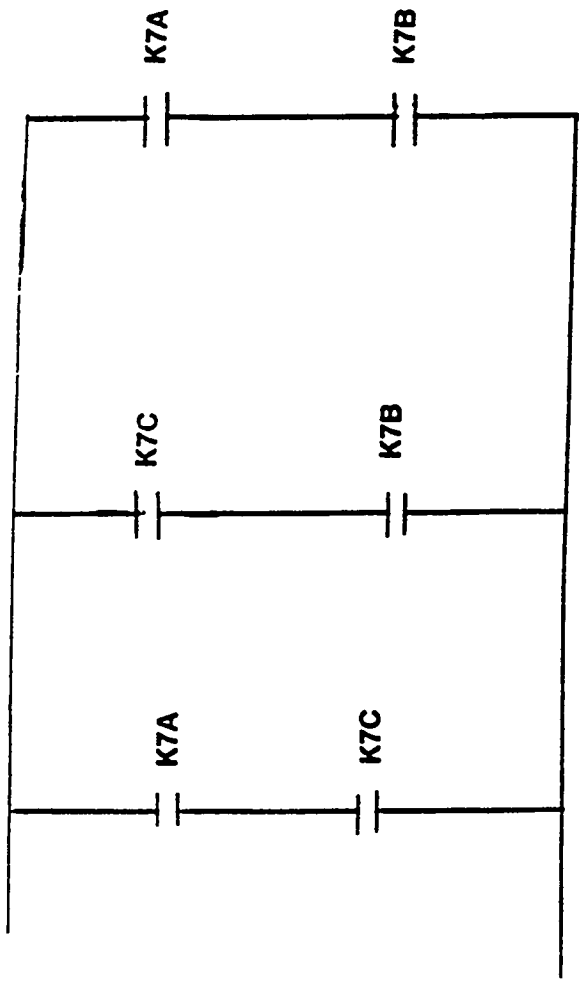
SCRAM CAUSE SUMMARY

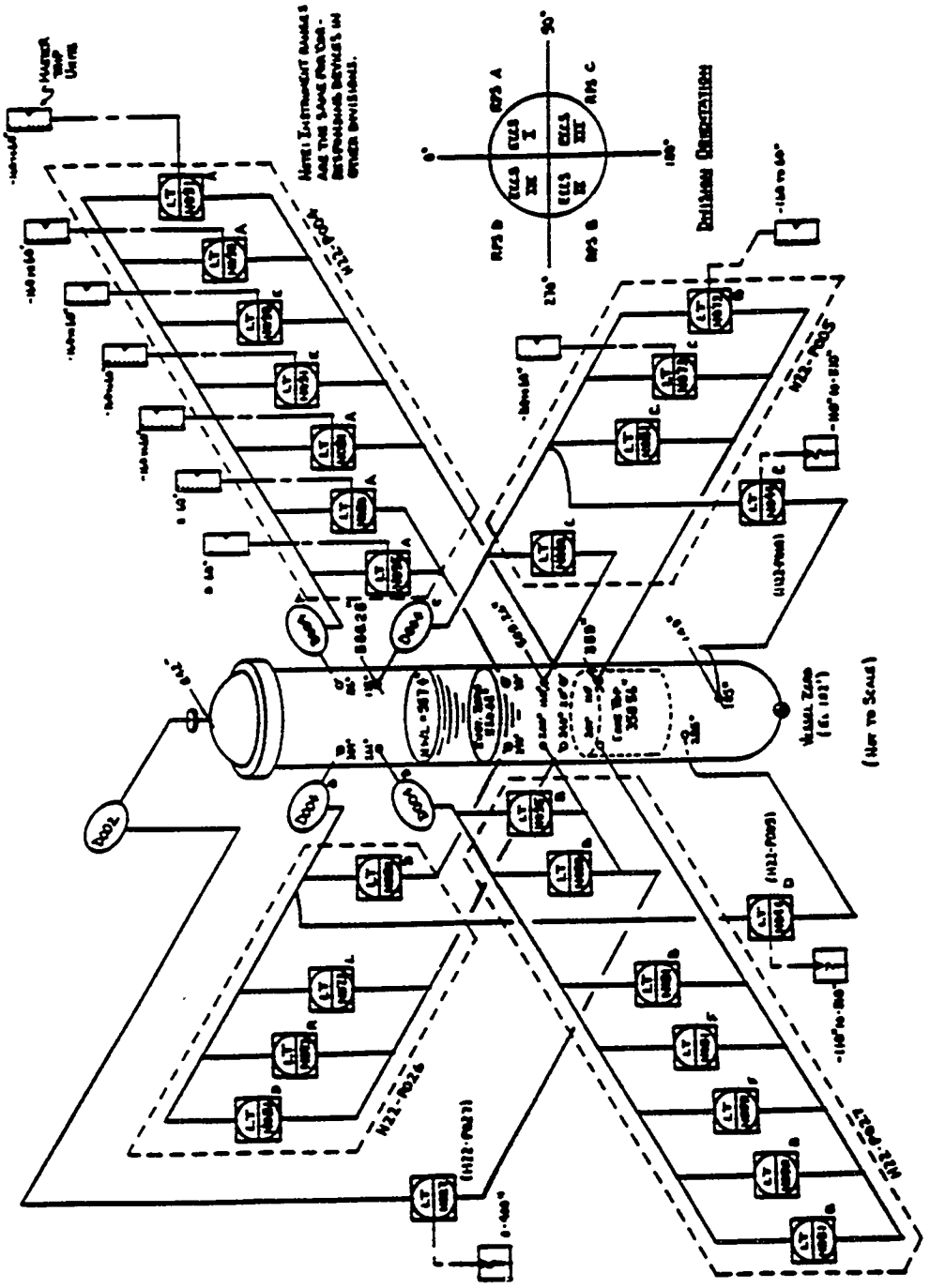
- EXTENSIVE INVESTIGATION NARROWED PROBABLE CAUSES
- THOROUGH INVESTIGATION TO EVALUATE POTENTIAL INITIATORS
  - POTENTIAL IN-VESSEL INITIATOR LED TO REACTOR VESSEL DISASSEMBLY
    - » PLAUSIBLE EXPLANATION FOR PROCESS NOISE
    - » CONCERNED THAT INITIATOR COULD HAVE BEEN DAMAGED SPARGER / OTHER INTERNAL COMPONENTS
  - POSTULATED SCENARIOS INVESTIGATED IN PARALLEL
- CONCLUSION
  - PROCESS NOISE IN COMBINATION WITH UNDAMPED ROSEMOUNT MODEL 1153 LEVEL TRANSMITTERS

PAGE 9


SIMPLIFIED RPS LOGIC CIRCUITRY
DIV I
RPS Bus 'A'
'A' Trip Channel
'C' Trip Channel
'A' Scram Valve Solenoids (typ of 145)
RPS Bus 'A'
DIV II
RPS Bus 'B'
'B' Trip Channel
'D' Trip Channel
'B' Scram Valve Solenoids (typ of 145)
RPS Bus 'B'
Both 'A' and 'B' Scram Valve Solenoids must deenergize to Scram a Control Rod.

RX FEED PUMP AND TURBINE HIGH WATER LEVEL TRIP





LEVEL INSTRUMENT ARRANGEMENT

SCRAM CORRECTIVE ACTIONS

- ACTION PLAN
  - ADDRESS VULNERABILITIES
  - COMPREHENSIVE START-UP MONITORING PLAN

PAGE 13

INVESTIGATION RESULTS

- DETAILS OF INVESTIGATION
- INVESTIGATION SUMMARY
- INVESTIGATION CONCLUSIONS

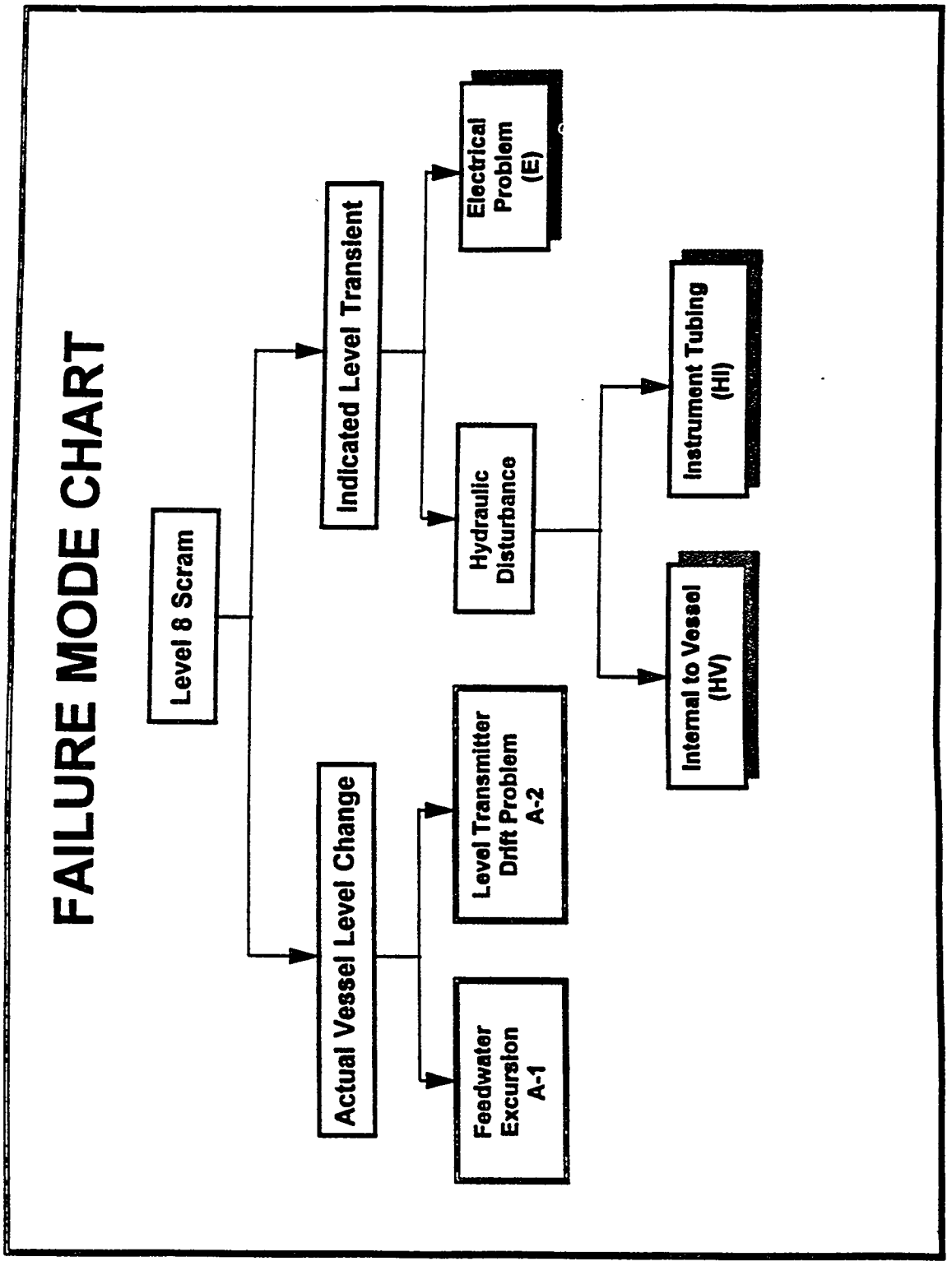
MIKE KRUPA
Manager -
System Engineering

PAGE 14

DETAILS OF INVESTIGATION

- DEVELOPED SCENARIOS (37)
- INDEPENDENCE
- OBTAINED FACTS
  - SUPPORTING EVIDENCE
  - REFUTING EVIDENCE
- PERFORMED NECESSARY DIAGNOSTICS
  - TESTING
  - INSPECTIONS / WALKDOWNS
  - ANALYSIS / CALCULATION
- DOCUMENTED ASSUMPTIONS
- ESTABLISHED CONCLUSIONS

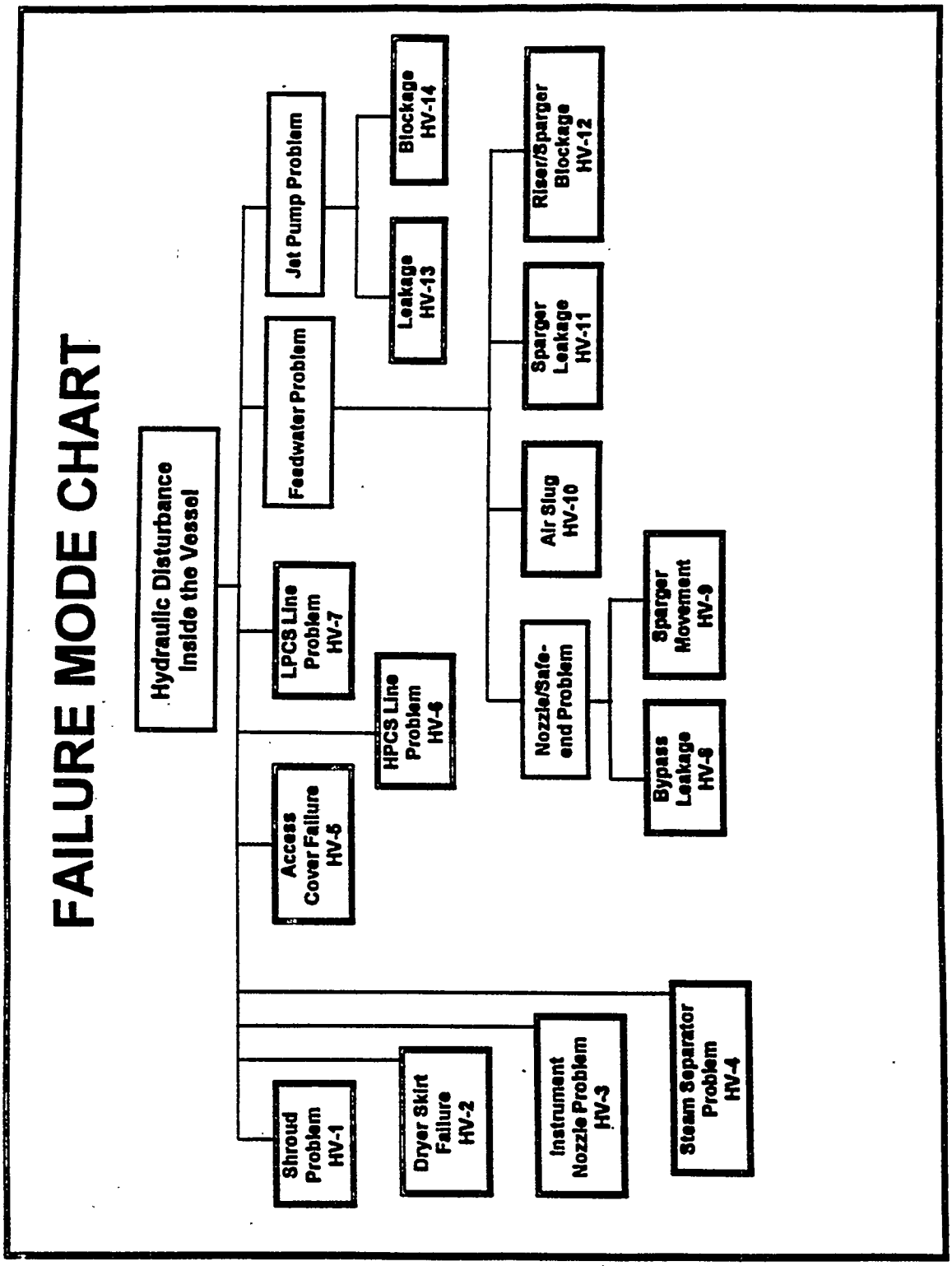
PAGE 15


FAILURE MODE CHART
Level 8 Scram
Indicated Level Transient
Electrical Problem (E)
Hydraulic Disturbance
Instrument Tubing (HI)
Internal to Vessel (HV)
Actual Vessel Level Change
Level Transmitter Drift Problem A-2
Feedwater Excursion A-1

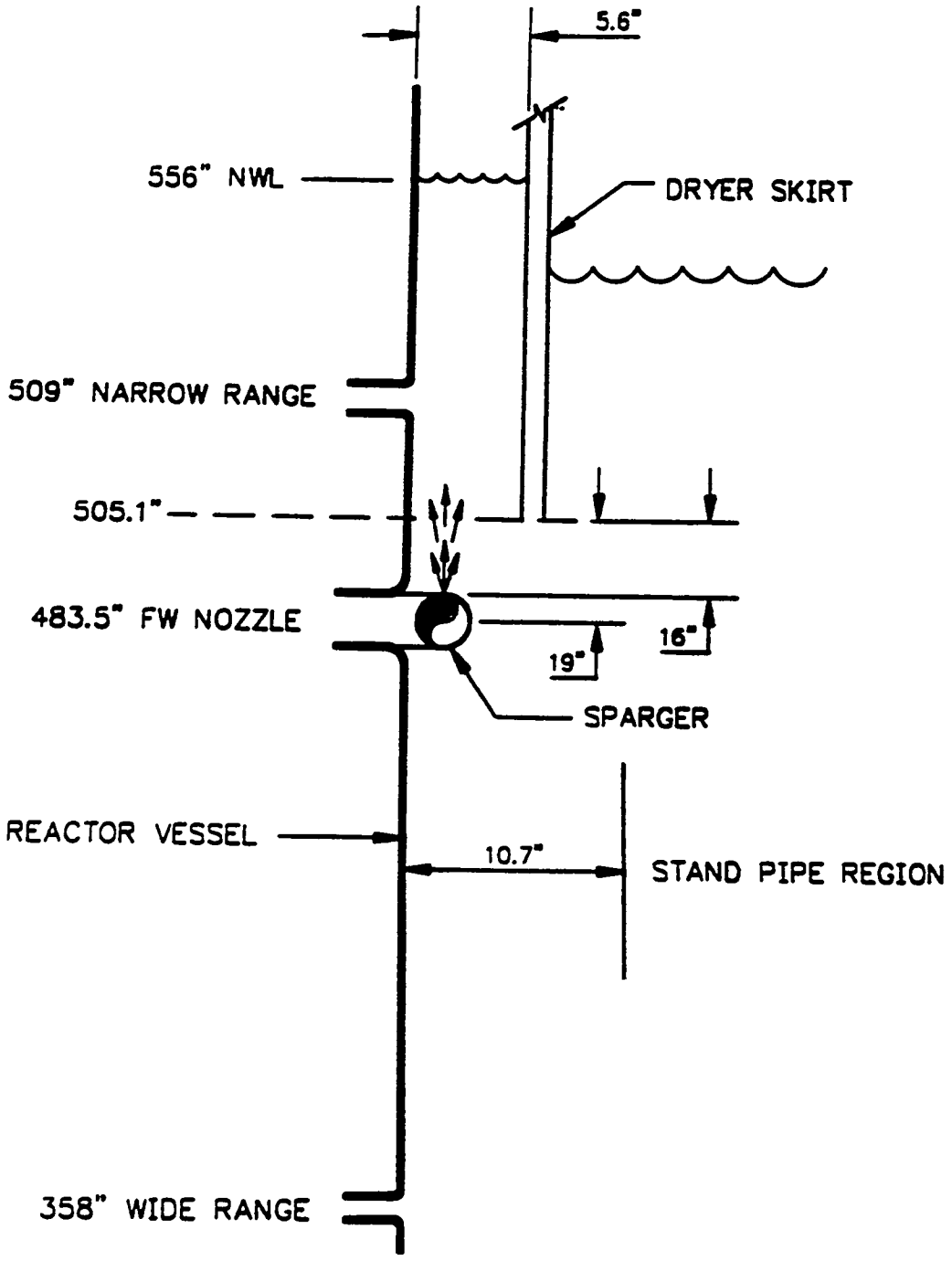
INVESTIGATION SUMMARY

- ACTUAL LEVEL 8 REACTOR TRIP
  - SUPPORTING EVIDENCE
    - » C AND D NARROW RANGE RPS AND FEEDWATER TRANSMITTERS TRIPPED
  - REFUTING EVIDENCE
    - » NO OTHER LEVEL INSTRUMENTS RESPONDED
    - » FEEDWATER FLOW REMAINED CONSTANT
    - » MAIN STEAM FLOW / FEED FLOW MISMATCH WAS NULLED
    - » CALIBRATION WAS VERIFIED ON THE LEVEL CONTROL TRANSMITTERS
- CONCLUSION: (2 FAILURE MODES RULED OUT)
  - NO ACTUAL VESSEL LEVEL CHANGE
  - REACTOR SCRAM WAS THE RESULT OF A SPURIOUS LEVEL 8 TRIP

PAGE 17


FAILURE MODE CHART
Hydraulic Disturbance Inside the Vessel
Feedwater Problem
Jet Pump Problem
Blockage HV-14
Leakage HV-13
Riser/Sparger Blockage HV-12
Sparger Leakage HV-11
Air Slug HV-10
Nozzle/Safe-end Problem
Sparger Movement HV-9
Bypass Leakage HV-8
LPCS Line Problem HV-7
HPCS Line Problem HV-6
Access Cover Failure HV-5
Shroud Problem HV-1
Dryer Skirt Failure HV-2
Instrument Nozzle Problem HV-3
Steam Separator Problem HV-4

LEVEL SWELL SCENARIO



INVESTIGATION SUMMARY

- HYDRAULIC DISTURBANCE: INTERNAL TO VESSEL
  - SUPPORTING EVIDENCE
    - » WAVE THEORY GENERATED TO SUPPORT PRESSURE PULSE AT TWO INDEPENDENT VARIABLE LEGS
  - REFUTING EVIDENCE
    - » EXTENSIVE VESSEL INTERNAL INSPECTION WAS PERFORMED WITH NO FAILURE MECHANISMS FOUND
    - » FULL FLOW FEEDWATER TESTS WERE RUN TO ELIMINATE SPARGER BLOCKAGE AND LOOSE PARTS
    - » RECIRCULATION SYSTEM WAS RUN TO ELIMINATE JET PUMP PLUGGING OR OTHER DAMAGE

PAGE 20

INVESTIGATION SUMMARY

- CONCLUSION: (14 FAILURE MODES WERE ELIMINATED)
  - NO INTERNAL DAMAGE OR FEEDWATER BLOCKAGE CAUSED THE LEVEL 8 TRIP
  - NO MAJOR HYDRAULIC DISTURBANCE INTERNAL TO VESSEL

PAGE 21

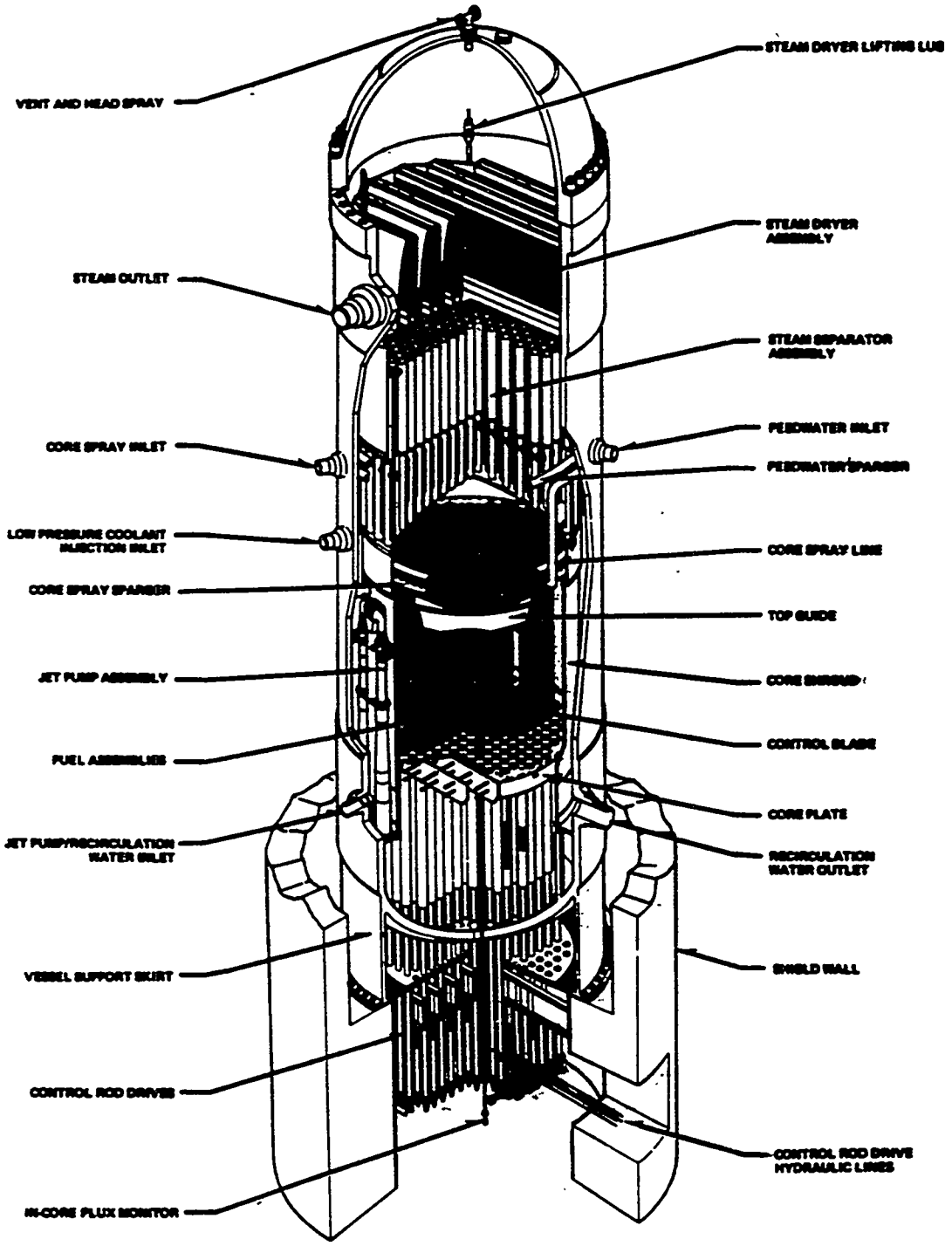
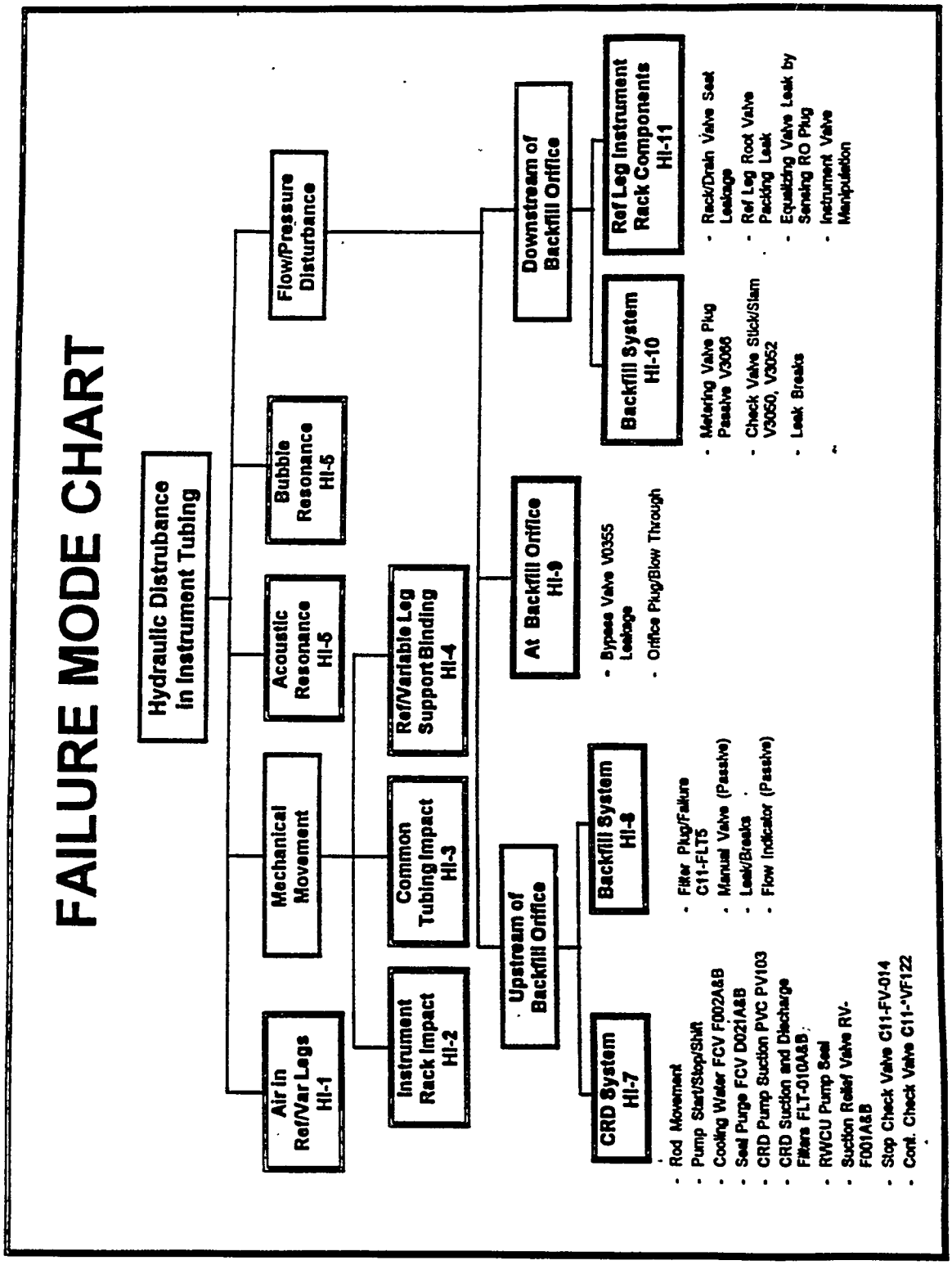


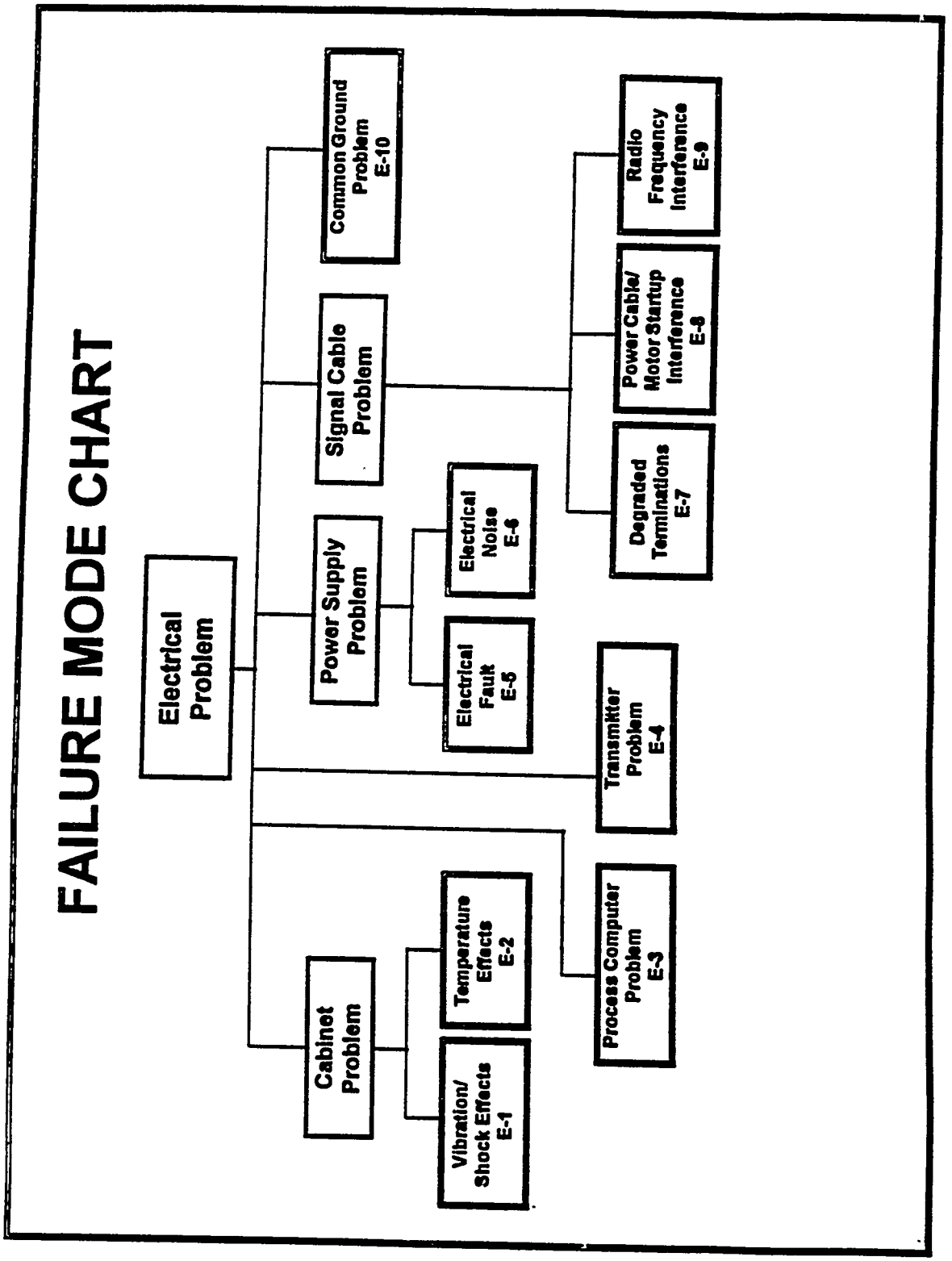
Figure 2-1. Reactor Assembly


FAILURE MODE CHART
Hydraulic Distrubance In Instrument Tubing
Air In Ref/Var Legs HI-1
Mechanical Movement
Acoustic Resonance HI-5
Bubble Resonance HI-5
Flow/Pressure Disturbance
Instrument Rack Impact HI-2
Common Tubing Impact HI-3
Ref/Variable Leg Support Binding HI-4
Upstream of Backfill Orifice
Backfill System HI-8
CRD System HI-7
Rod Movement
Pump Start/Stop/Shift
Cooling Water FCV F002A&B
Seal Purge FCV D021A&B
CRD Pump Suction PVC PV103
CRD Suction and Discharge Filters FLT-010A&B
RWCU Pump Seal
Suction Relief Valve RV-F001A&B
Stop Check Valve C11-FV-014
Cont. Check Valve C11-VF122
Filter Plug/Failure C11-FLT5
Manual Valve (Passive)
Leak/Breaks
Flow Indicator (Passive)
At Backfill Orifice HI-9
Bypass Valve V0355 Leakage
Orifice Plug/Blow Through
Downstream of Backfill Orifice
Backfill System HI-10
Ref Leg Instrument Rack Components HI-11
Metering Valve Plug Passive V3066
Check Valve Stick/Slam V3050, V3052
Leak Breaks
Rack/Drain Valve Seat Leakage
Ref Leg Root Valve Packing Leak
Equalizing Valve Leak by Sensing RO Plug
Instrument Valve Manipulation

INVESTIGATION SUMMARY

- HYDRAULIC DISTURBANCE: INSTRUMENTATION AND TUBING
  - SUPPORTING EVIDENCE
    - » BACKFILL MODIFICATION COMMON TO ALL REFERENCE LEGS INSTALLED DURING RF-5
    - » CHANNEL C TRANSMITTER REPLACED WITH MODEL 1153 WITH NO DAMPING BOARD
    - » TESTING VALIDATED SPURIOUS REBOUND RESPONSE FROM UNDAMPENED MODEL 1153
  - REFUTING EVIDENCE
    - » TESTING COULD NOT DUPLICATE TRIP OF ONLY MODEL 1153 TRANSMITTERS
    - » TESTING DID DEMONSTRATE TRANSMITTERS WOULD HAVE FUNCTIONED PROPERLY DURING ACTUAL LEVEL TRANSIENT
- CONCLUSIONS: (10 OF 11 FAILURE MODES ELIMINATED, EXCEPT HI-10)
  - UNDAMPENED ROSEMOUNT MODEL 1153 TRANSMITTERS ARE SUSCEPTIBLE TO TRIPS FROM PROCESS NOISE

PAGE 24


FAILURE MODE CHART
Electrical Problem
Power Supply Problem
Electrical Noise E-6
Electrical Fault E-5
Signal Cable Problem
Common Ground Problem E-10
Radio Frequency Interference E-9
Power Cable/ Motor Startup Interference E-8
Degraded Terminations E-7
Transmitter Problem E-4
Process Computer Problem E-3
Cabinet Problem
Temperature Effects E-2
Vibration/ Shock Effects E-1

INVESTIGATION SUMMARY

- INDICATED LEVEL TRANSIENT: ELECTRICAL PROBLEM
  - SUPPORTING EVIDENCE
    - » SIMULTANEOUS MIS-OPERATION OF THREE MODEL 1153 TRANSMITTERS
    - » LIGHTNING WAS OBSERVED IN AREA
  - REFUTING EVIDENCE
    - » THREE TRANSMITTERS POWERED BY SEPARATE POWER SUPPLIES
    - » NO MAJOR EQUIPMENT STARTED OR STOPPED
    - » POWER SUPPLY CABLES ARE ROUTED IN SEPARATE RACEWAYS AND PENETRATIONS
    - » PHYSICAL TRANSMITTER LOCATIONS PREVENTS SHOCK OR RF FROM AFFECTING ALL THREE
    - » SIGNAL CURVES NOT CHARACTERISTIC OF ELECTRICAL NOISE AND MORE SUSCEPTIBLE INSTRUMENTS DID NOT RESPOND

PAGE 26

INVESTIGATION SUMMARY

- CONCLUSION: (9 OF 10 FAILURE MODES WERE RULED OUT, EXCEPT E-4)
  - BASED ON REVIEW OF SIL 463 AND THE ROSEMOUNT NEWS LETTER, WE HAVE DETERMINED THAT MODEL 1153 TRANSMITTERS WITH NO OR MINIMAL DAMPING ARE SUSCEPTIBLE TO SPURIOUS TRIPS FROM PROCESS NOISE

PAGE 27

INVESTIGATION CONCLUSIONS

- NO ELECTRICAL OR SIGNIFICANT HYDRAULIC TRANSIENT EXISTED
- PROCESS NOISE CAUSED THE UNDAMPED MODEL 1153 TRANSMITTER TO TRIP
  - ELIMINATED ALL OTHER CAUSES
    - » ONLY 3 TRANSMITTERS GOT LEVEL 8 SIGNALS
    - » ALL 3 WERE MODEL 1153 TRANSMITTERS
- CORRECTIVE ACTIONS HAVE BEEN TARGETED TO REDUCE POTENTIAL FOR SIMILAR EVENT
- TESTING CONCLUDED TRANSMITTERS WOULD HAVE FUNCTIONED PROPERLY DURING ACTUAL LEVEL TRANSIENT

PAGE 28

CORRECTIVE ACTIONS AND START-UP MONITORING PLAN

- SCRAM CORRECTIVE ACTIONS
- START-UP MONITORING PLAN

TED LEONARD
Director - Engineering

PAGE 29

SCRAM CORRECTIVE ACTIONS

- CORRECTIVE ACTION PLAN TO ADDRESS CAUSES
  - MOVED MODEL 1153 TRANSMITTER FROM CHANNEL D TO A
    - » NO IMPACT ON RPS CAPABILITY
  - PROPERLY DAMP MODEL 1153 TRANSMITTERS WHICH CAUSED SCRAM
  - VERIFIED PROPER APPLICATION OF MODEL 1153 TRANSMITTERS RELATED TO SCRAM
- BACKFILL SYSTEM VULNERABILITY MODIFICATION
- ADDING ERIS COMPUTER DATA POINTS

PAGE 30

START-UP MONITORING PLAN SUMMARY

- AREAS OF FOCUS
  - HYDRAULIC NOISE INTERNAL TO VESSEL
    - » FEEDWATER SYSTEM
    - » RECIRCULATION SYSTEM
  - MODEL 1153 PROCESS SIGNAL SENSITIVITY
  - BACKFILL SYSTEM NOISE
- ACTIVITIES
  - ERIS DATA MONITORED AND STORED FOR EVALUATION
  - ROUND-THE-CLOCK ENGINEERING SUPPORT TO EVALUATE AND REVIEW DATA REAL-TIME
  - SYSTEM MONITORING BY COGNIZANT SYSTEM ENGINEERS TO IDENTIFY ANOMALIES
  - TEMPORARY VIBRATION MONITORING POINTS ON BACKFILL SYSTEM

PAGE 31

CORRECTIVE ACTIONS DAMPING

- TRANSMITTER RESPONSE
- CAUSES
- ACTION PLAN

EARLY EWING
Manager - Maintenance

PAGE 32

TRANSMITTER RESPONSE

- THE 3 TRANSMITTERS THAT INDICATED LEVEL INCREASE WERE MODEL 1153's
  - PREVIOUSLY REPLACED MODEL 1152's
  - HAD MINIMUM DAMPING
    - » 2 SET TO MINIMUM DAMPING
    - » 1 WITH NO DAMPING CARD

PAGE 33

CAUSES

- INADEQUATE WORK INSTRUCTIONS LED TO:
  - FAILURE TO INSTALL DAMPING CARD IN NARROW RANGE LEVEL TRANSMITTER 80C
  - FEEDWATER LEVEL TRANSMITTER 04C WAS UNDAMPED
- INADEQUATE CONTROLS OF DAMPING REQUIREMENTS
- METHODOLOGY FOR TIME RESPONSE TESTING NEGATES DAMPING
- NOTE:
  - HIGHLY LIKELY, HAD ALL TRANSMITTERS BEEN REPLACED AS SPECIFIED (I.E. JOB INSTRUCTIONS CORRECT) THE SCRAM WOULD HAVE STILL OCCURRED

PAGE 34

ACTION PLAN

- VERIFY THOSE TRANSMITTERS REQUIRING DAMPING ARE SET PROPERLY PRIOR TO START-UP
- REQUIRE COMPONENT SPECIFIC ENGINEERING INSTRUCTIONS FOR FUTURE REPLACEMENT OF 1152 UNTIL MORE APPROPRIATE CONTROLS ESTABLISHED PRIOR TO START-UP
- REVISE LOOP CALIBRATION REPORTS FOR TRANSMITTERS WITH DAMPING REQUIREMENTS (MODEL 1153 AND 1154)
- REVISE TIME RESPONSE METHODOLOGY FOR THE MODEL 1153 TRANSMITTERS TO ALLOW MORE DAMPING PRIOR TO START-UP

PAGE 35

SUMMARY AND CONCLUSIONS

- SUMMARY
- CONCLUSIONS

MIKE SELLMAN
General Manager
Plant Operations

PAGE 36

SUMMARY

- CAUSE
  - PROCESS NOISE IN COMBINATION WITH LACK OF TRANSMITTER DAMPING
- INVESTIGATION DID NOT REPRODUCE INITIATING EVENT
- CORRECTIVE ACTIONS ADDRESS PROBABLE CAUSES OF EVENT
  - TRANSMITTER DAMPING
  - CONFIGURATION MANAGEMENT
  - OPERATIONAL EXPERIENCE
- COMPREHENSIVE START-UP MONITORING WILL IDENTIFY ANY ANOMALIES

PAGE 37

CONCLUSIONS

- COMPREHENSIVE INVESTIGATION DID NOT IDENTIFY MAJOR PROBLEMS
- CORRECTIVE ACTIONS WILL PREVENT REPEAT EVENT
- NECESSARY ACTIONS HAVE BEEN COMPLETED TO ENSURE SAFE START-UP AND OPERATION

PAGE 38

Appendix I

Inspection Report 482/94-18
Wolf Creek

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-482/94-18

License: NPF-42

Licensee: Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas

Facility Name: Wolf Creek Generating Station

Inspection At: Coffey County, Burlington, Kansas

Inspection Conducted: November 28 through December 2, 1994

Inspector: J. F. Ringwald, Senior Resident Inspector

Approved: Dwight D Chamberlain 12-7-94
D. D. Chamberlain, Acting Chief, Date
Project Branch B,
Division of Reactor Projects

Inspection Summary

Areas Inspected: Nonroutine, unannounced inspection of Unresolved Item 482/9410-01 pertaining to the drain-down event of September 17, 1994.

Results:

- Three apparent violations were identified:

  (1) The first apparent violation involved the failure to comply with the requirements of Technical Specification 6.8.1.a. On September 17, 1994, operators opened Valve EJ HV8716A, Residual Heat Removal (RHR) A to safety injection system hot leg recirculation Loops 2 and 3 isolation. when Procedure SYS EJ-120, "Startup of A Residual Heat Removal Train," Revision 22, required the valve to be shut. This directly caused the transfer of approximately 9200 gallons of water from the reactor coolant system (RCS) to the refueling water storage tank (RWST).

  (2) The second apparent violation involved the failure to comply with the requirements of Technical Specification 6.8.1.a. On September 16, 1994, operators omitted Step 5.3 of

Procedure STS EJ-202, "RHR System Inservice Valve Test," Revision 4, in that, the step required that the test be performed in Mode 5 or 6 when the test was actually performed in Mode 4, an action prohibited by licensee administrative procedures.

(3) The third apparent violation involved the failure to comply with the requirements of Technical Specification 6.8.1.a. On September 17, 1994, after the drain-down event occurred, operators in the control room failed to comply with Off Normal Procedure OFN BB-031, "Shutdown LOCA [Loss of Coolant Accident]," Revision 1, by not opening the procedure and following the requirement of the foldout page, paragraph 4 requiring operators to determine emergency action levels while continuing with the procedure.

Summary of Inspection Findings:

- Apparent Violations 482/9418-01, 482/9418-02, and 482/9418-03 were opened (Section 2.1.1).
- Unresolved Item 482/9410-01 was closed (Section 2.1).
- Two noncited violations were identified (Sections 2.1.2 and 2.1.3)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

During this inspection the facility operated at essentially 100 percent power.

2 UNRESOLVED ITEM REVIEW (92901)

2.1 (Closed) Unresolved Item 482/9410-01: Procedural Adherence and Control Room Personnel Control and Cognizance of Activities Which Have The Potential To Affect Plant Conditions

This unresolved item addressed events associated with control room operator performance of activities having the potential to affect plant conditions. These events included the drain-down event, an inadvertent ESF actuation, and a failure to follow an alarm response procedure. The review of each event is addressed separately as follows:

2.1.1 Drain-Down Event

On September 17, 1994, with the plant in Mode 4 at approximately 290°F cold leg temperature and 345 psig, operators opened Valve EJ HV8716A, RHR A to safety injection system hot leg recirculation Loops 2 and 3 isolation, with Valve BN V8717, RHR pump to the RWST open causing the RHR Train A pump to transfer approximately 9,200 gallons of water from the RCS to the RWST. This drained the pressurizer from an almost solid condition to nearly empty, depressurized the RCS to approximately 250 psig, and caused approximately 600 gallons of water to overflow the top of the RWST to the liquid radwaste system. Operators responded immediately by isolating letdown, maximizing charging, stopping the two running reactor coolant pumps, and shutting Valve EJ HV8716A.

This event involved an unanticipated flow path associated with the concurrent performance of two incompatible activities. This unintended flowpath resulted in the drain-down event described in further detail in NRC Inspection Report 50-482/94-10, paragraph 2.4. NRC Inspection Report 50-482/94-10 opened an unresolved item to review licensee corrective actions related to the event and to continue the review of licensee performance related to procedural adherence and control room personnel control and cognizance of activities which have the potential to affect plant conditions. The NRC Office for Analysis and Evaluation of Operational Data also decided to review the event onsite to evaluate the potential safety significance of events of this type. The results of further review of the event are discussed below.

On September 17. 1994, operators were working with maintenance personnel who were performing a packing leak repair of Valve EJ HV8716A, under Work Request 05811-93. At the request of maintenance personnel as part of the retest, operators cycled Valve EJ HV8716A on several occasions. Operators concurrently began the system alignment to recirculate RHR Train B in

preparation for placing it in service. Step 6.10.1 of Procedure SYS EJ-120, "Startup of a Residual Heat Removal Train," opened Valve BN V8717, RHR Pump to RWST. The opening of Valve EJ HV8716A with Valve BN V8717 open resulted in a flowpath from the RCS through the RHR system directly to the RWST, which inadvertently transferred approximately 9200 gallons of water from the RCS to the RWST. The event was diagnosed by a supervising operator (SO) who was not part of the operating crew nor involved in the actual valve manipulations. At the start of the refueling outage, the licensee modified the operations shift schedule to assign two crews to each shift so additional operations support would be available for the anticipated increased operations workload. The SO who recognized the cause of the event was from this additional operations crew.

Operators used Section 6.3 of Procedure SYS EJ-120 to startup RHR Train B. Step 5.1 required operators to verify the RHR system lineup per Procedure CKL EJ-120, "RHR Normal System Lineup." Step 6.3.3.3 of Procedure SYS EJ-120, closed Valve EJ HV8716A. Step 6.3.11 directed operators to perform Section 6.10 to recirculate RHR Train B using Containment Spray Pump B. Step 6.10, therefore, relied on the lineup from Procedure CKL EJ-120, and the changes to that lineup specifically required by Procedure SYS EJ-120. The opening of Valve EJ HV8716A under Work Request 05811-93 while performing Section 6.10 of Procedure SYS EJ-120 was an apparent violation of Step 6.3.3.3 of the procedure and Technical Specification 6.8.1.a. This apparent violation directly caused the inadvertent flowpath.

The area operator who opened Valve BN V8717 stated that a considerable water hammer was heard initially upon starting to open Valve BN V8717. The area operator also stated that a second water hammer was heard after Valve BN V8717 was fully open. The area operator did not note any pipe movement during the first water hammer. Subsequent discussions between members of the Office for Analysis and Evaluation of Operational Data and the system engineer revealed that the occurrence of a water hammer was never communicated to the system engineer. The inspector questioned whether snubbers in the affected systems were tested during refueling outage number seven. The licensee responded that none of the potentially affected snubbers were tested as part of the snubber test sample during refueling outage number seven. All potentially affected snubbers were however visually inspected during a licensee walkdown of all accessible portions of the entire flowpath from the RHR system to the RWST and overflow piping. The system engineer completed the walkdown of RHR system piping up to Valve BN V8717 on September 20, 1994. and of the piping from Valve BN V8717 to the RWST on November 2, 1994. Licensee personnel did not identify damage to any plant equipment as a result of the event.

The work schedule for the packing adjustment of Valve EJ HV8716A suggested that the packing adjustment should occur prior to placing RHR Train A in service. Mechanics completed the initial packing adjustment and electricians completed the initial Valve Operation Testing Evaluation System retest before operators placed RHR Train A in service. After operators placed RHR Train A in service, operators noted additional leakage. The shift supervisor (SS) and

SO discussed Valve Operation Testing Evaluation System testing of Valve EJ HV8716A with RHR Train A in service and determined that the testing would be feasible if Valves EJ HV8716B, RHR B to safety injection system hot leg recirculation Loops 2 and 3 isolation, and Valve BN V8717 remained shut. The SS did not initiate any additional actions to ensure that these valves remained shut. The inspector concluded that the performance of rework that was not on the schedule and had the potential to affect the only available safety train imposed an unwarranted risk. This issue was discussed in NRC Inspection Report 50-482/94-12, paragraph 4.1.

One specified retest following the packing adjustment of Valve EJ HV8716A was the performance of Procedure STS EJ-202, "RHR System Inservice Valve Test," Revision 4. Step 5.3 of Procedure STS EJ-202 required that the plant be in Mode 5 or 6 during the performance of this test. Precautions and limitations, Step 2.2.2.5 of Procedure STS EJ-202 required that the test be performed in Mode 5 or 6. Procedure AP 15C-002, "Procedure Use and Adherence," Revision 0, Step 6.7.5.2, allows omission of a step or section if the omission does not violate the precautions and limitations stated in the procedure. On September 16, 1994, operators performed the applicable portion of STS EJ-202, and marked Step 5.3 as not applicable, while operating the plant in Mode 4. The omission of a step specifically required by the precautions and limitations of Procedure STS EJ-202 is an apparent violation of Technical Specification 6.8.1.a.

During interviews, the SS and SO stated that they used the guidance from Off Normal Procedure OFN BB-031, "Shutdown LOCA [Loss of Coolant Accident]," Revision 1, but did not actually open and read the procedure. Paragraph 4 of the foldout page required operators to determine emergency action levels while continuing with the procedure. The SS and SO further stated during interviews that they did not even consider whether this event should be classified per the emergency plan. The failure to review the procedure for consideration of emergency action levels as required by OFN BB-031 is an apparent violation of Technical Specification 6.8.1.a.

2.1.1.1 Potential Consequences

From November 7-10, 1994, members of the Office for Analysis and Evaluation of Operational Data, visited the site, interviewed personnel, reviewed records, and collected data. The purpose of this visit was to attempt to determine the potential consequences of this event if it had not been terminated promptly. With RCS water entering the RHR system at approximately 290°F, the water entering the RWST was approximately 260°F. Since the flowpath of the water entering the RWST shared a portion of the line from the RWST to the suction of the emergency core cooling system pumps (the centrifugal charging pumps, the safety injection pumps, the RHR pumps, and the containment spray pumps), this water at approximately 260°F would be the first water to enter the suction of these pumps. The members of the Office for the Analysis and Evaluation of Operational Data attempted to determine whether the water at the suction of the emergency core cooling system pumps could have been warm enough to have caused flashing or possibly steam binding had these pumps been called upon to

inject water into the reactor vessel. The piping between Valve BN V8717 and the common RWST suction line was 8 inches in diameter. The common RWST suction piping was 24 inches in diameter. The 8-inch return line from Valve BN V8717 entered the RWST suction line between the suctions for the Trains A and B emergency core cooling system pumps. At the conclusion of this inspection, the licensee had not completed the evaluations needed to determine the impact of the hot water at the suction of the emergency core cooling system pumps had they been called upon to operate.

2.1.1.2 Licensee Investigation

After the event, the Vice President Plant Operations directed that an Incident Investigation Team (IIT) be formed to conduct an investigation in accordance with Procedure AP 34E-001, "Self Assessment Process." The team completed the initial IIT Report 94-04 on September 29, 1994. Errors were identified and corrected in Revision 1 to IIT Report 94-01 which was issued on November 3, 1994. At the conclusion of the visit from the members of the Office for the Analysis and Evaluation of Operational Data, the Vice President Plant Operations stated that IIT Report 94-04 had been re-opened to consider additional questions resulting from the Office for the Analysis and Evaluation of Operational Data visit. IIT Report 94-04, Revision 1, concluded that the retest of Valve EJ HV-8716A was not compatible with the boundary conditions established by Procedure SYS EJ-120; that check valve leakage through Valves EP 8818C, RHR to accumulator injection line check. and BB 8948C, safety injection/accumulator to Loop 3 check valve, led to the dilution of RHR Train B; and the requirement in Procedure SYS EJ-120 for RHR boron concentration to be within 50 ppm of the RCS prompted operators to prepare to increase the boron concentration by recirculating the system to the RWST. IIT Report 94-04, Revision 1, recommended that a placard be placed on Valve BN V8717 directing operators to check that Valves EJ HV8716A and EJ HV8716B are in the correct positions to prevent an inadvertent transfer of water from the RCS to the RWST; that engineering review the boron concentration requirement to reduce or eliminate the need for recirculating the RHR system; and that IIT Report 94-04 be placed in operations required reading and be considered by training for inclusion into operator training. The inspector noted that IIT Report 94-04 did not address several pertinent factors. The IIT Report 94-04 did not address the failure of the SS to ensure that Valves BN V8717 and EJ HV8716B remained shut while stroking Valve EJ HV8716A despite the SS and SO discussion which established this as a requirement for stroking Valve EJ HV8716A while RHR Train A was in service. The IIT Report 94-04 did not address the potential safety impact of performing nonessential work on the only available safety system train. The IIT Report 94-04 did not discuss the inappropriate omission of the mode verification discussed in paragraph 2.1.1 above. The IIT Report 94-04 did mention the fact that the emergency plan and off normal procedures were not reviewed; however. the report failed to draw any conclusions regarding procedure use from this observation. The IIT Report 94-04 did not discuss the potential consequences if problems had been encountered in promptly closing Valve EJ HV8716A. The inspector concluded that the IIT report and its conclusions were narrowly focused.

2.1.1.3 Past History of Problems with Operators Maintaining Control of Plant Configurations

The inspector reviewed inspection reports during the past 2 years and identified ten violations or examples of violations involving problems with plant configuration. The events identified were:

- NRC Inspection Report 50-482/93-01, paragraph 2.7
  On February 4, 1993, an inadvertent RWST inventory loss occurred when operators failed to close Valve BN V0004, safety injection to RWST isolation, following the performance of a surveillance test.

- NRC Inspection Report 50-482/93-01, paragraph 2.9
  On January 14, 1993, operators failed to maintain the fuel building at a negative pressure because an operator failed to open two ventilation dampers that the procedure required to be opened.

- NRC Inspection Report 50-482/93-03, paragraph 2.6
  On March 10, 1993, a containment purge isolation and control room ventilation isolation signal was received when operators opened Valve BG V0221, excess letdown heat exchanger tube side combined drain valve, with the pressurizer relief tank pressurized. This permitted gases in the tank to vent into containment.

- NRC Inspection Report 50-482/93-03, paragraph 2.13
  On March 21, 1993, operators continued to drain the reactor vessel below half pipe due to a miscoordination of two clearance orders.

- NRC Inspection Report 50-482/93-16
  On May 8, 1993, operators entered Mode 3 with both motor-driven auxiliary feedwater pumps in pull to lock.

- NRC Inspection Report 50-482/93-21, paragraph 6.2.3
  On April 29, 1993, operators failed to shut Valve EF V0263, essential service water warming line, as required by Procedure STN GP-001, "Plant Winterization," Step 6.3.3.1.

- NRC Inspection Report 50-482/93-24, paragraph 2.5
  On August 13, 1993, operators started Safety Injection Pump A, without starting a component cooling water pump to provide cooling to the safety injection pump bearing oil heat exchanger.

- NRC Inspection Report 50-482/93-27, paragraph 2.1
  On September 21, 1993, an operator failed to ensure that Valve BG V0149, boric acid filter inlet isolation, and Valve BG V0152, boric acid filter outlet isolation, were fully shut as required by Clearance Order 93-1825-BG.

- NRC Inspection Report 50-482/93-29, paragraph 2.3.1
  During May 1993, the air supply to Valve BB PCV455, RCS Loop 1 pressurizer spray valve, was isolated. Operators failed to recognize this during the performance of STS RE-013B, "Incore-Excore Detector Axial Flux Difference Calibrations," Revision 2, performed on May 20. and July 30, 1993.

- NRC Inspection Report 50-482/93-29, paragraph 2.3.3
  On November 7, 1993, operators found that Valves BM HV0019, Steam Generator A upper sample isolation, and BM HV0022, Steam Generator D upper sample isolation, were open when they should have been closed. These valves were opened on November 5, 1993, at approximately 2 a.m.. and remained in that position until November 7, 1993, when the condition was discovered.

- NRC Inspection Report 50-482/93-29, paragraph 2.3.4
  On November 12, 1993, operators found Valve EF HV0043, Essential Service Water A to air compressor, closed when it should have been open. Restoration from a clearance order closed the valve approximately 9 hours prior to its discovery.

- NRC Inspection Report 50-482/94-06, paragraph 2.3
  On June 16, 1994, operators opened Valves EF HV0059, component cooling water (CCW) heat exchanger (HX) essential service water Train A outlet, and EF HV0060, CCW HX essential service water Train B outlet, without shutting Valves EF HV0051, CCW HX essential service water Train A inlet, and EF HV0052, CCW HX essential service water Train B inlet, thereby reducing the essential service water flow through the emergency diesel generator heat exchangers below their minimum flow requirements without recognizing the effect of this condition.

While corrective actions for these ten violations have addressed the specific issues associated with the individual events, the number of events during the past 2 years suggests the need for a more generic review to determine why these events continue to occur.

2.1.1.4 Licensee Corrective Actions

The IIT Report 94-04, Revision 0, contained the three recommendations discussed above in paragraph 2.1.1.2. PIRs were generated to track these three recommendations. Revision 1 to the IIT Report 94-04 did not alter these recommendations. On November 10, 1994, the licensee identified several additional corrective actions. These actions included the installation of a positive padlock on Valve BN V8717 such that it required operations manager or vice president plant operations permission to open Valve BN V8717, an operations manager briefing on this event with all operating crews, and a review and plans to revise OFN BB-031 to require immediate tripping of the reactor coolant pumps for a rapid depressurization event. In addition, the IIT was reopened to consider the potential consequences of the temperature of

the water flowing into the RWST and any other concerns which may arise. Since November 10, 1994, the licensee has completed several additional corrective actions. PIRs 94-1533 and 94-1565 evaluated the cold pressurizer insurge and determined that one thermal cycle on the pressurizer occurred during the event. Engineering completed the evaluation of the need to recirculate the RHR loops to equalize boric acid concentration and determined that the recirculation would not be necessary in the future. Operations revised Procedure SYS EJ-120 to add a caution prior to placing an RHR train in recirculation to check either EJ HV-8716A or B shut prior to opening Valve BN V8717 to avoid the transfer of water from the RCS to the RWST. Operations revised Procedures SYS EJ-120 and SYS EJ-121, "RHR Train Startup in Cooldown Mode," to delete the requirements for recirculating the RHR loops to equalize boric acid concentration. Mechanics repaired the check valves that caused the RHR system dilution during refueling outage number seven. The licensee did not take this action in response to the event as it had already been planned as part of the outage schedule.

2.1.2 Inadvertent ESF Actuation

This event involved operators mistakenly restoring Radiation Monitor GT RE-27, fuel building exhaust monitor, to service on September 6, 1994, when they had been requested to restore Radiation Monitor GG RE-22, the containment purge exhaust radiation monitor. Operators subsequently received an inadvertent engineered safety features actuation of the control room ventilation isolation actuation system and the containment purge isolation actuation system when instrumentation and control technicians inserted a test signal to Radiation Monitor GT RE-27 per scheduled surveillance testing. The licensee initiated PIR 94-1468, counselled the reactor operator who restored the incorrect radiation monitor, and had that reactor operator brief management on the event at the morning meeting. The inspector concluded that this was a violation of Technical Specification 6.8.1.a. This violation is not being cited because the licensee satisfied the criteria specified in paragraph VII.B.2 of the NRC's Enforcement Policy.

2.1.3 Alarm Response Procedure Not Followed

This item involved the SS's and SO's failure to follow Alarm Response Procedure ALR CO-061B, "Process Rad Hi," Revision 9, in response to a process radiation high alarm received at 10:44 a.m., on September 8, 1994. The licensee promptly changed the alarm response procedure to more clearly associate the required actions with the potential conditions. The operations manager also counseled the SS and SO regarding the need to initiate a procedure change whenever the procedure is determined to be inappropriate for the encountered circumstances. This issue was also discussed and this expectation clearly communicated at the SS/SO meeting held on September 8, 1994. The inspector concluded that this was a violation of Technical Specification 6.8.1.a. This violation is not being cited because the licensee satisfied the criteria specified in paragraph VII.B.2 of the NRC's Enforcement Policy.

ATTACHMENT

1 PERSONS CONTACTED

N. S. Carns, President and Chief Executive Officer
T. D. Damashek, Supervisor, Regulatory Compliance
C. W. Fowler, Manager, Maintenance and Modifications
R. B. Flannigan, Manager, Regulatory Services
W. J. Goshorm, Wolf Creek Coordinator-KEPCO
R. C. Hagan, Vice President Technical Services
R. Johannes, Chief Administrative Officer
W. M. Lindsay, Manager, Performance Assessment
O. L. Maynard, Vice President Plant Operations
P. M. Martin, Superintendent, Operations
B. T. McKinney, Manager, Operations
R. A. Meister, Senior Engineering Specialist, Regulatory Compliance
T. S. Morrill, Manager, Quality Control
W. B. Norton, Manager, Nuclear Engineering
D. K. Parks, Supervisor, Corporate Training
L. L. Parmenter, Supervisor, Operations Procedures
J. M. Pippin, Manager, Integrated Plant Scheduling
F. T. Rhodes, Vice President Engineering
R. L. Schneider, Shift Supervisor, Operations
M. A. Schreiber, Supervisor, Emergency Planning
R. L. Sims, Supervisor, Operations Support
J. D. Stamm, Manager, System Engineering
L. W. Stevens, Supervisor, Nuclear Safety Engineering
J. D. Weeks, Assistant to Vice President Plant Operations
S. G. Wideman, Supervisor, Licensing
M. G. Williams, Manager, Plant Support
W. B. Wood, General Counsel and Secretary

The above licensee personnel attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on December 2, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

LER No. 482/94-013
Wolf Creek

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORD REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
WOLF CREEK GENERATING STATION	05000482	1 OF 7

TITLE (4)

Personnel Error Resulted in an Unanticipated Loss of Reactor Coolant Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV. NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
09	17	94	94	013	00				FACILITY NAME	DOCKET NUMBER

OPERATING		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)					
POWER	4	20.402(b)	20.405(c)	50.73(a)(2)(iv)		73.71(b)	
	0%	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)		73.71(c)	
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X	OTHER	
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)		Voluntary	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)			
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)			

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Richard D. Flannigan Manager Regulatory Services	316-364-4117

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
N/A										

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED	MONTH	DAY	YEAR
YES (If yes, completed EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT:

On September 17, 1994, with the plant in MODE 4 at 300 °F and 340 psig, Wolf Creek Generating Station experienced an unanticipated decrease in Reactor Coolant level due to personnel error. The "A" Residual Heat Removal (RHR) [BP] train was lined up to the Reactor Coolant System (RCS) [AB] providing cooldown. Efforts were in progress to place the "B" RHR train in recirculation to sample and adjust boron concentrations prior to aligning the train to the RCS. Maintenance was performed to correct a packing leak and the Control Room Operators were stroking valve EJ HV-8716A (the "A" RHR to Safety Injection System (SIS) Hot Leg Recirculation Loops 2 & 3 isolation valve) to seat the packing and to perform motor operated valve testing. When the Control Room operators stroked valve EJ HV-8716A, they noted a rapid drop in pressurizer level. They immediately diagnosed the problem and shut valve EJ HV-8716A. The root cause of this event was that Licensed Operators inappropriately allowed two incompatible evolutions to occur simultaneously. At the time of the event the "B" RHR train was being lined up for RWST recirculation concurrent with the stroking of EJ HV-8716A. Corrective Actions include improved physical and administrative controls and additional operator training.

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	2 OF 7

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

Plant Conditions:

Operational Status = MODE 4
Reactor Coolant Temperature = 300 °F
Reactor Coolant Pressure = 340 psig
Two Reactor Coolant Pumps running
Four Steam Generators operable and available
"A" Residual Heat Removal Train in service and providing cooling to the core

Basis for Reportability:

Due to the potential generic implications of this event, WCNOC is voluntarily submitting this Licensee Event Report.

Description of Event:

Initial Conditions:

At 4:00 a.m., Wolf Creek Generating Station was in MODE 4, cooling down at the beginning of the Seventh Refueling Outage. The Reactor Coolant System (RCS) [AB] was at 300 degrees F and 340 psig. The Control Room operators were in the process of taking the Pressurizer solid. The "A" Residual Heat Removal (RHR) [BP] train was lined up to RCS providing cooldown. The valve line up for recirculating the "B" RHR train to the Refueling Water Storage Tank (RWST), to bring boron concentration within specification of the RCS boron concentration, was in progress.

System Description:

The "A" and "B" RHR trains are cross-connected downstream of the heat exchangers. The line cross-connecting the trains has a motor-operated valve at either end: EJ HV-8716A and EJ HV-8716B. Between these two valves, manual valve BN 8717 isolates a 8 inch line to the RWST via the common Emergency Core Cooling System (ECCS) pump suction header.

Event Description:

Valves EJ HV-8716A, EJ HV-8716B, and BN 8717 had been closed. To accomplish the recirculation of the "B" RHR to the RWST, Control Room operators dispatched a Nuclear Station Operator (non-licensed) (NSO) to open BN 8717.

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	3 OF 7

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

On September 16, 1994, with the plant in MODE 3, the pre-planned outage work on EJ HV-8716A was performed. The work on the valve actuator was completed early in the evening, and Maintenance personnel contacted the Control Room to discuss motor-operated valve testing for EJ HV-8716A. The purpose of this discussion was to ensure the plant configuration was satisfactory for the required testing. The Shift Supervisor and the Supervising Operator discussed the test with Maintenance personnel and correctly determined that plant conditions were acceptable. At 9:00 p.m., EJ HV-8716A was tested satisfactorily. Part of the maintenance performed on EJ HV-8716A was to repack the valve. To ensure the packing was installed correctly, Maintenance personnel had to wait for pressure to be at the valve after the Residual Heat Removal System was placed in service. Residual Heat Removal Train A was placed in service after the plant entered MODE 4 later that evening. Maintenance then rechecked the packing on EJ HV-8716A and noticed it was leaking.

On September 17, 1994, at approximately 3:00 a.m., the Shift Supervisor held discussions with Maintenance personnel concerning EJ HV-8716A. Permission was granted to adjust the packing which would require stroking EJ HV-8716A for motor-operated valve testing provided appropriate plant conditions existed as per the direction of the on-shift Supervising Operator (SO). Following the packing adjustment (approximately 4:00 a.m.), Maintenance personnel contacted the Control Room to stroke the valve. The Balance of Plant (BOP) Operator took the call. He conferred with the SO and inappropriately received concurrence to conduct the valve stroke.

Meanwhile, the NSO had arrived at BN 8717 and proceeded to slowly open the valve as directed to place the "B" Train RHR on recirculation to the RWST.

At 4:10 a.m., the BOP Operator stroked EJ HV-8716A, Control Room operators did not observe anything out of the ordinary. About 30 seconds later, the BOP Operator commenced a second stroke of EJ HV-8716A at about the time BN 8717 was fully opened. This provided a flow path from the RCS, via the "A" RHR train through EJ HV-8716A and BN 8717, to the RWST suction header. Pressurizer level dropped rapidly concurrent with a high RWST level alarm. The Control Room operators immediately diagnosed the problem and closed EJ HV-8716A, terminating the flow. During the response, the Control Room operators also isolated low pressure letdown, maximized charging, and secured the operating Reactor Coolant Pumps (RCPs).

During the 66 seconds that EJ HV-8716A was not fully closed, approximately 9,200 gallons of RCS water transferred to the RWST. This overfilled the RWST resulting in about 650 gallons flowing to the Waste Hold Up Tank (WHUT) [WH] via the installed overflow piping. Pressurizer level never went below the top of the heaters. RCS pressure stabilized at

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	4 OF 7

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

about 225 psig, maintaining a sub-cooling margin of greater than 90 degrees F. The temperature of the RCS increased about seven degrees F due to the Pressurizer outsurge.

Evaluation:

Equipment:

Subsequent evaluation of the "A" RHR pump, RWST, RCPs and Pressurizer determined that no equipment damage occurred as a result of this event.

Recirculation of the RHR system was required because minor back leakage of the RHR line check valves during normal operation, slowly diluted the water in the RHR piping over the 18 month cycle. The back leakage was well below the Technical Specification limit of one

gallon per minute. This is not a concern for accident conditions since the RHR will always be at or above the RCS boron concentration during normal operations.

Personnel Actions:

Two activities were performed simultaneously: (1) "B" RHR lineup for recirculation to RWST, and (2) EJ HV-8716A packing adjustment. The second activity was incompatible with the first because EJ HV-8716A was a boundary valve between the primary system and the reactor coolant. The BOP Operator and SO erred by stroking EJ HV-8716A.

Administrative controls were not sufficient to guard against a potential RCS drain down should a misalignment occur with valves EJ HV-8716A or EJ HV-8716B and BN 8717.

Once the event initiated, the response by the Control Room operators was prompt and correct. This minimized the extent of water transfer and prevented any equipment damage or degradation. The Control Room operators closed Valve EJ HV-8716A. Closure of this valve isolated the flow path to the RWST. Additionally, the Control Room operators had assessed the event and determined four acceptable alternate actions which would have terminated the event if valve EJ HV-8716A had not closed on demand. The alternate actions included:

1. The closure of BN 8717 (this action had been ordered), or
2. The closure of either RCS loop suction valves (BB PV-8702A or EJ HV-8701A), or
3. The closure of the RHR heat exchanger outlet valve and bypass valve (EJ FCV-618 and EJ HCV-606), or

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	5 OF 7

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

4. The closure of the RHR pump manual outlet valve (EJ 8724A) and tripping of the RHR pump (EJ-HIS-1)

Following the event WCNOC personnel performed an evaluation to determine if the event should be classified in accordance with the WCNOC Emergency Response Plan. This evaluation included a review/evaluation of:

1. Event duration,
2. Time required to terminate the event,
3. The lack of any radioactive material being released from the system,
4. Water volumes remaining contained within plant systems, The RCS remaining subcooled,
5. The health and safety of the public (this review clearly showed the event did not impact the public health and safety)

This review determined that the event did not meet the event classification scheme used by WCNOC (as supported by the NEI methodology), nor did it warrant the activation of the emergency response organization.

WCNOC maintained ECCS makeup capability and the ability to place the plant in cold shutdown.

Root Cause and Corrective Actions:

Root Cause:

The root cause of this event was that Licensed inappropriately allowed two incompatible evolutions to occur simultaneously. At the time of the event the "B" RHR train was being lined up for RWST recirculation concurrent with the stroking of EJ HV-8716A.

Causal Factors:

1. The stroking of EJ HV-8716A was not compatible with the boundary conditions for RCS cooldown using "A" RHR train.

2. Minor check valve leakage led to the reduction of the "B" RHR train boron concentration, thus requiring recirculation prior to placing this train in service for normal cooldown during an outage.

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	6 OF 7

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

Corrective Actions:

Immediate:

The Manager Operations thoroughly discussed, at the Management Meeting on the morning of the event, perceived cause, immediate actions taken, and all planned corrective actions.

The Manager Operations briefed all operating crews on this event. Management's expectations were clearly delineated at the briefings.

Procedure SYS EJ-120, "Startup Of A Residual Heat Removal Train," has been revised to preclude future occurrence of this event.

A placard has been placed on BN 8717 to require the NSO to check with the Control Room to verify that EJ HV-8716A and EJ HV-8716B are in the appropriate position before opening BN 8717.

A unique lock has been placed on BN 8717 and Administrative Procedure ADM 02-102, "Control Of Locked Component Status," requires the approval of either Vice President Operations or the Manager Operations before opening.

An engineering evaluation determined that recirculation of the RHR trains prior to placing them in service is not required provided:

1. The boron concentration in the applicable train exceeds the boron concentration required for shutdown margin, or

2. The boron concentration is less than 100 ppm below the concentration required for shutdown margin, and at least two RCPs are running.

3. The boron concentration is greater than or equal to the required shutdown margin boron concentration and no Technical Specification Action Statement limiting positive reactivity addition is in effect.

4. If the boron concentration is not acceptable, the RHR system will be aligned to the RHUT via the low pressure letdown system and the water volume will be changed. The use of BN 8717 will not be required for this activity.

The above note criteria has been incorporated in to System Operating Procedures SYS EJ-120, "Startup Of A Residual Heat Removal Train," and SYS EJ-121, "RHR Train Startup In Cooldown Mode."

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORD REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Wolf Creek Generating Station	05000 482	94	013	00	7 OF 7

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

Longterm:

Training will be provided to the operators covering the potential consequences of this type of event. This training is scheduled for completion in the first quarter of 1995.

Procedure OFN BB-031, "Shutdown LOCA," is being revised to require immediate tripping of the RCPs for a rapid depressurization event, to enhance the RCP tripping criteria, and to enhance the safety injection reduction criteria for cold over-pressurization or pressurized thermal shock concerns. Further evaluation of the mitigation strategy is ongoing. The revised procedure will be issued by 3/1/95.

WCNOC is continuing to evaluate this event. WCNOC Incident Investigation Team Report 94-04 will be revised as appropriate based on further review of this event. WCNOC's review activities will be completed by 3/1/95. Final IIT Recommendations will be evaluated and implemented as appropriate.

Safety Significance:

During the RCS drain down to the RWST in MODE 4, high temperature water was transferred to the RWST through the RHR train A return line. The RCS pressure began dropping due to rapid decrease of the RCS inventory. Based on preliminary calculations, the event was terminated prior to there being significant voiding in the ECCS piping to cause steam binding of any ECCS pump. If the event would not have been terminated when it was, and if the event would have occurred earlier in MODE 4 than it did, flashing would have eventually occurred in the RCS and a steam/water mixture would have been released to the ECCS piping. A thermal-hydraulic analysis has been initiated to determine the fluid conditions in the RCS and the ECCS piping. This analysis will provide conclusions on whether the ECCS pumps would fail during the recovery period. The preliminary analysis results have determined that a void fraction of less than 5% would have occurred at the ECCS pump suction under various conditions including those supported by operator action times from a simulator run in November, 1994. The ECCS pumps would not fail under any of these conditions although some pump degradation could be expected due to the low void fractions at the ECCS pump suctions. Based on the preliminary analysis results and Westinghouse findings, it is concluded that the ECCS make up capability can be maintained to bring the plant to cold shutdown conditions.

Other Previous Occurrences:

None.

LER No. 529/94-002
Palo Verde, Unit 2

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
PALO VERDE UNIT 2	0 5 0 0 0 5 2 9	1 OF 0 7

TITLE (4)
REACTOR TRIP CAUSED BY PERSONNEL ERROR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									N/A	0 5 0 0 0
0 5	2 8	9 4	9 4	- 0 0 2	- 0 0	0 6	2 3	9 4	N/A	0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	8 6	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
BURTON A. GRABO, SUPERVISOR, NUCLEAR REGULATORY AFFAIRS	6 0 2 3 9 3 - 6 4 9 2

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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

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

On May 28, 1994, at approximately 1115 MST, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION) operating at approximately 86 percent power when the Unit sustained a reactor trip. The trip was due to a low Departure from Nucleate Boiling Ratio signal which was a result of Reactor Coolant Pump (RCP) 1B tripping on a phase-to-phase electrical fault. The plant responded normally to the event. No safety functions were challenged and no Engineered Safety Features Actuation System actuations were received or required. The Control Room Supervisor classified the event as an uncomplicated reactor trip at 1130 MST and the Unit was stabilized in Mode 3 (HOT STANDBY). Management has conducted briefings with Operation and Maintenance personnel regarding the circumstances of the event. The 1B RCP supply cables and the penetration termination box have been repaired. At approximately 1515 MST on June 2, 1994, the Plant Review Board reviewed the status of the recovery/restart plan and approved entry into Mode 2 (STARTUP). Unit 2 returned to 86 percent power at approximately 1235 MST on June 5, 1994. An investigation of the event is continuing.

There have been two previous similar events (LER 528/88-011 and 529/92-006) reported pursuant to 10CFR50.73.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	- 0 0 2	- 0 0	0 2 OF 0 7

TEXT

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

At approximately 1115 MST on May 28, 1994, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION) at normal operating temperature and pressure.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: An event that resulted in the automatic actuation of the Reactor Protection System (RPS).

At approximately 1115 MST on May 28, 1994, Unit 2 sustained a reactor trip on a low Departure from Nucleate Boiling Ratio (DNBR) signal. The low DNBR signal was the result of the 1B Reactor Coolant Pump (RCP)(AB) tripping on a phase-to-phase electrical fault. The plant responded normally to the event and no safety functions were challenged. No Engineered Safety Features Actuation System (ESFAS) actuations were received or required. The Control Room Supervisor (utility, licensed) classified the event as an uncomplicated reactor trip at approximately 1130 MST and the Unit was stabilized in Mode 3 (HOT STANDBY).

Approximately two hours prior to the event, Control Room personnel (utility, licensed) had authorized troubleshooting and replacement of the sub-group K111 relay (RLY) in the A Train ESFAS (JE) relay cabinet. The function of the sub-group K111 relay is to provide an open signal to the A Train Containment Spray (CS)(BE) isolation valve (ISV), SIA-UV-672. This occurs when a Containment Spray Actuation Signal (CSAS) is initiated by a high-high containment pressure signal of 8.5 pounds per square inch gage (PSIG).

The work to be performed by the Maintenance technicians (utility, nonlicensed) required access to the A Train ESFAS relay cabinet. Therefore prior to starting work, SIA-UV-672 was isolated and down-powered by Operations personnel to prevent it from opening. Earlier, each technician had been involved in different aspects of the work. One had been testing the new relay and the other was briefing Control Room personnel and preparing the work area. Both technicians returned to the Control Room together to begin work, and setup in front of the incorrect ESFAS relay cabinet:

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	0 0 2	0 0	0 3 OF 0 7

TEXT

Work was started without independent verification of the train to be worked on. The technicians inadvertently removed the sub-group K111 relay in the B Train ESFAS relay cabinet. The removal of the this relay caused the B Train CS isolation valve, SIB-UV-671, to receive an open signal. The opening of SIB-UV-671 resulted in a flow path which allowed water to gravity drain from the Refueling Water Tank (RWT)(BQ) into Containment through the 140 and 120 foot elevation auxiliary CS nozzles (BE). There were no audible alarms warning the operators of the valve opening.

There are a total of 620 CS nozzles. 160 are located in the auxiliary headers below the 140 and 120 foot levels of Containment. Nozzles in the auxiliary headers are designed to deliver 3.0 gallons per minute each at 40 pounds per square inch differential (PSID). During this event, the CS pumps (P) did not start. The level differential between the auxiliary spray nozzles and the RWT provided the driving head.

Approximately 7000 gallons of borated water entered the Containment (NH) over a period of approximately 1 hour and 55 minutes. This volume represents about a one percent change in RWT level which was not noticeable to the Control Room staff. Some of the borated water flowed down on and entered an RCP penetration termination box (JBX) which contained the 1B RCP power leads (JX). The water intrusion caused the exposed 13.8 kV connectors of the power leads to short circuit causing the 1B RCP power supply breaker (BKR) to trip on instantaneous overcurrent. This caused the RPS to generate a low DNBR trip signal resulting in a reactor trip.

Prior to the trip, Control Room personnel were in the process of conducting high rate blowdowns of the Steam Generators (SG)(AB). At approximately 0944 MST, the east Containment Sump level alarm (LA) annunciated in the Control Room. Using approved procedures, the sump level alarm was investigated and a reactor water inventory balance was initiated. The SG blowdowns were terminated and the lineup secured. The Control Room staff verified an increasing east sump level and increasing Containment humidity. No Radiation Monitors (IL) were in alarm at the time of the event. Trending of the sump level increase was started and preparations for a Containment entry were initiated.

A Containment entry was made at approximately 1108 MST to identify the source of the water. Prior to identifying the source of water, the Reactor tripped. Once water was visually identified as coming from the auxiliary CS nozzles, Control Room

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	0 0 2	0 0	0 4 OF 0 7

TEXT

personnel identified that SIB-UV-671 was open. Valve SIB-UV-671 was closed at approximately 1131 MST terminating the flow of water into Containment.

Containment components within the area affected by the spray of borated water from the auxiliary CS nozzles were visually inspected by teams comprised of Engineering and Maintenance personnel. The inspection found two RCP penetration termination boxes (1A and 1B), one coil box, and one nozzle dam test panel (PL) with evidence of water intrusion. Repairs to the affected enclosures along with the repairs to the 1B RCP penetration termination box were completed. In addition, the remaining RCP penetration termination boxes were inspected and returned to NEMA-4 drip-tight standards. A cleanup of Containment followed a detailed walkdown prior to close out of the Containment.

An incident investigation is continuing to be conducted into the event. At approximately 1515 MST on June 2, 1994, the Plant Review Board reviewed the status of the recovery/restart plan and approved entry into Mode 2 (STARTUP). Unit 2 returned to 86 percent power at approximately 1235 MST on June 5, 1994.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

Not applicable - no structures, systems, or components were inoperable at the start of the event which contributed to this event.

D. Cause of each component or system failure, if known:

Not applicable - no component or system failures were involved.

E. Failure mode, mechanism, and effect of each failed component, if known:

Not applicable - no component failures were involved.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no failures of components with multiple functions were involved.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	— 0 0 2	— 0 0	0 5 OF 0 7

TEXT

G. For a failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

Not applicable - no failures that rendered a train of a safety system inoperable were involved.

H. Method of discovery of each component or system failure or procedural error:

Not applicable - there have been no component or system failures or procedural errors identified. There were no procedural errors which contributed to this event.

I. Cause of Event:

The cause of the event was a cognitive personnel error made by the Maintenance technicians failing to verify the correct equipment before commencing work. Prior to the event, one of the Maintenance technicians had prestaged equipment in the general location of the work activity. After the tailboard briefing, the other Maintenance technician went to the work location and did not verify the equipment had been staged at the correct train. The first technician had left the equipment by the incorrect train ESFAS cabinet.

No unusual characteristics of the work location (e.g., noise, heat, poor lighting) directly contributed to this event. However, the lack of formal communications between the Maintenance technician and Operation Department personnel as well as between the two Maintenance technicians contributed to this event (SALP Cause Code A: Personnel Error).

An independent investigation of this event is being conducted in accordance with the APS Incident Investigation Program. If information is developed which would affect the reader's understanding or perception of this event, a supplement to this LER will be submitted.

J. Safety System Response:

Not applicable - there were no safety system responses and none were necessary.

K. Failed Component Information:

Not applicable - no component failures were involved.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	— 0 0 2	— 0 0	0 6 OF 0 7

TEXT

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

Nuclear Fuel Management personnel (utility, nonlicensed) determined that this event did not result in a transient more severe that those already analyzed. The loss of 1B RCP caused an automatic reactor trip when low DNBR signals were received on two RPS channels. Other equipment and systems assumed in the Updated Final Safety Analysis Report (UFSAR), Chapter 15 were functional and performed as required. Scenarios defined in UFSAR Chapter 6 concerning a Loss of Coolant Accident (LOCA) were not challenged during this event. A review of RCS average temperature, pressure, and level plots indicated that adequate subcooled margin was maintained throughout the event and RCS conditions posed no threat to fuel integrity. Peak RCS pressure was approximately 2245 pounds per square inch absolute (PSIA) and is below the Safety Limit of 2750 psia. Therefore, the event did not result in any challenges to the fission product barriers or result in any releases of radioactive materials. There were no adverse safety consequences or implications as a result of this event. This event did not adversely affect the safe operation of the plant or the health and safety of the public.

III. CORRECTIVE ACTION:

A. Immediate:

Once water was identified as coming from the auxiliary CS nozzles, Control Room personnel determined that CS Isolation Valve SIB-UV-671 was open and at approximately 1131 MST, the valve was closed terminating the flow of water into Containment.

The penetration termination box containing the 1B RCP supply cables was replaced, the cables repaired, and equipment checks completed.

The remaining Unit 2 RCP penetration termination boxes were inspected and returned to NEMA-4 drip-tight standards. Containment components within the area affected by the water from the auxiliary spray nozzles were visually inspected by a team comprised of Engineering and Maintenance personnel. A cleanup was conducted and no other significant problems were identified.

Unit 3 Containment termination boxes were inspected for adherence to NEMA-4 drip-tight standards. No problems were identified.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Palo Verde Unit 2	0 5 0 0 0 5 2 9	9 4	0 0 2	0 0	0 7 OF 0 7

TEXT

Unit 1 Containment termination boxes were inspected for adherence to NEMA-4 drip-tight standards. No problems were identified.

A plant stand-down was conducted with

- Maintenance personnel to discuss the event and management expectations associated with communications and train verification, and

- Operations personnel, including STAs, to discuss the event including communications with non-departmental personnel and the mitigating actions taken during the event.

Both Maintenance technicians also received coaching from their Team Leader and Senior Management.

B. Action to Prevent Recurrence:

The PVNGS Training Department will review the contents of this LER and the associated Incident Investigation for inclusion into applicable training programs. This review will be conducted and completed in accordance with Training Department procedures.

An independent investigation of this event is continuing to be conducted in accordance with the APS Incident Investigation Program. The investigation is expected to be completed by June 27, 1994. If additional corrective actions or information is developed which would affect the reader's understanding or perception of this event, a supplement will be submitted.

IV. PREVIOUS SIMILAR EVENTS:

There have been two previous events reported pursuant to 10CFR50.73 (LER 528/88-011 and 529/92-006) where personnel error (operating the wrong equipment) resulted a reactor trip. Cognitive personnel errors that are the result of inattention to detail are not normally correctable with revised procedures or additional training. Therefore, the corrective actions for the previous event would not have prevented this event.

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

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ORNL/NOAC-232
Vol. 22

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Precursors to Potential Severe Core Damage Accidents: 1994
A Status Report

Appendix I

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5. AUTHOR(S)
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*Science Applications International Corporation
Oak Ridge, TN 37831

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Office for Analysis and Evaluation of Operational Data
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

Nine operational events that affected ten commercial light-water reactors (LWRs) during 1994 that are considered to be precursors to potential severe core damage are described. All of these events had conditional probabilities of subsequent core damage greater than or equal to 1.0×10^{-6}. These events were identified by computer-screening the 1994 licensee event reports from commercial LWRs to identify those that could be potential precursors. Candidate precursors were then selected and evaluated in a process similar to that used in previous assessments. Selected events underwent engineering evaluation that identified, analyzed, and documented the precursors. Other events designated by the Nuclear Regulatory Commission (NRC) also underwent a similar evaluation. Finally, documented precursors were submitted for review by licensees and NRC staff to ensure that the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work, which evaluated 1969-1981 and 1984-1993 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for events. This document is bound in two volumes: Volume 21 contains the main report and Appendices A-H; Volume 22 contains Appendix I.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*
Nuclear Power Plant, Accident Sequence Precursors, Risk Analysis, Event Trees, Core Damage Probability, Accident Sequences, Licensee Event Reports, Operational Events

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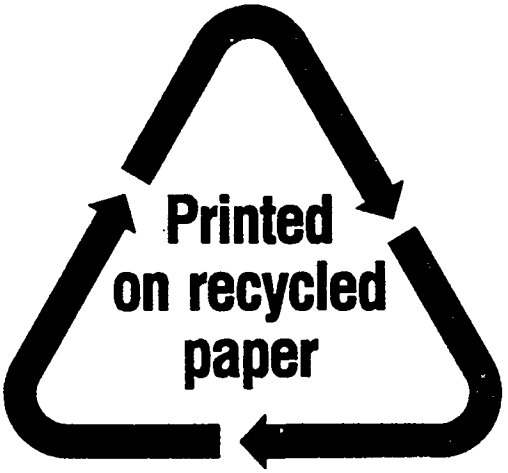

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