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Precursors to Potential Severe Core Damage Accidents: 1995 A Status Report

Prepared by
R. J. Belles, J. W. Cletcher, D. A. Copinger, B. W. Dolan,
J. W. Minarick, M. D. Muhlheim

Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

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Abstract

Ten operational events that affected 10 commercial light-water reactors during 1995 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 first computer-screening the 1995 licensee event reports from commercial light-water reactors to identify those events that could potentially be precursors. Candidate precursors were 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 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 1984–1994 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 the events.

Contents

Appendices

List of Figures

List of Tables

PREFACE

The Accident Sequence Precursor (ASP) Program was established at the Nuclear Operations Analysis Center (NOAC) 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 Sect. 5.0, Refs. 1–13). These reports describe events that occurred from 1969 through 1994, 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 (AEOD) 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 1995 is a continuation of the assessment undertaken in the previous reports for operational events that occurred in 1969–1981 and 1984–1994.

The preliminary analyses of the 1995 events were sent for review to NRC staff and to licensees for those plants for which potential ASP events were identified. This method is similar to the review process used for the 1992–1994 events. Similar to the 1994 event analyses, the 1995 analyses 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 has been normally included in past ASP analyses of events. Therefore, comparing and trending analysis results from prior years is more difficult because analysis results before 1992 are likely to have been different if additional information had been solicited from the licensees and incorporated.

For 1995 the total number of precursors identified is about the same as in past years. The same models were used for the analysis of 1995 events as were used in the analysis of 1994 events. These models utilize ASP class-based event trees and plant-specific linked fault trees. Because these models were introduced in 1994, care must be used when comparing results from 1994 and 1995 with results 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 1995 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, degradation 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.

As was done in the evaluation of 1994 events, the ASP analyses of 1995 operational events were performed using simplified, plant-specific models, which calculate the conditional core damage probability using fault-tree linking techniques, instead of the event tree-based models which had been employed in previous years.

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 the established practice, the 1995 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 revised where appropriate. The objective of the review process was to provide as realistic an analysis of the significance of the event as possible. In a change in practice implemented for the first time this year, once all comments received from the review of the preliminary analyses had been resolved, the final analyses were transmitted to the licensees and made publicly available at that time. 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 (10) identified for 1995 is almost the same as last year's total (9), but is less than the number identified in years prior to 1994. The most important precursor event for 1995 consisted of a complex event at a PWR involving: (1) failure of pressurizer power-operated relief valves, (2) failures of multiple stages of a reactor coolant pump seal, and (3) the unavailability of shutdown cooling.

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The authors are grateful for the assistance of the Nuclear Regulatory Commission's Office for Analysis and Evaluation of Operational Data (AEOD). The AEOD project manager, P. D. O'Reilly, was instrumental in obtaining timely comments from the NRC staff and licensees and providing guidance on technical issues. Donnie Whitehead of Sandia National Laboratories provided an independent technical review of each analysis. We would also like to thank the Project Managers from the NRC's Office of Nuclear Reactor Regulation for their efforts in recieving comments from the licensees. The authors wish to thank the following individuals for their technical review and analysis; their assistance was vital to the completion of this report.

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List of Acronyms

ac	alternating current
AEOD	Analysis and Evaluation of Operational Data
AIT	augmented inspection team
ANO 1	Arkansas Nuclear One, Unit 1
ANO-2	Arkansas Nuclear One, Unit 2
AOP	abnormal operating procedures
ASP	accident sequence precursor
ATWS	anticipated transient without scram
BWR	boiling water reactor
CCDP	conditional core damage probability
CCP	centrifugal charging pump
CCW	component cooling water
cd	core damage
CDP	core damage probability
CST	condensate storage tank
dc	direct current
DHR	decay heat removal
DNBR	departure from nucleate boiling ratio
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFIC	emergency feedwater isolation control
EFW	emergency feedwater current
EOP	emergency operating procedure
ESF	engineered safety feature
ESWS	emergency service water system
FSAR	final safety analysis report
GL	generic letter
HPCI	high pressure coolant injection
HPI	high pressure injection
HPR	high pressure recirculation
HPSI	high pressure safety injection
I&C	instrumentation and control
IIT	incident investigation team
IN	information notice
IRRAS	integrated reliability and risk analysis system
IPE	individual plant examination
IPEEE	individual plant examination for external events
INPO	Institute of Nuclear Power Operations
kV	kilovolts
kW	kilowatt
LBLOCA	large-break LOCA
LER	licensee event report

LCO	limiting condition for operation
LPSI	low pressure safety injection
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LPSI	low pressure safety injection
LOOP	loss-of-offsite power
LTOP	low temperature overpressure
LWR	light-water reactors
MBLOCA	medium-break LOCA
MDAFWP	motor-driven auxiliary feedwater pump
MDEFWP	motor-driven emergency feedwater pump
MFIV	main feedwater isolation valves
MFP	main feedwater pump
MFW	main feedwater
MGL	multiple greek letter
MOV	motor-operated valve
MSIS	main steam isolation signal
MSIV	main steam isolation valve
MSR	moisture separator reheater
NOAC	Nuclear Operations Analysis Center
NRC	Nuclear Regulatory Commission
NPSH	net positive suction head
NSR	negative sequence relay
ORNL	Oak Ridge National Laboratory
OTSG	once-through steam generator
PMW	primary makeup water
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PWR	pressurized water reactor
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RT	reactor transient
RWSP	refueling water storage pool
RWT	refueling water tank
RWST	refueling water storage tank
SBO	station blackout
SCSS	sequence coding and search system
SDC	shutdown cooling
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SLOCA	small-break loss-of-coolant accident
SNL	Sandia National Laboratories
SOER	significant operating events report

SRAS	sump recirculation actuation signal
SRV	safety relief valve
SSF	standby shutdown facility
SUT	startup transformer
SV	safety valve
SWS	service water system
TDAFWP	turbine driven auxiliary feedwater pump
TDEFWP	turbine-driven emergency feedwater pump
TGB	turbine generator building
TRC	time reliability correlation
UAT	unit auxiliary transformer

1. Introduction

The Accident Sequence Precursor (ASP) Program involves the systematic review and evaluation of operational events or conditions that have occurred at licensed U.S. commercial light-water reactors (LWRs). The ASP Program identifies and categorizes precursors to potential severe core damage accident sequences. The present report is a continuation of the work published in NUREG/CR-2497, *Precursors to Potential Severe Core Damage Accidents: 1969–1979, A Status Report*,[1] as well as in earlier versions of this document.[2-13] This report details the review and evaluation of operational events that occurred in 1995. The requirements for licensee event reports (LERs) are described in NUREG-1022, *Licensee Event Report System, Description of System and Guidelines for Reporting*.[14-16]

1.1 Background

The ASP Program owes its genesis to the Risk Assessment Review Group,[17] which concluded that "unidentified event sequences significant to risk might contribute… a small increment...[to the overall risk]." The report continues, "It is important, in our view, that potentially significant [accident] sequences, and precursors, as they occur, be subjected to the kind of analysis contained in WASH-1400."[18] Evaluations done for the 1969–1981 period were the first efforts in this type of analysis.

Accident sequences of interest are those that, if additional failures had occurred, would have resulted in inadequate core cooling that could have caused severe core damage. For example, a postulated loss-of-coolant accident with a failure of a high-pressure injection (HPI) system may be examined or studied. In this simple example, the precursor would be the HPI system failure.

Events considered to be potential precursors are analyzed, and a conditional probability for subsequent core damage is calculated. This probability is done by mapping failures observed during the event onto ASP event trees. Those events with conditional probabilities of subsequent severe core damage $\geq 1.0 \times 10^{-6}$ are identified and documented as precursors.

1.2 Current Process

The current process for identifying, analyzing, and documenting precursors is described in detail in Chap. 2. Documented precursors were transmitted for review by licensees and Nuclear Regulatory Commission (NRC) staff. Each documented precursor analysis also received an independent review by an NRC contractor.

In addition to the events selected as accident sequence precursors, those involving loss of containment function and others considered serious but which are not modeled in the ASP Program were identified during the 1995 LER review. These events are also documented in this report.

The NRC's Sequence Coding and Search System (SCSS) data base contained 1,275 LERs for 1995. The ASP computer search algorithm selected 514 of these for two-engineer review as potential precursors. Of the 16 events that the NRC identified from other sources for review, 9 events were not selected by the computer search. As a result of the two-engineer review process, 62 LERs, representing 52 individual events, were determined to be potentially significant. Of these 52, 32 were rejected after detailed review, 1 LER was determined to be impractical to analyze, and 6 LERs were documented as "interesting" events. The remaining 13 LERs combined to result in 10 precursor events for 1995. The results of these analyses are shown in Tables 3.1–3.4.

In addition to the 1995 results, two events that occurred in 1996 were analyzed. Both of the 1996 events analyzed by the ASP Program were important precursors. (Events with CCDPs $\geq 10^{-4}$ have traditionally been considered important in the ASP Program.)

Chapter 2 describes the selection and analysis process used for the review of 1995 events. Chapter 3 provides a tabulation of the precursor events, a summary of the more important precursors, and insights on the results. The remainder of this report is divided into six appendices: Appendix A describes the ASP calculational methodology, Appendix B describes the at-power precursors, Appendix C contains the potentially significant events considered impractical to analyze, Appendix D describes the requirements for an event to be considered a "containment-related" event, Appendix E contains "interesting" events, and Appendix F contains the resolution of comments on the preliminary 1995 ASP analyses. Appendix G describes the two at-power 1996 precursors analyzed during 1995 and Appendix H contains the resolution of comments for these analyses.

2. Selection Criteria and Quantification

2.1 Accident Sequence Precursor Selection Criteria

The Accident Sequence Precursor (ASP) Program is concerned with the identification and documentation of operational events that have involved portions of core damage sequences and with the estimation of associated frequencies and probabilities.

Identification of precursors requires the review of operational events for instances in which plant functions that provide protection against core damage have been challenged or compromised. Based on previous experience with reactor plant operational events, it is known that most operational events can be directly or indirectly associated with four initiators: trip [which includes loss of main feedwater (LOFW) within its sequences], loss-of-offsite power (LOOP), and small-break loss-of-coolant accident (LOCA) and steam generator tube ruptures (SGTR) [pressurized water reactors (PWRs) only]. These four initiators are primarily associated with loss of core cooling. ASP Program staff members examine licensee event reports (LERs) and other event documentation to determine the impact that operational events have on potential core damage sequences.

2.1.1 Precursors

This section describes the steps used to identify events for quantifying. Figure 2.1 illustrates this process.

A computerized search of the Sequence Coding and Search System (SCSS) data base at the Nuclear Operations Analysis Center (NOAC) of the Oak Ridge National Laboratory (ORNL) was conducted to identify LERs that met minimum selection criteria for precursors. This computerized search identified LERs potentially involving failures in plant systems that provide protective functions for the plant for core damage-related initiating events. A review of four years of precursor data and one year of LERs determined that this computerized search successfully identifies almost all precursors within a subset of approximately one-third to one-half of all LERs.

LERs were also selected for review if an Augmented Inspection Team (AIT) or Incident Investigation Team (IIT) report was written regarding the event. In addition, the Nuclear Regulatory Commission (NRC) designated other events for inclusion in the review process.

Those events selected for review underwent at least two independent reviews by different NOAC staff members. Each LER was reviewed to determine if the reported event should be examined in greater detail. This initial review was a bounding review, meant to capture events that in any way appeared to deserve detailed review and to eliminate events that were clearly unimportant. This process involved eliminating events that satisfied predefined criteria for rejection and accepting all others as potentially significant and requiring analysis.

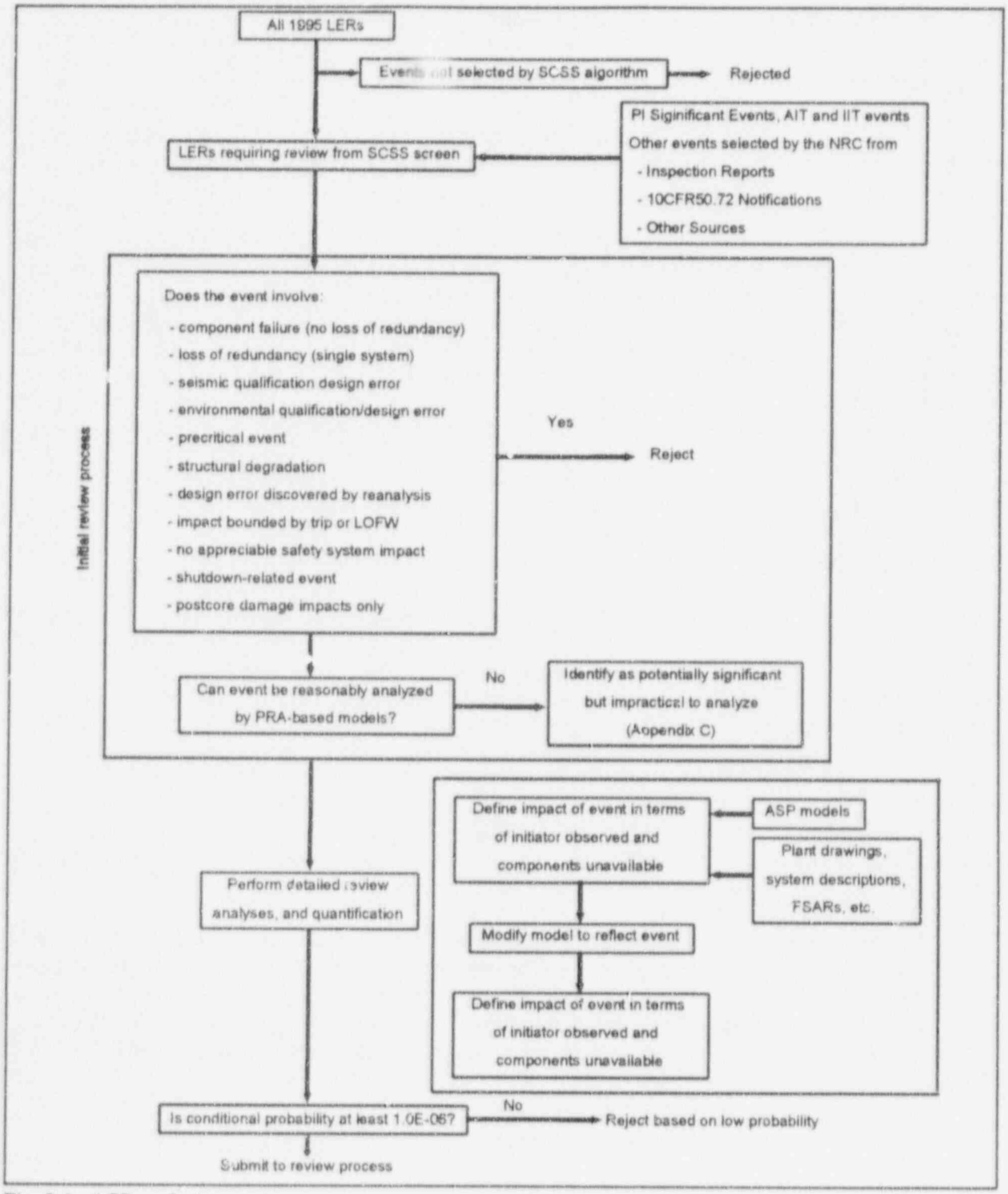

Fig. 2.1. ASP analysis process.

LERs were eliminated from further consideration as precursors if they involved only one of the following:

- a component failure with no loss of redundancy,
- a short-term loss of redundancy in only one system,
- a seismic design or qualification error,
- an environmental design or qualification error,
- a structural degradation,
- an event that occurred prior to initial criticality,
- a design error discovered by reanalysis,
- an event bounded by a reactor trip or a LOFW,
- an event with no appreciable impact on safety systems, or
- an event involving only post core-damage impacts.

Events identified for further consideration typically included the following:

- unexpected core damage initiators (LOOP, SGTR, and small-break LOCA);
- all events in which a reactor trip was demanded and a safety-related component failed;
- all support system failures, including failures in cooling water systems, instrument air, instrumentation and control, and electric power systems;
- any event in which two or more failures occurred;
- any event or operating condition that was not predicted or that proceeded differently from the plant design basis; and
- any event that, based on the reviewers' experience, could have resulted in or significantly affected a chain of events leading to potential severe core damage.

Events determined to be potentially significant as a result of this initial review were then subjected to a thorough, detailed analysis. This extensive analysis was intended to identify those events considered to be precursors to potential severe core damage accidents, either because of an initiating event, or because of failures that could have affected the course of postulated off-normal events or accidents. These detailed analyses were not limited to the LERs; they also used final safety analysis reports (FSARs) and their amendments, individual plant examinations (IPEs), and other information available at NOAC and from the NRC, related to the event of interest.

The detailed analysis of each event considered the immediate impact of an initiating event or the potential impact of the equipment failures or operator errors on readiness of systems in the plant for mitigation of off-normal and accident conditions. In the review of each selected event, three general scenarios (involving both the actual event and postulated additional failures) were considered.

1. If the event or failure was immediately detectable and occurred while the plant was at power, then the event was evaluated according to the likelihood that it and the ensuing plant response could lead to severe core damage.

2. If the event or failure had no immediate effect on plant operation (i.e., if no initiating event occurred), then the review considered whether the plant would require the failed items for

mitigation of potential severe core damage sequences should a postulated initiating event occur during the failure period.

3. If the event or failure was identified while the plant was not at power, then the event was first assessed to determine whether it could have impacted at-power operation. If the event could have impacted at-power operation, its impact on at-power operation was assessed. If the event could only occur at cold shutdown or refueling shutdown, then its impact on continued decay heat removal during shutdown was assessed; otherwise its at-power impact was assessed.

For each actual occurrence or postulated initiating event associated with an operational event reported in an LER, the sequence of operation of various mitigating systems required to prevent core damage was considered. Events were selected and documented as precursors to potential severe core damage accidents (accident sequence precursors) if the conditional probability of subsequent core damage was at least 1.0×10^{-6} (see Sect. 2.2). Events of low significance are thus excluded, allowing attention to be focused on the more important events.

This approach is consistent with the approach used to define 1988–1994 precursors, but differs from that of earlier ASP reports, which addressed all events meeting the precursor selection criteria regardless of conditional core damage probability. While review of LERs identified by this process is expected to identify almost all precursors, it is possible that a few precursors exist within the set of unreviewed LERs. Some potential precursors that would have been found if all 1995 LERs had been reviewed may not have been identified. Because of this, it should not be assumed that the set of 1988–1995 precursors is consistent with precursors identified in 1984–1987.

Ten operational events with conditional probabilities of subsequent severe core damage $\geq 1.0 \times 10^{-6}$ were identified as accident sequence precursors. All 10 events were analyzed as at-power events and are documented in Appendix B.

2.1.2 Potentially Significant Events Considered Impractical to Analyze

In some cases, events are impractical to analyze because of lack of information or inability to reasonably model within a probabilistic risk assessment (PRA) framework, considering the level of detail typically available in PRA models and the resources available to the ASP Program.

One LER was identified as potentially significant but impractical to analyze. Such events are thought to be capable of impacting core damage sequences. However, the events usually involve component degradations in which the extent of the degradation could not be determined or the impact of the degradation on plant response could not be ascertained.

For many events classified as impractical to analyze, an assumption that the affected component or function was unavailable over a 1-year period (as would be done using a bounding analysis) would result in the conclusion that a very significant condition existed. This conclusion would not be supported by the specifics of the event as reported in the LER or by the limited engineering evaluation performed in the ASP Program. A description of the event considered impractical to analyze is provided in Appendix C.

2.1.3 Containment-Related Events

Events involving loss of containment functions—such as containment cooling, containment spray, containment isolation (direct paths to the environment only), or hydrogen control—are classified as "containment-related" events. The review of the 1995 LERs identified no containment-related events; however, Appendix D provides the basis for events to be considered containment-related events.

2.1.4 "Interesting" Events

Events that provide insight into unusual failure modes with the potential to compromise continued core cooling but are considered not to be precursors are documented as "interesting" events. The review of the 1995 LERs resulted in 6 events being classified as interesting. These events are documented in Appendix E.

2.2 Precursor Quantification

Quantification of accident sequence precursor significance involves determination of a conditional probability of subsequent severe core damage, given the failures observed during an operational event. This probability is estimated by mapping failures observed during the event onto the ASP event trees, which depict potential paths to severe core damage, and calculating a conditional probability of core damage through the use of event trees and linked fault trees modified to reflect the event. The effect of a precursor on event tree branches is assessed by reviewing the operational event specifics against system design information. This information is used to modify the supporting fault trees. Quantification results in a revised conditional probability of system failure, given the operational event. The conditional probability estimated for each precursor is useful in ranking because it provides an estimate of the measure of protection against core damage that remains once the observed failures have occurred. Details of the event modeling process and calculational results can be found in Appendix A of this report.

The calculational approach used for the analysis of 1995 events was similar to that used for the 1994 events. Linked fault tree models were used instead of the earlier event tree-based models. The use of linked fault trees allows the impact of individual component failures to be correctly addressed; this could only be approximated in the earlier models. As with the 1994 events, the conditional core damage probability (CCDP) during the time period in which the failures were observed was used to rank most events involving conditions. For pre-1994 assessments, the difference between the CCDP and the nominal core damage probability (CDP) for the same period of time (an importance measure) was used to rank conditions. For most conditions that meet the ASP selection criteria, the observed failures significantly impact the core damage model. In these cases, there is little numeric difference between the CCDP and the importance measure that was previously used (CCDP - CDP). For some events, however, the nominal plant response during the time period dominates the results. In these cases, the CCDP can be considerably higher than the importance measure (the impact of such a condition on plant response is relatively minor). By only looking at the CCDP for such an event, its significance may be overestimated. Therefore, for condition assessments, the CCDP, the CDP, and the difference between these values (i.e., the importance) are provided.

The frequencies and failure probabilities used in the calculations are derived in part from data obtained across the light-water reactor (LWR) population. An attempt has been made to make the frequencies and failure probabilities plant-specific. However, this effort is not complete. Because of this, the conditional probabilities determined for each precursor cannot be rigorously associated with the probability of severe core damage resulting from the actual event at the specific reactor plant at which it occurred.

The evaluation of precursor events in this report considers and, where appropriate, gives credit for additional equipment or recovery procedures at the plants. Accordingly, the evaluations for 1994-1995 are not directly comparable to the results of prior years. Examples of additional equipment and recovery procedures addressed in the 1995 analyses, when information was available, include use of supplemental diesel generators (DGs) for station blackout mitigation and alternate systems for steam generator (SG) and reactor coolant system (RCS) makeup.

2.3 Review of Precursor Documentation

This section describes the steps involved in the review of the event analyses. Fig. 2.2 illustrates this process.

After completion of the initial analyses of the precursors, the 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 was evaluated for reasonableness and pertinence to the ASP analysis. Although all of the preliminary precursor events were sent out for review, comments were not received from all the licensees.

As with the 1993-1994 events, the 1995 precursor analyses were also sent to an NRC contractor, Sandia National Laboratories (SNL), for an independent review. The review was intended to (1) provide an independent quality check of the analyses, (2) ensure consistency with the ASP analysis guidelines and with other ASP analyses for the same event type, and (3) verify the adequacy of the modeling approach and appropriateness of the assumptions used in the analyses.

After the preliminary analyses were revised based on licensee, NRC, and SNL comments, the analyses were sent back to NRC and SNL for additional comments.

The analyses were revised again, as necessary, based on the additional NRC and SNL comments.

In some cases the analysis results were significantly affected as a result of comments received. In general, this was the result of incorporation of plant-specific equipment or strategies for mitigating events. Incorporation of these factors for a subset of the analyses reduces the validity of ranking the events by conditional core damage probability. Consistent incorporation of these mitigation strategies across all of the events could affect the conditional core damage probability of some events and may affect the ranking of the events.

A summary of the comments received from the licensees and the NRC staff, as well as a response to each comment, can be found in Appendix F.

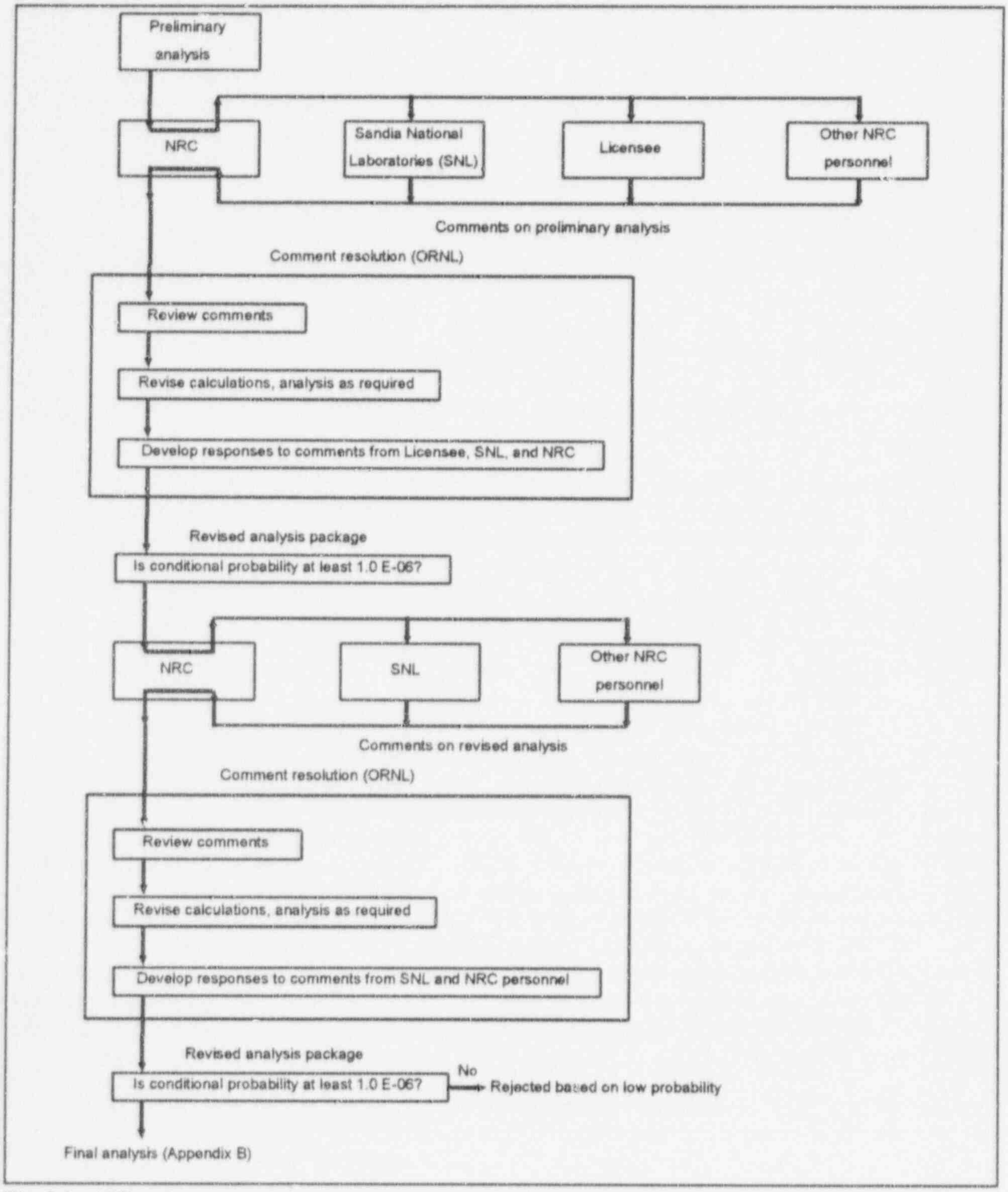

Fig. 2.2. ASP review process.

2.4 Precursor Documentation Format

The at-power events are contained in Appendix B. A description of each event is provided with additional information relevant to the assessment of the event, the ASP modeling assumptions and approach used in the analysis, and the analysis results. A figure indicating the dominant core damage sequence postulated for each event is also included.

The conditional core damage probability calculation for each precursor event is documented. The tables associated with each specific event analysis include selected basic event probabilities; sequence logic, probabilities, and importance; system names for higher probability sequences; and selected cut sets for higher probability sequences.

2.5 Potential Sources of Error

As with any analytic procedure, the availability of information and modeling assumptions can bias results. In this section, several of these potential sources of error are addressed.

1. *Evaluation of only a subset of 1995 LERs.* For 1969–1981 and 1984–1987, all LERs reported during the year were evaluated for precursors. For 1988–1995, only a subset of the LERs was evaluated in the ASP Program after a computerized search of the SCSS data base and screening by NRC personnel. While this subset is thought to include most serious operational events, it is possible that some events that would normally be selected as precursors were missed because they were not included in the subset that resulted from the screening process.

2. *Inherent biases in the selection process.* Although the criteria for identification of an operational event as a precursor are fairly well defined, the selection of an LER for initial review can be somewhat judgmental. Events selected in the study were more serious than most, so the majority of the LERs selected for detailed review would probably have been selected by other reviewers with experience in LWR systems and their operation. However, some differences would be expected to exist; thus, the selected set of precursors should not be considered unique.

3. *Lack of appropriate event information.* The accuracy and completeness of the LERs and other event-related documentation in reflecting pertinent operational information are questionable in some cases. Requirements associated with LER reporting (i.e., 10 CFR 50.73), plus the approach to event reporting practiced at particular plants, can result in variation in the extent of events reported and report details among plants. Although the LER rule of 1984 has reduced the variation in reported details, some variation still exists. In addition, only details of the sequence (or partial sequences for failures discovered during testing) that actually occurred are usually provided; details concerning potential alternate sequences of interest in this study must often be inferred.

4. *Accuracy of the ASP models and probability data.* The event trees used in the analysis are plant-class specific and reflect differences between plants in the eight plant classes that have been defined. The fault trees are structured to reflect the plant-specific systems. While major differences between plants are represented in this way, the plant models utilized in the analysis may not

adequately reflect all important differences. Known problems concern ac power recovery following a LOOP and battery depletion (station blackout issues). Modeling improvements that address these problems are being pursued in the ASP Program.

A number of problems have been identified with the new Integrated Reliability and Risk Analysis System (IRRAS)-based models supplied to ORNL by the NRC that were used to analyze the 1995 problems identified. Not all of the problems could be resolved prior to the completion of this report. ORNL event analysts identified and corrected those problems that were judged to have a significant impact on the analysis results. The impact of the remaining problems on the analysis results is unknown, but it is thought to be small.

Because of the sparseness of system failure events, data from many plants must be combined to estimate the failure probability of a multitrain system or the frequency of low- and moderate-frequency events (such as LOOPs and small-break LOCAs). Because of this, the modeled response for each event will tend toward an average response for the plant class. If systems at the plant at which the event occurred are better or worse than average (difficult to ascertain without extensive operating experience), the actual conditional probability for an event could be higher or lower than that calculated in the analysis.

Known plant-specific equipment and procedures that can provide additional protection against core damage beyond the plant-class features included in the ASP event tree models were addressed in the 1995 precursor analysis. This information was not uniformly available; much of it was provided in licensee comments on preliminary analyses and in individual plant examination (IPE) documentation available at the time this report was prepared. As a result, consideration of additional features may not be consistent in precursor analyses of events at different plants. However, analyses of multiple events that occurred at an individual plant or at similar units at the same site have been consistently analyzed.

5. *Difficulty in determining the potential for recovery of failed equipment.* Assignment of recovery credit for an event can have a significant impact on the assessment of the event. The approach used to assign recovery credit is described in detail in Appendix A. The actual likelihood of failing to recover from an event at a particular plant is difficult to assess and may vary substantially from the values currently used in the ASP analyses. This difficulty is demonstrated in the genuine differences in opinion among analysts, operations and maintenance personnel, and others, concerning the likelihood of recovering from specific failures (typically observed during testing) within a time period that would prevent core damage following an actual initiating event. Programmatic constraints have prevented substantial efforts in estimating actual recovery class distributions. The values currently used are based on a review of recovery actions during historic events and also include consideration of human error during recovery. These values have been reviewed both within and outside the ASP Program. While it is acknowledged that substantial uncertainty exists in them, they are thought adequate for ranking purposes, which is the primary goal of the current precursor calculations. This assessment is supported by the sensitivity and uncertainty calculations documented in the 1980–1981 report (see Ref. 2). These calculations

demonstrated only a small impact on the relative ranking of events from changes in the numeric values used for each recovery class.

6. *Assumption of a 1-month test interval.* The core damage probability for precursors involving unavailabilities is calculated on the basis of the exposure time associated with the event. For failures discovered during testing, the time period is related to the test interval. A test interval of 1 month was assumed unless another interval was specified in the LER. See Ref. 2 for a more comprehensive discussion of test interval assumptions.

3. Results

This chapter summarizes the results of the review and evaluation of 1995 operational events. The primary result of the Accident Sequence Precursor (ASP) Program is the identification of operational events and conditions with conditional core damage probabilities (CCDPs) $\geq 1.0 \times 10^{-6}$ that satisfy at least one of the four precursor selection criteria: (1) a core damage initiator requiring safety system response, (2) the failure of a complete system required to mitigate the consequences of a core damage initiator, (3) degradation of more than one system required for mitigation, or (4) a trip or loss-of-feedwater with a degraded mitigating system. Thirteen preliminary analyses were transmitted to the respective licensees for comment and review. Based on licensee comments, three events were reclassified as "interesting" events. Ten events that occurred during 1995 were determined to have a CCDP $\geq 10^{-6}$, and are documented as precursor events in Appendix B. In addition to the 1995 results, Appendix G includes the results of precursor analyses of two events that occurred in 1996—the loss of offsite power (LOOP) event which occurred at Catawba 2 on February 6, 1996 (LER 414/96-001), and the degraded essential service water system following a reactor trip as a result of frazil ice formation, which occurred at the Wolf Creek plant on January 30, 1996 (LERs 482/96-001, -002). Because these events represent only two data points from the operational experience for 1996, they are not included in the discussions or summary tables presented in this section. They will be included in next year's report.

Direct comparison of results with those of earlier years is not possible without substantial effort to reconcile analysis differences. The major differences in the selection and modeling of events, which were implemented for event assessments for 1984, 1988, 1992, and 1994, are discussed below.

<u>1984–1987</u> The revised LER rule, which went into effect in 1984, resulted in more LERs being selected for detailed review even though fewer LERs were reported. One requirement of the revised LER rule is the detailed reporting of all operational events involving reactor trip. The new LER rule also required additional detail for those events that are reported. Model changes included using event trees that were developed on a plant-class basis to more accurately reflect plant response following an initiating event. The models also included additional mitigating systems that could prevent core damage. This allowed reactor trips with degraded mitigating systems to be analysed as precursors (previously, the plant state at the time a degraded system was discovered could not be discerned in the LERs). The system failure probabilities were estimated using simplified train-based system models. Section 5 in NUREG/CR-4674, Vol. 3, provides additional details of these changes (Ref. 4).

<u>1988–1992</u> Two major types of changes for 1988 resulted in differences between the 1988-1992 ASP program efforts and those of earlier years. Prior to 1988, all LERs were reviewed by members of the project team. Starting in 1988, the project team evaluated only a portion of the LERs. Computerized searches of the Sequence Coding and Search System (SCSS) data base identified LERs that meet minimum selection criteria (e.g., failures in plant systems that provide protective functions for the plant for core damage-related initiating events). Sect. 2.1.1 provides further details of the selection criteria. Model changes included: (1) revising the LOOP recovery model, (2) the explicit modeling of PWR seal LOCA sequences, and (3) the reassigment of core vulnerability sequences on earlier trees to either success or core damage sequences. The net effect of the last change was a significant reduction in the

complexity of the event trees, with little impact on the relative significance estimated for each precursor. Details of these changes are provided in NUREG/CR-4674, Vol. 9 (Ref. 7).

1992–1993 Beginning with 1992, each preliminary analysis was transmitted to the affected licensee for their review and comment. As a result of comments received from reviews by the licensees, by the NRC staff, and by the NRC's independent contractor, credit for additional equipment and recovery procedures that were added by the plants was incorporated into the analyses of the precursor events. Examples include the use of supplemental diesel generators for station blackout mitigation, alternate systems for steam generator and reactor coolant system makeup, and venting in BWRs. Other changes incorporated over the years are documented in Appendix A of NUREG/CR-4674, Vol. 17 (Ref. 11).

1994–present The plant-class event trees and plant-specific fault trees were incorporated in 1994. The use of linked fault trees allows the impact of individual component failures to be correctly addressed; this could only be approximated in the earlier models. In addition, the method for calculating the probability for condition assessments (events in which components are unavailable for a period of time during which the initiating event could have occurred) was modified. Additional discussion concerning the current analysis methods are given in Appendix A.

Because of the differences in analysis methods, only limited observations are provided here. Refer to the 1986 precursor report[5] for a discussion of observations for 1984–1986 results and to the 1987–1994 reports[6-13] for the results of those years.

3.1 Tabulation of Precursor Events

The 1995 accident sequence precursor events are listed in Tables 3.1 through 3.4. The following information is included on each table:

- Docket/LER number associated with the event (Event Identifier)
- Name of the plant where the event occurred (Plant)
- A brief description of the event (Description)
- Conditional probability of potential core damage associated with the event (CCDP)
- Date(s) of the event (Event Date)
- Plant type (Plant Type)
- Initiator associated with the event or unavailability if no initiator was involved (TRANS)

The tables are sorted as follows:

- Table 3.1 - At-power precursors involving initiating events sorted by plant
- Table 3.2 - At-power precursors involving unavailabilities sorted by plant
- Table 3.3 - At-power precursors involving initiating events sorted by CCDP (or importance)
- Table 3.4 - At-power precursors involving unavailabilities sorted by CCDP (or importance)

Three of the events were complex and involved both initiating events and unavailability assessments. These events are listed in Tables 3.1 through 3.4 by the dominant contributor to the CCDP.

Table 3.1 At-Power Precursors Involving Initiating Events Sorted by Plant

Plant	Event Identifier	Description	Plant Type[a]	Event Date	CCDP	Event Type
Arkansas Nuclear One (ANO), Unit 1	LER 313/95-005	Trip with one Emergency Feed-water (EFW) Train Unavailable	PWR	4/20/95	2.0×10^{-5}	Reactor Trip
Comanche Peak	LERs 445/95-003, -004	Reactor Trip, Auxiliary Feedwater (AFW) Pump Trip, Second AFW Pump Unavailable	PWR	2/16/95	2.9×10^{-5}	Reactor Trip

[a]pressurized water reactor (PWR).

Table 3.2 At-Power Precursors Involving Unavailabilities Sorted by Plant

Plant	Event Identifier	Description	Plant Type[a]	Event Date	CCDP	Importance (ccdp-cdp)	Event Type
ANO, Unit 2	LER 368/95-001	Loss of dc Bus Could Fail both EFW Trains	PWR	7/19/95	6.0×10^{-5}	1.1×10^{-5}	Unavailability
Cook 1	LER 315/95-011	One Safety Injection Pump Unavailable for Six Months	PWR	9/12/95	3.7×10^{-5}	7.7×10^{-6}	Unavailability
Haddam Neck	LER 213/95-010	Multiple Safety Injection Valves are Susceptible to Pressure Locking	PWR	3/9/95	6.8×10^{-6}	4.7×10^{-6}	Unavailability
Limerick 1[b]	LER 352/95-008	Safety-Relief Valve Fails Open, Scram, Suppression Pool Strainer Fails	BWR	9/11/95	1.3×10^{-5}	9.0×10^{-6}	Unavailability
Millstone 2	LER 336/95-002	Containment Sump Isolation Valves Potentially Unavail-able due to Pressure Locking	PWR	1/25/95	7.7×10^{-5}	3.1×10^{-5}	Unavailability
St. Lucie 1[b]	LER 335/95-004, -005, -006	Failed Power-Operated Relief Valves (PORVs), Reactor Coolant Pump (RCP) Seal Failure, Relief Valve Failure, and Subsequent Unavail-ability, Plus Other Problems	PWR	8/2/95	1.1×10^{-4}	9.3×10^{-5}	Unavailability
St. Lucie 2	LER 389/95-005	Failure of One Emergency Diesel Generator (EDG) with Common-Cause Failure Implications	PWR	11/20/95	1.4×10^{-5}	1.3×10^{-5}	Unavailability
Waterford 3[b]	LER 382/95-002	Reactor Trip, Breaker Failure and Fire, Degraded Offsite Power, and Degraded Shutdown Cooling	PWR	6/10/95	9.1×10^{-5}	1.7×10^{-5}	Unavailability

[a]boiling water reactor (BWR).

[b]The CCDP values associated with the initiating event assessments of the complex events at Limerick 1, St. Lucie 1, and Waterford 3 were above the ASP Precursor cut-off value of 1.0×10^{-6}. The CCDP for the initiating event assessment at Limerick 1 is 2.5×10^{-6}; at St. Lucie 1 is 5.6×10^{-6}; and at Waterford 3 is 2.5×10^{-5}.

Table 3.3 At-Power Precursors Involving Initiating Events Sorted by CCDP

CCDP	Plant	Plant Type	Event Identifier	Description	Event Date	Event Type
2.9×10^{-5}	Comanche Peak	PWR	LERs 445/95-003, -004	Reactor Trip, AFW Pump Trip, Second AFW Pump Unavailable	2/16/95	Reactor Trip
2.0×10^{-5}	ANO, Unit 1	PWR	LER 313/95-005	Trip with One EFW Train Unavailable	4/20/95	Reactor Trip

Table 3.4 At-Power Precursors Involving Unavailabilities Sorted by Importance

Importance (ccdp-cdp)	CCDP	Plant	Plant Type	Event Identifier	Description	Event Date	Event Type
9.3×10^{-5}	1.1×10^{-4}	St. Lucie 1	PWR	LERs 335/95-004, -005, -006	Failed PORVs, RCP Seal Failure, Relief Valve and Subsequent Shutdown Cooling System (SDC) Unavailability, Plus Other Problems	8/2/95	Unavailability
3.1×10^{-5}	7.7×10^{-5}	Millstone 2	PWR	LER 336/95-002	Containment Sump Isolation Valves Potentially Unavailable due to Pressure Locking	1/25/95	Unavailability
1.7×10^{-5}	9.1×10^{-5}	Waterford 3	PWR	LER 382/95-001	Reactor Trip with a loss of Train A of the Essential Service Water and the Turbine-Driven Auxiliary Feedwater Pump	6/10/95	Reactor Trip
1.3×10^{-5}	1.4×10^{-5}	St. Lucie 2	PWR	LER 389/95-005	Failure of One EDG with Common Cause Failure Implications	11/20/95	Unavailability
1.1×10^{-5}	6.0×10^{-5}	ANO, Unit 2	PWR	LER 368/95-001	Loss of dc Bus Could Fail Both EFW Trains	7/19/95	Unavailability
7.7×10^{-6}	3.7×10^{-5}	Cook 1	PWR	LER 315/95-011	One Safety Injection Pump Unavailable for Six Months	9/12/95	Unavailability
9.0×10^{-6}	1.3×10^{-5}	Limerick 1	BWR	LER 352/95-002	Safety-Relief Valve Fails Open, Scram, Suppression Pool Strainer Fails	9/12/95	Unavailability
4.7×10^{-6}	6.8×10^{-6}	Haddam Neck	PWR	LER 213/95-010	Multiple Safety Injection Valves are Susceptible to Pressure Locking	3/9/95	Unavailability

[a] The CCDP values associated with the initiating event assessments of the complex events at Limerick 1, St. Lucie 1, and Waterford 3 were above the ASP Precursor cut-off value of 1.0×10^{-6}. The CCDP for the initiating event assessment at Limerick 1 is 2.5×10^{-6}; at St. Lucie 1 is 5.6×10^{-6}; and at Waterford 3 is 2.5×10^{-5}.

Because the analyses of 1996 events are not complete and currently consist of only two data points, these events are not included in these tables.

3.1.1 Potentially Significant Events That Were Impractical to Analyze

One potentially significant event was considered impractical to analyze for 1995. Typically, this event category includes events that are impractical to analyze because of lack of information or inability to reasonably model the event within a probabilistic risk assessment framework, considering the level of detail typically available in probabilistic risk analysis models. This potentially significant event is documented in Appendix C.

3.1.2 Containment-Related Events

No containment-related events were identified for 1995. This event category includes losses of containment functions, such as containment cooling, containment spray, containment isolation (direct paths to the environment only), or hydrogen control. A description of the basis for events to be considered containment-related events is given in Appendix D.

3.1.3 "Interesting" Events

Six "interesting" events were identified for 1995. This event category includes events that were not selected as precursors but that provided insight into unusual failure modes with the potential to compromise continued core cooling. Descriptions of these events are located in Appendix E.

3.2 Number of Precursors Identified

Ten precursors with a CCDP greater than 1.0×10^{-6} affecting 10 units were identified in 1995 (i.e., none of the events at multiunit sites affected more than one unit). The distribution of precursors as a function of CCDP for 1984 through 1995 is shown in Table 3.5 and in Figures 3.1–3.4. Because the 1996 results currently consist of only two data points, they are not included in this table or these figures.

As described previously, differences in the ASP models and the analysis methods from year to year preclude a direct comparison between the number of events identified for different calendar years. In particular, the CCDPs estimated for the 1992 through 1995 events are lower than for equivalent events in earlier years because supplemental and plant-specific mitigating systems beyond those included in the pre-1992 ASP models were incorporated into the analyses. In addition, new modeling techniques were adopted for the analysis of the 1994–1995 events.

Table 3.5 Number of Precursors by Year

Year[a]	No. of Reactor Years[b]	$10^{-3} \le$ CCDP < 1	$10^{-4} \le$ CCDP $\le 10^{-3}$	$10^{-5} \le$ CCDP $\le 10^{-4}$	$10^{-6} \le$ CCDP $\le 10^{-5}$	Total No. of Precursors
1984	52.5	1	16	8	8	33
1985	61.7	2	8	14	16	40
1986	63.9	2	3	8	5	18
1987	70.6	0	10	9	14	33
1988	76.0	0	7	14	11	32
1989	76.0	0	7	11	12	30
1990	80.7	0	6	11	11	28
1991	83.9	1	12	8	6	27
1992	83.7	0	7	7	13	27
1993	82.9	0	4	7	5	16
1994	86.8	1	1	4	3	9
1995[c]	88.8	0	1	7	2	10

[a] In 1988, the ASP program began using computerized searches to identify LERs that meet minimum selection criteria, revised the LOOP recovery model, and explicitly modeled PWR seal LOCA sequences. In 1992, additional equipment and procedures were incorporated into the plant models. In 1994, the project began using plant-class event trees and plant-specific fault trees. Consequently, a direct comparison of results is not possible without substantial effort to reconcile analysis differences.

[b] The number of reactor years is based on the total number of operating hours.

[c] The measure of significance for the unavailability assessments is the Importance (see Sect. 2.2).

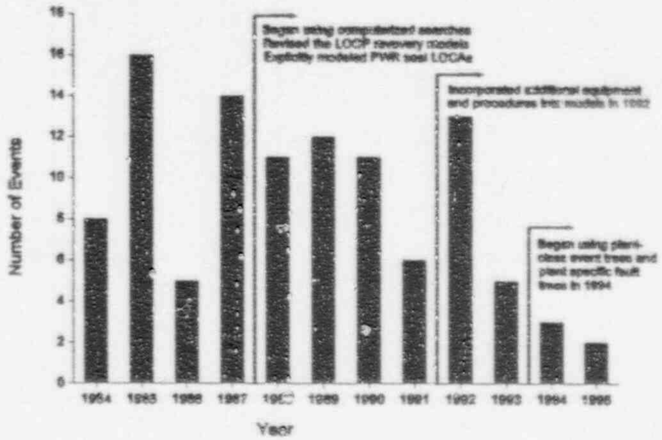

Fig. 3.1. CCDP results by year for 10^{-6} to 10^{-5}.

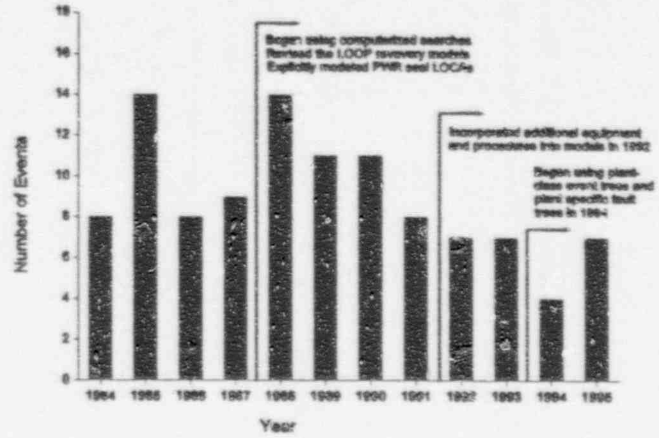

Fig. 3.2. CCDP results by year for 10^{-5} to 10^{-4}.

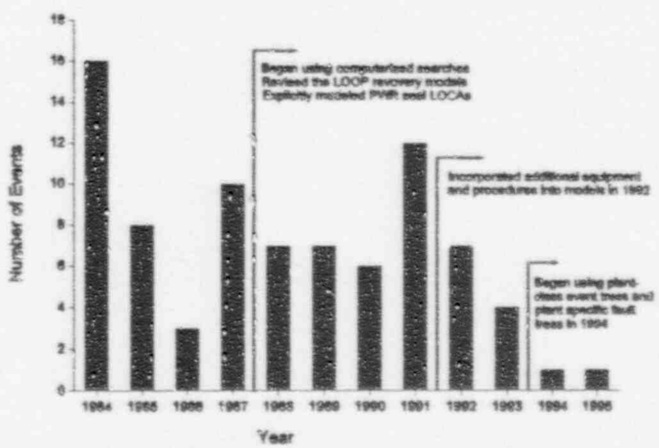

Fig. 3.3. CCDP results by year for 10^{-4} to 10^{-3}.

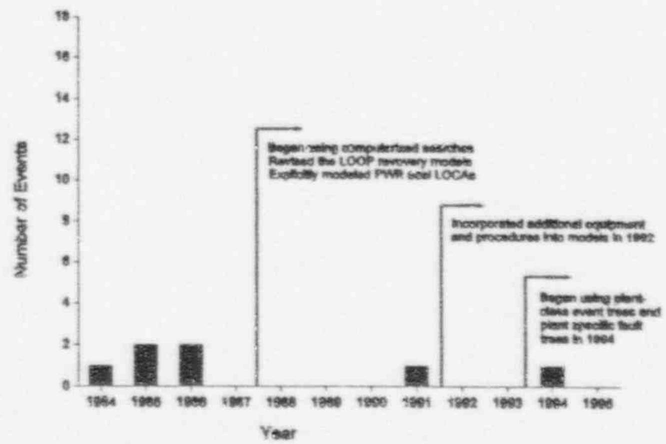

Fig. 3.4. CCDP results by year for 10^{-3} to 1.0.

3.3 Important Precursors

Although the CCDP for the actual transient event at St. Lucie 1 (a potential RCP seal LOCA) was 5.6×10^{-6}, the CCDP for both PORVs being failed (a long-term unavailability assessment) was $> 10^{-4}$. Events with CCDPs $\geq 10^{-4}$ have traditionally been considered important in the ASP Program. This important 1995 event is summarized below and is discussed in detail in Appendix B.

3.3.1 St. Lucie 1

On August 1, 1995, St. Lucie 1 shut down to Mode 3 in preparation for Hurricane Erin. The next day reactor coolant pump (RCP) 1A2 lower seal stage failed. When operators attempted to restage the seal, two additional stages failed and resulted in a 7.6 l/m (2-gpm) leak. The reactor coolant system (RCS) was cooled down and depressurized to replace the failed seal. The next day, while in Mode 4, both PORVs were tested and subsequently determined to be failed, a result of incorrect reassembly during the fall 1994 refueling outage. The failed PORVs required the plant to be cooled down, depressurized, and placed in Mode 5. During this cooldown, a thermal relief valve on the LPSI common discharge piping [part of the shutdown cooling (SDC) system] lifted and did not reseat. Discovery of the open valve was delayed for 2 h because normally open floor drain valves were closed. After the open relief valve was discovered, the SDC system was removed from service for about a day to replace the valve. During this time, only the steam generators were available for decay heat removal. The CCDP associated with the potential RCP seal LOCA (a transient analysis) is 5.6×10^{-6}. The CCDP estimated for the PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal CDP for the same period.

3.4 Insights

A review of the analyses for all 10 precursors for 1995 and a comparison with analyses for previous years revealed the following trends.

1. The number of precursors involving initiators and unavailabilities of equipment is given in Table 3.6. Three of the unavailability events also had CCDP values associated with the initiating event assessments that were above the ASP Precursor cut-off value of 1.0×10^{-6}.

Table 3.6 Number of Precursors by Event Type

Event category	$10^{-3} \leq$ CCDP < 1	$10^{-4} \leq$ CCDP $\leq 10^{-3}$	$10^{-5} \leq$ CCDP $\leq 10^{-4}$	$10^{-6} \leq$ CCDP $\leq 10^{-5}$	Total
At-power unavailabilities		1	6	1	8
At-power initiators			2		2

2. Electric power-related events and conditions continue to be a significant fraction of the precursor events (six of the ten 1995 precursors involved problems with electrical equipment, although none involved a total loss of offsite power). These results are consistent with the previous five years (1990–1994), for which about 60% of the precursor events involved electric power-related issues.

3. Events involving the degradation of auxiliary feedwater continue to be a large contributor to the fraction of the precursor events (three of the ten 1995 precursors involved problems with auxiliary feedwater, although none involved a total loss of feedwater). These results are consistent with the previous five years (1990–1994), which averaged three events involving feedwater problems per year.

4. Seventy percent (seven out of ten) of the 1995 precursor events occurred at multi-unit sites. This is about the same as the percentage of units at multi-unit sites (71%). None of the 1995 precursor events affected both units at a dual-unit site.

5. Three of the events were complex and involved both initiating events and unavailabilities; CCDPs above the 10^{-6} cut-off value were calculated for both initiating event and unavailability assessments.

6. The number of precursors identified for 1995 is about the same as for 1994. The number of precursors for 1994–1995 is lower than for previous years in part because of the differences in the ASP models for 1994–1995. In addition, the CCDPs estimated for the 1994 and 1995 events are lower than equivalent events in earlier years because of consideration of supplemental and plant-specific mitigating systems beyond those modeled earlier in the ASP models. A number of events that would have met the precursor criteria for prior years were rejected on low probability following the incorporation of additional mitigating systems.

4. Glossary

Accident. An unexpected event (frequently caused by equipment failure or some misoperation as the result of human error) that has undesirable consequences.

Accident sequence precursor. A historically observed element or condition in a postulated sequence of events leading to some undesirable consequence. For purposes of the ASP study, the undesirable consequence is usually severe core damage. The identification of an operational event as an accident sequence precursor does not of itself imply that a significant potential for severe core damage existed. It does mean that at least one of a series of protective features designed to prevent core damage was compromised. The likelihood of severe core damage, given the occurrence of an accident sequence precursor, depends on the effectiveness of the remaining protective features and, in the case of precursors that do not include initiating events, the probability of such an initiator.

Availability. The characteristic of an item expressed by the probability that it will be operational on demand or at a randomly selected future instant in time. Availability is the complement of unavailability.

Common-cause failures. Multiple failures attributable to a common cause.

Common-mode failures. Multiple, concurrent, and dependent failures of identical equipment that fails in the same mode.

Components. Items from which equipment trains and/or systems are assembled (e.g., pumps, pipes, valves, and vessels).

Conditional probability. The probability of an outcome given certain conditions.

Core damage. See *Severe core damage.*

Core-melt accident. An event in a nuclear power plant in which core materials melt.

Coupled failure. A common-cause or common-mode failure of more than one piece of equipment. See *Common-cause failures* and *Common-mode failures.*

Degraded system. A system with failed components that still meets minimum operability standards.

Demand. A test or an operating condition that requires the availability of a component or a system. In this study, a demand includes actuations required during testing and because of initiating events. One demand is assumed to consist of the actuation of all redundant components in a system, even if these were actuated sequentially (as is typical in testing multiple-train systems).

Demand failure. A failure following a demand. A demand failure may be caused by a failure to actuate when required or a failure to run following actuation.

Dependent failure. A failure in which the likelihood of failure is influenced by the failure of other items. Common-cause failures and common-mode failures are two types of dependent failures.

Dominant sequence. The sequence in a set of sequences that has the highest probability of leading to a common end state.

Emergency-core-cooling systems. Systems that provide for removal of heat from a reactor following either a loss of normal heat removal capability or a LOCA.

Engineered safety features. Equipment and/or systems (other than reactor trip or those used only for normal operation) designed to prevent, limit, or mitigate the release of radioactive material.

Event. An abnormal occurrence that is typically in violation of a plant's Technical Specifications.

Event sequence. A particular path on an event tree.

Event tree. A logic model that represents existing dependencies and combinations of actions required to achieve defined end states following an initiating event.

Failure. The inability to perform a required function. In this study, a failure was considered to have occurred if some component or system performed at a level below its required minimum performance level without human intervention. The likelihood of recovery was accounted for through the use of recovery factors. See *nonrecovery factor*.

Failure probability. The long-term frequency of occurrence of failures of a component, system, or combination of systems to operate at a specified performance level when required. In this study, failure includes both failure to start and failure to operate once started.

Failure rate. The expected number of failures of a given type, per item, in a given time interval (e.g., capacitor short-circuit failures per million capacitor hours).

Front-line system. A system that directly provides a mitigative function included on the event trees used to model sequences to an undesired end state, in contrast to a support system, which is required for operability of other systems.

Immediately detectable. A term used to describe a failure resulting in a plant response that is apparent at the time of the failure.

Independence. A condition existing when two or more entities do not exhibit a common failure mode for a particular type of event.

Initial criticality. The date on which a plant goes critical for the first time in first-cycle operation.

Initiating event. An event that starts a transient response in the operating plant systems. In the ASP study, the concern is only with those initiating events that could lead to severe core damage.

Licensee Event Reports. Those reports submitted to NRC by utilities who operate nuclear plants as described in 10 CFR 50.73. LERs describe abnormal operating occurrences that generally involve violation of the plant's Technical Specifications.

Multiple failure events. Events in which more than one failure occurs. These may involve independent or dependent failures.

Nonrecovery factor (recovery class). See *Recovery factor.* Recovery and nonrecovery are used interchangeably throughout this report.

Operational event. An event that occurs in a plant and generally constitutes a reportable occurrence under 10 CFR 50.73 as an LER.

Postulated event. An event that may happen at some time in the course of a plant's operation.

Potential severe core damage. A plant operating condition in which following an initiating event, one or more protective functions fail to meet minimum operability requirements over a period sufficiently long that core damage could occur. This condition has been called in other studies "core melt," "core damage," and "severe core damage," even though actual core damage may not result unless further degradation of mitigation functions occurs.

Precursor. See *Accident sequence precursor.*

Reactor years. The accumulated total number of years of reactor operation. For the ASP study, operating time starts when a reactor goes critical, ends when it is permanently shut down, and includes all intervening outages and plant shutdowns.

Recovery factor (recovery class). A measure of the likelihood of not recovering a failure. Failures were assigned to a particular recovery class based on an assessment of likelihood that recovery would not be affected, given event specifics. Considered in the likelihood of recovery was whether such recovery would be required in a moderate- to high-stress situation following a postulated initiating event.

Redundant equipment or system. A system or some equipment that duplicates the essential function of another system or other equipment to the extent that either may perform the required function regardless of the state of operation or failure of the other.

Reliability. The characteristic of an item expressed by the probability that it will perform a required function under stated conditions for a stated period of time.

Risk. A measure of the frequency and severity of undesired effects.

Sensitivity analysis. An analysis that determines the variation of a given function caused by changes in one or more parameters about a selected reference value.

Severe core damage. The result of an event in which inadequate core cooling was provided, resulting in damage to the reactor core. See *Potential severe core damage*.

Technical Specifications. A set of safety-related limits on process variables, control system settings, safety system settings, and the performance levels of equipment that are included as conditions of an operating license.

Unavailability. The probability that an item or system will not be operational at a future instant in time. Unavailability may be a result of the item being tested or may occur as a result of malfunctions. Unavailability is the complement of availability.

Unit. A nuclear steam supply system, its associated turbine generator, auxiliaries, and engineered safety features.

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Appendix A:

ASP Calculational Methodology

A.1 Introduction

This appendix describes the approach used in the Accident Sequence Precursor (ASP) Program to estimate the significance of an operational event. The process used to screen the operational event data base for potential precursors and the characteristics of events ultimately selected as precursors are described in Chap. 2 of this report.

The ASP Program performs retrospective analyses of operating experience. These analyses require that certain methodological assumptions be made to estimate the risk significance of an event. If one assumes, following an operational event in which core cooling was successful, that components observed failed were "failed" with probability 1.0, and components that functioned successfully were "successful" with probability 1.0, then one can conclude that the risk of core damage was zero and that the only potential sequence was the combination of events that occurred. To avoid such trivial results, the status of certain components must be considered latent. In the ASP Program, this latency is associated with components that operated successfully—these components are considered to have been capable of failing during the operational event.

Quantifying the significance of the events identified as precursors involves determining a conditional probability of subsequent severe core damage given the failures and other undesirable conditions (such as an initiating event or an unexpected relief valve challenge) that were observed during an operational event. The effect of a precursor on basic events in the core damage models is assessed by reviewing the operational event specifics against plant design and operating information and then translating the results of the review into a revised model for the plant that reflects the observed failures. The precursors' significance is then estimated by calculating a conditional probability of core damage given the observed failures. The probabilities of components observed to operate successfully are not modified. The conditional probability calculated in this way is useful in ranking because it provides an estimate of the measure of protection against core damage remaining once the observed failures have occurred.

The accident sequence models used to estimate the significance of 1995 precursors consist of fault-tree models that depict the logical combination of component failures (basic events) that would result in failure of each system that provides protection against core damage. The fault trees are linked together in a logical structure based on event trees that describe potential combinations of system successes and failures that would result in core damage following postulated initiating events. The resulting Boolean equations, when reduced to their simplest form, consist of a series of combinations of basic events (cut sets), any of which would result in core damage if all of the basic events in the cut set occurred. A detailed description of the use of linked fault trees in probabilistic risk assessment (PRA) analysis is included in Ref. 1. The current ASP models are described in NUREG/CR-4674, Vol. 21 (i.e., the ASP Programs' 1994 status report). These models are constructed and solved using the SAPHIRE suite of PRA software (Ref. 2).

A.2 Types of Events Analyzed

Two different types of events are addressed in precursor quantitative analysis. In the first, an initiating event such as a loss of offsite power (LOOP) or small-break loss-of-coolant accident (LOCA) occurs as a part of the precursor. The probability of core damage for this type of event is calculated based on the required plant response to the particular initiating event and other failures that may have occurred at the same time. The assessment of an observed initiating event is referred to as an Initiating Event Assessment.

The second type of event involves a failure condition that existed over a period of time during which an initiating event could have occurred, but did not occur. The probability of core damage is calculated based on the required plant response to a set of postulated initiating events, considering the failures that were observed. Unlike an initiating event assessment, where a probability of 1.0 is used for the observed initiating event, each initiating event is assumed to occur with a probability based on the initiating event frequency and the failure duration. The assessment of failed equipment over a period of time is referred to as a Condition Assessment.

A.3 Modification of Basic Event Probabilities to Reflect Observed Failures

The ASP models describe sequences to core damage in terms of combinations of basic events (cut sets). Each basic event typically represents the failure of a particular component or group of components in a system at a plant, an occurrence such as a relief valve lift, or the failure of an operator to perform a required action. Failures observed during an operational event must be represented in a model in terms of changes to one or more of the basic events.

If a failed component is included as a basic event in a model, the failure can be reflected by setting its basic event probability to 1.0 (failed). In actuality, such a basic event must be set to the logical state "true" if a new minimum set of cut sets reflecting the conditional state of the plant is to be generated.[a]

In addition to revising the basic events associated with failed components, basic events related to the common-cause failure of similar components may also have to be revised to reflect the observed failures. If the failure could also have occurred in other similar components at the same time, then the common-cause failure probability is increased to represent this likelihood. If the failure could not simultaneously occur in other components (for example, if a component was removed from service for preventive maintenance), then the common-cause failure probability is also revised, but only to reflect the "removal" of the unavailable component from the model. The Multiple Greek Letter (MGL) method is used to quantify the common-cause failure basic events (see Ref. 3 for a description of the MGL model).

If a failed component is not specifically included as a basic event in a model, then the failure is addressed by setting basic events impacted by the failure to "failed." For example, support systems are not completely developed in the current ASP models. A breaker failure that results in the loss of power to a group of components would be represented by setting the basic events for each component in the group to "true."

Occasionally, a precursor occurs that cannot be modeled by modifying existing basic event probabilities. In such a case, the model is revised as necessary to address the event, typically by adding basic events to a fault tree or by addressing an unusual initiating event through the use of an additional event tree.

[a] Practical considerations in the solution of large linked fault trees, primarily the use of the Delete Term process to solve sequences involving system success, also require failed basic events to be represented as "true" if correct sequence probabilities are to be calculated.

A.4 Recovery from Observed Failures

If recovery of a system is dominated by operator action, and if information concerning the time available for recovery is provided in the event report, then the probability of failing to recover from the failure is estimated using a Time-Reliability Correlation (TRC) model. The available time to respond, the underlying type of response (rule- or knowledge-based), and whether unusual conflict or burden would exist in response to an actual initiating event are addressed when developing an estimate of the operator (crew) error probability. The basic model structure is described in Ref. 4. The probability of operator error is described using a lognormal distribution with the following parameters:

Type of action	Median	Error factor
rule-based, unburdened	2	3.2
rule-based, burdened	2	6.4
knowledge-based, unburdened	4	3.2
knowledge-based, burdened	4	6.4

For an available time t_{avail}, the probability of operator error is estimated as

$$1 - \Phi[(\ln t_{avail} - m) / \sigma]$$

where Φ is the normal distribution, m = ln(median), and σ = ln(error factor)/1.645.

The potential for recovery from observed failures considers the time available and the nature of the failures. If information concerning response time is unavailable, then the likelihood of not recovering system failures is determined by assigning the failure to one of four broad recovery classes.

This is a carryover from the earlier event-tree based ASP models (cut set-based recovery may be added to the models in the future). In the current approach, the potential for recovery is addressed by assigning a recovery action to each system failure and initiating event. Four classes are currently used to describe the different types of recovery that could be involved:

Recovery class	Likelihood of nonrecovery	Recovery characteristic
R1	1.00	The failure did not appear to be recoverable in the required period, either from the control room or at the failed equipment.
R2	0.34	The failure appeared recoverable in the required period at the failed equipment, and the equipment was accessible; recovery from the control room did not appear possible.
R3	0.12	The failure appeared recoverable in the required period from the control room, but recovery was not routine or involved substantial operator burden.
R4	0.04	The failure appeared recoverable in the required period from the control room and was considered routine and procedurally based.

The assignment of an event to a recovery class is based on engineering judgment, which considers the specifics of each operational event and the likelihood of not recovering from the observed failure in a moderate to high-stress situation following an initiating event.

Note that the actual likelihood of failing to recover from an event at a particular plant is difficult to assess and may vary substantially from the values listed. This difficulty is demonstrated in the genuine differences in opinion among analysts, operations and maintenance personnel, etc., concerning the likelihood of recovering specific failures (typically observed during testing) within a time period that would prevent core damage following an actual initiating event.

A.5 Conditional Probability Associated with Each Precursor

As described previously in this appendix, the calculation process for each precursor involves a determination of initiators that must be modeled, plus any modifications to system probabilities necessitated by failures observed in an operational event. Once the basic event probabilities that reflect the conditions of the precursor are established, the sequences leading to core damage are calculated to estimate the conditional probability for the precursor. This calculational process is summarized in Table A.1.

Several simplified examples that illustrate the basics of the precursor calculational process follow. The intent of the examples is not to describe a detailed precursor analysis, but instead to provide a basic understanding of the process. The examples are presented in terms of branch probabilities that are multiplied to calculate sequence probabilities. Readers familiar with the use of linked fault trees for PRA can readily extrapolate the process illustrated in the example calculations to analyses employing fault trees.

Table A.1. Rules for Precursor Calculation

Event sequences requiring calculation. If an initiating event occurs as part of a precursor (i.e., the precursor consists of an initiating event plus possible additional failures), then use the accident sequence model associated with the initiator; otherwise, use all accident sequence models impacted by the observed unavailability.
Initiating event probability. If an initiating event occurs as part of the precursor, then the initiating event probability used in the calculation is 1.0. If an initiating event does not occur as part of the precursor, then the probability is developed assuming a constant hazard rate. Event durations (the period of time during which the failure existed) are based on information included in the event report, if provided. If the event is discovered during testing, then one-half of the test period (15 d for a 30-d test interval) is typically assumed, unless a specific failure duration is identified.
Component failure probability estimation. For components that are observed failed during the precursor, the associated basic event is set to "true." Associated common-cause basic events are revised to reflect the type of failure that occurred. For components that are observed to operate successfully or that are not challenged during the event, a failure probability equal to the nominal component failure probability is utilized.
Nonrecovery probability. If an initiating event or a total system failure occurred as a part of the precursor, then the basic event representing the probability of not recovering from the failure is revised to reflect the potential for recovery of the specific failures observed during the event. For condition assessments, the probability of nonrecovery is estimated under the assumption that an initiating event has occurred.
Failures in support systems. If the support system is not included in the ASP models, the impact of the failure is addressed by setting impacted components to failed. The modeling of a support system failure recognizes that as long as the failure remains unrecovered, all impacted components are unavailable; but if the support system failure is recovered, all impacted components are also recovered. Such failures can be modeled through multiple calculations that address the impact of failure and success of the failed support system components. Calculated core damage probabilities for associated cut sets for each case are normalized based on the likelihood of not recovering the support system failure. (Support systems, except for emergency power, are not modeled in the current ASP models.)

The hypothetical core damage model for these examples, shown in Figure A.1, consists of initiator I and four single-component systems that provide protection against core damage: systems A, B, C, and D. In Figure A.1, the up branch represents success, and the down branch represents failure for each of the systems. (In an accident sequence model for an actual reactor plant, the fault tree logic for each system could involve hundreds of components, and thousands of cut sets could be required to represent the basic event failure combinations that constitute the core damage sequences.) Three sequences result in core damage if completed: sequence 3 [I /A ("/" represents system success) C D], sequence 6 (I A /B C D), and sequence 7 (I A B). In a conventional PRA approach, the frequency of core damage would be calculated from the initiating event frequency of I, $\lambda(I)$ and the failure probabilities for A, B, C, and D [p(A), p(B), p(C), and p(D)]. Assuming $\lambda(I) = 0.1\ y^{-1}$ and $p(A|I) = 0.003$, $p(B|IA)$[b] $= 0.01$, $p(C|I) = 0.05$, and $p(D|IC) = 0.1$, the frequency of core damage is determined by calculating the frequency of each of the three core damage sequences and adding the frequencies:

$$0.1\ y^{-1} \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3) } +$$

$$0.1\ y^{-1} \times 0.003 \times (1 - 0.01) \times 0.05 \times 0.1 \text{ (sequence 6) } +$$

$$0.1\ y^{-1} \times 0.003 \times 0.01 \text{ (sequence 7)}$$

$$= 4.99 \times 10^{-4} y^{-1} \text{ (sequence 3) } + 1.49 \times 10^{-6} y^{-1} \text{ (sequence 6) } + 3.00 \times 10^{-6} y^{-1} \text{ (sequence 7)}$$

$$= 5.03 \times 10^{-4} y^{-1}.$$

In a nominal PRA, sequence 3 would be the dominant core damage sequence.

As described earlier, the ASP Program calculates a conditional probability of core damage, given an initiating event or component failures. This probability is different than the frequency calculated previously and cannot be directly compared with it.

A.5.1 Example 1: Initiating Event Assessment

Assume that a precursor involving initiating event I occurs. In response to I, systems A and C start and operate correctly and systems B and D are not demanded. In a precursor initiating event assessment, the <u>probability</u> of I is set to 1.0. Although systems A and C were successful, nominal failure probabilities are assumed. Because systems B and D were not demanded, a nominal failure probability is assumed for them as well. The conditional probability of core damage associated with precursor I is calculated by summing the conditional probabilities for the three sequences:

$$1.0 \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3) } +$$

$$1.0 \times 0.003 \times (1 - 0.01) \times 0.05 \times 0.1 \text{ (sequence 6) } +$$

$$1.0 \times 0.003 \times 0.01 \text{ (sequence 7)}$$

$$= 5.03 \times 10^{-3}.$$

If instead B was determined to have been failed at the time of initiating event I, its probability would have been set to 1.0. The conditional core damage probability for precursor IB would be calculated to be

$$1.0 \times (1 - 0.003) \times 0.05 \times 0.1 \text{ (sequence 3) } + 1.0 \times 0.003 \times 1.0 \text{ (sequence 7) } = 7.99 \times 10^{-3}.$$

Because B is failed, sequence 6 cannot occur.

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[b] The notation P(B/IA) means the probability that B fails, given I occurred <u>and</u> A failed.

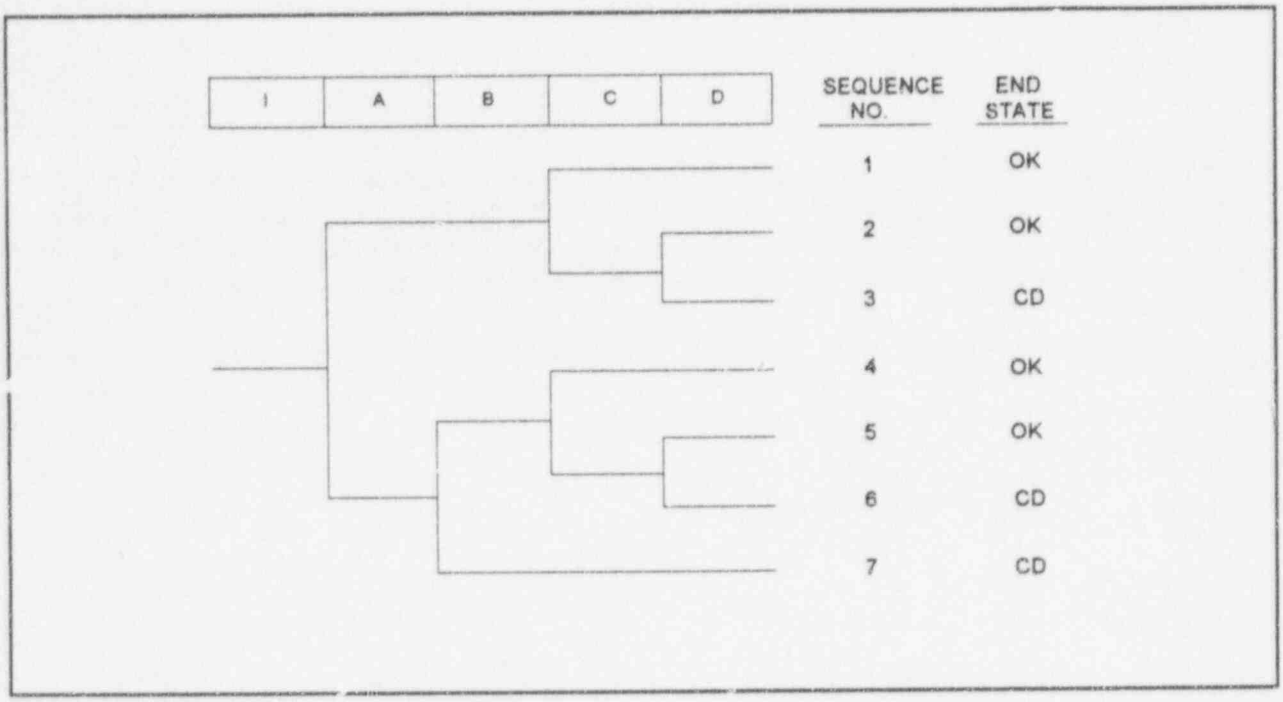

Fig. A.1 Hypothetical core damage model.

A.5.2 Example 2: Condition Assessment

Assume that during a monthly test system B is found to be failed and that the failure could have occurred at any time during the month. The best estimate for the duration of the failure is one-half of the test period, or 360-h. To estimate the probability of initiating event I during the 360 h period, the yearly frequency of I must be converted to an hourly rate. If I can only occur at power, and if the plant is at power for 70% of a year, then the frequency for I is estimated to be $0.1\ \text{yr}^{-1}/(8760\ \text{h/yr}^{-1} \times 0.7) = 1.63 \times 10^{-5}\ \text{h}^{-1}$.

The expected number of core damage sequences in the 360 h period is

$$1.63 \times 10^{-5}\ \text{h}^{-1} \times 360\ \text{h} \times (1 - 0.003) \times 0.05 \times 0.1\ \text{(sequence 3)} +$$

$$1.63 \times 10^{-5}\ \text{h}^{-1} \times 360\ \text{h} \times 0.003 \times 1.0\ \text{(sequence 7)}$$

$$= 4.69 \times 10^{-5},$$

and the probability of at least one core damage sequence is[c]

$$1 - e^{4.69 \times 10^{-5}} = 4.69 \times 10^{-5}.$$

As before, because B is failed, sequence 6 cannot occur. The conditional probability is the probability of core damage in the 360-h period, given the failure of B. Note that the dominant core damage sequence is sequence 3, with a conditional probability of 2.93×10^{-5}. This sequence is unrelated to the failure of B. The potential failure of systems C and D over the 360-h period still drives the core damage risk.

To understand the significance of the failure of system B, another calculation—an importance measure—is required. The importance measure that is used is equivalent to risk achievement worth on an interval scale (see Ref. 5). In this calculation, the increase in core damage probability over the 360-h period because of the failure of B is estimated:

$$p(cd \mid B) - p(cd) = \Delta CDP.$$

In this example the value is

$$4.69 \times 10^{-5} - 2.95 \times 10^{-5} = 1.74 \times 10^{-5},$$

where the second term on the left side of the equation is calculated using the previously developed probability of I in the 360-h period and nominal failure probabilities for A, B, C, and D.

The importance measure for unavailabilities (condition assessments) like this event was previously referred to as the conditional core damage probability in 1993 and earlier annual precursor reports. For most conditions identified as precursors in the ASP Program, its value and the CCDP are numerically close, and the CCDP can be used as a significance measure for the precursor. However, for some events—typically those in which the components that are failed are not the primary mitigating plant features—the CCDP can be significantly higher than the importance. In such cases, it is important to note that the potential failure of other components, unrelated to the precursor, are still dominating the plant risk (i.e., the impact of the precursor on plant risk is not substantial). Condition assessments documented in this report include both an estimate of the CCDP and the importance of the event.

A.6 References

1. *PRA Procedures Guide*, NUREG/CR-2300, January 1983, Section 6.3.2.

[c] Note that this calculation assumes that failures are only detected when core damage occurs. This calculational approach differs from previous years where it was assumed that a failed component would be detected when the first initiating event occurred. The current approach may overestimate the core damage probability for a long-duration condition that would be detected at the time of the initiating event, but has little impact on most analyses. (The earlier approach could underestimate the event significance for failures that would remain undetected following a nominal initiating event.)

2. *Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) Version 5.0*, NUREG/CR-6116, Vols. 1–10.

3. *Procedures for Treating Common Cause Failures in Safety and Reliability Studies*, NUREG/CR-4780, January 1989, Appendix C.

4. E.M. Dougherty and J.R. Fragola, *Human Reliability Analysis*, John Wiley and Sons, New York, 1988

5. W.E. Vesely, T.C. Davis, R.S. Denning, and N. Saltos, *Measures of Risk Importance and Their Applications*, NUREG/CR-3385, July 1983.

Appendix B:

At-Power Precursors for 1995

B.1 At-Power Precursors

B.1.1 Accident Sequence Precursor Program Event Analyses for 1995

This appendix documents 1995 operational events selected as accident sequence precursors that are analyzed with the plant in an at-power condition.

Licensee Event Reports (LERs) and other event documentation describing operational events at commercial nuclear power plants were reviewed for potential precursors if

1. the LER was identified as requiring review based on a computerized search of the Sequence Coding and Search System data base maintained at Oak Ridge National Laboratory or

2. the LER or other event documentation was identified as requiring review by the NRC Office for Analysis and Evaluation of Operational Data.

Details of the precursor review, analysis, and documentation process are provided in Appendix A of this report.

B.1.2 Precursors Identified

Ten precursors were identified among the 1995 events reviewed at the Nuclear Operations Analysis Center. Events were identified as precursors if they met one of the following precursor selection criteria and the conditional core damage probability estimated for the event was at least 10^{-6}:

1. the event involved the total failure of a system required to mitigate effects of a core damage initiator,

2. the event involved the degradation of two or more systems required to mitigate effects of a core damage initiator,

3. the event involved a core damage initiator such as a loss of offsite power or small-break loss-of-coolant accident (LOCA), or

4. the event involved a reactor trip or loss-of-feedwater with a degraded safety system.

The precursors identified are listed in Table B.1.

Table B.1 List of 1995 ASP Events

Event Number	Plant	Event descriptions	Page
LER 213/95-010	Haddam Neck	Multiple Safety Injection Valves are Susceptible to Pressure Locking	B.2-1
LER 313/95-005	Arkansas Nuclear One, Unit 1	Trip with One Emergency Feedwater Train Unavailable	B.3-1
LER 315/95-011	Cook 1	One Safety Injection Pump Unavailable for Six Months	B.4-1
LERs 335/95-004, -005, -006	St. Lucie 1	Failed Powered-Operated Relief Valves, Reactor Coolant Pump Seal Failure, Relief Valve Failure and Subsequent Shutdown Cooling System Unavailability, Plus Other Problems	B.5-1
LER 336/95-002	Millstone 2	Containment Sump Isolation Valves Potentially Unavailable due to Pressure Locking	B.6-1
LER 352/95-008	Limerick 1	Safety Relief Valve Fails Open, Scram, Suppression Pool Strainer Fails	B.7-1
LER 368/95-001	Arkansas Nuclear One, Unit 2	Loss of dc Bus Could Fail Both Emergency Feedwater Trains	B.8-1
LER 382/95-002	Waterford 3	Reactor Trip with a loss of Train A of the Essential Service Water and the Turbine-Driven Auxiliary Feedwater Pump	B.9-1
LER 389/95-005	St. Lucie 2	Failure of One Emergency Diesel Generator with Common-Cause Failure Implications	B.10-1
LERs 445/95-003, -004	Comanche Peak	Reactor Trip, Auxiliary Feedwater (AFW) Pump Trip, Second AFW Pump Unavailable	B.11-1

B.1.3 Event Documentation

Analysis documentation and precursor calculation information for each precursor are attached. The precursors are in docket/LER number order.

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

A figure is included which highlights the dominant core damage sequence associated with the event. Conditional core damage calculation information is also provided. This includes the following tables:

- Probabilities for selected basic events
- Sequence logic, sequence probabilities, and importances and system names for higher probability sequences
- Higher probability cutsets for higher probability sequences

B.2 LER No. 213/95-010

Event Description: Multiple safety injection valves are susceptible to pressure locking

Date of Event: March 9, 1995

Plant: Haddam Neck

B.2.1 Event Summary

In preparation for the closeout of Generic Letter (GL) 89-10, personnel at Haddam Neck determined that the following motor-operated valves (MOVs) were potentially susceptible to pressure locking (Fig. B.2.1):

- Valves SI-MOV-861A, -861B, -861C and -861D (the HPSI admission valves),
- Valves SI-MOV-871A and -871B (the LPSI admission valves), and
- Valve SI-MOV-873 (the common LPSI isolation valve).

This analysis assumes the susceptible valves could impact the plant response to a large-break LOCA (LBLOCA). An increase in the core damage probability (CDP) during the time that the necessary conditions for pressure locking these valves exists is 4.7×10^{-6}. The nominal CDP for the same period is 2.1×10^{-6}. The uncertainty in the frequency of LBLOCAs and the uncertainty in the likelihood that the pressure locking conditions will exist contribute to the uncertainty in this estimate.

B.2.2 Event Description

On March 9, 1995, personnel at Haddam Neck determined that several safety injection (SI) valves were susceptible to pressure locking, which could preclude them from performing required safety functions following a postulated LOCA (Ref. 1 and 2).

Pressure locking occurs when the fluid in the valve bonnet is at a higher pressure than the adjacent piping at the time of the valve opening. The two most likely scenarios for elevating the pressure in the valve bonnet relative to the pressure in the valve system are given below.

1. Thermal pressure locking (or bonnet heatup) can occur when an incompressible fluid is trapped in the valve bonnet (e.g., during valve closure), followed by heating-up the volume in the bonnet. The bonnet heatup scenarios include heating the valve bonnet by an increase in the temperature of the environment during an accident, heat up due to an increase in the temperature of the process fluid on either side of the valve, etc. (Normal ambient temperature variation is not considered because it occurs over a long time period and pressure changes tend to be alleviated through extremely small amounts of leakage. Further, operating experience shows that normal temperature variations are not a source of pressure locking events.)

2. Hydraulic pressure locking (or pressure-trapping) can occur when an incompressible fluid is trapped in the valve bonnet, followed by depressurization of the adjacent piping prior to valve opening. Examples of hydraulic pressure locking scenarios include back-leakage past check valves, and system operating pressures that are higher than the system pressure when the valve is required to open.

Pressure locking is of concern because the pressure in the space between the two discs of a gate valve can become pressurized above the pressure assumed when sizing the valve's motor operator. This prevents the valve operator from opening the valve when required.

Thermal binding is a phenomenon where temperature changes of the valve internal components causes the valve stem to expand after closure. This results in a higher required opening thrust that may be above the opening thrust assumed when sizing the valve motor operator.

In 1990, plant personnel reviewed the potential of flexible wedge gate valves becoming pressure locked and thermally bound in response to the Institute of Nuclear Power Operations' significant operating events report (SOER) number SOER 84-7. As a result of these reviews, personnel implemented remedial measures consisting of procedural changes (stroking valves during plant heatup), analytical treatment of pressure locking effects, and limited testing of valves to address the high priority valves found subject to pressure locking and thermal binding.

In order to upgrade the quality of the documentation on pressure locking and thermal binding issues in preparation for the closeout of GL 89-10, personnel determined that several of the valves in the safety injection system were potentially subjected to pressure locking conditions that were more significant than previously concluded. According to plant personnel, the concern is the thermal pressure locking of the HPSI admission valves, the LPSI admission valves, and the common LPSI isolation valve (Ref. 3 and 4).

B.2.3 Additional Event-Related Information

NRC Information Notice (IN) 95-18 (Ref. 5), which addresses the Haddam Neck event, elaborates on the mechanisms of pressure locking:

> Pressure-locking may occur in flexible-wedge and parallel disk gate valves when fluid entrapped in the bonnet becomes pressurized and the actuator is incapable of overcoming the additional thrust requirements needed to overcome the increased friction resulting from the differential pressure on both valve disks from the pressurized fluid. IN 95-14 discusses several ways in which fluid may enter the valve bonnet . . . . These mechanisms represent potential common-cause failure modes that can render redundant trains of safety-related emergency core cooling systems incapable of performing their safety functions.

According to personnel at Haddam Neck, the pressure locking condition of concern for the HPSI admission valves, the LPSI admission valves, and the common LPSI isolation valve is thermal pressure locking. Hence, these valves are susceptible to becoming pressure locked if (1) water (the incompressible fluid) becomes trapped in the bonnet during valve closure and (2) water in the valve bonnet becomes heated by an increase in the temperature of the environment or the process fluid on either side of these valves.

B.2.4 Modeling Assumptions

Personnel at Haddam Neck indicated that the failure mode of concern for the high-pressure and low-pressure safety injection valves is believed to be thermally-induced pressure locking, wherein water trapped in the valve bonnets may expand during plant heatup and prevent the valves from opening. This analysis assumes that valves SI-MOV-861A, -861B, -861C -861D and valves SI-MOV-871A, -871B could be unavailable because of pressure locking following a large-break LOCA, which would render LPSI and HPSI inoperable. The potential failure of valve SI-MOV-873 was not considered because its failure is only significant if valves SI-MOV-871A and -871B function correctly, which is assumed not to be the case.

The Haddam Neck *Individual Plant Examination* (IPE) (Ref. 6) indicates that LPSI will provide adequate makeup during a LBLOCA to prevent core damage. The simple event tree model used for this event (Fig. B.2.2) consists of a postulated LBLOCA initiating event with the success or failure of the following two modes of operation: LPSI and decay heat removal (DHR). Consistent with other ASP analyses, an annual LBLOCA frequency of 2.7×10^{-4}/yr was assumed (Ref. 7).

The significance of an unavailability such as this event is estimated in the Accident Sequence Precursor (ASP) Program in terms of the increase in CDP over the unavailability period, which is also referred to as the importance. Because a nonrecoverable failure of the HPSI admission valves and the LPSI admission valves will fail both high- and low-pressure injection, and injection is required following a large-break LOCA, the significance of the event can be estimated directly from the change in the probability of injection failure and the probability of a large-break LOCA in the unavailability period. The time interval during which the SI valves could have been inoperable is difficult to determine. This analysis assumes that the valves may have been unavailable for a total of 1 week during the prior year because once the pressure in the bonnet equalizes, pressure locking is no longer a concern. Hence, the temperatures on both sides of the valve equalizing and normal valve leakage will remove the susceptibility to pressure locking. Figure B.2.3 explores the impact of different assumptions regarding the duration of the time these valves are unavailable.

The CCDP associated with this event is estimated to be

$$\frac{2.7 \times 10^{-4}}{52} \left\{\begin{matrix}\text{CCDP for a LBLOCA} \\ \text{in a 1-wk period}\end{matrix}\right\} + \frac{8.2 \times 10^{-5}}{52} \left\{\begin{matrix}\text{CCDP from the IRRAS} \\ \text{base case for 1-wk period}\end{matrix}\right\}$$

$$= 6.8 \times 10^{-6} \left\{\begin{matrix}\text{Total CCDP} \\ \text{in a 1-wk period}\end{matrix}\right\}.$$

The importance for this event (CCDP–CDP) is estimated to be

$$6.8 \times 10^{-6} \left\{\begin{matrix}\text{Total CCDP} \\ \text{in a 1-wk period}\end{matrix}\right\} - \frac{8.2 \times 10^{-5}}{52} \left\{\begin{matrix}\text{CDP from the IRRAS} \\ \text{base case fo -wk period}\end{matrix}\right\}$$

$$= \frac{2.5 \times 10^{-5}}{52} \left\{ \begin{array}{l} \text{Representative base case} \\ \text{LBLOCA CDP} \end{array} \right\}$$

$$= 4.7 \times 10^{-6} \ \{\text{Importance}\}.$$

B.2.5 Analysis Results

An increase in the core damage probability (CDP) during the time that the necessary conditions for pressure locking these valves exists is 4.7×10^{-6}. The nominal CDP for the same period is 2.1×10^{-6}. The dominant core damage sequence for the event (sequence No. 3 on Fig. B.2.2) involves:

- a postulated large-break LOCA and
- failure of low-pressure injection.

This estimate is based on estimated frequencies of large-break LOCAs. No large-break LOCAs have been observed to date, so there is substantial uncertainty associated with the frequency estimate. The CCDP estimate also is dependent on the assumption that the pressure-locking phenomenon would prevent the injection valves from opening during large-break LOCAs. This assumption is consistent with those made in the analysis reported in LER 213/95-010, but may be pessimistic.

B.2.6 References

1. LER 213/95-010, Rev. 0, "Pressure Locking of Safety Injection Valves," April 6, 1995.

2. LER 213/95-010, Rev. 1, "Pressure Locking of Safety Injection Valves," November 8, 1995.

3. Conference call with personnel from Haddam Neck, the NRC's Office for Analysis and Evaluation of Operational Data, and the Oak Ridge National Laboratory (ORNL), January 23, 1997.

4. Personnel communication between P. D. O'Reilly, U.S. NRC, and M. D. Muhlheim, ORNL.

5. Information Notice 95-18, "Potential Pressure-Locking of Safety-Related Power-Operated Gate Valves," U.S. Nuclear Regulatory Commission, March 15, 1995.

6. Haddam Neck Plant , *Individual Plant Examination*.

7. NUREG/CR-4674, Vol. 21, *Precursors to Potential Severe Core Damage Accidents: 1994, A Status Report*, Appendix H, U.S. Nuclear Regulatory Commission, December 1995.

8. *Final Safety Analysis Report*, Connecticut Yankee Atomic Power Company, Haddam Neck Plant.

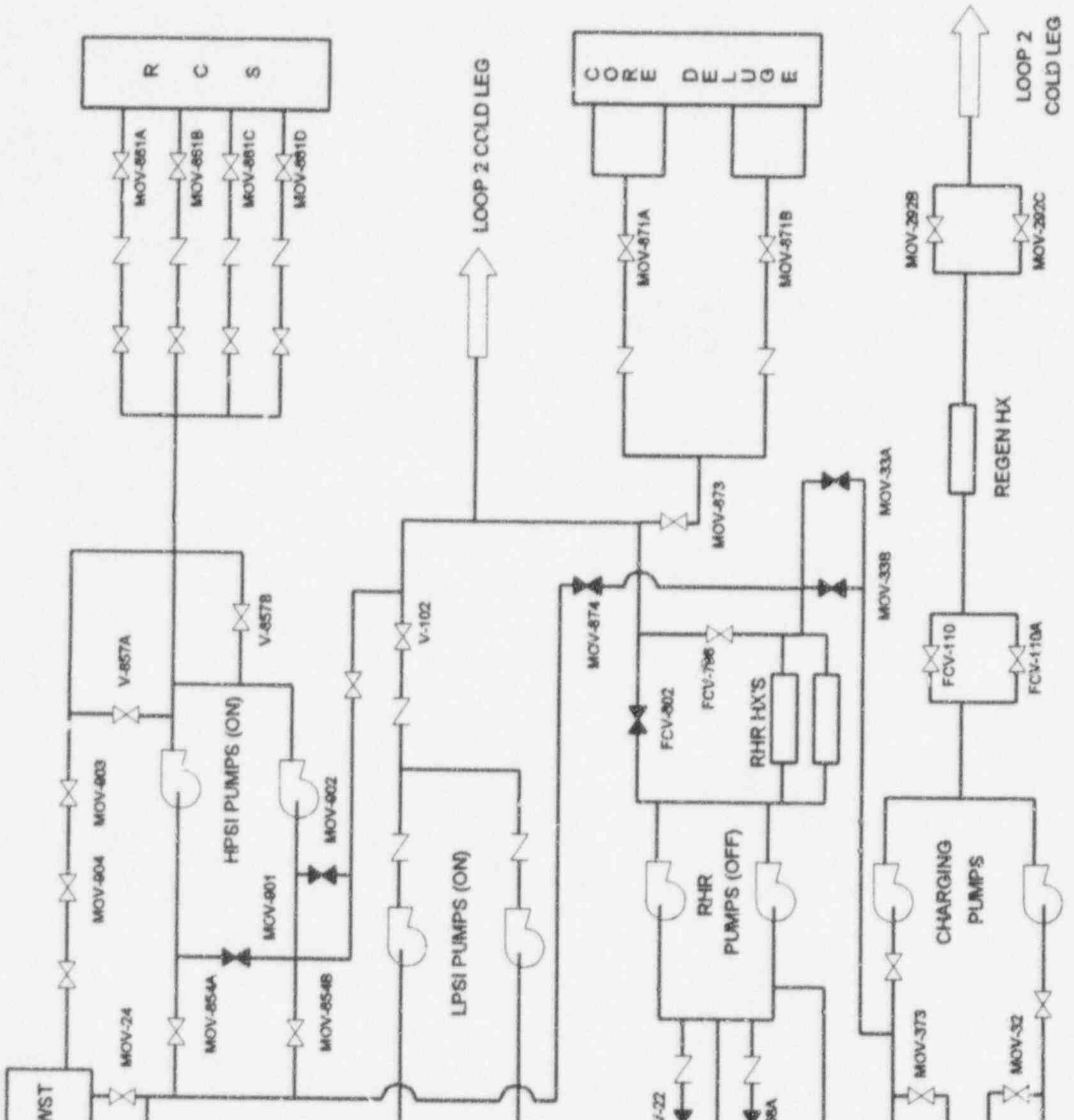

Fig. B.2.1 Safety injection systems at Haddam Neck (injection phase shown). (Source: *Final Safety Analysis Report*, Connecticut Yankee Atomic Power Company.)

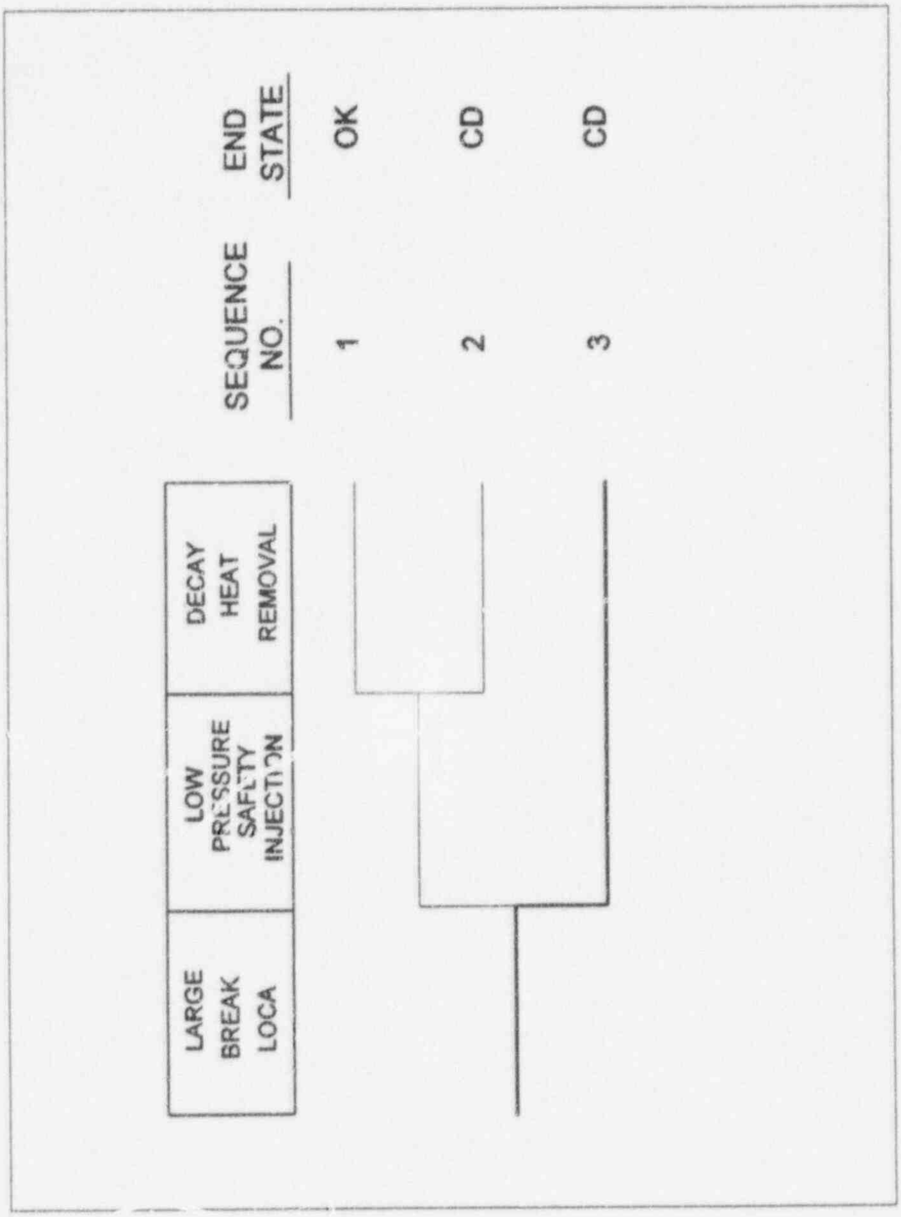

Fig. B.2.2. Dominant core damage sequence for LER No. 213/95-010.

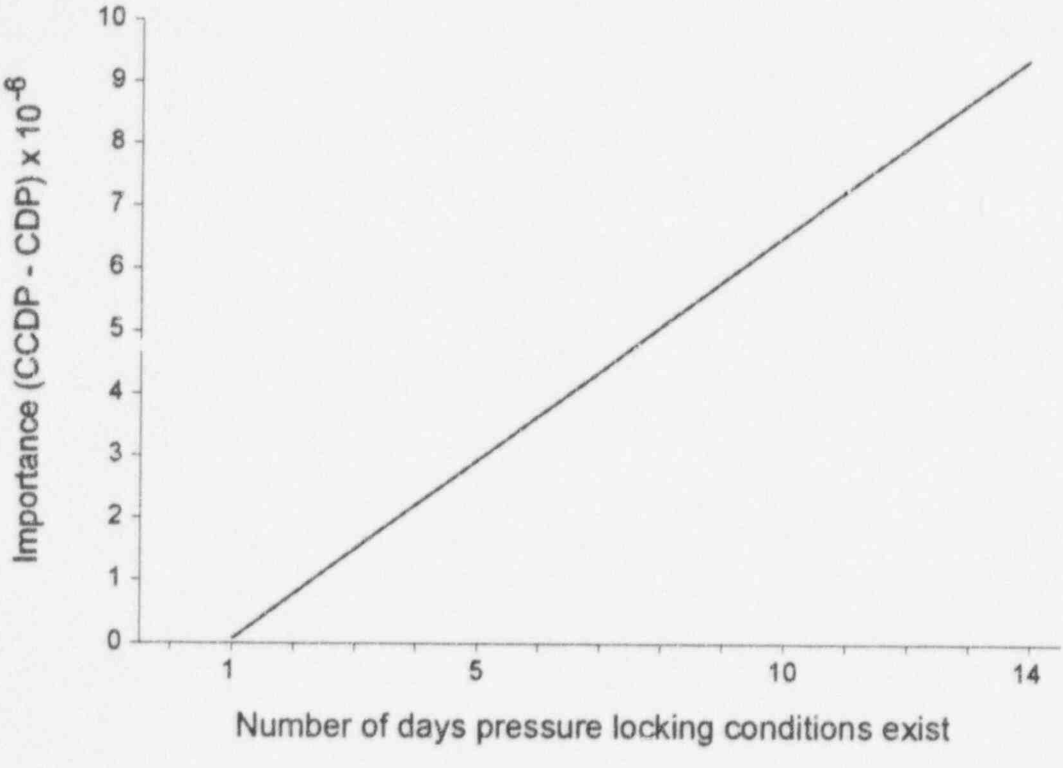

Fig. B.2.3 Importance of the potential thermal pressure locking conditions over time.

B.3 LER No. 313/95-005

Event Description: Trip with one emergency feedwater train unavailable

Date of Event: April 20, 1995

Plant: Arkansas Nuclear One, Unit 1

B.3.1 Event Summary

Arkansas Nuclear One, Unit 1 (ANO 1) was operating at 100% power when a spurious trip of the main generator resulted in a main turbine trip, thereby causing an automatic trip of the reactor. Multiple equipment malfunctions were experienced, including failure of both flow control valves associated with the motor-driven emergency feedwater pump (MDEFWP) train. The conditional core damage probability (CCDP) estimated for this event is 6.4×10^{-6}.

B.3.2 Event Description

ANO 1 was operating at full power when a ground fault on the B phase of the current transformer supplying the negative sequence relay (NSR) caused a generator lockout followed by turbine and reactor trips. (The NSR protects the main generator from thermal damage due to negative sequence current caused by system faults or an open phase condition.) During the post-trip response, one main steam safety valve, PSV-2684 (see Fig. B.3.1), appeared to remain open longer than operators expected. To reduce the pressure in the B once-through steam generator (OTSG), operators opened the B turbine bypass valve to approximately 50%. As pressure in the B steam generator (SG) dropped, PSV-2684 seated and the B turbine bypass valve closed. PSV-2684 reopened and operators again opened the B turbine bypass valve, thereby allowing PSV-2684 to reclose. Subsequent review verified that valve PSV-2684 responded normally on blowdown and reseat.

Both main feedwater pumps (MFPs) were used to maintain SG levels, running back to minimum speed after the reactor trip, as expected. After SG levels stabilized, the MFPs should have returned to automatic level control. The A MFP returned to automatic control as designed, but the B MFP did not. Operators manually adjusted the B MFP flow and returned it to automatic control. The B MFP failed to shift back to automatic control because foreign material (a calibration sticker) on a module connector prevented a proper electrical connection to a relay coil.

During the first hour after the trip, condenser vacuum gradually decreased to about 0.068 Mpa (20 in. Hg). The decrease was attributed to excessive air in-leakage, coupled with a failure of the B vacuum pump to automatically shift into hogging mode (higher flow rate at reduced vacuum). Operators determined that the excessive air in-leakage was occurring through the moisture separator reheater (MSR) relief valves. By increasing the MSR steam seal pressure and switching the B vacuum pump to hogging mode, the vacuum in the condenser was recovered.

About an hour after the trip, a +5-volt dc power supply for Train A of the emergency feedwater (EFW) initiation and control (EFIC) system failed. This failure, believed to be caused by component failure in the voltage regulating circuit for the power supply, resulted in a half-trip of the EFIC system. Train A SG level indication was lost, as was remote control of atmospheric dump valve (ADV) CV-2668 and emergency feedwater valves CV-2646 and CV-2648 (see Fig. B.3.2).

B.3.3 Additional Event-Related Information

To adequately remove heat from the reactor core after a scram or a trip, only one of two EFW pump trains must be available to deliver water to at least one of the two OTSGs. The failure of the +5-volt power supply resulted in the loss of EFW flow control valves in the MDEFWP train (CV-2646 and CV-2648) and ADV CV-2668 control in either automatic or manual control (local control of the ADV was still possible).

B.3.4 Modeling Assumptions

About 1 hour after the trip, EFIC Train A failed, resulting in a loss of automatic and manual control of EFW flow control valves CV-2646 and -2648. The licensee event report (LER) for this event is not specific regarding the as-failed position of the MDEFWP flow control valves and the impact of the failure on system performance. If the valves failed closed, then the auxiliary feedwater supply from the MDEFWP would be unavailable. If the valves failed full-open, then they would not be capable of regulating flow. This latter condition could eventually require the operators to trip the MDEFWP to prevent steam generator overfill. In this case, tripping the MDEFWP would be modeled as a recoverable system failure. Either of the above cases (failed open or failed closed) leads to the unavailability of the MDEFWP; therefore, this event was modeled as a reactor trip with flow from the MDEFWP made unavailable by failure of its EFW flow control valves. Note that failure of the flow control valves in the open position in conjunction with operator failure to control SG level by tripping the MDEFWP could result in failure of the turbine-driven EFW pump (TDEFWP). This potential failure mode was not explored.

Control of EFW flow control valves CV-2646 and CV-2648 was lost when a +5-volt dc power supply in EFIC Train A failed. This failure was apparently caused by a random failure of a voltage regulator within the power supply. No information was provided that specifically indicated an increased potential for common-cause failure of the flow control valves in the TDEFWP train, so no increase in common-cause failure probability was modeled.

To implement the assumed failure of the MDEFWP flow control valves, the set of valves associated with the MDEFWP (Basic Event EFW-MOV-CF-DISM) was set to TRUE (i.e., the valves were failed). This setting caused the motor-driven train of the EFW to be failed in the model. The turbine-driven train was still available and was not subject to the common-cause failure (i.e., loss of the +5-volt dc power supply in EFIC Train A) that rendered the MDEFWP flow control valves inoperable. Basic event probability changes are noted in Table B.3.1.

B.3.5 Analysis Results

The CCDP estimated for this event is 6.4×10^{-6}. The dominant sequence, highlighted on the event trees in Figs. B.3.3 and B.3.4, involves

- the observed trip demand with a failure to trip, and
- failure of EFW to provide sufficient flow for ATWS mitigation.

The assumed inoperability of MDEFWP valves increased the failure probability for the MDEFWP train.

Definitions and probabilities for selected basic events are shown in Table B.3.1. The conditional probabilities associated with the highest probability sequences are shown in Table B.3.2. Table B.3.3 lists the sequence logic associated with the sequences listed in Table B.3.2. Table B.3.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.3.5.

B.3.6 References

1. LER 313/95-005, "Reactor Trip Initiated by Main Turbine Generator Protective Circuitry as a Result of a Logic Circuit Ground Caused by Vibration Induced Insulation Wear," May 19, 1995.

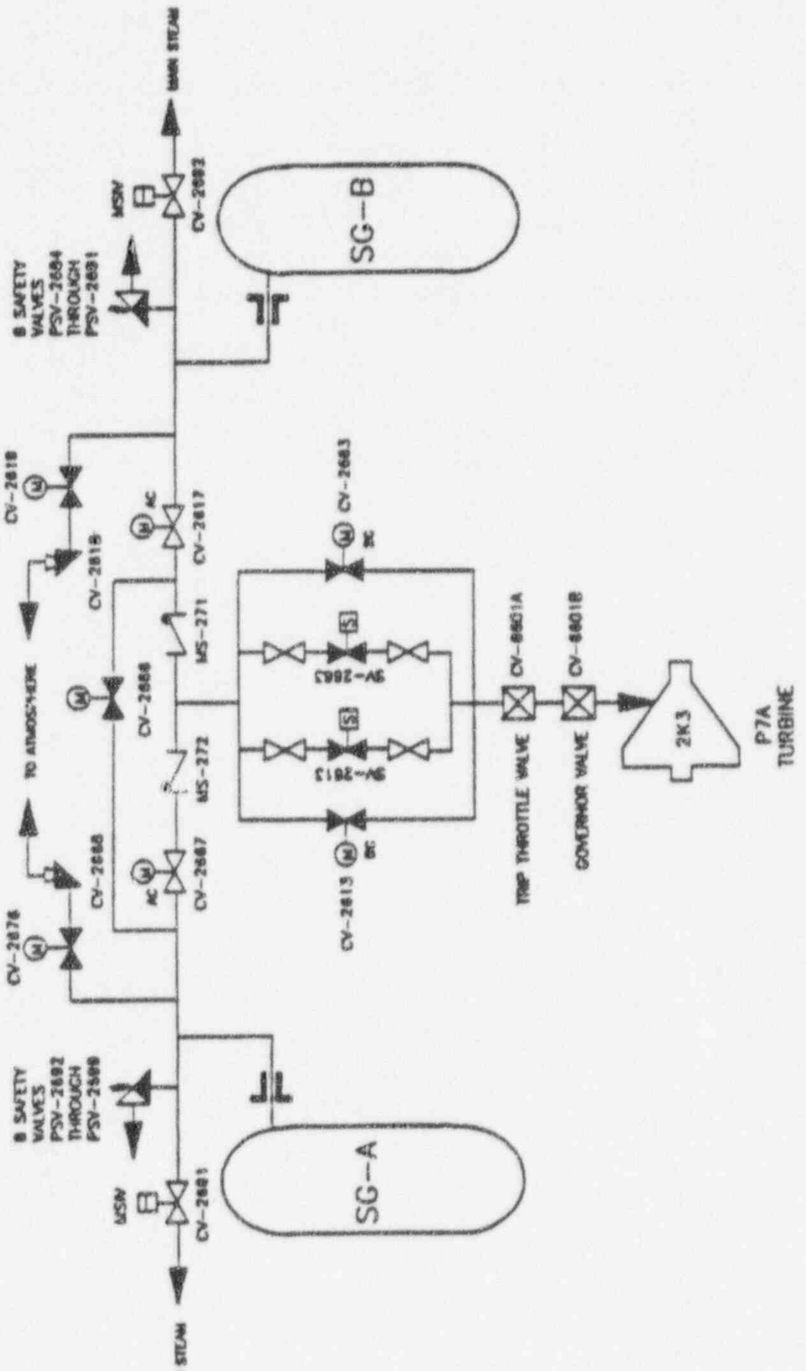

Fig. B.3.1 ANO 1 Emergency Feedwater System.

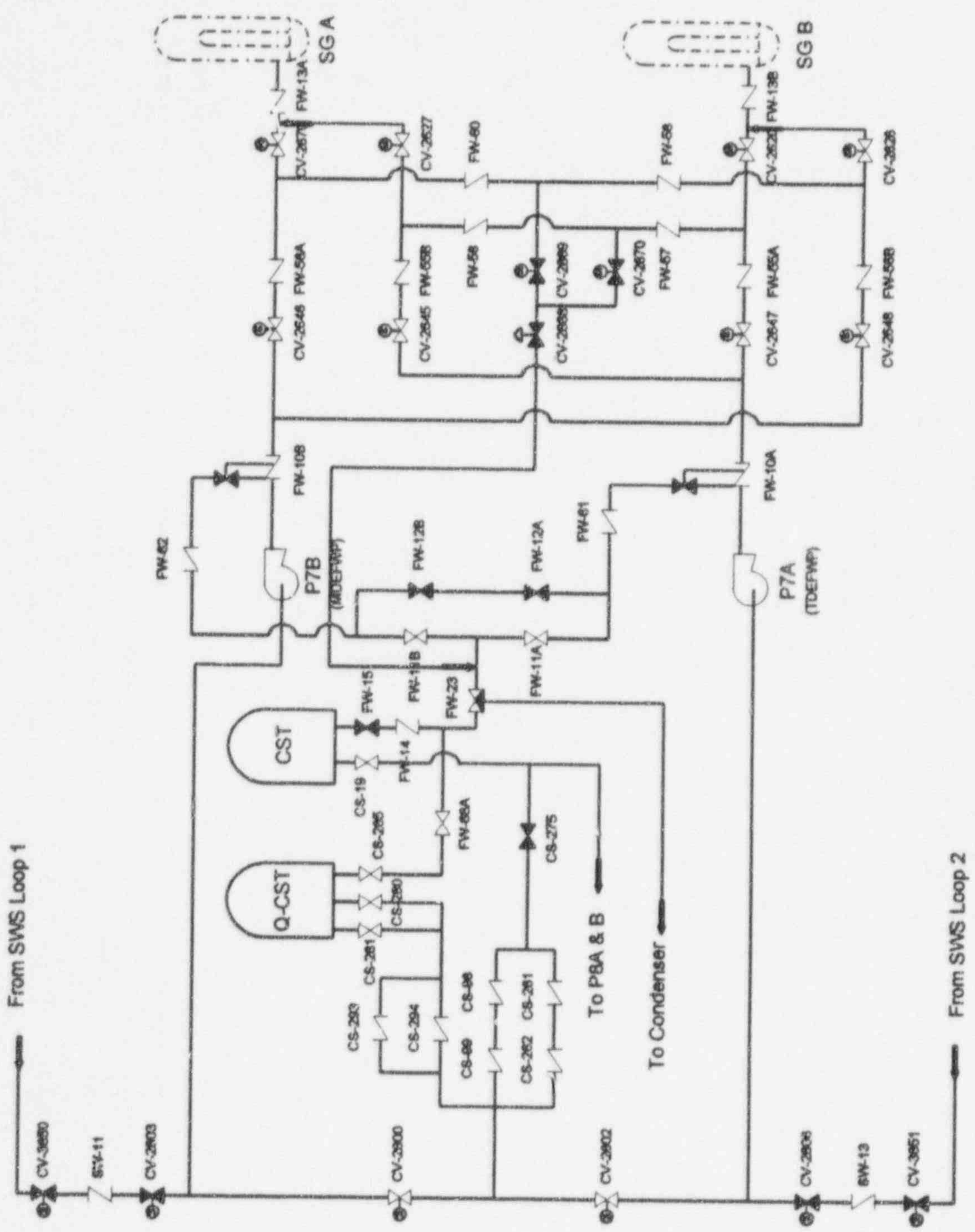

Fig. B.3.2 ANO 1 Emergency Feedwater System.

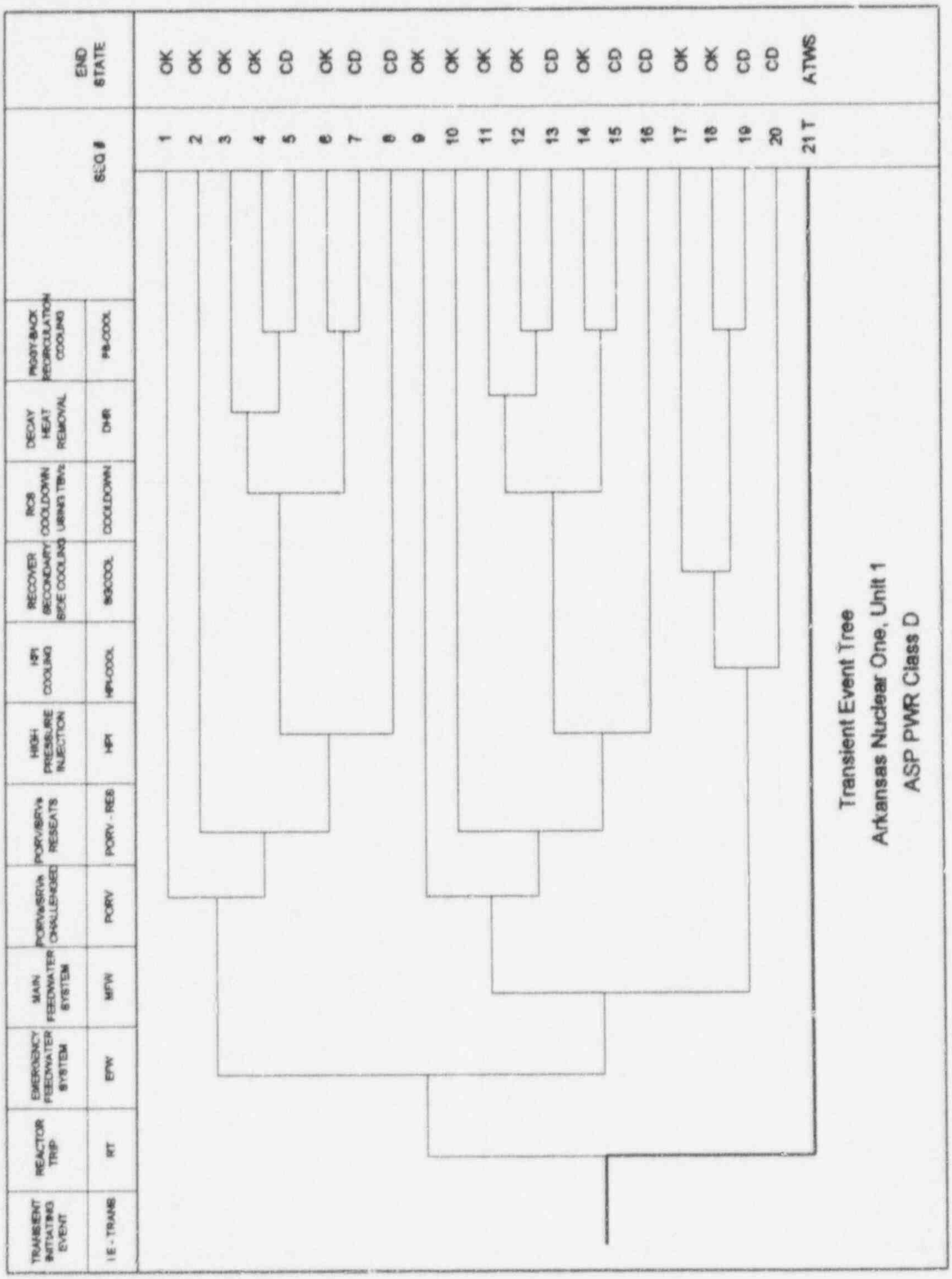

Fig. B.3.3. Dominant core damage sequence for LER 313/95-005.

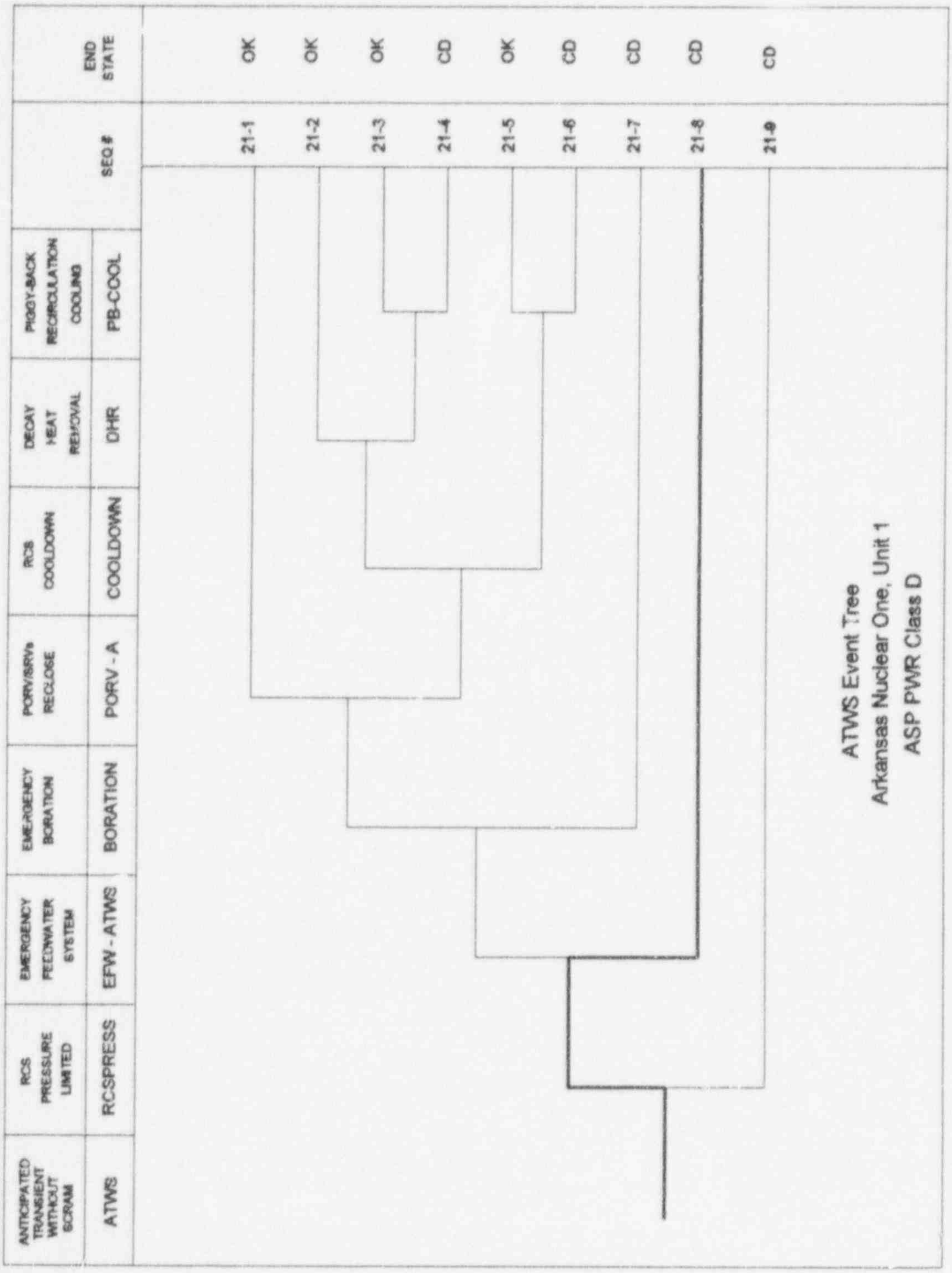

Fig. B.3.4. Event tree for Arkansas Nuclear One, Unit 1.

Table B.3.1. Definitions and Probabilities for Selected Basic Events for LER 313/95-005

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss-of-Offsite Power Initiating Event	8.5 E-006	0.0 E+000	IGNORE	Yes
IE-STGR	Steam Generator Tube Rupture Initiating Event	1.6 E-006	0.0 E+000	IGNORE	Yes
IE-SLOCA	Small Loss- of-Coolant Accident Initiating Event	1.0 E-006	0.0 E+000	IGNORE	Yes
IE-TRANS	Transient Initiating Event	1.3 E-004	1.0 E+000		Yes
EFW-MOV-CF-DISM	MDEFWP Discharge Valves Fail From Common-Cause	2.6 E-004	1.0 E+000	TRUE	Yes
EFW-TDP-FC-1B	Failure of TDEFWP	3.2 E-002	3.2 E-002		No
EFW-XHE-NOREC	Operator Fails to Recover EFW System	2.6 E-001	2.6 E-001		No
EFW-XHE-NOTHROT	Operator Fails to Throttle EFW Flow	5.0 E-003	5.0 E-003		No
EFW-XHE-XA-CST	Operator Fails to Align a Backup Water Supply	1.0 E-003	1.0 E-003		No
HPI-CKV-OO-MST	Makeup Storage Tank Suction Isolation Motor-Operated Valve (MOV) Common-Cause Failures	3.0 E-003	3.0 E-003		No
HPI-MDP-CF-ABC	High Pressure Injection (HPI) Common-Cause Failures	1.1 E-004	1.1 E-004		No
HPI-MOV-CF-SUCT	HPI Suction Isolation Motor-Driven Pump Common-Cause Failures	2.6 E-004	2.6 E-004		No
HPI-XHE-NOREC	Operator Fails to Recover the HPI System	8.4 E-001	1.0 E+000		Yes
HPI-XHE-XM-HPIC	Operator Fails to Initiate HPI Cooling	1.0 E-002	1.0 E-002		No
MFW-SYS-TRIP	Main Feedwater MFW System Trips	2.0 E-001	2.0 E-001		No
MFW-XHE-NOREC	Operator Fails to Recover MFW	1.6 E-002	1.6 E-002		No
PCS-ICC-FA-TT	Failure of the Main Turbine to Trip	1.0 E-003	1.0 E-003		No

Table B.3.1. Definitions and Probabilities for Selected Basic Events for LER 313/95-005

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-MOV-OO-BLK	Power-Operated Relief Valve (PORV) Block Valve Fails to Close	4.0 E-003	4.0 E-003		No
PPR-SRV-CC-PORV	PORV Fails to Open on Demand	6.3 E-003	6.3 E-003		No
PPR-SRV-CC-RCS	Relief Valves Fail to Limit Reactor Coolant System (RCS) Pressure	4.4 E-004	4.4 E-004		No
PPR-SRV-CO-TRAN	PORV Opens During a Transient	8.0 E-002	8.0 E-002		No
PPR-SRV-OO-PORV	PORV Fails to Reclose After Opening	3.0 E-002	3.0 E-002		No
PPR-XHE-NOREC	Operator Fails to Close the Block Valve	1.1 E-002	1.1 E-002		No
RCS-PHN-MODPOOR	Moderator Temperature Coefficient is not Negative Enough	1.4 E-002	1.4 E-002		No
RPS-NONREC	Nonrecoverable Reactor Protection System (RPS) Failures	2.0 E-005	2.0 E-005		No
RPS-REC	Recoverable RPS Failures	4.0 E-005	4.0 E-005		No
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	1.0 E-002	1.0 E-002		No

Table B.3.2. Sequence Conditional Probabilities for LER 313/95-005

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
TRANS	21-8	5.3E-006	82.7
TRANS	20	6.3E-007	9.9
TRANS	21-9	3.1E-007	4.9
Total (all sequences)		6.4E-006	

Table B.3.3. Sequence Logic for Dominant Sequences for LER 313/95-005

Event tree name	Sequence number	Logic
TRANS	21-8	RT, /RCSPRESS, EFW-ATWS
TRANS	20	/RT, EFW, MFW, HPI-COOL
TRANS	21-9	RT, RCSPRESS

Table B.3.4. System Names for LER 313/95-005

System name	Logic
EFW	No or Insufficient EFW System Flow
EFW-ATWS	No or Insufficient EFW System Flow During an Anticipated Transient Without Scram Event
HPI	No or Insufficient Flow from the HPI System
HPI-COOL	Failure to Provide HPI Cooling
MFW	Failure of the MFW System
PORV	PORV Opens During Transient
PORV-RES	PORV Fails to Reseat
RCSPRESS	Failure to Limit RCS Pressure
RT	Reactor Fails to Trip During Transient

Table B.3.5. Conditional Cut Sets for Higher Probability Sequences for LER 313/95-005

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
TRANS Sequence 21-8		5.3 E-006	
1	98.0	5.2 E-006	RPS-NONREC, EFW-XHE-NOREC
2	1.9	1.0 E-007	RPS-XHE-XM-SCRAM, RPS-REC, EFW-XHE-NOREC
TRANS Sequence 20		6.3 E-007	
1	41.9	2.6 E-007	EFW-MOV-CF-DISM, EFW-TDP-FC-1B, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-HPIC, HPI-XHE-NOREC
2	26.4	1.6 E-007	EFW-MOV-CF-DISM, EFW-TDP-FC-1B, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-PORV
3	12.5	7.9 E-008	EFW-MOV-CF-DISM, EFW-TDP-FC-1B, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-CKV-OO-MST, HPI-XHE-NOREC
4	6.5	4.1 E-008	EFW-XHE-NOTHROT, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-HPIC, HPI-XHE-NOREC
5	4.1	2.6 E-008	EFW-XHE-NOTHROT, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-PORV
6	1.9	1.2 E-008	EFW-XHE-NOTHROT, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-CKV-OO-MST, HPI-XHE-NOREC
7	1.3	8.3 E-009	EFW-XHE-XA-CST, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-HPIC, HPI-XHE-NOREC
8	1.1	7.0 E-009	EFW-MOV-CF-DISM, EFW-TDP-FC-1B, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-MOV-CF-SUCT, HPI-XHE-NOREC
TRANS Sequence 21-9		3.1 E-007	
1	88.9	2.8 E-007	RPS-NONREC, RCS-PHN-MODPOOR
2	6.3	2.0 E-008	RPS-NONREC, PCS-ICC-FA-TT
3	2.7	8.8 E-009	RPS-NONREC, PPR-SRV-CC-RCS
4	1.7	5.6 E-009	RPS-XHE-XM-SCRAM, RPS-REC, RCS-PHN-MODPOOR
Total (all sequences)		**6.4 E-006**	

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilities for the initiating events and the basic events are given in Table B.3.1.

[b]Basic event EFW-MOV-CF-DISM is a type TRUE event and these type of events are normally not included in the output of fault tree reduction programs. This event has been added to aid in understanding the sequences to potential core damage associated with the event.

B.4 LER No. 315/95-011

Event Description: One safety injection pump unavailable for 6 months

Date of Event: September 12, 1995

Plant: D. C. Cook, Unit 1

B.4.1 Event Summary

As the result of a surveillance test performed while the unit was shut down in Mode 6, personnel determined that the West Centrifugal Charging Pump (CCP) had been inoperable for about 6 months. The pump was inoperable because a relay calibration had been performed incorrectly 6 months earlier. The unavailability of the West CCP primarily affects the unit's response to a small-break loss-of-coolant accident (SLOCA) event. The estimated *increase* in core damage probability (CDP) for this event (i.e., the importance) is 7.7×10^{-6} above a base probability of core damage (the CDP) for the same period of 2.9×10^{-5}.

B.4.2 Event Description

On September 12, 1995, the plant was shut down in Mode 6 when the West CCP was started to perform the emergency core cooling system (ECCS) full flow test surveillance. The West CCP provides injection flow on the receipt of a safety injection (SI) signal. After operating at full flow for 7 min, the pump tripped on motor overcurrent. Personnel determined that the pump tripped because the 1-51-TA8 time overcurrent relay was set incorrectly. It was determined that this relay was last calibrated on March 15, 1995, 180 days before the full-flow test. The West CCP was rendered inoperable for the preceding 6 months.

During the event review, the Instrumentation and Control (I&C) technicians involved in calibrating the relays demonstrated the way they typically determine the relay pick-up current. Because their technique was incorrect, the relays were miscalibrated. Both I&C technicians involved in the relay calibration were trained and qualified in the D. C. Cook Nuclear Plant relay training program. However, a significant amount of time had elapsed between the end of the training program and the time the 1-51-TA8 time overcurrent relay on the West CCP breaker was calibrated incorrectly.

B.4.3 Additional Event-Related Information

During normal plant operation, both charging pumps (East and West) are configured for their charging function. One charging pump is sufficient to supply full charging flow and reactor coolant pump seal injection during normal leakage and normal letdown conditions. A third positive displacement charging pump is available but is not normally used. On receipt of a valid SI signal, the CCPs operate in the high pressure injection (HPI) mode.

D. C. Cook also has a separate SI system. The system, with two pumps operating in parallel, runs in an intermediate pressure injection mode. The two SI pumps deliver flow from the Refueling Water Storage Tank

(RWST) at a maximum injection pressure of approximately 7.6 MPa (1100 psig). The residual heat removal (RHR) pumps can be aligned for recirculation from the containment sump to the suction of either the SI pumps or the CCPs.

The licensee indicated that the East CCP had been inoperable for less than 18 h during the 6-month period that the West CCP was unavailable. Additionally, the emergency diesel generator (EDG) supporting the East CCP was unavailable for less than 50 h during the 6-month period that the West CCP was unavailable.

B.4.4 Modeling Assumptions

This event was modeled as a long term (4320 hours, 180 days × 24 h/day) unavailability of the West CCP. The event model was broken into three cases based on reported equipment availability. The first case modeled only the West CCP as being unavailable for 4252 hours. The second case took into account that the opposite train EDG was periodically unavailable for time periods totaling 50 hours while the West CCP was unavailable. Finally, the third case accounted for the report that both CCPs were simultaneously unavailable for various maintenance periods totaling 18 hours.

Loss-of-offsite power (LOOP) sequences are prominent in the second case when only one EDG was available. LOOP probabilities for short-term and long-term off-site power recovery and the probability of a reactor coolant pump (RCP) seal LOCA following a postulated station blackout were developed based on data distributions contained in NUREG 1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*. The RCP seal LOCA models were developed as part of the NUREG-1150 PRA efforts. These probabilities and models are described in *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989.

The CCPs were subject to common-cause failure during this 6-month period resulting from incorrect maintenance practices. Because the success criterion in the Integrated Reliability and Risk Analysis System (IRRAS) model assumes both CCPs are required for success of the CCP portion of the HPI function in response to either an SLOCA or a steam generator tube rupture (SGTR), no changes were required to model the increased potential for common-cause failure. Success of one of the two SI pumps also ensures success of the HPI function in the IRRAS model, independent of the success of the CCPs. This assumption is not as stringent as that of the plant Individual Plant Examination, which is that one of two CCPs and one of two SI pumps are required in response to an SLOCA.

The IRRAS response to an SGTR was modified. Previously, a loss of the HPI function lead directly to core damage. The possibility of lowering RCS pressure below the steam generator safety valve set point within 30 min was allowed following the loss of HPI capability by adding a basic event PCS-XHE-DEPRES. Based on the operator burden under a short time constraint, a failure probability of 0.1 was assigned to the new basic event, PCS-XHE-DEPRES.

B.4.5 Analysis Results

Determining the overall increase in the CDP required determining the increase in the CDP for the three different cases and then summing the cases. The three cases are:

Case 1 the increase in the CDP due to the long-term unavailability of the West CCP (4252 h).
Case 2 the increase in the CDP from the opposite train EDG being unavailable periodically while the West CCP was unavailable (50 h).
Case 3 the increase in the CDP due to the time that the CCPs were simultaneously unavailable because of various maintenance activities (18 h).

Combining the probability estimates for the three cases results in an overall increase of 7.7×10^{-6} in the CDP for the 180-day period. This is above a base probability for core damage (the CDP) for the same period of 2.9×10^{-5}. Most of the increase (56%) is driven by the long-term unavailability of the West CCP (Case 1). An additional 44% of the increase in CDP is added by Case 2. The dominant core damage sequence, highlighted as sequence number 6 on the event tree in Fig. B.4.1, contributes approximately 44% to the combined increase in the CDP estimate for all three modeled cases. Sequence number 6 involves:

- an SLOCA,
- the successful trip of the reactor,
- the successful operation of the Auxiliary Feedwater (AFW) system, and
- the failure of the HPI system to provide sufficient cooling flow.

The next most dominant sequence involves a LOOP and contributes approximately 13% to the combined increase in the CDP estimate for all three modeled cases.

The nominal CDP over a 6-month period estimated using the Accident Sequence Precursor (ASP) models for D. C. Cook is approximately 2.9×10^{-5}. The failed West CCP increased this probability by 28% to 3.7×10^{-5}. This latter value (3.7×10^{-5}) is the conditional core damage probability (CCDP) for the 6-month pe iod in which the West CCP was inoperable.

For most ASP analyses o conditions (equipment failures over a period of time during which postulated initiating events could have occurred), sequences and cut sets associated with the observed failure dominate the CCDP (i.e., the probability of core damage over the unavailability period, given the observed failures). The increase in CDP because of the failures is, therefore, essentially the same as the CCDP, and the CCDP can be considered a reasonable measure of the significance of the observed failures. However, for this event, sequences unrelated to the failure of the West CCP dominated the CCDP estimate. The increase in CDP given the West CCP inoperability, 7.7×10^{-6}, is, therefore, a better measure of the significance of the failure of the West CCP.

Definitions and probabilities for selected basic events are shown in Table B.4.1. The conditional probabilities associated with the highest probability sequences for the condition assessment are shown in Table B.4.2. The sequence logic associated with the sequences listed in Table B.4.2 are given in Table B.4.3. Table B.4.4 lists the system names associated with the dominant sequences for the condition assessment. Minimal cut sets associated with the dominant sequences for the condition assessment are shown in Table B.4.5.

B.4.6 References

1. LER 315/95-011, Rev 0, "West Centrifugal Charging Pump Inoperable due to Inability to Meet Design Basis Requirements for Six Months as a Result of Personnel Error During Relay Calibration," November 20, 1995.

2. Indiana Michigan Power Company, *Donald C. Cook Nuclear Plant Individual Plant Examination Summary Report*.

3. Indiana Michigan Power Company, *Donald C. Cook Nuclear Plant Final Safety Analysis Report*.

4. *Evaluation of Station Blackout Accidents at Nuclear Power Plants*, NUREG-1032.

5. *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989.

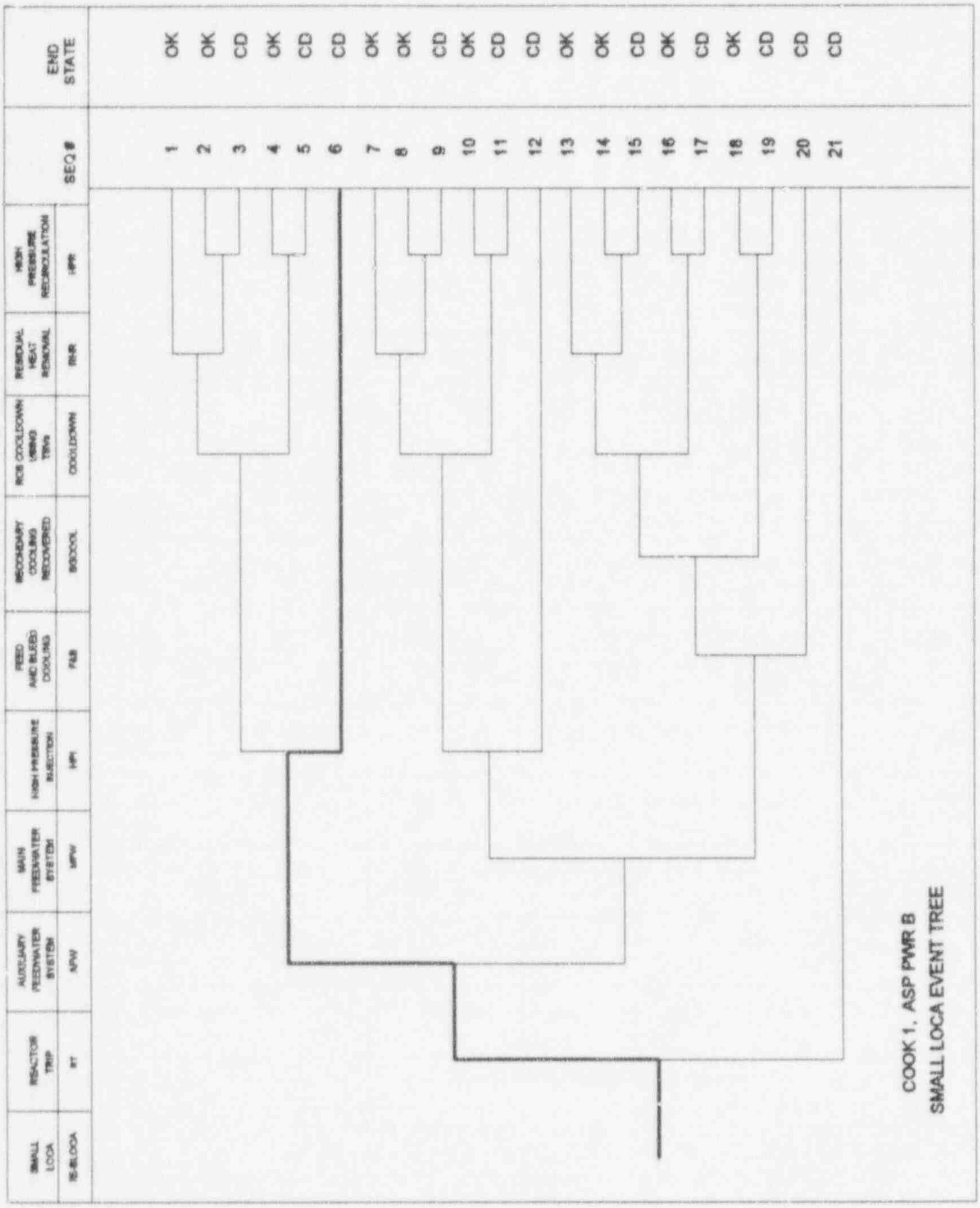

Fig. B.4.1. Dominant core damage sequence given a small LOCA for LER 315/95-011.

Table B.4.1. Definitions and Probabilities for Selected Basic Events for LER No. 315/95-011

Event name	Description	Base probability	Current probability	Type	Modified for this event
CVC-MDP-FC-1A	Failure of Charging Pump A	9.0E-004	1.0E+000	TRUE	Yes
HPI-MDP-CF-ALL	HPI Motor-Driven Pump Common-Cause Failures	7.8E-004	7.8E-004		No
HPI-MDP-FC-1A	HPI Motor-Driven Pump A Fails	3.9E-003	3.9E-003		No
HPI-MDP-FC-1B	HPI Motor-Driven Pump B Fails	3.9E-003	3.9E-003		No
HPI-MOV-OC-SUC	HPI Serial Component Failures	1.4E-004	1.4E-004		No
HPI-MOV-OO-RWST	Failure to Isolate the RWST From the HPI System	3.0E-003	3.0E-003		No
HPI-XHE-NOREC	Operator Fails to Recover the HPI System	8.4E-001	8.4E-001		No
HPR-XHE-NOREC	Operator Fails to Recover the High Pressure Recirculation (HPR) System	1.0E+000	1.0E+000		No
PCS-XHE-DEPRES	Failure to Depressurize the RCS Within 30 Minutes	1.0E-001	1.0E-001	NEW	No
RHR-MDP-CF-ALL	RHR Pump Common-Cause Failures	4.5E-004	4.5E-004		No
RHR-MDP-FC-1A	RHR Motor-Driven Pump 1A Fails	4.1E-003	4.1E-003		No
RHR-MDP-FC-1B	RHR Motor-Driven Pump 1B Fails	4.1E-003	4.1E-003		No
RHR-MOV-CC-SUC1	Failure of RHR Hot Leg Suction Motor-Operated Valve (MOV) A	3.0E-003	3.0E-003		No
RHR-MOV-CC-SUC2	Failure of RHR Hot Leg Suction MOV B	3.0E-003	3.0E-003		No
RHR-MOV-OO-RWST	Failure to Isolate the RWST During RHR	3.0E-003	3.0E-003		No
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	1.0E+000	1.0E+000		No

Table B.4.2. Sequence Conditional Probabilities for LER No. 315/95-011

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP–CDP)	Percent contribution[d]
SLOCA	06	3.3E-006	2.9E-008	3.3E-006	77.2
SGTR	08	5.4E-007	4.8E-009	5.4E-007	12.5
SLOCA	03	2.2E-008	2.0E-006	1.5E-007	3.7
Subtotal Case 1 (shown)[a]		3.3E-005	2.9E-005	4.3E-006	
Subtotal Case 2[b]		3.7E-006	3.4E-007	3.4E-006	
Subtotal Case 3[c]		1.4E-007	1.2E-007	1.8E-008	
Total (all sequences)		**3.7E-005**	**2.9E-005**	**7.7E-006**	

[a] Case 1 represents the increase in the core damage probability due to the long-term unavailability of the West CCP (4252 h).

[b] Case 2 represents the increase in the CDP from the opposite train EDG being unavailable periodically while the West CCP was unavailable (50 h).

[c] Case 3 represents the increase in the core damage probability due to the time that the CCPs were simultaneously unavailable because of various maintenance activities (18 h).

[d] Percent contribution to the total importance.

Table B.4.3. Sequence Logic for Dominant Sequences for LER No. 315/95-011 (Case 1 only)

Event tree name	Sequence name	Logic
SLOCA	06	/RT, /AFW, HPI
SGTR	08	/RT, /AFW, HPI, RCS-SG-H
SLOCA	03	/RT, /AFW, /HPI, /COOLDOWN, RHR, HPR

Table B.4.4. System Names for LER No. 315/95-011 (Case 1 only)

System name	Logic
AFW	No or Insufficient AFW Flow
COOLDOWN	RCS Cooldown to RHR Pressure Using Turbine-Bypass Valves, etc.
HPI	No or Insufficient Flow From HPI System
HPR	No or Insufficient HPR Flow
RHR	No or Insufficient Flow From RHR System
RCS-SG-H	Failure to Depressurize the RCS Below the Steam Generator Safety Valve Setpoint Without HPI
RT	Reactor Fails to Trip During Transient

Table B.4.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 315/95-011

Cut set no.	Percent contribution	Change in CCDP (Importance)[a]	Cut sets[a]
SLOCA Sequence 06		3.3E-006	
1	83.1	2.8E-006	CVC-MDP-FC-1A, HPI-MDP-CF-ALL, HPI-XHE-NOREC
2	14.9	5.0E-007	CVC-MDP-FC-1A, HPI-MOV-OC-SUC, HPI-XHE-NOREC
3	1.6	5.4E-008	CVC-MDP-FC-1A, HPI-MDP-FC-1A, HPI-MDP-FC-1B, HPI-XHE-NOREC
SGTR Sequence 08		5.4E-007	
1	83.1	4.5E-007	CVC-MDP-FC-1A, HPI-MDP-CF-ALL, HPI-XHE-NOREC, PCS-XHE-DEPRES
2	14.9	8.0E-008	CVC-MDP-FC-1A, HPI-MOV-OC-SUC, HPI-XHE-NOREC, PCS-XHE-DEPRES
3	1.6	8.6E-009	CVC-MDP-FC-1A, HPI-MDP-FC-1A, HPI-MDP-FC-1B, HPI-XHE-NOREC, PCS-XHE-DEPRES
SLOCA Sequence 03		1.6E-007	
1	86.4	1.5E-007	RHR-MDP-CF-ALL, RHR-XHE-NOREC, HPR-XHE-NOREC
2	3.2	6.2E-009	RHR-MDP-FC-1A, RHR-MDP-FC-1B, RHR-XHE-NOREC, HPR-XHE-NOREC
3	1.7	3.6E-009	CVC-MDP-FC-1A, HPI-MOV-OO-RWST, RHR-MOV-CC-SUC2, RHR-XHE-NOREC, HPR-XHE-NOREC
4	1.7	3.6E-009	CVC-MDP-FC-1A, HPI-MOV-OO-RWST, RHR-MOV-OO-RWST, RHR-XHE-NOREC, HPR-XHE-NOREC
5	1.7	3.6E-009	CVC-MDP-FC-1A, HPI-MOV-OO-RWST, RHR-MOV-CC-SUC1, RHR-XHE-NOREC, HPR-XHE-NOREC
Subtotal Case 1[b] (shown above)		**4.3E-006**	
Subtotal Case 2[c]		**3.4E-006**	
Subtotal Case 3[d]		**1.8E-008**	
Total (all sequences)		**7.7E-006**	

[a] The change in conditional probability (importance) is determined by calculating the conditional probability for the period in which the condition existed, and subtracting the conditional probability for the same period but with plant equipment assumed to be operating nominally. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per-hour basis), and t is the duration time of the event. This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are:

$$\lambda_{TRANS} = 5.3 \times 10^{-4}/h,\ \lambda_{LOOP} = 3.8 \times 10^{-6}/h,\ \lambda_{SLOCA} = 1.0 \times 10^{-6}/h,\ \text{and}\ \lambda_{SGTR} = 1.6 \times 10^{-6}/h.$$

[b] Case 1 represents the increase in the core damage probability due to the long term unavailability of the West CCP (4252 h).

[c] Case 2 represents the increase in the CDP from the opposite train EDG being unavailable periodically while the West CCP was unavailable (50 h).

[d] Case 3 represents the increase in the core damage probability due to the time that the CCPs were simultaneously unavailable because of various maintenance activities (18 h).

[e] Basic event, CVC-MDP-FC-1A, is a TRUE type event which is not normally included in the output of fault tree reduction programs. This event has been added to aid in understanding the sequences to potential core damage associated with the event.

B.5 LER Nos. 335/95-004, -005, -006

Event Description: Failed power-operated relief valves, reactor coolant pump seal failure, relief valve failure, and subsequent shutdown cooling unavailability, plus other problems

Date of Event: August 2, 1995

Plant: St. Lucie 1

B.5.1 Event Summary

On August 1, 1995, St. Lucie 1 shut down to Mode 3 in preparation for Hurricane Erin. The next day, the lower seal stage on reactor coolant pump (RCP) 1A2 failed. When operators attempted to restage the seal, two additional stages failed resulting in a 7.6-l/m (2-gpm) leak. The reactor coolant system (RCS) was cooled down and depressurized to replace the failed seal. The next day, while in Mode 4, both power-operated relief valves (PORV) were tested and subsequently determined to be failed, a result of incorrect reassembly during the fall 1994 refueling outage. The failed PORVs required the plant to be cooled down, depressurized, and placed in Mode 5. During this cooldown, a thermal relief valve on the low pressure safety injection (LPSI) common discharge piping [part of the shutdown cooling system (SDC) system] lifted and did not reseat. Discovery of the open valve was delayed for 2 h because normally open floor drain valves were closed. After the open relief valve was discovered, the SDC system was removed from service for about a day to replace the valve. During this time, only the steam generators were available for decay heat removal. The conditional core damage probability (CCDP) estimated for the PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal core damage probability (CDP) for the same period. The CCDP associated with the potential RCP seal loss-of-cooling accident (LOCA) is 5.6×10^{-6}. The increase in CDP associated with the removal of the SDC system from service to replace the thermal relief valve is less than the Accident Sequence Precursor (ASP) program screening value of 1.0×10^{-6}.

B.5.2 Event Description

On August 1, 1995, the National Hurricane Center predicted hurricane force winds from the passage of Hurricane Erin near the St. Lucie site. Both units were shut down and cooled down to an average temperature of 177°C (350°F) to allow for enhanced steam generator heat removal capability with a steam-driven auxiliary feedwater (AFW) pump, and a storm crew was stationed on-site to support potential recovery efforts.

Hurricane Erin made landfall approximately 32 km (20 miles) north of the site, and maximum wind speed on-site was less than 72 km/h (45 mph). The Unusual Event that had been declared because of the hurricane was terminated at 0542 on August 2, 1995, and a decision was made to return both units to service.

At 0805, while Unit 1 was in Mode 3 with an RCS pressure of 10.7 MPa (1550 psia), RCP 1A2 middle seal cavity pressure was observed to be approximately equal to RCS pressure—an indication that the lower seal had failed. A decision was made to "restage" the leaking seal, increasing the differential pressure across it by sequentially depressurizing the seal cavities from top to bottom.

During the restaging evolution, the RCP middle seal failed and the upper and vapor seal degraded. The licensee attributed these failures to the performance of the restaging procedure at RCS temperatures above 93°C (200°F) and on a rotating pump. At 1810, on August 2, 1995, 20 min after control room indication of the failed middle seal, operators began to cool down and depressurize the RCS. At 1840, RCP 1A2 was secured.

By 2018 on August 2, 1995, reactor cavity leakage had increased to about 7.6 l/m (2 gpm). This leakage decreased the next day because of the ongoing RCS cooldown and depressurization. The RCP 1A2 seal was subsequently replaced, as was the RCP 1A1 seal (because of degraded performance).

During the RCS depressurization and cooldown on August 3, 1995, the PORVs also were stroke tested. No increase in acoustical flow indication was observed. Because of apparent inconsistencies with other indications, the problem was initially attributed to the acoustic monitors, and further PORV testing was planned following replacement of the RCP seals. On August 9, 1995, the PORVs again were tested with unsatisfactory results—first at 1.8 MPa (260 psia), then in Mode 4 at 2.2 MPa (320 psia) and with SDC secured, and finally at an RCS pressure of 3.28 MPa (475 psia).

The problem with both PORVs was caused by the improper installation of the main disc guides, following overhaul during the 1994 fall refueling outage, and by inadequate post-maintenance testing before returning the valves to service. (Only a seat leakage test was performed.)

With both PORVs inoperable, Limiting Condition for Operation (LCO) 3.4.13 required the unit to be depressurized and a vent path established within 24 h. A cooldown and depressurization was begun.

At 0018 on August 10, 1995, with the unit at 137°C (278°F) and 1.8 MPa (261 psia), the 1A LPSI pump was started to place the SDC system in service to continue the cooldown. Shortly after starting the pump, pressurizer level and letdown flow were observed to be decreasing. Because no annunciations associated with RCS leakage were received, no increases in reactor cavity sump flow or waste management system sump levels and tanks were detected; and because no leakage was observed in the LPSI pump rooms and other auxiliary building areas, the operators concluded that the unexpected mismatch between charging and letdown flow was the result of the RCS cooldown. At 0105, the 1B LPSI pump was started, and the remaining steps in the SDC normal operating procedure were completed.

At 0215 on August 10, 1995, water was discovered to be accumulating in the auxiliary building pipe tunnel. Both trains of SDC were secured (decay heat removal was provided by the steam generators). Pressurizer level and charging/letdown flow were observed to be stable, indicating that the leakage had stopped. The floor drain isolation valves to the safeguards pump room sump were found to be closed. When these valves were subsequently opened, high sump level annunciated. The safeguards pump room sump isolation valves had been stroke-tested in preparation for Hurricane Erin, and some of the seven valves controlled by a single switch had failed to close. Following trouble-shooting efforts, the control switch had been left in the closed position.

At 0611 on August 10, 1995, thermal relief valve V3439 was determined to have been the cause of the leakage. The valve is located in LPSI pump discharge piping, which is common to both trains. During the event, the operating pressure of the SDC system immediately following LPSI pump start was within the relief valve's lift-pressure range, resulting in the valve opening. The SDC system operating pressure remained above the relief valve reseat pressure, which prevented the valve from closing. Approximately 15,000 l (4000 gal) of reactor coolant was discharged during the almost 2-h period the valve was open.

Three and one-half hours after the relief valve leakage was identified, both trains of the SDC system were removed from service for approximately 20 h to replace the valve. RCS temperature was increased to 152°C (305°F), where the PORV Technical Specification was not applicable. Decay heat was removed using the steam generators, the only source of decay heat removal at that point. Following relief valve replacement, both SDC trains were restored to operable status, and the RCS was cooled down and depressurized to repair the PORVs.

Three other reportable events occurred during the same time frame as the events described previously. These events, which would not be selected as precursors, are summarized to provide a more complete picture of the situation at St. Lucie 1 during the August 1995 time period.

While RCS temperature was being decreased on August 2, 1995, in response to the failed RCP seal, the main steam isolation signal (MSIS) block permissive annunciators were alarmed and were acknowledged by an operator. That operator did not refer to the annunciator summary procedure but concluded that blocking MSIS was not required because all valves that would have been affected by an MSIS actuation were already in their actuated positions. The shift technical advisor subsequently questioned whether MSIS should be blocked, but the annunciator procedure again was not consulted. Six minutes after the block permissive annunciated, the annunciator for MSIS actuation alarmed. Before operator action could be taken, MSIS actuated and was subsequently blocked and reset.

On August 11, 1995, the Train A containment spray header flow control valve, FCV-07-1A, failed its stroke test and was declared inoperable. Because repair of the valve was expected to take a significant length of time, the valve was placed in its safeguard position (open), and repair was deferred until the next refueling outage. On August 16, 1995, a Unit 1 heatup was begun, and the SDC system was secured. Unspecified maintenance on the LPSI system delayed performance of the emergency core cooling system venting procedure until 1756 on August 17, 1995, when the RCS was at 278°C (532°F) and 10.7 MPa (1550 psia). As part of the venting procedure, the 1A LPSI pump was started and used to circulate refueling water tank (RWT) water through the SDC warm-up line. The SDC heat exchanger inlet and outlet valves were then opened to circulate water through the heat exchanger. Because FCV-07-1A was open, a direct path from the RWT was provided to the A containment spray header. Three minutes later, at 1806, the control room received high reactor cavity leakage annunciation, multiple containment fire alarms, and rapidly increasing containment sump flow indication, and entered the off-normal operating procedure for excessive RCS leakage. The 1A LPSI pump was stopped, the flow path through the spray header identified, the SDC heat exchanger isolation valves closed, and the venting procedure exited. Approximately 38,000 l (10,000 gal) of borated water was sprayed into the containment. The containment fire detection system malfunctioned during the event; 90% of the containment smoke detectors either alarmed or faulted. In addition, an electrical ground occurred on one safety injection tank sample valve [Ref. 4].

On August 28, 1995, with the unit in Mode 5 with an RCS temperature of approximately 49°C (120°F) and an RCS pressure of 1.7 MPa (250 psia), high pressure safety injection (HPSI) header stop valve V-3656 was opened and HPSI pump 1A was started to support an inservice leak test of header relief valve V-3417. This valve is the HPSI equivalent of the LPSI relief valve that opened on August 10, 1995. HPSI pump operation is prohibited at RCS temperatures below 113°C (236°F). All four HPSI injection valves were shut and disabled at the time, so the RCS was not affected [Ref. 5].

B.5.3 Additional Event-Related Information

The PORVs provide three functions at St. Lucie: (1) low temperature overpressure protection when the RCS temperature is below 152°C (305°F) and not vented, (2) RCS pressure relief above normal operating pressure to minimize challenges to the pressurizer code safety valves, and (3) a bleed path for "once-through cooling" (feed-and-bleed) in the event that secondary-side decay heat removal is unavailable.

The LPSI system at St. Lucie provides injection for large- and medium-break loss-of-coolant accidents (LOCAs). The system is secured at the start of the recirculation phase, and the HPSI pumps are realigned and used to provide RCS makeup from the containment sump. The LPSI system also provides decay heat removal during normal plant shutdowns. Either LPSI pump can be used to circulate reactor coolant through a shutdown heat exchanger, returning it to the RCS via the low-pressure injection header.

B.5.4 Modeling Assumptions

The combined event has been modeled as (1) an unavailability of both PORVs from the time St. Lucie 1 returned to power following its fall 1994 refueling outage, (2) a potential RCP seal LOCA resulting from the two failed seal stages, and (3) a 22 h unavailability of the SDC system for decay heat removal. The failure of the operator to block the MSIS, inadvertent spray-down of the containment, and HPSI pump start at low temperature, while problematic, did not substantially impact core damage sequences and were not addressed.

PORV unavailability. St. Lucie 1 returned to power on December 1, 1994, and the failed PORVs were discovered on August 3, 1995. During this period (approximately 5880 h), the PORVs were unavailable for both pressure relief and for feed-and-bleed. To reflect the unavailability for feed-and-bleed, basic events for failure of the valves to open (PPR-SRV-CC-1 and PPR-SRV-CC-2) were set to TRUE.

The Accident Sequence Precursor (ASP) models do not specifically address failure of relief valves to open for pressure relief; a sufficient number of valves are assumed to open to prevent overpressure.

Because the two PORVs were failed, the pressurizer code safety valves (SVs) would have been demanded in the event of high RCS pressure. Because SVs cannot be isolated, failure of an open valve to close would result in an unisolatable small-break LOCA. The potential for the SVs to be challenged instead of the PORVs was reflected in the model by setting the basic events for failure of the PORVs to close (PPR-SRV-OO-1 and PPR-SRV-OO-2) to FALSE and adding a basic event (PPR-SRV-OO-SRVS) to represent the potential that an open SV will fail to close.

The relief valve challenge rate used in the model was not revised to reflect the fact that the SVs would be challenged on high RCS pressure instead of the PORVs. The SV lift pressure is 0.7 MPa (100 psi) greater than the PORV lift pressure, and fewer transients are expected to reach this pressure, which should result in fewer SV challenges and, therefore, a lower challenge rate. Unfortunately, because PORVs are usually available, operational data on SV challenges do not exist. The significance of impacted sequences (primarily transient sequences 5, 7, and 8 in Fig. B.5.1), is, therefore, potentially overestimated in the analysis. However, these sequences do not significantly contribute to the overall results even with the conservative SV challenge rate.

Potential RCP seal LOCA. The seal on RCP 1A2 could have degraded further and failed, resulting in a small-break LOCA. The probability of a small-break LOCA, given the degraded seal, was estimated from Byron-Jackson RCP seal data in Tables 4 and B-3 of NUREG-1275, Vol. 7 [Ref. 6]. These tables list actual RCP seal degradations (e.g., the failure of a stage or increased controlled bleed-off flow) in which plant operation was allowed to continue for some period of time in accordance with operating procedures.

Most of the data in Tables 4 and B-3 of Ref. 6 were from the Nuclear Plant Reliability Data System and excluded the names of the plants at which the events occurred. However, data were listed for Arkansas Nuclear One (ANO), Units 1 and 2. These data were compared with the seal history data included for these two units in Appendix A of Ref. 6 to determine the fraction of events in Tables 4 and B-3 that were unrelated to the seal degradation observed during this event—primarily seal degradations caused component cooling water transients, weld cracks, and end-of-life failures. Approximately one-third of the ANO degradations were determined to be unrelated to this event. Assuming this fraction is applicable to all of the data in Tables 4 and B-3 of Ref. 6, 25 instances of seal degradation have occurred which appear to be relevant to the failure observed during this event and in which RCP operation continued. None of these 25 instances proceeded to a catastrophic seal failure.[1] Using a Chi-square approach[2] with zero observed seal failures in these 25 demands, a probability of 0.028 is estimated for a subsequent RCP seal failure and a small-break LOCA, given an observed seal degradation (stage failure).

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[1] One catastrophic seal failure was included in Table B-3 in Ref. 6 but was excluded from the set of seal degradations relevant to this event. That event occurred at ANO 1 and followed a loss of off-site power (LOOP) and a deliberate isolation of seal injection during a test.

[2] The use of a Chi-square distribution, a standard approach to estimate failure probabilities for small numbers of events, is described in Chapter 5 of NUREG/CR-2300, *PRA Procedures Guide*.

The probability of a small-break LOCA resulting from further degradation of the RCP 1A2 seal was reflected in the ASP model by revising basic event IE-SLOCA to 0.028. Consistent with the analysis of the failed PORVs, PPR-SRV-CC-1 and PPR-SRV-CC-2 were set to TRUE to reflect the unavailability of the PORVs for feed-and-bleed cooling, and PPR-SRV-OO-1 and PPR-SRV-OO-2 were set to FALSE to reflect the unavailability of the PORVs for pressure relief.[3]

SDC unavailability for 22 h. During the 22 h that the SDC system was removed from service to repair failed thermal relief valve V3439, the only source of decay heat removal was via the steam generators. Feed-and-bleed was unavailable because of the failed PORVs. The analysis for this case assumed that both motor-driven AFW pumps were available for use and that if both failed, RCS heatup would allow use of the turbine-driven AFW pump as well. The analysis also assumed that the AFW system had been returned to its pre-initiation state before the discovery of the stuck-open relief valve and that component failure probabilities applicable following a typical reactor trip from power were applicable in this situation as well.[4]

The LPSI system was removed from service nine days after St. Lucie was shut down for Hurricane Erin, when decay heat was approximately one-eighth of its nominal post-trip value. The lower decay heat level would substantially extend the time available to recover the AFW system if it failed and would eliminate the requirement to provide an alternate AFW suction source because the CST would not be expected to be emptied during the 22-h LPSI unavailability. (The decay heat load for this period is estimated to be less than 79% of the Technical Specification-required CST volume.) This was reflected in the model by reducing the probability of not recovering AFW, as described in the following paragraph; setting the basic event representing the failure of the operator to provide an alternate water source upon depletion of the condensate storage tank (CST), AFW-XHE-XA-CST2, to FALSE; and utilizing a 22-h mission time.[5]

The ASP models utilize a probability of 0.26 for failing to recover an initially failed AFW system within about 0.5 h following a reactor trip from power (basic event AFW-XHE-NOREC). Assuming the time available to recover AFW is proportional to the decay heat load, 4 h would be available if AFW had failed during the LPSI relief valve repair. AFW-XHE-NOREC was changed to 0.12 to reflect this greater recovery time. This value is the demand-related AFW nonrecovery probability developed in *Faulted Systems Recovery Experience*, NSAC-161 [Ref. 7] (Fig. 3.1-2) at 2 h, the longest nonrecovery duration addressed in that document. The probability is conservative for 4 h but consistent with the data-

[3] Since high RCS pressure would not exist following a postulated small-break LOCA, model changes were not actually required to reflect the unavailability of the PORVs for pressure relief.

[4] This, most likely, is conservative since at least some of the AFW components had recently operated and non-demand, standby failures, therefore, would not substantially contribute to these component failure probabilities.

[5] Certain basic events in the ASP models address both failure to start and failure to run. The probabilities for these basic events were not revised to reflect the 22-h mission time, which has less than a 2% percent impact on these basic event probabilities.

based approach summarized in NUREG/CR-4834, Vol. 2 [Ref. 8]; the data in Fig. 3.1-2 of Ref. 7 were not extrapolated.

The probability that AFW would have failed during the 22 h that the SDC system was removed from service is estimated to be 3.0×10^{-5}, using the St. Lucie ASP model modified as described previously. If the AFW system had failed, the condensate system could have been used for steam generator (SG) makeup. In addition, if the AFW system had failed when initially demanded, following isolation of the SDC system (failure at this time is more likely than failure following a successful demand), the SDC system could have been returned to service with the leaking relief valve until the AFW system had been restored to operation. The probability that both of these alternatives would fail is estimated to be well below 0.03, which reduces the overall conditional probability for the 22-h SDC unavailability to less than 1.0×10^{-6}, the truncation limit for documentation in the ASP program. Because the conditional probability for the 22-h SDC unavailability is estimated to be less than 1.0×10^{-6}, it was not analyzed further.

B.5.5 Analysis Results

The CCDP estimated for the 5880-h PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal CDP of 1.6×10^{-5} for the same period. The dominant core damage sequence, highlighted as sequence number 21 on the event tree in Fig. B.5.1, contributes about 55% to the increase in the CCDP and involves

- a postulated reactor trip during the 5880 h the PORVs were unavailable,
- nonrecoverable failures of main feedwater (MFW) and AFW, and
- loss of feed-and-bleed ability because of the unavailability of the PORVs.

The second highest core damage sequence, which contributes about 33% of the increase in CCDP, is similar to sequence number 21 on Fig. B.5.1 but involves a postulated LOOP instead of a transient and is highlighted on Fig. B.5.2 . Sequence 16 involves

- a successful reactor trip given a LOOP with emergency power available,
- failure of the AFW system, and
- loss of feed-and-bleed ability because of the unavailability of the PORVs.[6]

Table B.5.1 provides the definitions and probabilities for selected basic events for the assessment of the unavailable PORVs. The conditional probabilities associated with the highest probability sequences sorted by the increase in conditional probability for the condition assessment are shown in Table B.5.2. Table B.5.3 shows the sequence logic associated with the sequences in Table B.5.2. Table B.5.4

[6] The LOOP event tree includes the successful recovery of offsite power within 6 h in the dominant sequence. This is an artifice of the top event ordering. Feed-and-bleed challenge would occur about 20 min after the trip, and core damage would begin shortly thereafter. Sequences 16 and 21 together represent the core damage sequence involving emergency power success and AFW and feed-and-bleed failure.

describes the system names associated with the dominant sequences for the condition assessment. Cut sets associated with the dominant sequences for the condition assessment are shown in Table B.5.5.

The CCDP estimated for the potential RCP seal LOCA is 5.6×10^{-6}. The dominant core damage sequence (the only sequence above the 1×10^{-6} ASP screening value) involves

- a postulated RCP seal LOCA,
- AFW success, and
- failure of HPI.

Definitions and probabilities for selected basic events for the potential RCP seal failure are shown in TableB.5.6. The conditional probabilities associated with the highest probability sequences sorted by the increase in CCDP are shown in Table B.5.7. Table B.5.8 shows the sequence logic associated with the sequences in Table B.5.7. Table B.5.9 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.5.10.

B.5.6 References

1. LER 335/95-004, Rev. 0, "Hurricane Erin at St. Lucie," August 27, 1995.

2. LER 335/95-005, Rev. 0, "Pressurizer Power Operated Relief Valves (PORV) Inoperable due to Personnel Error," August 22, 1995.

3. LER 335/95-006, Rev. 0, "Loss of Reactor Coolant Inventory Through a Shutdown Cooling Relief Valve due to Lack of Design Margin," August 22, 1995.

4. LER 335/95-007, Rev. 0, "Inadvertent Containment Spray via 1A Low Pressure Safety Injection Pump While Venting the Emergency Core Cooling System During Startup due to Inadequate Procedure," August 27, 1995.

5. LER 335/95-008, Rev. 0, "High Pressure Safety Injection Pump Operation During Plant Conditions Not Allowed by Technical Specifications due to Personnel Error," September 27, 1995.

6. *Operating Experience Feedback Report - Experience with Pump Seals Installed in Reactor Coolant Pumps Manufactured by Byron Jackson*, L. G. Bell and P. D. O'Reilly, NUREG-1275, Vol. 7, U.S. Nuclear Regulatory Commission, September 1992.

7. *Faulted Systems Recovery Experience*, H. R. Booth, F. J. Mollerus, and J. L. Wray, NSAC-161, Nuclear Safety Analysis Center, May 1992.

8. *Recovery Actions in PRA for the Risk Methods Integration and Evaluation Program (RMIEP), Volume 2: Application of the Data-Based Method*, D. W. Whitehead, NUREG/CR-4834, Vol. 2, Sandia National Laboratories, 1987.

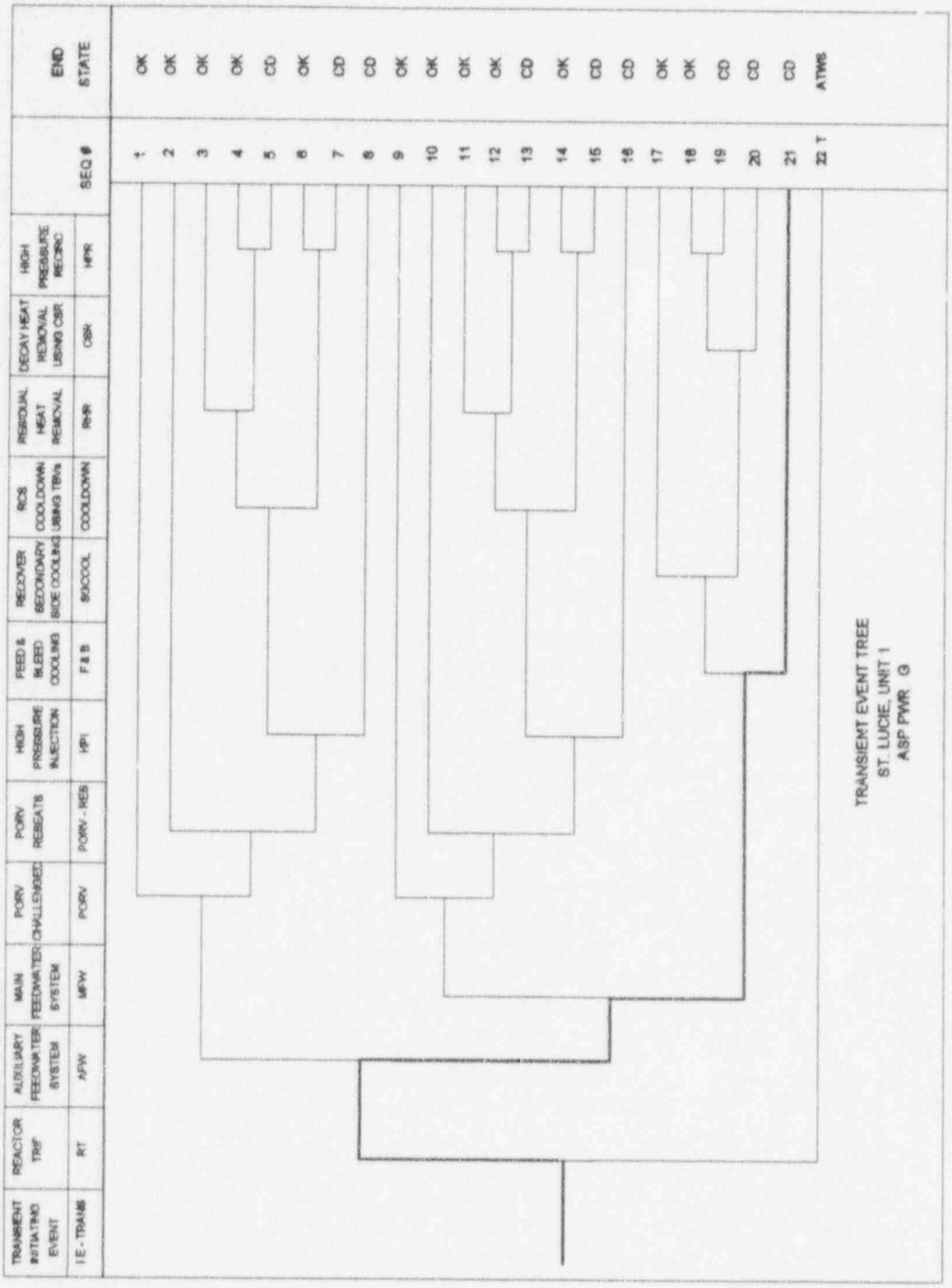

Fig. B.5.1. Dominant core damage sequence given a transient for LER Nos. 335/95-004, -005, -006.

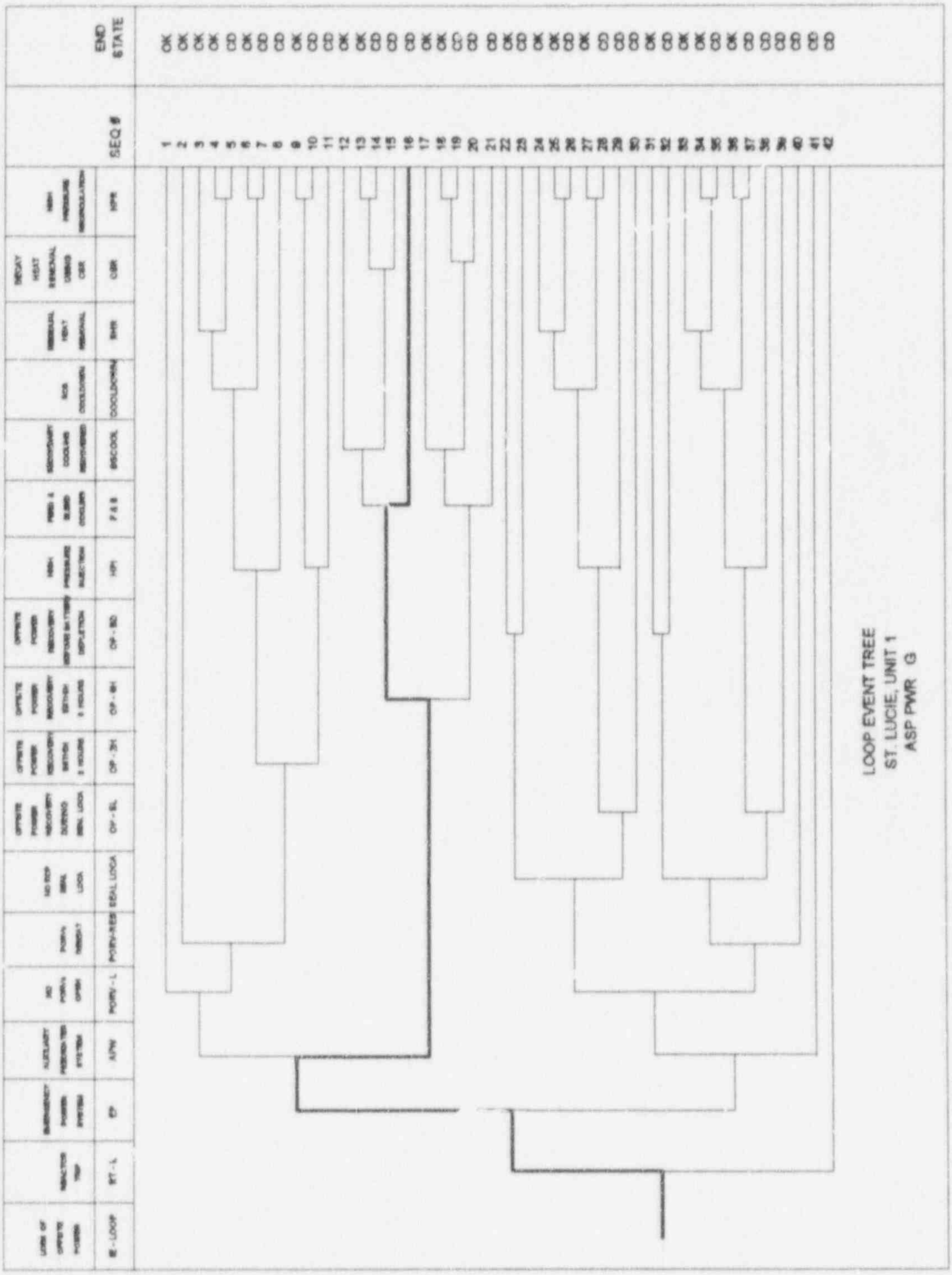

Fig. B.5.2. Dominant core damage sequence given a LOOP for LER Nos. 335/95-004, -005, -006.

Table B.5.1. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event name	Description	Base probability	Current probability	Type	Modified for this event
AFW-MOV-CF-SGALL	Common-Cause Failure of all Steam Generator Motor-Operated Valves	5.5E-005	5.5E-005		No
AFW-PMP-CF-ALL	Common-Cause Failure of all AFW Pumps	1.7E-004	1.7E-004		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6E-001	2.6E-001		No
AFW-XHE-NOREC-L	Operator Fails to Recover AFW During a LOOP	2.6E-001	2.6E-001		No
AFW-XHE-XA-CST2	Operator Fails to Initiate Backup Water Source	1.0E-003	1.0E-003		No
AFW-XHE-XA-CST2L	Operator Fails to Initiate Backup Water Source During a LOOP	1.0E-003	1.0E-003		No
EPS-DGN-CF-AB	Common-Cause Failure of Diesel Generators	1.6E-003	1.6E-003		No
EPS-DGN-FC-DGA	Diesel Generator A Failures	4.2E-002	4.2E-002		No
EPS-DGN-FC-DGB	Diesel Generator B Failures	4.2E-002	4.2E-002		No
EPS-XHE-NOREC[a]	Operator Fails to Recover Emergency Power	8.0E-001	8.0E-001		No
HPI-MDP-CF-ALL	Common-Cause Failure of HPI Motor-Driven Pumps	1.0E-004	1.0E-004		No
HPI-MOV-CF-DISAL	Common-Cause Failure of all HPI Injection Valves	5.5E-005	5.5E-005		No
HPI-TNK-FC-RWST	Refueling Water Storage Tank and Water Supply Valve Failures	2.7E-006	2.7E-006		No
MFW-SYS-TRIP	Main Feedwater (MFW) System Trips	2.0E-001	2.0E-001		No

[a] The potential recovery of ac power through recovery of offsite power or use of the unit 1/unit 2 cross-tie is addressed in basic events OEP-XHE-NOREC-BD (operator fails to recover offsite power before batteries are depleted) and OEP-XHE-NOREC-SL [operator fails to recover offsite power (seal LOCA)]. Because these basic events are in sequences that contribute to less than 1% of the total CCDP, they do not appear in Table 1 which provides definitions and probabilities for basic events that appear in the dominant sequences, or Table 5 which lists the dominant sequences and their cut sets.

Table B.5.1. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event name	Description	Base probability	Current probability	Type	Modified for this event
MFW-XHE-NOREC	Operator Fails to Recover MFW	3.4E-001	3.4E-001		No
PPR-SRV-CC-1	PORV 1 Fails to Open on Demand	2.0E-003	1.0E+000	TRUE	Yes
PPR-SRV-CC-2	PORV 2 Fails to Open on Demand	2.0E-003	1.0E+000	TRUE	Yes
PPR-SRV-CO-SBO	PORVs Open During a Station Blackout	3.7E-001	3.7E-001		No
PPR-SRV-CO-TRAN	PORVs Open During Transient	4.0E-002	4.0E-002		No
PPR-SRV-OO-1	PORV 1 Fails to Reclose After Opening	2.0E-003	0.0E+000	FALSE	Yes
PPR-SRV-OO-2	PORV 2 Fails to Reclose After Opening	2.0E-003	0.0E+000	FALSE	Yes
PPR-SRV-OO-SRVS	At Least One Safety Valve Fails to Reclose After Opening	0.0E+000	9.0E-002		Yes

Table B.5.2. Sequence Conditional Probabilities for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP–CDP)	Percent contribution[a]
TRANS	21	5.1E-005	7.2E-007	5.0E-005	54.9
LOOP	16	3.1E-005	4.5E-007	3.0E-005	33.3
LOOP	40	8.5E-006	1.2E-008	8.5E-006	9.2
TRANS	08	1.3E-006	8.1E-010	1.3E-006	1.4
Total (all sequences)		1.1E-004	1.6E-005	9.3E-005	

[a] Percent contribution to the total importance.

Table B.5.3. Sequence Logic for Dominant Sequences for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Event tree name	Sequence name	Logic
TRANS	21	/RT, AFW, MFW, F&B
LOOP	16	/RT-L, /EP, AFW-L, /OP-6H, F&B-L
LOOP	40	/RT-L, EP, /AFW-L, PORV-SBO, PRVL-RES
TRANS	08	/RT, /AFW, PORV, PORV-RES, HPI

Table B.5.4. System Names for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

System name	Logic
AFW	No or insufficient AFW flow
AFW-L	No or insufficient AFW flow during LOOP
EP	Failure of both trains of emergency power
F&B	Failure to provide feed-and-bleed cooling
F&B-L	Failure of feed-and-bleed cooling during a LOOP
HPI	No or insufficient flow from HPI system
MFW	Failure of the main feedwater system
OP-6H	Operator fails to recover off-site power within 6 h
PORV	PORVs open during transient
PORV-RES	PORVs fail to reseat
PORV-SBO	PORVs open during station blackout event
PRVL-RES	PORVs and block valves fail to reclose [electric power (EP) succeeds]
RT	Reactor fails to trip during transient
RT-L	Reactor fails to trip during LOOP

Table B.5.5. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 335/95-004, -005, -006 (PORV Unavailability)

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
TRANS Sequence 21		5.1E-005	
1	80.2	4.1E-005	AFW-XHE-XA-CST2, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	14.2	7.0E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.4	2.2E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
LOOP Sequence 16		3.1E-005	
1	79.0	2.4E-005	AFW-XHE-XA-CST2L, AFW-XHE-NOREC-L, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	13.9	4.4E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.3	1.3E-006	AFW-MOV-CF-SGALL, AFW-XHE-NOREC-L, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
LOOP Sequence 40		8.5E-006	
1	52.4	4.5E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
2	47.5	4.0E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-SRVS
TRANS Sequence 08		1.3E-006	
1	62.6	8.2E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-MDP-CF-ALL
2	34.7	4.5E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-MOV-CF-DISAL
3	1.6	2.2E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-SRVS, HPI-TNK-FC-RWST
Total (all sequences)		**1.1E-004**	

[a]The conditional probability for each cut set is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given

on a per-hour basis), and t is the duration time of the event (in this case, 5880 h). This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are:
$\lambda_{TRANS} = 4.0 \times 10^{-4}$/h and $\lambda_{LOOP} = 1.6 \times 10^{-5}$/h.

[b]Basic events PPR-SRV-CC-1 and PPR-SRV-CC-2 are type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

Table B.5.6. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event - Loss-of-Offsite Power	1.6E-005	0.0E+000		Yes
IE-SGTR	Initiating Event - Steam Generator Tube Rupture	1.6E-006	0.0E+000		Yes
IE-SLOCA	Initiating Event - Small Break Loss-of-Coolant Accident	1.0E-006	2.8E-002		Yes
IE-TRANS	Initiating Event - Transients	4.0E-004	0.0E+000		Yes
AFW-MOV-CF-SGALL	Common-Cause Failure of all Steam Generator Motor-Operated Valves	5.5E-005	5.5E-005		No
AFW-PMP-CF-ALL	Common-Cause Failure of all AFW Pumps	1.7E-004	1.7E-004		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6E-001	2.6E-001		No
AFW-XHE-XA-CST2	Operator Fails to Initiate Backup Water Source	1.0E-003	1.0E-003		No
HPI-MDP-CF-ALL	Common-Cause Failure of HPI Motor-Driven Pumps	1.0E-004	1.0E-004		No
HPI-MOV-CF-DISAL	Common-Cause Failure of all HPI Injection Valves	5.5E-005	5.5E-005		No
HPI-TNK-FC-RWST	Refueling Water Storage Tank and Water Supply Valve Failures	2.7E-006	2.7E-006		No
MFW-SYS-TRIP	MFW System Trips	2.0E-001	2.0E-001		No
MFW-XHE-NOREC	Operator Fails to Recover MFW	3.4E-001	3.4E-001		No
PPR-SRV-CC-1	PORV 1 Fails to Open on Demand	2.0E-003	1.0E+000	TRUE	Yes
PPR-SRV-CC-2	PORV 2 Fails to Open on Demand	2.0E-003	1.0E+000	TRUE	Yes
PPR-SRV-OO-1	PORV 1 Fails to Reclose After Opening	2.0E-003	0.0E+000	FALSE	Yes

Table B.5.6. Definitions and Probabilities for Selected Basic Events for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-SRV-OO-2	PORV 2 Fails to Reclose After Opening	2.0E-003	0.0E+000	FALSE	Yes
PPR-SRV-OO-SRVS	At Least One Safety Relief Valve Fails to Reclose After Opening	0.0E+000	9.0E-002		Yes
RPS-NONREC	Nonrecoverable Reactor Protection System Trip Failures	2.0E-005	2.0E-005		No

Table B.5.7. Sequence Conditional Probabilities for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
SLOCA	06	4.4E-006	78.6
SLOCA	23	6.1E-007	10.9
SLOCA	24	5.6E-007	10.0
Total (all sequences)		5.6E-006	

Table B.5.8. Sequence Logic for Dominant Sequences for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Event tree name	Sequence name	Logic
SLOCA	06	/RT, /AFW, HPI
SLOCA	23	/RT, AFW, MFW, F&B
SLOCA	24	RT

Table B.5.9. System Names for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

System name	Logic
AFW	No or insufficient AFW flow
F&B	Failure to provide feed-and-bleed cooling
HPI	No or insufficient flow from HPI system
MFW	Failure of the MFW system
RT	Reactor fails to trip during transient

Table B.5.10. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 335/95-004, -005, -006 (RCP Seal Leak)

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
SLOCA Sequence 06		4.4E-006	
1	62.6	2.8E-006	HPI-MDP-CF-ALL
2	34.7	1.5E-006	HPI-MOV-CF-DISAL
3	1.6	7.5E-008	HPI-TNK-FC-RWST
SLOCA Sequence 23		6.1E-007	
1	80.2	4.9E-007	AFW-XHE-XA-CST2, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
2	14.2	8.7E-008	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
3	4.4	2.7E-008	AFW-MOV-CF-SGALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1 (or PPR-SRV-CC-2)
SLOCA Sequence 24		5.6E-007	
1	100.0	5.6E-007	RPS-NOREC
Total (all sequences)		**5.6E-006**	

[a] The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probability of the initiating events are given in Table 6 and begin with the designator "IE." The probabilities for the basic events are also given in Table 6.

[b] Basic events PPR-SRV-CC-1 and PPR-SRV-CC-2 are type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

B.6 LER No. 336/95-002

Event Description: Containment sump isolation valves potentially unavailable due to pressure locking

Date of Event: January 25, 1995

Plant: Millstone 2

B.6.1 Event Summary

Northeast Utilities determined that the containment sump isolation valves at Millstone 2 were subject to pressure locking, which could preclude their operating following a loss of coolant accident (LOCA). This analysis assumes the pressure-locking problem would impact plant response to a large- and medium-break LOCA, and estimates an increase in the core damage probability (CDP) over a one-year period of 3.1×10^{-5}, over a nominal value for the same period of 4.6×10^{-5}. Uncertainty in the frequency of large- and medium-break LOCAs (neither of which have been observed) and in the impact of the pressure-locking problem contribute to a substantial uncertainty in this estimate.

B.6.2 Event Description

On January 25, 1995, Northeast Utilities determined that the containment sump isolation valves (valves 2-CS-16.1A and -16.1B) at Millstone 2 were subject to pressure locking, which could preclude their operating for sump recirculation following a LOCA (see Fig. B.6.1). Pressure locking is a phenomenon where water trapped in the bonnet cavity and in the space between the two disks of a parallel-disk gate valve is pressurized above the pressure assumed when sizing the valve's motor operator. This prevents the valve operator from opening the valve when required. Water can enter a valve bonnet during normal valve cycling or when a differential pressure moves a disk away from its seat, creating a path to either increase fluid pressure or fill the bonnet with high-pressure fluid. A subsequent increase in the temperature of the fluid in the valve bonnet will cause an increase in bonnet cavity pressure due to thermal expansion of the fluid.

Valves 2-CS-16.1A and -16.1B had initially been reviewed for pressure locking and thermal binding issues in December 1989. That review, in response to an Institute of Nuclear Power Operations (INPO) Significant Operating Events Report (SOER), was conducted by Stone and Webster and concluded that these valves were not susceptible to pressure locking or thermal binding.

In 1994, following an inspection of the Millstone 1 motor-operated valve (MOV) program by the NRC and in order to address a planned NRC Generic Letter (GL) on the pressure locking/thermal binding issue (GL 95-07), Raytheon Corporation was contracted by the licensee to perform a second analysis of all safety-related "GL 89-10" MOVs. Raytheon's final report, issued in October 1994, concluded that valves 2-CS-16.1A and -16.1B were susceptible to pressure locking.

A subsequent analysis by the valve vendor, Anchor Darling, determined that the maximum pressure lock that valves 2-CS-16.1A and -16.1B could overcome and still open was approximately 1.0 MPa (150 psi). Based on information provided in NUREG-1275, Vol. 9 (Ref. 2), an increase in bonnet temperature of about 3°C (5°F), if the bonnet were water solid, would cause this pressure.[a] Following a LOCA, water in the containment sump could reach 143°C (289°F). During the approximately 44 min before the initiation of sump recirculation, the hot water in the containment sump would easily heat the valve bonnet by the 3°C (5°F) required to pressure-lock the valve.

The licensee noted that the two containment sump isolation valves, as well as two downstream check valves (2-CS-15A and -15B) are subject to periodic surveillance testing. As a consequence of these tests, water tends to accumulate in the piping between the isolation valves (-16.1A/B) and the sump. This water may serve as an insulator, preventing hot sump water from reaching the isolation valves and minimizing the impact of the pressure locking condition. At the time Licensee Event Report (LER) No. 336/95-002 was written, check valve 2-CS-15A was being overhauled because the train A sump piping was found to be full of water. Evidence of water was also found in the train B piping. Further analysis by Raytheon concluded that if the sump piping was full of water, the temperature increase would only occur along the first 0.3 m (about 1 ft) of the filled pipe on the containment side.

The report of a special NRC inspection that was performed at the time of the event (Ref. 3) provides additional information concerning the testing of isolation valves 2-CS-16.1A and -16.1B and check valves 2-CS-15A and -15B, plus the arrangement and condition of the valves. Valves 2-CS-16.1A and -16.1B were cycled monthly to verify operability and measure valve opening time. When cycled, water that collected in the piping between the isolation and check valve [0.6 to 0.9 m of 61-cm pipe (2 to 3 ft of 24-in. pipe)] would flow into the longer containment piping, equalizing the water level upstream and downstream of the valves. Prior to each test, a vent valve between the isolation and associated check valve was opened to confirm that the check valve was not leaking excessively. If it was, the Refueling Water Storage Tank (RWST) was isolated from the Emergency Core Cooling System (ECCS) header during the valve test to minimize the amount of water that flowed into the containment.

Every three months, valves 2-CS-16.1A and -16.1B, and check valves 2-CS-15A and -15B were also tested to meet the inservice testing requirements of ASME Section XI. The piping between the two valves was filled with borated water by hose-jumpering around the check valve using two vent connections. A hose and rotameter was then connected from the Primary Makeup Water (PMW) system to the vent connection between the two valves and the piping was pressurized to the normal operating pressure of the PMW system [0.86–1.0 MPa (125–150 psi)]. Flow through the rotameter indicated the partial stroking of the check valve. This test, by filling and pressurizing the fluid volume between the valves, would tend to move the downstream (pressurized) isolation valve disk away from its seat, and fill and pressurize the valve bonnet. The isolation valves were also stroked, but the testing sequence (before or after the check valve test) was not specified. If the isolation valves were stroked before the check

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[a]Preliminary pressure-locking data from flexible wedge gate valve tests at the Idaho National Engineering Laboratory indicates that bonnet pressurization also occurs if small quantities of air are trapped in the bonnet, although at higher temperatures than for a water-solid condition (NRC memorandum from M.E. Mayfield to R.H. Wessman, June 25, 1996).

valves were tested, the piping between the two valves would have been left full of water following the check valve test.

A walkdown in conjunction with the inspection indicated that packing leakage had occurred on valves 2-CS-16.1A and -16.1B since the last packing change in 1992. This was indicated by boric acid crystals and rust in the packing gland areas of both valves. This leakage indicated that the valve bonnets had been filled with water at least some of the time since 1992. A closed 1984 work order for valve 2-CS-16.1B to be cleaned of boric acid crystals and for the valve packing to be tightened provides evidence of earlier water-filled valve bonnets.

In order to preclude pressure locking of valves 2-CS-16.1A and -16.1B, licensee personnel drilled a 0.3 cm (1/8 in.) diameter hole through the containment-side disk center line on these valves. These holes will prevent the volume between the two disks from pressurizing.

B.6.3 Additional Event-Related Information

Following a LOCA, the containment sump collects water from the break in the reactor coolant system, (RCS), the safety injection systems, and the containment spray system. After water in the refueling water storage tank (RWST) is depleted, the containment sump provides a source of recirculation water for continued decay heat removal and containment spray. Upon receipt of a sump recirculation actuation signal (SRAS), at 9.5% RWST level, the high-pressure and low-pressure safety injection (HPSI and LPSI) pumps and the containment spray pump suctions are automatically transferred to the containment sump by the opening of valves 2-CS-16.1A and -16.1B. The SRAS also trips the LPSI pumps to maximize the net positive suction head to the HPSI pumps and the containment spray pumps. HPSI pump flow provides decay heat removal following sump switchover.

The containment "sump" at Millstone 2 is actually the floor of the containment, and not a separate pit below the containment floor. Two 61-cm (24-in.) diameter pipes, which protrude approximately 28 cm (11 in.) above the floor, drop vertically about 1.5 m (5 ft), and then run almost horizontally, with a slight downward slope, about 6.1 m (20 ft) to valves 2-CS-16.1A and -16.1B. Check valves CS-15A and -15B are located 0.6–0.9 m (2–3 ft) downstream of the isolation valves (Fig. B.6.2).

B.6.4 Modeling Assumptions

This analysis assumes that sump isolation valves 2-CS-16.1A and -16.1B would be unavailable due to pressure locking following a large-break LOCA, and possibly following a medium-break LOCA, for those periods during which the valve bonnets were filled with water prior to drilling holes in the containment-side disks. Both of these LOCAs rapidly deplete the RWST and provide little time for thermal equilibration and valve bonnet depressurization which would permit initially pressure-locked isolation valves to operate. However, switchover to sump recirculation following a small-break LOCA occurs after about 6 h; this time is assumed to be adequate to allow the valve bonnets to depressurize to the point that the valves will operate correctly.

The valve bonnets for valves 2-CS-16.1A and -16.1B were assumed to be filled with water following the quarterly tests of 2-CS-15A and -15B, during which the PMW system was used to fill and pressurize the pipe section between each isolation and check valve. Reference 3 notes that the isolation valve vendor, Anchor/Darling had concluded that a closing thrust of 12,580 N (91,000 pounds) would be required to seal the isolation valve disk against a pressure of 45 psig (a conservative estimate of the pressure the RWST head would impose on the valve disk). With a valve actuator maximum thrust of 6,220 N (45,000 pounds) [approximately one-half of the required closing thrust for 0.31 MPa (45 psig)] and an actuator torque switch trip point one-half again of the required value, it is reasonable to assume that the isolation valve disk would move away from its seat during the 0.86–1.0 MPa (125–150 psi) PMW system pressurization imposed during the tests on check valves 2-CS-15A and -15B. This disk movement would allow water to enter the space between the isolation valve disks and, with leaking packing, the isolation valve bonnet. Once a bonnet was filled with water, minor leakage past the normally-closed check valve would be sufficient to maintain the bonnet full of water.

Filled valve bonnets were assumed to remain filled until an isolation valve was cycled. When the valve was cycled, water in the bonnet and between the check valve and the isolation valve would flow into the sump piping in the containment, equalizing the water levels on both sides of the isolation valve. Evaporation[b] would gradually reduce the volume of water in the sump piping. This would explain why only evidence of water (boric acid crystals) was found in the B train piping, and not a large volume of water (the large quantity of water found in the A train piping was the result of excessive check valve leakage). Because check valves 2-CS-15A and -15B were tested quarterly and valves 2-CS-16.1A and -16.1B were cycled monthly, the valve bonnets would normally (without the excessive check valve leakage) be expected to be filled with water one-third of the time if the isolation valves were always cycled before the check valves were tested. Although no requirement was placed on the sequence of testing, the isolation valves (2-CS-16.1A and -16.1B) were typically cycled after the check valve tests (2-CS-15A and -15B) most of the time.[c] Assuming this occurred in 75% of the tests reduces the estimated fraction of time during which the sump isolation valves were subject to pressure locking to one-twelfth. (If the sump valves had always been tested after the check valves, the potential for pressure locking would be significantly reduced, or perhaps eliminated. Pressure locking of the isolation valves would only be possible under these conditions if a substantial leak path exists past both the check valve disk and the isolation valve bonnet.)

The impact of partially-filled sump piping (evidence of past water in the B train sump piping was described in the LER), caused by monthly isolation valve cycling, on reducing the potential for pressure locking was considered to be minor and was not addressed. The piping arrangement at Millstone 2 (see Additional Event-Related Information) prevents water from entering the sump piping until the containment water level reaches 28 cm (11 in.). At this point, hot water will drop into the vertical sump

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[b]Following the discovery of the potential for pressure-locking and the drilling of holes in the downstream disks, the licensee began to bypass the check valve and fill the sump piping to provide an insulating barrier against the hot sump water that would exist following a LOCA. This process is performed monthly to ensure that evaporation to the containment will not significantly reduce the volume of water in the sump piping [personal communication, D. Beaulieu (NRC) and J. Minarick (SAIC), July 26, 1996].

[c]Personal communication, M. Buckley (NRC) and J. Minarick (SAIC), February 21, 1997.

piping segment and rapidly fill the piping. The turbulence that results is expected to mix the hot containment water with the water in the partially-filled sump pipes, exposing the sump isolation valves to temperatures well above ambient.[d] However, the excessive amount of water that apparently existed in the train A sump piping due to leakage past check valve 2-CS-15A is believed to have provided an insulating barrier for MOV 2-CS-16.1A for part of the one-year period prior to discovery of the pressure locking problem (one year is the longest unavailability period used in an ASP analysis). During the time that water in the train A sump piping insulated 2-CS-16.1A, the potential impact of sump valve pressure locking was minimal (an increase in CDP less than the ASP screening value of 1×10^{-6} is calculated).

Reference 3 notes that 2-CS-15A leaked excessively during a test on December 8, 1993, when water completely filled the train A sump piping, as evidenced by an increase in containment sump level. No further incidents of gross check valve leakage were identified. In early 1995, when the sump valves and piping were inspected, the water level in the train A pipe was found to be at the top of the 2-CS-16.1A disk (because of the slight upward slope of the sump lines towards containment, the water only partially filled the horizontal pipe). The reduction in water level since December 8, 1993, is assumed to have been caused by evaporation. This reduction is reasonably consistent with a licensee estimate of the evaporation rate in the sump piping, performed to support a strategy of maintaining the sump lines full of water to prevent pressure locking (described in footnote b), and submitted as a part of Reference 4 (calculation GL89-10-1243 M2, Rev. 1).

Following the December 8, 1993, check valve leakage, when the sump piping was completely filled, MOV 2-CS-16.1A would be protected from heatup during a LOCA. At some time thereafter, as water in the sump piping evaporated, the MOV would become susceptible to pressure locking. Licensee memorandum NE-95-SAB-297, dated July 26, 1995, and also included in Reference 4, concluded that the water level in the sump piping should be maintained above −7.3 m (−24 ft) [0.6 m (2 ft) below the top of the vertical sump piping shown in Figure B.6.2] to eliminate the potential formation of thermal diffusive currents, which could cause sump valve heatup and pressure locking following a LOCA. The licensee estimated that water in a completely full sump pipe would evaporate to −7.3 m (−24 ft) in about 106 d. Applying this estimate in this analysis, 2-CS-16.1A, and, therefore, both 2-CS-16.1A and -16.1B, were assumed to be potentially vulnerable to pressure locking for [1 − (106/365)], or 0.71 of the one-year period prior to discovery. Combining this value with the fraction of time the valves were considered subject to pressure locking based on the testing regimen at Millstone 2, 0.083, results in an overall estimate of 0.059.

The Accident Sequence Precursor (ASP) Program typically considers the potential for core damage following four postulated initiating events in pressurized water reactors: transient, loss of offsite power (LOOP), small-break LOCA, and steam generator tube rupture (SGTR). Supercomponent-based linked fault tree models are available for each of these postulated initiating events. The two initiating events that are of concern in this analysis (i.e., large- and medium-break LOCAs) are not currently modeled. However, for both of these initiating events, unavailability of sump recirculation is assumed to result in core damage in all probabilistic risk assessments.

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[d]A simple mixing calculation, without consideration of the sump piping as a heat sink, supports an assumption that the sump piping would have to be initially almost full to preclude a substantial temperature increase.

The significance of this event was estimated by first considering the increase in CDP over the unavailability period. Since a nonrecoverable failure of valves 2-CS-16.1A and -16.2B will fail both high- and low-pressure recirculation, and recirculation is required following a medium- or large-break LOCA, the significance of the event can be estimated directly from the change in the probability of recirculation failure and the probability of a medium- and large-break LOCA in the unavailability period.

During the time period that valves 2-CS-16.1A and -16.1B were assumed to be subject to pressure locking, this pressure-locking condition was assumed to prevent the valves from opening for sump recirculation following a large-break LOCA (LBLOCA). Sump recirculation would be initiated by an SRAS signal about 44 min after the break, allowing little time for bonnet depressurization. The RWST would be empty about 4 min later, allowing little time for corrective action.

Following a medium-break LOCA (MBLOCA), the condition of the valves is considered indeterminate. Additional time (well over 1 h) exists before the RWST is depleted, and this time may allow for depressurization of at least one of the valve bonnets to the point that the valve will operate. For a medium-break LOCA, a sump isolation valve failure probability of 0.5 was assumed, given the pressure-locking condition existed.

The frequency of a large-break LOCAs is estimated to be 2.7×10^{-4}/yr, while that of a medium-break LOCA is estimated to be 5.0×10^{-4}/yr. These values are based on a survey of large- and medium-break LOCA frequencies performed in support of the analysis of Turkey Point LER 250/94-005 in the 1994 precursor report (see Appendix H to Ref. 5 for additional information).

The increase in core damage probability due to LBLOCAs and MBLOCAs based on these initiating event frequencies and the assumed probability of pressure locking are given below. The probability of core damage due to a LBLOCA is

$$2.7 \times 10^{-4} \begin{Bmatrix}\text{prob of a LBLOCA} \\ \text{over a 1-yr period}\end{Bmatrix} \times 0.059 \begin{Bmatrix}\text{prob that pressure-} \\ \text{lock condition exists}\end{Bmatrix} \times$$

$$\left[1.0 \begin{Bmatrix}\text{prob of sump recirc failure} \\ \text{due to press-locked valves}\end{Bmatrix} - 2.6 \times 10^{-4} \begin{Bmatrix}\text{nominal failure prob} \\ \text{for two sump valves}\end{Bmatrix} \right]$$

$$= 1.6 \times 10^{-5} \begin{Bmatrix}\text{increase in core damage} \\ \text{prob due to a LBLOCA}\end{Bmatrix}.$$

The probability of core damage due to a MBLOCA is

$$5.0 \times 10^{-4} \begin{Bmatrix}\text{prob of a MBLOCA} \\ \text{over a 1-yr period}\end{Bmatrix} \times 0.059 \begin{Bmatrix}\text{prob that pressure-} \\ \text{lock condition exists}\end{Bmatrix} \times$$

$$\left[0.5 \begin{Bmatrix}\text{prob of sump recirc failure} \\ \text{due to press-locked valves}\end{Bmatrix} - 2.6 \times 10^{-4} \begin{Bmatrix}\text{nominal failure prob} \\ \text{for two sump valves}\end{Bmatrix} \right]$$

$$= 1.5 \times 10^{-5} \begin{Bmatrix}\text{increase in core damage} \\ \text{prob due to a MBLOCA}\end{Bmatrix}.$$

B.6.5 Analysis Results

Combining the estimates for large- and medium-break LOCAs results in an estimated increase in the CDP because of the sump isolation valve pressure locking over a 1-year period of 3.1×10^{-5}. The dominant core damage sequences for these events involve

- a postulated large-break or medium-break LOCA and
- the failure of high-pressure recirculation.

The dominant sequence for a large-break LOCA is highlighted on the event tree in Figure B.6.3. A similar sequence exists for the medium-break LOCA.

A greater than usual uncertainty is associated with this estimate. This uncertainty is dominated by the uncertainties in the frequencies of large- and medium-break LOCAs (neither of which have occurred) and by uncertainties in the assumptions regarding the inoperability of the sump isolation valves because of the pressure-locking problem.

The nominal CDP over a one-year period estimated using the ASP Integrated Reliability and Risk Analysis System (IRRAS) models for Millstone 2 is 4.6×10^{-5}. The increase in the CDP because of the unavailable sump isolation valves (3.1×10^{-5}) was added to the nominal CDP for a one-year period (4.6×10^{-5}) to estimate a CCDP of 7.7×10^{-5} for the one-year period prior to discovery of the pressure locking problem. For earlier one-year periods, when 2-CS-15A was not leaking excessively, the CCDP for the event would not be affected by the flooded train A sump piping. For such periods, a CCDP of 8.9×10^{-5} would be estimated.

Section 6.3.3.1 of the Millstone 2 FSAR states that during normal operation the containment sump recirculation lines between the sump isolation valves and the HPSI pumps will be filled with stagnant water, while portions between the sump inlets and the sump valves will not be filled with water. As described in the Event Description, piping downstream of the isolation valves was not maintained full of water following valve testing, and water was allowed to accumulate in the sump piping upstream of the isolation valves. If the licensee had taken measures to adhere to the FSAR statement, the isolation valves would most likely have been subject to pressure locking at all times. This would have increased the CCDP associated with the event to 5.7×10^{-4}.

B.6.6 References

1. LER 336/95-002, Rev. 1, "Containment Sump Isolation Valves—Potentially Subject to Pressure Locking," July 7, 1995.

2. *Operating Experience Feedback Report—Pressure Locking and Thermal Binding of Gate Valves*, NUREG-1275, Vol. 9, March 1993.

3. "Millstone 2 Motor-Operated Valve Inspection," NRC Special Inspection Report 50-336/95-08, U.S. Nuclear Regulatory Commission, March 22, 1995.

4. "Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," Response to Request for Additional Information," letter from T. C. Feigenbaum, Northeast Utility Services Company, to U. S. Nuclear Regulatory Commission, August 7, 1996.

5. *Precursors to Potential Severe Core Damage Accident Sequences: 1994, A Status Report*, NUREG/CR-4674, Vol. 21, December 1995.

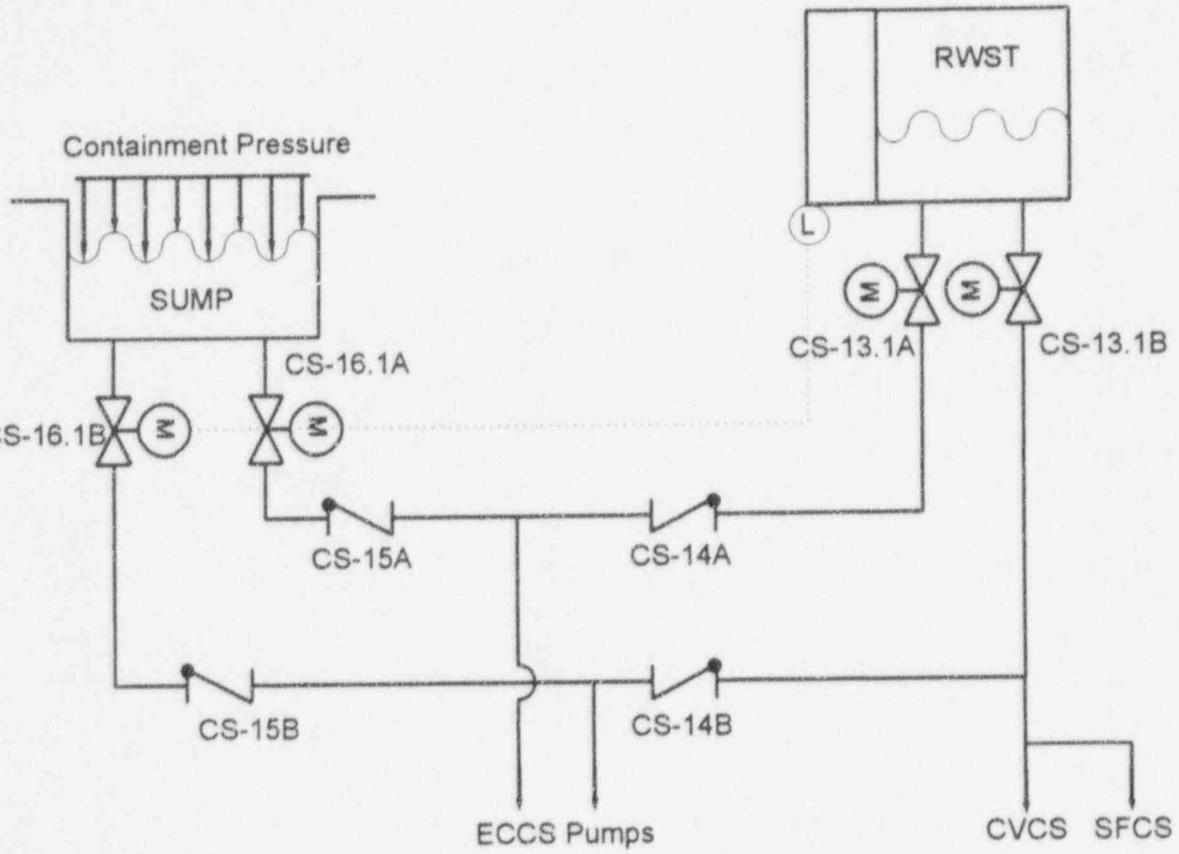

Fig. B.6.1. Containment Sump/RWST Configuration for Millstone 2 (Source: *Millstone 2 Individual Plant Examination*).

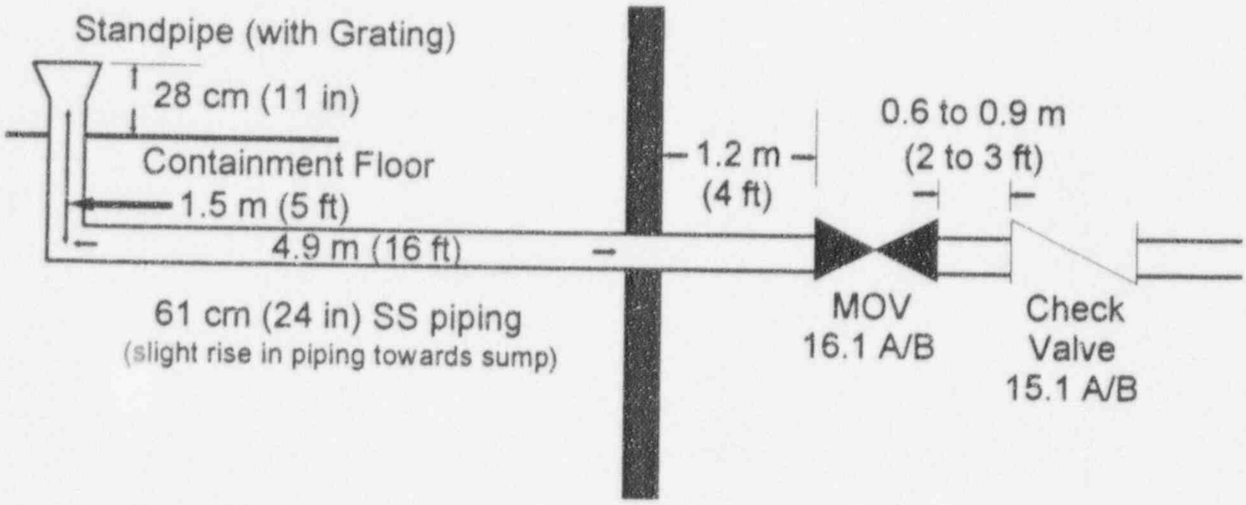

Fig. B.6.2. Millstone Unit 2 Containment Sump Piping (Source: "Millstone 2 Motor-Operated Valve Inspection," NRC Special Inspection Report 50-336/95-08, March 22, 1995).

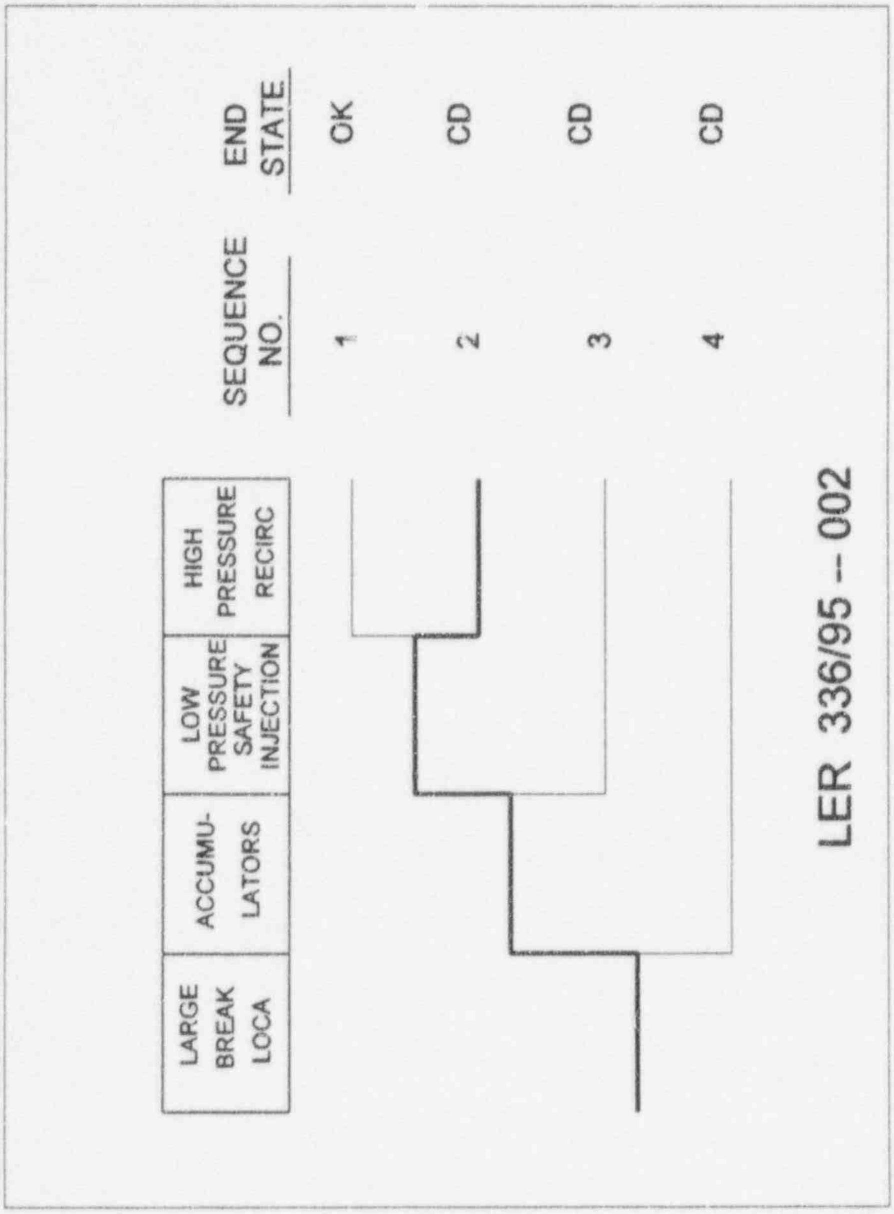

Fig. B.6.3. Dominant core damage sequence for LER No. 336/95-002.

B.7 LER No. 352/95-008

Event Description: Safety/relief valve fails open, reactor scram, suppression pool strainer fails

Date of Event: September 11, 1995

Plant: Limerick 1

B.7.1 Event Summary

Limerick Unit 1 was manually scrammed from 100% power after a safety/relief valve (SRV) failed open. Residual heat removal (RHR) pump A was in the suppression pool cooling (SPC) mode of operation and was being used to remove heat from the suppression pool to compensate for various SRV steam leaks when an SRV failed open, forcing the manual scram. RHR pump A was secured and declared inoperable after oscillations in the pump motor current and decreasing pump flow were observed. Subsequent examination revealed that the pump suction strainer had become obstructed with debris from the suppression pool. The conditional core damage probability (CCDP) estimate for the one-year potential unavailability of the Emergency Core Cooling Systems (ECCS) dependent upon the suppression pool is 1.3×10^{-5}. This is an increase of 9.0×10^{-6} over the nominal core damage probability (CDP) of 4.0×10^{-6} for the same period. The CCDP for the actual transient event is 2.5×10^{-6}.

B.7.2 Event Description

Limerick 1 was operating at 100% power at 1245 on September 11, 1995, when SRV "M" failed open. When plant operators were unable to reclose the valve within 2 min, they manually scrammed the reactor in accordance with technical specification requirements. At the time of the SRV failure, RHR pump A was in service to remove heat from the suppression pool to compensate for various SRV steam leaks.

After the scram, operators aligned RHR B pump for SPC as well. At 1307, the pressure in the reactor had decreased from 6.930 to 2.83 MPa (1005 psig to 410 psig). Even though a closed indication was received for the "M" SRV, reactor pressure continued to decrease. Typically, Technical Specifications for boiling water reactors (BWRs) require a controlled depressurization if the temperature in the suppression pool exceeds 49°C (120°F). In such a case, the cooldown rate is typically limited to less than 38°C/h (100°F/h). During this event, however, the uncontrolled depressurization resulted in a cooldown rate of approximately 54°C/h (130°F/h) and the temperature in the suppression pool peaked at 51°C (124°F).

At 1320, operators observed a decrease and fluctuations in flow from the A RHR pump as well as oscillations in its motor current. Operators, attributing these signs to suction strainer fouling, secured the A RHR pump and declared it inoperable. After it was checked, the A pump was restarted but at a reduced flow rate of 7570 l/m (2000 gpm). No problems were observed so the flow rate was gradually increased to 32,170 l/m (8500 gpm) and no problems were observed. A pressure gauge located on the pump suction was observed to have a gradually lower reading, which was believed to be indicative of an increased pressure drop across the pump suction strainers located in the suppression pool (Ref. 2). At 0227 on September 12, 1995, reactor pressure was reduced below 0.52 MPa (75 psig), with one loop of shutdown cooling in service. By 0430, the unit was in cold shutdown with a reactor coolant temperature of 90°C (194°F).

B.7.3 Additional Event-Related Information

SRV "M" was removed and sent to a laboratory for testing, where it was found to have been damaged by steam erosion of the pilot valve seat. Failure of the pilot valve caused a pressure differential across the SRV main disk, which resulted in spurious operation of the main SRV valve. The SRV was reported to have been leaking for more than a year before its failure. Four other SRVs were found to have seat damage and were also replaced.

During an inspection of the A RHR pump suction strainer assembly, a mat of brown, fibrous material and a sludge of oxide corrosion products were found covering most of the assembly. The sludge material was determined to have come from the suppression pool. Upon inspection, personnel discovered that most of the suction strainer assembly for the B RHR pump was covered with a thinner layer of the same material. However, the B RHR pump ran normally during and after the event. The other strainers in the suppression pool for the pumps which were not employed during this event also had minor sludge accumulations. Limerick concluded that the blowdown caused by the SRV opening did not significantly increase the rate of debris accumulation on the strainer. Approximately 635 kg (1,400 lb) of debris (wet weight, dry weight would be less) were removed from the suppression pool. A similar amount of material had been removed previously from the Unit 2 suppression pool.

B.7.4 Modeling Assumptions

Two assessments were required to analyze this event. First, a transient event assessment was performed to analyze the actual event. Second, a condition assessment was performed because of the prolonged potential unavailability of those ECCS systems which are dependent on the suppression pool.

Transient event assessment

This event was modeled as a scram with one SRV failed open and one train of RHR unavailable in all modes except SDC because train A of RHR was declared inoperable and secured when debris from the suppression pool clogged its suction strainer. Similar debris was found on other strainers, and 635 kg (1,400 lb) of debris (wet weight) were later removed from the suppression pool. Reference 4 indicates that, under some circumstances, debris could have migrated and caused obstruction of additional pump strainers. This effect could depend on a number of factors, including the amount of suppression pool agitation caused by shock waves from SRV discharge; the amount of debris in the suppression pool; which specific pumps were placed in service; what flow rates were demanded; how long the pumps were operated, etc.

The potential for common-cause failure of all strainers was modeled by adding an additional basic event to the model for each appropriate system. The event "RHRSTRAINERS" was added to the suppression pool cooling models (SPC, SPC/L), the low pressure coolant injection models (LCI/L), and the containment spray system models (CSS/L). In addition, this event was added to the low pressure core spray system models (LCS/L),as core spray is also dependent upon the suppression pool for water. No change was made to the high pressure coolant injection (HPCI) or reactor core isolation cooling (RCIC) system models, which may take suction from the suppression pool, because these systems also are provided with an alternate water supply from the condensate storage system.

The CCDP calculated for this event is dependent upon assumptions made regarding the likelihood that the foreign matter in the suppression pool could cause failure of additional ECCS pumps. Research cited in Reference 4 indicates that the debris concentrations present in the Limerick suppression pool 635 kg sludge/3,780 m^3 suppression pool water volume × 1,008 kg/m^3 = 0.02% wt % sludge) were easily sufficient to obstruct multiple ECCS system strainers. Based on Reference 5, a common-cause strainer failure probability of 0.135 was used in the analysis because the A train of RHR had operated over an extended period for SPC, during which time the strainer was believed to have clogged gradually. A sensitivity analysis also was performed, assuming a common-cause strainer failure probability of 1.0.

Condition assessment

In addition to the analysis of the reported transient event, an analysis was made of the prolonged potential unavailability of the ECCS systems that are dependent upon the suppression pool for water. The debris in the suppression pool was assumed to have been present throughout the operating year (6,132 h, assuming a 70% availability), and it was assumed to have the potential to cause failure of LCI, LCI/L, LCS/L, SPC/L, and CSS/L. This event was modeled with one train of RHR unavailable because, during an actual demand, train A of RHR was declared inoperable and secured when debris from the suppression pool clogged its suction strainer. A common-cause strainer failure probability of 0.135 was used in this analysis (RHRSTRAINERS), and a sensitivity case was evaluated for a common-cause failure probability of 1.0. Potential recovery of the power conversion system (PCS) was credited with event PCS-LONG, as it was in the transient assessment.

B.7.5 Analysis Results

The CCDP estimate for the one-year potential unavailability of ECCS systems dependent upon the suppression pool is 1.3×10^{-5}. This is an increase of 9.0×10^{-6} over the nominal CDP for the same period of 4.0×10^{-6}. The CCDP for the actual transient event is 2.5×10^{-6}. In both cases, the dominant sequence, highlighted as sequence number 4 on the event tree in Fig.B.7.1, involves

- the reactor successfully scrams,
- the PCS initially fails,
- RHR system fails,
- personnel fail to recover PCS in the long term, and
- containment venting fails.

Sequence number 4 is still the dominant sequence if a common-cause strainer failure probability of 1.0 is assumed (versus the 0.135 probability used for the actual event analysis). A CCDP of 7.1×10^{-5} with an importance of 6.7×10^{-5} is estimated for the long-term unavailability of the ECCS. The importance increased 7 times for this sensitivity analysis (from 9.0×10^{-6} to 6.7×10^{-5}). The CCDP for the sensitivity analysis for the transient event is 1.4×10^{-5}, or an increase of about 6 times over the CCDP for the actual transient event of 2.5×10^{-6}.

It should be noted that main feedwater success coincident with PCS failure is possible in the Limerick model because some failures that render the PCS incapable of functioning as a sink for reactor decay heat do not render it incapable of supporting main feedwater (e.g., turbine trips or load rejections with failures of the turbine bypass valves).

Definitions and probabilities for selected basic events are shown in Table B.7.1. Table B.7.2 describes the system names associated with the dominant sequences for both the condition assessment and the initiating event assessment. The conditional probabilities associated with the highest probability sequences for the condition assessment are shown in Table B.7.3. Table B.7.4 lists the sequence logic associated with the sequences listed in Table B.7.3. Minimal cut sets associated with the dominant sequences for the *condition assessment* are shown in Table B.7.5. The conditional probabilities associated with the highest probability sequences for the initiating event assessment are shown in Table B.7.6. Table B.7.7 lists the sequence logic associated with the sequences in Table B.7.6. Minimal cut sets associated with the dominant sequences for the *initiating event assessment* are shown in Table B.7.8.

B.7.6 References

1. LER 352/95-008 from PECO Energy to U.S. Nuclear Regulatory Commission, "Unusual Event and RPS Actuation When the Reactor was Manually Shutdown Due to the Inadvertent Opening of a Main Safety Relief Valve Caused by Pilot Valve Seat Leakage," October 10, 1995.

2. NRC Bulletin 95-02, "Unexpected Clogging of a Residual Heat Removal (RHR) Pump Strainer While Operating in a Suppression Pool cooling Mode," U.S. Nuclear Regulatory Commission, October 17, 1995.

3. NRC Information Notice 95-47, "Unexpected Opening of a Safety/Relief Valve and Complications Involving Suppression Pool Cooling Strainer Blockage," U.S. Nuclear Regulatory Commission, October 4, 1995.

4. Zigler, et al., *Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris*, NUREG/CR-6224, Science and Engineering Associates for U.S. Nuclear Regulatory Commission, 1995.

5. *Common-Cause Failure Data Collection and Analysis System*, Vol. 6, "Common-Cause Failure Parameter Estimations," INEL-94/0064, Marshall and Rasmuson, Idaho National Engineering Laboratory for U.S. Nuclear Regulatory Commission, 1995.

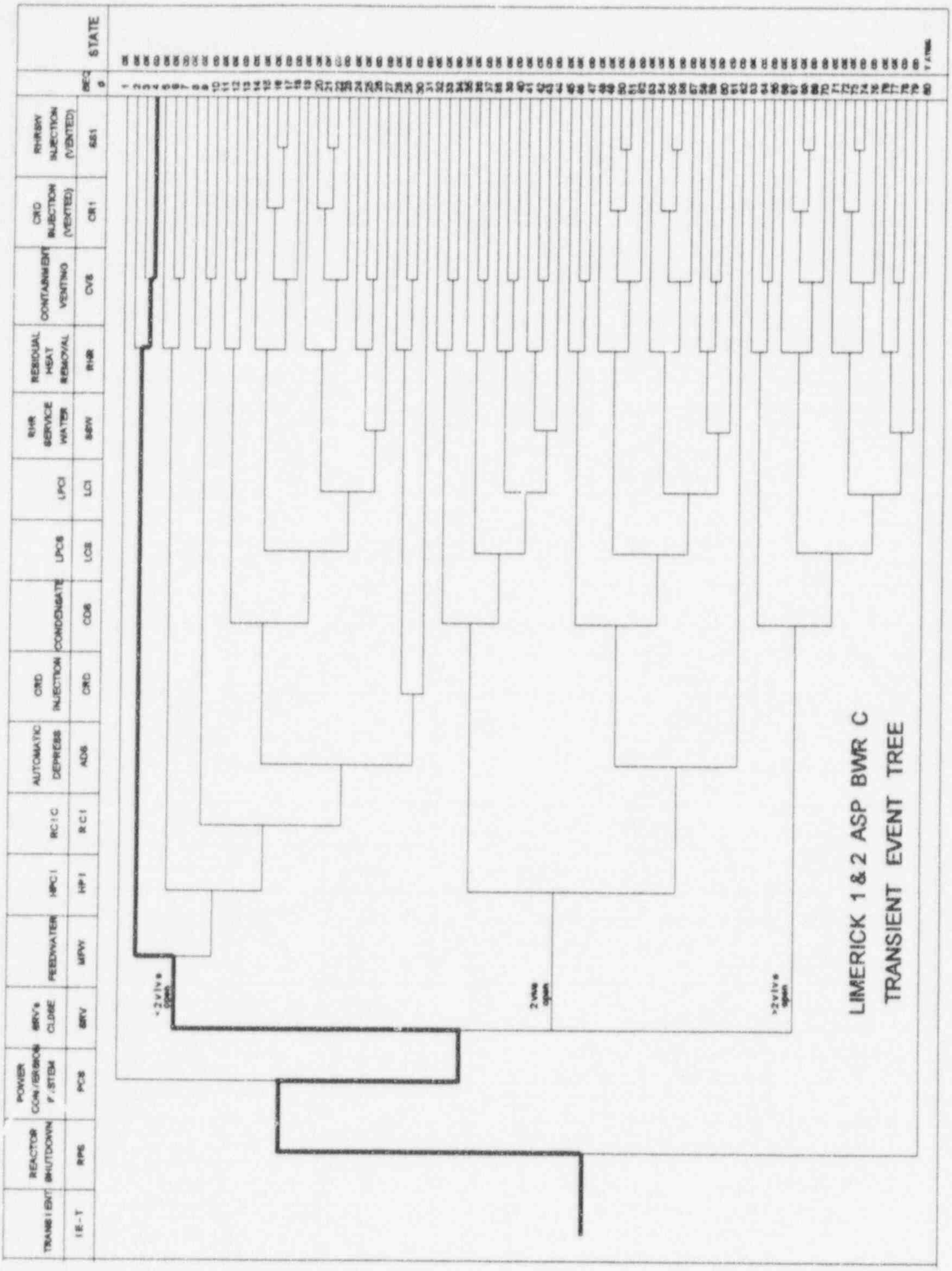

Fig. B.7.1. Dominant core damage sequence for the initiating event assessment and the condition assessment for LER No. 352/95-008.

Table B.7.1. Definitions and Probabilities for Selected Basic Events for LER No. 352/95-008

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-TRAN	Transient Initiator	4.5 E-004	1.0 E+000		Yes[a]
ADS-SRV-CC-VALVS	Automatic Depressurization System (ADS) Valves Fail to Open	3.7 E-003	3.7 E-003		No
ADS-XHE-XE-ERROR	Operator Error Prevents Depressurization	1.0 E-002	1.0 E-002		No
ADS-XHE-XE-NOREC	Operator Fails to Recover ADS	7.1 E-001	7.1 E-001		No
AD1-XHE-XE-ERROR	Operator Fails to Inhibit ADS and Control Level	1.0 E-002	1.0 E-002		No
CDS-SYS-VF-COND	Condensate Hardware Components Fail	3.4 E-001	3.4 E-001		No
CDS-XHE-XE-NOREC	Operator Fails to Recover Condensate	1.0 E+000	1.0 E+000		No
CVS-XHE-XE-VENT	Operator Fails to Vent Containment	1.0 E-002	1.0 E-002		No
EPS-DGN-FC-DGC	Diesel Generator Failure	1.9 E-002	1.9 E-002		No
EPS-XHE-XE-NOREC	Operators Fail to Recover Electric Power System	5.0 E-001	5.0 E-001		No
HCI-TDP-FC-TRAIN	HPCI Train Level Failures	8.6 E-002	8.6 E-002		No
HCI-XHE-XE-NOREC	Operator Fails to Recover HPCI	7.0 E-001	7.0 E-001		No
LCI-MOV-CC-LOOPB	Low Pressure Coolant Injection (LPCI) Train B Injection Valves Fail to Open	3.1 E-003	3.1 E-003		No
LCI-XHE-XE-NOREC	Operator Fails to Recover LPCI	1.0 E+000	1.0 E+000		No
LCS-XHE-XE-NOREC	Operator Fails to Recover Low Pressure Core Spray System	1.0 E+000	1.0 E+000		No
MFW-SYS-VF-FEEDW	Main Feedwater System (MFW) Hardware Components Fail	4.6 E-001	4.6 E-001		No
MFW-XHE-XE-NOREC	Operators Fail to Recover MFW	3.4 E-001	3.4 E-001		No
PCS-LONG	Operators Fail to Recover the PCS in the Long Term	3.9 E-001	3.9 E-001	NEW	No
PCS-SYS-VF-MISC	PCS Hardware Components Fail	1.7 E-001	1.7 E-001		No
PCS-XHE-XE-NOREC	Operator Fails to Recover PCS	1.0E+000	1.0 E+000		No

Table B.7.1. Definitions and Probabilities for Selected Basic Events for LER No. 352/95-008

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-SRV-OO-1VLV	One or Less SRVs Fail to Close	1.0 E+000	1.0 E+000	TRUE	Yes[a]
PPR-SRV-OO-2VLVS	Two SRVs Fail to Close	2.0 E-003	0.0 E+000	FALSE	Yes[b]
PPR-SRV-OO-3VLVS	More Than Two SRVs Fail to Close	2.0 E-004	0.0 E+000	FALSE	Yes[b]
RCI-TDP-FC-TRAIN	RCIC Train Component Failures	8.3 E-002	8.3 E-002		No
RCI-XHE-XE-NOREC	Operator Fails to Recover RCIC	7.0 E-001	7.0 E-001		No
RHR-MDP-CF-MDPS	Common-Cause Failure of RHR Pumps	3.0 E-004	3.0 E-004		No
RHR-MDP-FC-TRNA	RHR Train A Components Fail	3.8 E-003	1.0 E+000	TRUE	Yes[c]
RHR-MOV-OO-BYPSB	RHR Loop B Valve to Bypass Heat Exchangers Fails	3.0 E-003	3.0 E-003		No
RHRSTRAINERS	Common-Cause Failure of All Strainers	0.0 E+000	1.4 E-001	NEW	Yes[c]
RPS-NONREC	Nonrecoverable Reactor Protection System (RPS) Trip System Failures	2.0 E-005	2.0 E-005		No
RPS-SYS-FC-MECH	Mechanical Failures of the RPS	1.0 E-005	1.0 E-005		No
RRS-XHE-XE-ERROR	Operator Fails to Trip the Recirculation Pumps	1.0 E-002	1.0 E-002		No
SDC-MOV-CC-SUCT	Shutdown Cooling System (SDC) Suction Valves Fail to Open	6.0 E-003	6.0 E-003		No
SDC-XHE-XE-ERROR	Operator Fails to Align/Actuate the SDC	1.0 E-002	1.0 E-002		No
SDC-XHE-XE-NOREC	Operator Fails to Recover the SDC	1.0 E+000	1.0 E+000		No
SLC-CKV-CC-INJEC	The Injection Check Valves in the Standby Liquid Control System (SLC) Fail	2.0 E-004	2.0 E-004		No
SLC-EPV-CF-VALVS	The Explosive Valves in the SLC Fail From Common Cause	2.6 E-004	2.6 E-004		No

Table B.7.1. Definitions and Probabilities for Selected Basic Events for LER No. 352/95-008

Event name	Description	Base probability	Current probability	Type	Modified for this event
SLC-MDP-CF-MDPS	The Motor-Driven Pumps in the SDC Fail From Common Cause	6.3 E-004	6.3 E-004		No
SLC-XHE-XE-ERROR	Operator Fails to Start/Control the SDC	1.0 E-002	1.0 E-002		No
SLC-XHE-XE-NOREC	Operator Fails to Recover SDC	1.0 E+000	1.0 E+000		No
SRV	One or Less SRVs Fail to Close	2.2 E-003	2.2 E-003		No
SSW-MOV-CC-FLOOD	Valve Fails to Open	6.1 E-003	6.1 E-003		No
SSW-XHE-XE-ERROR	Operator Fails to Align RHR Service Water	1.0 E-002	1.0 E-002		No
SSW-XHE-XE-NOREC	Operator Fails to Recover RHR Service Water	1.0 E+000	1.0 E+000		No

[a]Applicable to the initiating event assessment only.
[b]The probability was set to 0.0 E+000 (FALSE) for the initiating event assessment. For the conditional event assessment, the base probability was not changed in the model.
[c]The base probability was changed for both the initiating event assessment and the conditional event assessment.

Table B 7.2. System Names for LER No. 352/95-008

System name	Logic
AD1	Failure to Inhibit ADS and Control Reactor Level
ADS	Automatic Depressurization Fails
CDS	Failure of the Condensate System
CVS	Containment (Suppression Pool) Venting
EPS	Emergency Power System Fails
HCI	HPCI Fails to Provide Sufficient Flow to the Reactor Vessel
LCI	LPCI Fails
LCIL	LPCI Fails During a LOOP
LCS	Low Pressure Core Spray (LPCS) Fails
LCSL	LPCS Fails During a LOOP
MFW	Failure of the MFW System
P2	Two SRVs Fail to Close
PCS	PCS Fails
RCI	RCIC Fails to Provide Sufficient Flow to RCS
RHRL	RHR System Fails During a LOOP
RHRPCS	RHR System Fails
RP1	Reactor Shutdown Fails
RPS	RPS Fails
RRS	Recirculation Pump Trip
SLC	SLC System Fails
SRV	One or Less SRVs Fail to Close
SSW	RHR Service Water Makeup Fails
SSWL	RHR Service Water Makeup Fails During a LOOP

Table B.7.3. Sequence Conditional Probabilities for the Condition Assessment for LER No. 352/95-008

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP-CDP)	Percent contribution[a]
TRANS	04	4.6 E-006	5.7 E-007	4.0 E-006	44.6
LOOP	03	1.9 E-006	2.4 E-007	1.7 E-006	19.1
TRANS	44	8.3 E-007	0.0 E+000	8.3 E-007	9.2
LOOP	20	7.2 E-007	0.0 E+000	7.2 E-007	7.9
TRANS	07	7.1 E-007	8.7 E-008	6.2 E-007	6.9
LOOP	34	4.1 E-007	0.0 E+000	4.1 E-007	4.5
TRANS	27	2.2 E-007	0.0 E+000	2.2 E-007	2.5
LOOP	06	1.1 E-007	1.4 E-008	1.0 E-007	1.1
Condition Assessment Total (all sequences)		**1.3 E-005**	**4.0 E-006**	**9.0 E-006**	

[a] Percent contribution to the total importance.

Table B.7.4. Sequence Logic for Dominant Sequences for the Condition Assessment for LER 352/95-008

Event tree name	Sequence name	Logic
TRANS	04	/RPS, PCS, /SRV, /MFW, RHRPCS, CVS
LOOP	03	/RP1, /EPS, /SRV, /HCI, RHRL, CVS
TRANS	44	/RPS, PCS, P2, /HCI, CDS, LCS, LCI, SSW
LOOP	20	/RP1, /EPS, /SRV, HCI, RCI, /ADS, LCSL, LCI/L, SSWL
TRANS	07	/RPS, PCS, /SRV, MFW, /HCI, RHRPCS, CVS
LOOP	34	/RP1, /EPS, P2, /HCI, LCSL, LCIL, SSWL
TRANS	27	/RPS, PCS, /SRV, MFW, HCI, RCI, /ADS, CDS, LCS, LCI, SSW
LOOP	06	/RP1, /EPS, /SRV, HCI, /RCI, RHRL, CVS

Table B.7.5. Conditional Cut Sets for Higher Probability Sequences for the Condition Assessment for LER No. 352/95-008

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets
TRANS Sequence 04		4.6 E-006	
1	54.5	2.5 E-006	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, SDC-XHE-XE-ERROR, RHRSTRAINERS, CVS-XHE-XE-VENT
2	32.4	1.5 E-006	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	12.0	5.6 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
LOOP Sequence 03		1.9 E-006	
1	53.6	1.0 E-006	/SRV, RHRSTRAINERS, SDC-XHE-XE-ERROR, CVS-XHE-XE-VENT
2	32.2	6.1 E-007	/SRV, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	11.9	2.4 E-007	/SRV, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
4	1.1	2.3 E-008	/SRV, RHR-MOV-OO-BYPSB, EPS-DGN-FC-DGC, EPS-XHE-XE-NOREC, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
TRANS Sequence 44		8.3 E-007	
1	52.1	4.3 E-007	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, PPR-SRV-OO-2VLVS, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-XHE-XE-ERROR
2	31.8	2.6 E-007	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, PPR-SRV-OO-2VLVS, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-MOV-CC-FLOOD, SSW-XHE-XE-NOREC
3	16.1	1.3 E-007	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, PPR-SRV-OO-2VLVS, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-MOV-CC-LOOPB, LCI-XHE-XE-NOREC, SSW-XHE-XE-NOREC
LOOP Sequence 20		7.2 E-007	
1	51.6	3.7 E-007	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-XHE-XE-ERROR

Table B.7.5. Conditional Cut Sets for Higher Probability Sequences for the Condition Assessment for LER No. 352/95-008

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets
2	31.5	2.3 E-007	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-MOV-CC-FLOOD, SSW-XHE-XE-NOREC
3	16.0	1.2 E-007	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-MOV-CC-LOOPB, LCI-XHE-XE-NOREC, SSW-XHE-XE-NOREC
TRANS Sequence 07		7.1 E-007	
1	54.9	3.9 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, RHRSTRAINERS, SDC-XHE-XE-ERROR, CVS-XHE-XE-VENT
2	32.9	2.3 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	12.2	8.7 E-008	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
LOOP Sequence 34		4.1 E-007	
1	52.1	2.1 E-007	PPR-SRV-OO-2VLVS, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-XHE-XE-ERROR
2	31.8	1.3 E-007	PPR-SRV-OO-2VLVS, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-MOV-CC-FLOOD, SSW-XHE-XE-NOREC
3	16.1	6.6 E-008	PPR-SRV-OO-2VLVS, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-MOV-CC-LOOPB, LCI-XHE-XE-NOREC, SSW-XHE-XE-NOREC
TRAN Sequence 27		2.3 E-007	
1	52.1	1.2 E-007	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-XHE-XE-ERROR

Table B.7.5. Conditional Cut Sets for Higher Probability Sequences for the Condition Assessment for LER No. 352/95-008

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets
2	31.8	7.3 E-008	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-MOV-CC-FLOOD, SSW-XHE-XE-NOREC
3	16.1	3.7 E-008	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-MOV-CC-LOOPB, LCI-XHE-XE-NOREC, SSW-XHE-XE-NOREC
LOOP Sequence 06		1.1 E-007	
1	54.9	6.0 E-008	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RHRSTRAINERS, SDC-XHE-XE-ERROR, CVS-XHE-XE-VENT
2	32.9	3.6 E-008	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	12.2	1.3 E-008	/SRV, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
Condition Assessment Total (all sequences)		**1.3 E-005**	

[a] The conditional probability for each cut set is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per-hour basis), and t is the duration time of the event (in this case, 6132 h). This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are: $\lambda_{TRANS} = 4.57 \times 10^{-4}$/h, and $\lambda_{LOOP} = 1.29 \times 10^{-5}$/h.

Table B.7.6. Sequence Conditional Probabilities for the Initiating Event Assessment for LER No. 352/95-008

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
TRANS	04	1.6 E-006	65.3
TRANS	07	2.6 E-007	10.2
TRANS	80-15	2.2 E-007	8.7
TRANS	80-16	2.0 E-007	8.0
TRANS	27	8.2 E-008	3.2
TRANS	80-14	3.4 E-008	1.3
IE Assessment Total (all sequences)		**2.5 E-006**	

Table B.7.7. Sequence Logic for Dominant Sequences for the Initiating Event Assessment for LER 352/95-008

Event tree name	Sequence name	Logic
TRANS	04	/RPS, PCS, /SRV, /MFW, RHRPCS, CVS
TRANS	07	/RPS, PCS, /SRV, MFW, /HCI, RHRPCS, CVS
TRANS	80-15	RPS, /RRS, SLC
TRANS	80-16	RPS, RRS
TRANS	27	/RPS, PCS, /SRV, MFW, HCI, RCI, /ADS, CDS, LCS, LCI, SSW
TRANS	80-14	RPS, /RRS, /SLC, PCS, AD1

Table B.7.8. Conditional Cut Sets for Higher Probability Sequences for the Initiating Event Assessment for LER No. 352/95-008

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets
TRANS Sequence 04		1.6 E-006	
1	53.7	8.9 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, SDC-XHE-XE-ERROR, RHRSTRAINERS, CVS-XHE-XE-VENT
2	32.2	5.3 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	11.9	1.9 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
TRANS Sequence 07		2.6 E-007	
1	53.7	1.4 E-007	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC. RHRSTRAINERS, SDC-XHE-XE-ERROR, CVS-XHE-XE-VENT
2	32.2	8.3 E-008	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, RHRSTRAINERS, SDC-MOV-CC-SUCT, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
3	11.9	3.1 E-008	PCS-LONG, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, RHR-MDP-CF-MDPS, SDC-XHE-XE-NOREC, CVS-XHE-XE-VENT
TRANS Sequence 80-15		2.2 E-007	
1	89.5	2.0 E-007	RPS-NONREC, SLC-XHE-XE-ERROR
2	5.6	1.2 E-008	RPS-NONREC, SLC-MDP-CF-MDPS, SLC-XHE-XE-NOREC
3	2.3	5.2 E-009	RPS-NONREC, SLC-EPV-CF-VALVS, SLC-XHE-XE-NOREC
4	1.7	4.0 E-009	RPS-NONREC, SLC-CKV-CC-INJEC, SLC-XHE-XE-NOREC
TRANS Sequence 80-16		1.0 E-007	
1	97.6	2.0 E-007	RPS-NONREC, RRS-XHE-XE-ERROR

Table B.7.8. Conditional Cut Sets for Higher Probability Sequences for the Initiating Event Assessment for LER No. 352/95-008

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets
TRANS Sequence 27		8.2 E-008	
1	51.7	4.2 E-008	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-XHE-XE-ERROR
2	31.5	2.6 E-008	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-XHE-XE-NOREC, SSW-MOV-CC-FLOOD, SSW-XHE-XE-NOREC
3	16.0	1.3 E-008	PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, /SRV, MFW-SYS-VF-FEEDW, MFW-XHE-XE-NOREC, HCI-TDP-FC-TRAIN, HCI-XHE-XE-NOREC, RCI-TDP-FC-TRAIN, RCI-XHE-XE-NOREC, CDS-SYS-VF-COND, CDS-XHE-XE-NOREC, RHRSTRAINERS, LCS-XHE-XE-NOREC, LCI-MOV-CC-LOOPB, LCI-XHE-XE-NOREC, SSW-XHE-XE-NOREC
TRANS Sequence 80-14		3.4 E-008	
1	99.5	3.4 E-008	RPS-NONREC, PCS-SYS-VF-MISC, PCS-XHE-XE-NOREC, AD1-XHE-XE-ERROR
IE Assessment Total (all sequences)		**2.5 E-006**	

[a] The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probability of the initiating events are given in Table B.7.1 and begin with the designator "IE." The probabilities for the basic events also are given in Table B.7.1.

B.8 LER No. 368/95-001

Event Description: Loss of direct current bus could fail both emergency feedwater trains

Date of Event: July 19, 1995

Plant: Arkansas Nuclear One, Unit 2

B.8.1 Event Summary

During a simulator procedure validation exercise, personnel discovered that both trains of emergency feedwater (EFW) could be failed by the loss of a single train of direct current (dc) power at Arkansas Nuclear One, Unit 2 (ANO-2). Plant personnel confirmed the validity of the simulator exercise and declared the motor-driven EFW pump inoperable. A 72-h Technical Specification action statement was entered until the bus providing power to the normally open green-powered EFW injection valves could be transferred to an alternate power source that precluded the condition, while a permanent solution could be developed and implemented. A modification to the control relays for the green-powered injection valves in the red EFW train was completed on July 27, 1995, that corrected the condition. The root cause of this condition was the assumption that the normally open motor-operated EFW injection valves (which replaced the electrohydraulic injection valves in 1984) would fail "as-is" upon loss of power. Because of a design error during development of the plant modification that implemented the injection valve replacement, a failure of the green train dc bus could cause the green-powered injection valves in series with the two red-powered valves for the motor-driven EFW pump to close enough to restrict EFW flow to the steam generators. The conditional core damage probability (CCDP) estimated for this event is 6.0×10^{-5}. The increase in the core damage probability (CDP), or importance, associated with this event is 1.1×10^{-5}.

B.8.2 Event Description

While validating Abnormal Operating Procedures (AOPs) on the plant simulator, a loss of "green-train" dc power was simulated during power operations. Approximately 3 s into the scenario, the main turbine tripped from loss of dc power to the electrohydraulic control system. The turbine trip resulted in the trip of the main generator output breaker, but, because of the loss of dc control power, the generator field breaker did not trip, and the generator remained tied to alternating current (ac) bus 2A2 via the Unit Auxiliary Transformer. Generator voltage decayed over the next 30 s.

The loss of green-train dc power rendered multiple dependent systems and sub-systems inoperable, including ac buses 2A2 and 2A4, emergency diesel generator (EDG) B, and the A-train turbine-driven EFW pump. In addition, an unexpected interaction rendered the B-train ("red-train") motor-driven EFW pump unavailable.

The discharge of EFW pump B can be routed to either steam generator via lines that each contain two isolation valves. The inboard (closest to the pump) valves are normally closed and are supplied by "red-train" power. The outboard valves are normally open and are supplied by green-train ac power. These valves have a normally energized green-train dc relay, which signals the valves to close on loss of dc control power. When this configuration was designed, it was assumed that any loss of green-train dc power would be accompanied by a simultaneous loss of green-train ac power. During the simulator run, the ac power remained available for approximately 30 s, which allowed the B-train EFW isolation valves to close, contrary to design intent. Once closed, the valves could not be reopened until ac power was restored and an open command was given.

B.8.3 Additional Event-Related Information

The Licensee Event Report (LER) for this event (Ref. 1) indicates that there is no conclusive evidence that the actual plant response would have resulted in complete closure of the affected EFW valves. Based on a review of plant documentation, the LER indicates that sufficient voltage to operate the EFW isolation valves might have existed for only about 10 s after a reactor trip. In this case, the EFW isolation valves would have closed only partially. In that event, some EFW flow—but less than the amount required by technical specifications—might have been maintained.

The ANO-2 Individual Plant Examination (IPE) (Ref. 2) indicates that the expected frequency for the loss of one dc bus is 3.94×10^{-4} per year. The IPE also provides information about the potential impacts of a loss of dc power. Once-through cooling (feed and bleed) requires that either the high-point vent line or one of the low temperature overpressure (LTOP) paths be opened. The loss of green-train dc power would render all pathways unavailable, hence once-through cooling would be unavailable. In addition, a dependency table in the IPE indicates that the following systems are also dependent on green-train dc power: high pressure safety injection (HPSI) train B, shutdown cooling (SDC) train A, and main feedwater (MFW).

B.8.4 Modeling Assumptions

The wiring logic error, which caused the loss of the green-train dc power, apparently existed from the time a plant modification was made in 1984 until 1995, when it was discovered. In this analysis, it was assumed that the plant performance would be similar to that of its simulator. For one operating year [the longest time period analyzed in the Accident Sequence Precursor (ASP) Program], both trains of EFW were assumed to be initially inoperable, given a loss of the green-train dc power. The frequency of this initiator, 3.9×10^{-4} per year, was taken from the ANO-2 IPE.

As described above, MFW and once-through cooling are unavailable following a loss of dc power. Core cooling, therefore, requires successful EFW operation or recovery of EFW if it were to initially fail (this is shown in Figure 1).

The nonrecovery probability of the EFW was calculated by determining:

(a) the nonrecovery probability of operators failing to manually open the EFW discharge valves, and

(b) failure to initiate once-through cooling given EFW is not recovered within 25 min.

The model used to estimate these failure probabilities is the time-reliability correlation given by Dougherty and Fragola in *Human Reliability Analysis* (Ref. 3). These two failure probabilities are then combined to determine the overall probability of operators failing to recover EFW by considering the availability of personnel throughout a 24-h period.

The probability of failing to recover the initially unavailable EFW system was estimated by assuming that the closed EFW discharge valves would be apparent to the operators and that the initial attempt to recover EFW would be by manually opening these valves. Assuming 70 min to core uncovery (Ref. 2, p. 3.1-20), 10 min to implement the emergency operating procedures (EOPs), diagnose the event and determine a recovery strategy, and 10 min for response, a failure probability of 0.056 is estimated. Because of the degree of stress expected during such an event, a time-reliability correlation involving "recovery with hesitancy" was used to model the operator response, as described in Ref. 3.

If EFW is not recovered within about 25 min of the start of the transient, the water level in the steam generator (SG) is expected to drop to a value where once-through cooling is required to be initiated (Ref. 2, p. 3.1-19, -20). Because the ability to initiate once-through cooling cannot be met because of the loss of dc power, it is expected that plant personnel will place additional emphasis on recovering EFW. Shortly thereafter, additional resources, if available, are assumed to be used to manually control the turbine-driven EFW pump and its discharge valves in a further attempt to feed water to the SGs. A failure probability of 0.27 is estimated for this action, assuming it occurs 30 min into the event (5 min after the cue for once-through cooling) and requires the 20 min response time specified in Ref. 2.

The failure probabilities for the two recovery actions are:

Recovery	*Failure Probability*
operators fail to manually open the EFW discharge valves	0.056
failure to initiate once-through cooling within time required	0.27

Assuming additional resources are available for initiating once-through cooling except on the back shift (resources are assumed to be available two-thirds of the time) provides an overall probability of failing to recover EFW of:

$$\text{probability of operators failing to recover EFW} = [(0.056)(0.27)(2/3)] + [(0.056)(1/3)] = 0.028.$$

These estimates result in the following *increase* in the CDP over a one-year period:

$$3.9 \times 10^{-4} \begin{Bmatrix}\text{prob of a loss of}\\ \text{the green dc bus}\end{Bmatrix} \times \left[1.0 \begin{Bmatrix}\text{prob of EFW failure}\\ \text{due to wiring error}\end{Bmatrix} \times 0.028 \begin{Bmatrix}\text{prob of failure}\\ \text{to recover EFW}\end{Bmatrix} - 1.1 \times 10^{-3} \begin{Bmatrix}\text{nominal failure prob}\\ \text{for EFW train B}\end{Bmatrix} \right]$$

$$= 1.1 \times 10^{-5} \begin{Bmatrix}\text{increase in CDP due}\\ \text{to wiring logic error}\end{Bmatrix}.$$

B.8.5 Analysis Results

The estimated *increase* in the CDP due to the wiring logic error is 1.1×10^{-5}. The dominant core damage sequence for this event (Sequence number 3 in Fig. B.8.1) involves:

- a postulated loss of the green dc bus,
- the resultant unavailability of EFW, and
- failure to recover EFW.

The *nominal* CDP over a one-year period estimated using the ASP Integrated Reliability and Risk Analysis System (IRRAS) models for ANO-2 is approximately 4.9×10^{-5}. The wiring logic error increased this probability to 6.0×10^{-5}. This value is the CCDP for a one-year period in which the wiring logic error existed.

B.8.6 References

1. LER 368/95-001, Rev. 0, "Unanticipated effect of analyzed failure of dc electrical bus upon train of EFW system containing ac motor-driven pump," August 18, 1995.

2. *Arkansas Nuclear One–Unit 2 Individual Plant Examination for Severe Accident Vulnerabilities*, August 1992.

3. Dougherty and Fragola, *Human Reliability Analysis*, Wiley and Sons, New York, 1988.

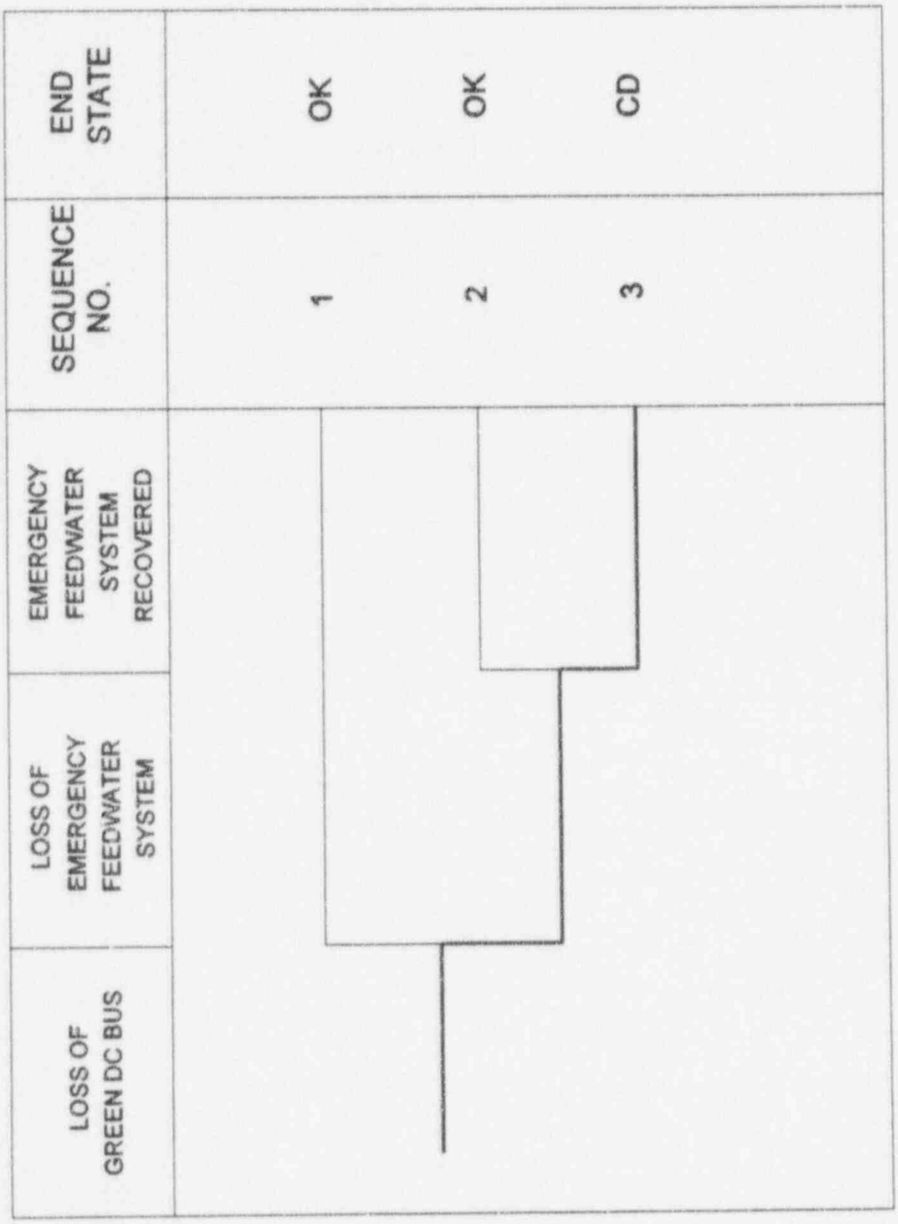

Fig. B.8.1. Dominant core damage sequence for LER 368/95-001.

B.9 LER No. 382/95-002

Event Description: Reactor trip, breaker failure and fire, degraded offsite power, and degraded shutdown cooling

Date of Event: June 10, 1995

Plant: Waterford 3

B.9.1 Event Summary

A switchyard lightning arrestor failure caused a trip from 100% power at Waterford 3. Delayed opening of the 4.16-kV unit auxiliary transformer (UAT) feeder breaker paralleled the grid with the main generator which was speeding up. The resulting out-of-phase condition caused an overvoltage and fault-level currents that started a fire that damaged cables and switchgear for nonvital Train A. Power was initially lost to Train A safety loads, but was recovered when emergency diesel generator (EDG) A started and loaded. Condenser vacuum was subsequently lost as a result of loss of power to balance of plant Train A equipment and the unexpected bypass of circulating water flow around the condenser. Plant cooldown was delayed when low hydraulic fluid levels prevented proper operation of shutdown cooling (SDC) system isolation valves. The conditional core damage probability (CCDP) estimated for this combined event is 9.1×10^{-5}. The increase in CCDP over a one-year period because of the unavailability of the SDC isolation valves is 1.7×10^{-5}. The CCDP for the actual transient is 2.5×10^{-5}.

B.9.2 Event Description

Waterford 3 was operating at 100% power on June 10, 1995. At 0858, a lightning arrestor failed at the Waterford Substation. The resulting grid disturbance caused the sudden pressure relay on Main Transformer A to actuate the main generator lockout relays. This actuation resulted in the trip of the main generator output breaker and exciter field breaker initiation of a fast dead bus transfer, and trip of the main turbine.

The B 6.9-kV and 4.16-kV buses successfully transferred to Startup Transformer (SUT) B. However, during the transfer of 4.16-kV bus A2 to SUT A, the A2 SUT feeder breaker closed before the A2 UAT breaker opened. The UAT and SUT breakers tripped and power was lost to bus A2.

The reactor tripped on low Departure from Nucleate Boiling Ratio (DNBR) signals, caused by low reactor coolant pump speed. Bus A1 (6.9-kV) deenergized, which tripped two reactor coolant pumps, circulating water pumps, condensate pumps, and condenser air evacuation pumps. Main feedwater (MFW) pump A also tripped, apparently from loss of power to the pump speed pickups.

Vital 4.16-kV bus A3 deenergized when power was lost to bus A2. EDG A started and reenergized the required safety-related loads via the load sequencer. Emergency feedwater (EFW) actuated, and within 13 min both MFW isolation valves had been closed as a result of high steam generator (SG) level.

Approximately 1 min after the trip, all turbine generator building (TGB) switchgear room fire alarm annunciators actuated. The TGB operator reported heavy smoke coming from the switchgear room 7 min later. Two auxiliary operators were directed to set up blowers to help dissipate the smoke, don protective clothing, and enter the switchgear room to investigate the cause of the smoke.

At 0935 (+37 min), the TGB auxiliary operator reported a fire in the 2A switchgear and in the cables above the switchgear. The fire was caused by the delayed opening of the A2 UAT breaker, which resulted in a voltage across the breaker during opening beyond the breaker's design and a subsequent high-energy fault. The breaker failed internally and caused the fire (the breaker failure and fire are described in more detail in **Additional Event-Related Information**).

Upon notification of an actual fire in the switchgear room, the shift supervisor sounded the plant fire alarm (post-event review indicated that the fire alarm should have been sounded when smoke was first detected), dispatched the fire brigade, and directed the motor-operated disconnect for SUT A to be opened to ensure electrical isolation of the A2 bus. The control room supervisor left the control room to serve as fire brigade leader.

The fire brigade attempted to extinguish the fire using halon, carbon dioxide and dry-chemical fire extinguishers. When the fire brigade leader arrived at the fire scene, he immediately notified the control room to request offsite fire department assistance. The Hahnville Fire Department was contacted at 0941 (+43 min) via 911 for support.

The Hahnville Fire Department arrived on-site 17 min later and recommended that water be used to extinguish the fire. Carbon dioxide and dry chemical extinguishers were being unsuccessfully used by the fire brigade to fight the fire (although experience gained from the 1976 Browns Ferry fire and other fires indicated that the use of water was necessary on large cable fires). The use of water was delayed for an additional 20 min. (Ref. 2 noted that interviews conducted with plant operators after the event indicated a general reluctance on the part of the operators to apply water to an electrical fire, based on previous training that had emphasized the use of water was a last resort on electrical fires.) The fire was extinguished within 4 min, once water was used.

At 1112 (+2.2 h), condenser vacuum was broken after it had fallen to 0.68 MPa (20 in. Hg). A condenser low vacuum alarm had actuated at 0940 hours, shortly after the fire was reported. The loss of vacuum was initially attributed to the unavailability of the two circulating water and condenser air evacuation pumps, resulting from the deenergization of bus A1 at the beginning of the event, combined with several steam loads that were still discharging to the condenser, and the operators made a decision not to divert resources from fighting the fire to attempt to recover condenser vacuum. In actuality, when the two circulating water pumps deenergized at 0858 hours, their associated motor-operated discharge valves also deenergized and remained open, resulting in a bypass of circulating water flow.

At 1147 (+2.8 h), the main steam isolation valves were closed and the atmospheric dump valves used for decay heat removal. At 2348 (14.8 h after the event began), EFW was secured, and Condensate Pump B (the operable condensate pump) was used to supply water to Steam Generator B.

By 1257 on June 11, 1996, the plant had been cooled down and depressurized to shutdown cooling entry conditions. At 1311, shutdown cooling suction header isolation valve SI-405B was commanded open while placing the shutdown cooling system in service. This valve closed after only partially opening and was declared inoperable The equivalent valve in Train A, SI-405A was then opened. Several hours later, this valve's hydraulic pump was observed to be continually running instead of cycling as designed. Valve SI-405A was also closed and declared inoperable.

A containment entry was made to inspect the two valves, and low hydraulic fluid levels were found in both valve actuator reservoirs. Approximately 3,280 cm^3 (200 $in.^3$) of hydraulic fluid were added to the reservoir for SI-405B, and the valve operated satisfactorily. Shutdown cooling loop B was placed in service between 1800 and 2400 on June 12, 1996.

When valve SI-405A was tested after fluid had been added to its reservoir, the valve opened slowly. Additional troubleshooting indicated that the valve's hydraulic pump had been damaged by the continuous operation caused by the low hydraulic fluid level. The pump was replaced and the valve was returned to service shortly after midnight on June 13, 1995. Cooldown to Mode 5 began, with Train A components still powered by EDG A.

B.9.3 Additional Event-Related Information

The Waterford 3 fast dead bus transfer scheme consists of automatic or manual transfer of in-house loads from the UATs to the SUTs. During a fast dead bus transfer, the UAT feeder breakers to the A1 and B1 6.9-kV and the A2 and B2 4.16-kV buses are designed to open in five cycles, and the SUT feeder breakers are designed to close in seven cycles, resulting in a two-cycle nominal deadband on the respective buses.

This scheme is a "simultaneous" (simultaneous trip and close signals with no interlock) bus transfer scheme (zero to two-cycle deadband) instead of the "sequential" (the tripping breaker interlocked with the closing breaker) bus transfer (greater than six-cycle deadband) commonly used in the United States. The simultaneous bus transfer scheme is used in all Swedish nuclear power plants. To prevent exceeding the fault duty of associated equipment and buses when two sources are in parallel, the Swedish design includes an interlock that limits the time period during which both breakers are permitted to remain closed to less than 0.1 s. The Waterford 3 design does not include the interlock, and both breakers appeared to have remained closed for about 0.3 s during the event.

During the time that the two breakers were simultaneously closed, the A2 bus connected SUT A to the main generator, which then provided power to the grid via the UAT and bus A2. During this time the main generator was rotating faster than the system frequency due to the load rejection. When the UAT breaker opened, the main generator was approaching 180 degrees out of phase with the system (~8 kV across the breaker). The interrupted current was ~28,800 A. This overvoltage due to the out-of-phase condition and the overcurrent resulted in an internal breaker failure and the creation of ionizing gases, which caused the fire in the A2 switchgear. A preliminary investigation indicated that the most probable cause for the slow opening time of the UAT breaker was restricted movement of the trip latch roller bearing.

The amount of damage to the breaker and surrounding equipment indicates that (1) the fault current through the breaker was extremely high and (2) significant arcing occurred for some period of time. The arc chutes and main contacts on all phases were destroyed, and the contact structures, breaker frame, and cubicle were also significantly damaged. The main bus and bus enclosure also appeared to have experienced severe arcing damage.

The fire that resulted from the breaker failure damaged the bus and surrounding cables and components. Two cubicles (the failed breaker was an end cubicle) were heavily damaged, and approximately 3 m (10 ft) of the cable bus duct was destroyed. Cables in approximately 1.5-m-diam (5-ft) column above the breaker had visible fire damage over their entire 3-m (10-ft) vertical run. At the top of the vertical run, the cables were routed through a horizontal cable tray. Approximately 2.4 m (8 ft) of cable in the horizontal tray had visible fire damage. General smoke and slight heat damage to the exterior of the remaining cubicles in the A2 bus occurred. In addition, damage included external heat to the jackets of four of the 15 feeder cables from the SUT to the A2 bus, and burn marks on the conduit of the cables that supply 6.9-kV power to the reactor coolant pump 1A and 2A motors.

The TGB switchgear room contains both the A and B trains of nonvital switchgear. The ceiling of the room is approximately 7.6 m (25 ft) above the floor; the tops of the switchgear cubicles are approximately 2.1 m (7 ft) high. A 3-m-high (10-ft) concrete block radiant heat shield, located 1.8 m (6 ft) from the front of each set of cubicles, separates the two trains. The fire did not affect the Train B switchgear or cables.

The TGB switchgear room had an ionization-type fire detection system, with detectors mounted on the ceiling, but no fire suppression system. The fire detection computer recorded the first fire alarm 55 s after the reactor trip. Within 7 s, all 36 fire detectors in the room had alarmed. Twenty-six min after the trip, the first detector went into "device communication error;" it apparently failed at that time and melted. By 0942 (+44 min), all detectors in the room had apparently failed.

Subsequent to the fire, the licensee found tape over the fire alarm annunciator buzzer located on the fire detection computer in the control room. Because of the tape, the alarm volume was low and nonintrusive. Due to the alarm panel's placement in the control room, alarm lights were also not readily visible. These factors, combined with the fact that the fire was not declared until after the auxiliary operators entered the switchgear room and observed it (36 min after the fire alarm annunciators actuated), contributed to the delay in responding to the fire.

Unlike many PWRs, the Waterford primary pressure relief system includes only code safety valves; no power-operated relief valves (PORVs) are incorporated in the design. The lack of PORVs prevents the use of feed-and-bleed for core cooling in the event both main and emergency feedwater systems are unavailable. If both of these systems were to fail at Waterford, safety-related, secondary-side atmospheric dump valves could be used to depressurize the steam generators to below the shutoff head of the condensate pumps. These pumps could then be used for decay heat removal.

B.9.4 Modeling Assumptions

The event was modeled both as (1) a reactor trip, loss of main feedwater (caused by the loss of condenser vacuum 2.2 h after the trip), loss of offsite power to Train A safety-related components, and unavailability of SDC isolation valves SI-405A and SI-405B during the cooldown (initiating event assessment) and (2) a long-term unavailability of the SDC isolation valves (condition assessment).

Reactor trip, loss of feedwater, and unavailable SDC isolation valves (initiating event assessment)

The ASP model for Waterford 3 was revised to address the potential failure of the main feedwater isolation valves (MFIVs) to open. These valves were closed because of high SG levels shortly into the event. Failure of these valves to open would prevent use of the auxiliary feedwater (AFW) system and the condensate system for SG makeup. Short-term ex-control room recovery of EFW (beyond the use of the AFW pump), high-pressure injection (HPI), and the condensate system, had these systems failed, was not considered feasible because significant crew resources were being used to fight the fire.

Redundant shutdown cooling isolation valves SI-405A and SI-405B were both assumed to have failed. This assumption may be conservative for SI-405A because it initially operated. However, the licensee determined that the valve's hydraulic motor was sufficiently damaged to require replacement before the plant cooldown continued.

The ASP models for a transient do not currently address the potential unavailability of offsite power to an individual train, as was observed in this event. During the event, power to safety-related Train A loads was provided by EDG A. The potential failure of the EDG to power Train A was modeled by adding a basic event to the model, EPS-DGN-FC-3AFR, to represent the potential failure of the EDG to start and run following the breaker failure.

The mission time for the initiating event assessment was assumed to be the time from the reactor trip until shutdown cooling was established, ~60 h. EDG A continued to supply Train A loads beyond this time. However, the added risk is considered to be small compared with the risk before shutdown cooling was established. [The Accident Sequence Precursor (ASP) Program addresses shutdown-related events that are considered unusual and significant. Events such as this one, where one train is powered from its EDG, are not typically selected for analysis.]

The following changes were made to basic events to reflect conditions observed during the event:

Basic event	Revised probability	Description (reason for change)
AFW-TRAIN-FC-ALL	9.8×10^{-3}	Nonsafety AFW system fails to provide flow to SGs (revised to reflect extended mission time)
COND-PFS-FC-SYS	7.8×10^{-3}	Secondary heat removal using condensate system fails (revised to reflect extended mission time and low probability of initial condensate system failure)

Basic event	Revised probability	Description (reason for change)
EFW-MDP-FC-A, B	5.0×10^{-3}	EFW motor-driven pump train failures (revised to reflect extended mission time)
EFW-PMP-CF-ALL	2.0×10^{-4}	Common cause failure of EFW pumps (revised to reflect extended mission time)
EFW-TDP-FC-TDP	4.1×10^{-2}	EFW turbine-driven pump train failures (revised to reflect extended mission time)
EFW-XHE-NOREC	TRUE	Ex-control room resources required for recovery utilized to fight fire
EPS-DGN-FC-3AFR	1.4×10^{-1}	EDG A fails to start and run (revised to reflect extended mission time)
HPI-XHE-NOREC	TRUE	Ex-control room resources required for recovery utilized to fight fire
MFW-SYS-TRIP	TRUE	MFW system trips (MFW unavailable because of loss of condenser vacuum)
MFW-VLV-CF-MFIV	2.6×10^{-4}	Common-cause failure of the MFW isolation valves to open (basic event added to model because these valves affect both the AFW and the condensate systems)
MFW-XHE-NOREC	TRUE	Operator fails to recover MFW (MFW not recoverable because of loss of vacuum)
RHR-MOV-CF-SUCT	TRUE	Common-cause failure of residual heat removal (RHR) suction valves (set to TRUE to reflect the failure of SI-405A and SI-405B)

The mission time for the HPI pumps was not revised to reflect the 60-h mission time. If a transient-induced loss-of-coolant accident (LOCA) had occurred, the modeled plant response would have been accomplished in less than 24 h. With the SDC isolation valves unavailable following a transient-induced (small-break) LOCA, the operators would have transferred to high-pressure recirculation (HPR) once the refueling water storage pool was depleted. This transfer would have occurred ~6 h following the LOCA.

The licensee addressed this specific switchgear room fire in the Waterford Individual Plant Examination for External Events (IPEEE) (Ref. 3). In that document the licensee concluded that the fire—while extensive and not suppressed until the cables from the UAT to the switchgear were fully involved—did not cause significant damage outside the plume/ceiling jet. Fire modeling also confirmed that a large TGB switchgear fire would not generate a hot gas layer that could fail cables outside the plume. Because of this, the IPEEE assumed that TGB switchgear fires would only cause damage to one train of offsite power. This assumption was used in this analysis as well. A sensitivity analysis, described in the Analysis Results, addresses the potential impact if the fire, or common cause breaker problems, had also resulted in a nonrecoverable loss of offsite power to Train B.

Long-term unavailability of the SDC isolation valves (condition assessment)

The SDC isolation valves were assumed to have been unavailable since the last refueling outage, in the spring of 1994. The longest time period used to assess a condition (unavailability) in the ASP Program is one year, during which the plant is typically assumed to have been at power 70% of the time. In this event, however, Waterford was at power for the full 1-year period, resulting in an unavailability of 8,760 hours. (Because a duration of 8,760 hours is longer than that used in the analysis of a typical long-term condition, the analysis results cannot be directly compared with those of other long-term condition assessments.) This assumption presumes that the loss of hydraulic fluid from the valve actuators occurs during valve operation (not when the valves are inoperative) and that the fluid level during the previous use of the valves was barely acceptable. If the hydraulic fluid was lost when the valves were in standby, then the analysis duration is overestimated (the valves would then become unavailable at one-half of the duration since last use; this would result in a 50% reduction in the increase in core damage probability caused by the failed valves).

Consistent with the previous assessment, shutdown cooling isolation valves SI-405A and SI-405B were both assumed to be failed. This assumption was reflected by setting basic event RHR-MOV-CF-SUCT to TRUE. Plant response to all initiators addressed in the ASP model was considered impacted by the unavailability of the SDC isolation valves.

B.9.5 Analysis Results

The CCDP estimated for trip, fire and resulting loss-of-offsite power to Train A, loss of feedwater, and unavailability of the SDC isolation valves is 2.5×10^{-5}. The dominant sequence, highlighted on the event tree in Fig. B.9.1 (transient sequence 19), contributes about 83% to the conditional probability estimate for the initiating event and involves

- the successful reactor trip,
- failure of EFW (including the AFW pump) to provide secondary-side cooling,
- MFW unavailability, and
- failure of the condensate system as an alternate source of cooling water.

The dominant cut sets involve failure to provide an alternate source of water to the EFW pumps following depletion of the condensate storage pool within the 60-h mission time and failure of the condensate system to provide flow to the steam generators (failure to initiate and equipment failure both contribute).

Table B.9.1 provides the definitions and probabilities for selected basic events for the initiating event assessment. The conditional probabilities associated with the highest probability sequences are shown in Table B.9.2, while Table B.9.3 lists the sequence logic associated with the sequences listed in Table B.9.2. Table B.9.4 describes the system names associated with the dominant sequences. The minimal cut sets associated with each sequence are shown in Table B.9.5.

The calculation for the reactor trip and fire is sensitive to the assumption that the fire or potential common cause breaker failures would not affect the availability of offsite power to Train B. If the fire could have affected Train B, or if slow breaker opening also resulted in the loss of Train B switchgear (which is believed to be unlikely), then the event could have been more significant. For example, an assumption of a 0.03 probability of nonrecoverable loss of offsite power to Train B (similar to Train A) results in an estimated CCDP of 1.4×10^{-4} (such an event would be considered important from an ASP standpoint).

The unavailable SDC isolation valves (the condition assessment) result in an overall increase in core damage probability for the assumed 1-year period of 1.7×10^{-5} over the nominal core damage probability (CDP) estimated for the same period of 8.8×10^{-5}. This is the sum of the changes to the sequence probabilities (importance) shown in Table B.9.7, which are calculated by subtracting the total CDP sequence value from the total CCDP sequence value for each sequence. The dominant core damage sequence involves

- a small-break LOCA initiating event,
- successful EFW and HPI operation,
- successful depressurization,
- failure to initiate SDC (which would avoid the use of high-pressure sump recirculation), and
- failure of high-pressure recirculation.

For most ASP analyses of conditions (equipment failures ovc. a period of time during which postulated initiating events could have occurred), sequences and cut sets associated with the observed failures dominate the CCDP (the probability of core damage over the unavailability period, given the observed failures). The increase in the CDP because of the failures is essentially the same as the CCDP, and the CCDP can be considered a reasonable measure of the significance of the observed failures.

For this event, however, sequences unrelated to the SDC isolation valves dominate the CCDP estimate. The increase in CDP given the failed SDC isolation valves, 1.7×10^{-5}, is, therefore, a better measure of the significance of the SDC valve problems.

Definitions and probabilities for selected basic events for the condition assessment are shown in Table B.9.6. The conditional probabilities associated with the highest probability sequences are shown in Table B.9.7. Table B.9.8 lists the sequence logic associated with the sequences listed in Table B.9.7. Table B.9.9 describes the system names associated with the dominant sequences. Cut sets associated with each sequence are shown in Table B.9.10.

B.9.6 References

1. LER 382/95-002, Rev. 0, "Reactor Trip and Non-Safety Related Switchgear Fire," July 7, 1995.

2. NRC Augmented Inspection Team Report 50-382/95-15, July 5, 1995

3. *Waterford 3 Individual Plant Examination for External Events*, July 1995.

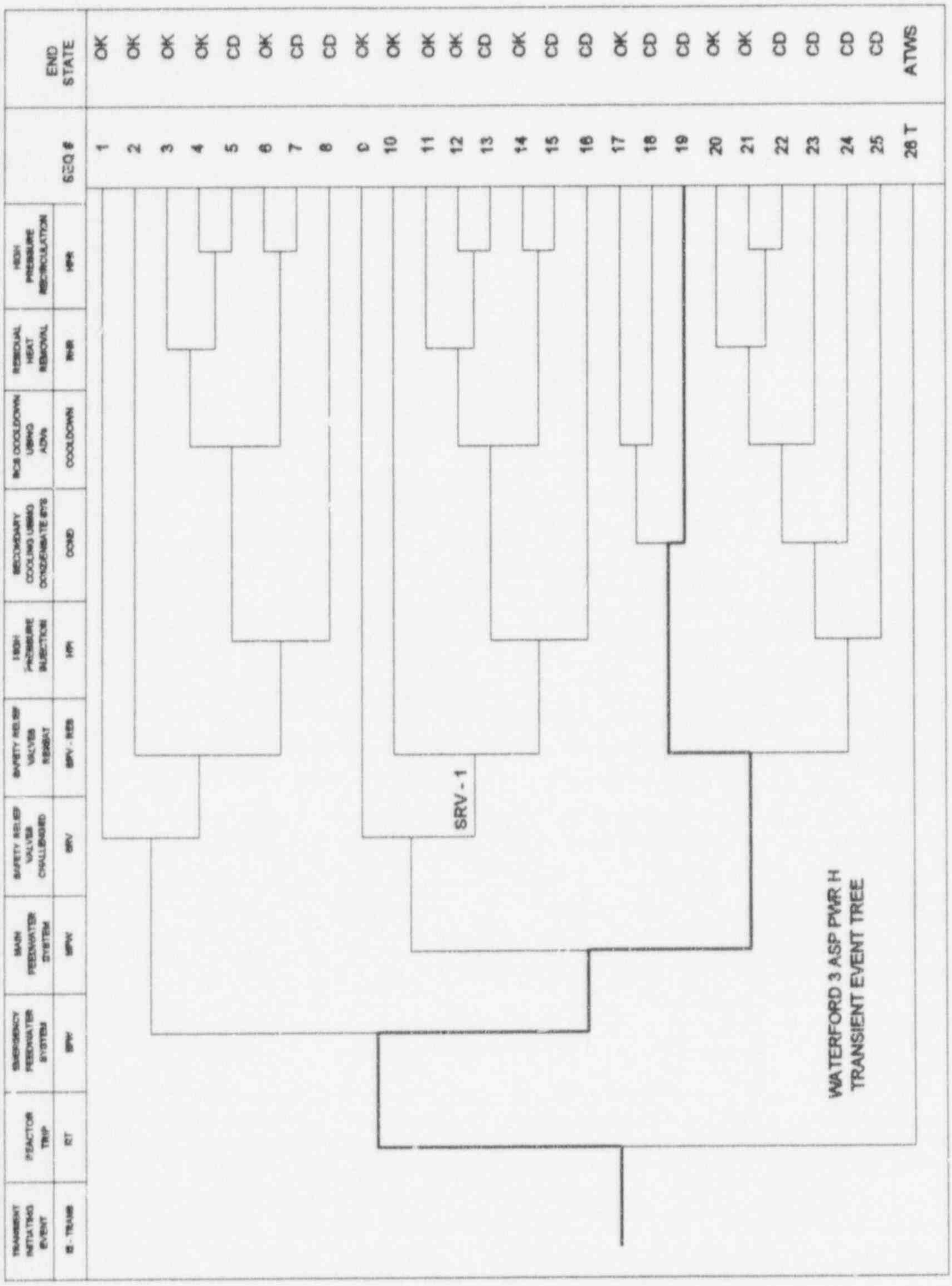

Fig. B.9.1. Dominant core damage sequences for LER No. 382/95-002.

Table B.9.1. Definitions and Probabilities for Selected Basic Events for the Initiating Event Assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss-of-Offsite Power Initiating Event	8.6E-006	0.0E+000	IGNORE	No
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6E-006	0.0E+000	IGNORE	No
IE-SLOCA	Small LOCA Initiating Event	1.0E-006	0.0E+000	IGNORE	No
IE-TRANS	Transient Initiating Event	6.8E-004	1.0E+000		Yes
AFW-TRAIN-FC-ALL	AFW Pump Train Fails to Provide Flow	8.7E-003	9.8E-003		Yes
COND-PFS-FC-SYS	Secondary Heat Removal Using Condensate System Fails	1.5E-002	7.8E-003		Yes
COND-XHE-XM	Operator Fails to Initiate Secondary Cooling	1.0E-002	1.0E-002		No
EFW-MDP-FC-A	EFW Motor-Driven Pump A Failures	3.9E-003	3.9E-003		No
EFW-MDP-FC-B	EFW Motor-Driven Pump B Failures	3.9E-003	5.0E-003		Yes
EFW-PMP-CF-ALL	Common-Cause Failure of EFW Pumps	1.4E-004	1.4E-004		No
EFW-TDP-FC-TDP	EFW Turbine-Driven Pump Train Failures	3.6E-002	4.0E-002		Yes
EFW-XHE-NOREC	Operator Fails to Recover EFW System	2.6E-001	1.0E+000	TRUE	Yes
EFW-XHE-XA-CCW	Operator Fails to Initiate Backup Water Source	1.0E-003	1.0 E-003		No
EPS-DGN-FC-3AFR	EDG 3A Fails to Start and Run	0.0E+000	1.4E-001	NEW	Yes
HPI-HDV-OC-SUCB	Refueling Water Storage Pool (RWSP) Suction Train B Failures	1. E-004	1.4E-004		No
HPI-MDP-CF-ALL	Common-Cause Failure of HPI Motor-Driven Pumps	1.0E-004	1.0E-004		No

Table B.9.1. Definitions and Probabilities for Selected Basic Events for the Initiating Event Assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-MDP-FC-B	HPI Motor-Driven Pump B Train Failures	3.9E-003	3.9E-003		No
HPI-MOV-CF-ALL	Common-Cause Failure of Injection Motor-Operated Valves	5.5E-005	5.5E-005		No
HPI-XHE-NOREC	Operator Fails to Recover the HPI System	8.4E-001	1.0E+000	TRUE	Yes
MFW-SYS-TRIP	MFW System Trips	2.9E-001	1.0E+000	TRUE	Yes
MFW-VLV-CF-MFIV	Common-Cause Failure of MFIVs to Open	0.0E+000	2.6E-004	NEW	Yes
MFW-XHE-NOREC	Operator Fails to Recover MFW	3.4E-001	1.0E+000	TRUE	Yes
PCS-VCF-HW	Turbine Bypass Valves / Condensate / Circulation Failures	1.0E-003	1.0E-003		No
PCS-XHE-XM-CDOWN	Operator Fails to Initiate Cooldown	1.0E-003	1.0E-003		No
PPR-SRV-CO-TRAN	Safety Relief Valves (SRVs) Open During Transient	2.0E-002	2.0E-002		No
PPR-SRV-OO-1	SRV 1 Fails to Reseat	1.6E-002	1.6E-002		No
PPR-SRV-OO-2	SRV 2 Fails to Reseat	1.6E-002	1.6E-002		No
RHR-MOV-CF-SUCT	Common-Cause Failure of RHR Suction Valves	1.2E-003	1.0E+000	TRUE	Yes

Table B.9.2. Sequence Conditional Probabilities for the Initiating Event Assessment for LER 382/95-002

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
TRANS	19	2.0E-005	82.9
TRANS	18	2.2E-006	9.1
TRANS	24	6.6E-007	2.6
TRANS	08	4.7E-007	1.9
Total (all sequences)		**2.5E-005**	

Table B.9.3. Sequence Logic for Dominant Sequences for the Initiating Event Assessment for LER 382/95-002

Event tree name	Sequence name	Logic
TRANS	19	/RT, EFW, MFW, /SRV-RES, COND
TRANS	18	/RT, EFW, MFW, /SRV-RES, /COND, COOLDOWN
TRANS	24	/RT, EFW, MFW, SRV-RES, /HPI, COND
TRANS	08	/RT, /EFW, SRV, SRV-RES, HPI

Table B.9.4. System Names for the Initiating Event Assessment for LER 382/95-002

System name	Logic
COND	Secondary Heat Removal Using Condensate System Fails
COOLDOWN	RCS Cooldown to RHR Pressure Using Turbine-Bypass Valves, etc.
EFW	No or Insufficient EFW Flow
HPI	No or Insufficient HPI System Flow
MFW	Failure of the Main Feedwater System
RT	Reactor Fails to Trip During Transient
SRV	SRVs Open During Transient
SRV-RES	SRVs Fail to Reseat

Table B.9.5. Conditional Cut Sets for Higher Probability Sequences for the Initiating Event Assessment for LER 382/95-002

Cut set number	Percent contribution	Conditional probability[a]	Cut sets[b]
TRANS Sequence 19		2.0E-005	
1	48.2	1.0E-005	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, COND-XHE-XM
2	37.6	7.8E-006	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, COND-PFS-FC-SYS
3	6.8	1.4E-006	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, COND-XHE-XM
4	5.3	1.1E-006	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, COND-PFS-FC-SYS
5	1.2	2.6E-007	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, MFW-VLV-CF-MFIV
TRANS Sequence 18		2.2E-006	
1	43.6	1.0E-006	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PCS-XHE-XM-CDOWN
2	43.6	1.0E-006	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PCS-VCF-HW
3	6.1	1.4E-007	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PCS-XHE-XM-CDOWN
4	6.1	1.4E-007	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PCS-VCF-HW
TRANS Sequence 24		6.6E-007	
1	24.1	1.6E-007	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-1, COND-XHE-XM
2	24.1	1.6E-007	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-2, COND-XHE-XM
3	18.8	1.2E-007	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-1, COND-PFS-FC-SYS
4	18.8	1.2E-007	EFW-XHE-XA-CCW, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-2, COND-PFS-FC-SYS
5	3.4	2.2E-008	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-1, COND-XHE-XM

Table B.9.5. Conditional Cut Sets for Higher Probability Sequences for the Initiating Event Assessment for LER 382/95-002

Cut set number	Percent contribution	Conditional probability[a]	Cut sets[b]
6	3.4	2.2E-008	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-2, COND-XHE-XM
7	2.6	1.7E-008	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-1, COND-PFS-FC-SYS
8	2.6	1.7E-008	EFW-PMP-CF-ALL, EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-OO-2, COND-PFS-FC-SYS
TRANS Sequence 08		4.7E-007	
1	36.6	1.7E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, EPS-DGN-FC-3AFR, HPI-MDP-FC-B, HPI-XHE-NOREC
2	36.6	1.7E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, EPS-DGN-FC-3AFR, HPI-MDP-FC-B, HPI-XHE-NOREC
3	6.7	3.2E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, HPI-MDP-CF-ALL, HPI-XHE-NOREC
4	6.7	3.2E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, HPI-MDP-CF-ALL, HPI-XHE-NOREC
5	3.7	1.7E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, HPI-MDP-CF-ALL, HPI-XHE-NOREC
6	3.7	1.7E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, HPI-MDP-CF-ALL, HPI-XHE-NOREC
7	1.3	6.2E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, EPS-DGN-FC-3AFR, HPI-MOV-OC-SUCB, HPI-XHE-NOREC
8	1.3	6.2E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, EPS-DGN-FC-3AFR, HPI-MOV-OC-SUCB, HPI-XHE-NOREC
Total (all sequences)		**2.5E-005**	

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilities for the initiating events and the basic events are also given in Table B.9.1

[b] Basic events EFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, and RHR-MOV-CF-SUCT are all type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

Table B.9.6. Definitions and Probabilities for Selected Basic Events for the Condition Assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPI-MDP-FC-B	HPI Motor-Driven Pump-B Train Failures	3.9E-003	3.9E-003		No
HPR-AOV-CC-SMPA	Containment Sump A Failures	1.1E-003	1.1E-003		No
HPR-AOV-CC-SMPB	Containment Sump B Failures	1.1E-003	1.1E-003		No
HPR-AOV-CF-SMP	Common-Cause Failure of Sump Air-Operated Valves	1.0E-004	1.0E-004		No
HPR-HDV-CF-RWSP	Common-Cause Failure of the Isolation Hydraulic Discharge Valves to the RWSP	2.0E-004	2.0E-004		No
HPR-HDV-OO-RWSPA	RWSP Train A Isolation Hydraulic Discharge Valve (HDV) Failures	2.0E-003	2.0E-003		No
HPR-HDV-OO-RWSPB	RWSP Train B Isolation HDV Failures	2.0E-003	2.0E-003		No
HPR-SMP-FC-SUMP	Containment Recirculation Sump Failures	5.0E-005	5.0E-005		No
HPR-XHE-NOREC	Operator Fails to Recover the HPR System	1.0E+000	1.0E+000	TRUE	No
HPR-XHE-NOREC-L	Operator Fails to Recover the HPR System During a LOOP	1.0E+000	1.0E+000	TRUE	No
MSS-VCF-HW-ISOL	Ruptured Steam Generator Isolation Failures	1.0E-002	1.0E-002		No
MSS-XHE-NOREC	Operator Recovery Action for Steam Generator Isolation	1.0E-001	1.0E-001		No
PPR-SRV-CO-L	SRVs Open During a LOOP	1.6E-001	1.6E-001		No
PPR-SRV-CO-TRAN	SRVs Open During Transient	2.0E-002	2.0E-002		No
PPR-SRV-OO-1	SRV 1 Fails to Reseat	1.6E-002	1.6E-002		No
PPR-SRV-OO-2	SRV 2 Fails to Reseat	1.6E-002	1.6E-002		No
RHR-MOV-CF-SUCT	Common-Cause Failure of RHR Suction Valves	1.2E-003	1.0E+000	TRUE	Yes
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	3.4E-001	3.4E-001		No

Table B.9.6. Definitions and Probabilities for Selected Basic Events for the Condition Assessment for LER 382/95-002

Event name	Description	Base probability	Current probability	Type	Modified for this event
RHR-XHE-NOREC-L	Operator Fails to Recover the RHR System During a LOOP	3.4E-001	3.4E-001		No
RWSP-REFILL	Operator Fails to Refill RWSP	8.5E-003	8.5E-003		No

Table B.9.7. Sequence Conditional Probabilities for the Condition Assessment for LER 382/95-002

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Core damage probability (CDP)	Importance (CCDP-CDP)	Percent contribution[a]
SLOCA	03	1.1E-006	8.5E-009	1.1E-006	65.4
TRANS	05	4.8E-007	3.4E-009	4.8E-007	28.7
LOOP	05	8.2E-008	3.6E-008	4.5E-008	2.6
SGTR	04	4.1E-008	2.9E-010	4.1E-008	2.4
Total (all sequences)		9.1E-005	8.9E-005	1.7E-005	

[a] Percent contribution to the total Importance.

Table B.9.8. Sequence Logic for Dominant Sequences for the Condition Assessment for LER 382/95-002

Event tree name	Sequence name	Logic
SLOCA	03	/RT, /EFW, /HPI, /COOLDOWN, RHR, HPR
TRANS	05	/RT, /EFW, SRV, SRV-RES, /HPI, /COOLDOWN, RHR, HPR
LOOP	05	/RT-L, /EP, /EFW-L, SRV-L, SRV-RES, /HPI-L, /COOLDOWN, RHR-L, HPR-L
SGTR	04	/RT, /EFW-SGTR, /HPI, /RCS-SG, SGISOL, /RCSCOOL, RHR, RWSPREFIL

Table B.9.9. System Names for the Condition Assessment for LER 382/95-002

System name	Logic
COOLDOWN	RCS Cooldown to RHR Pressure Using Turbine-Bypass Valves, etc.
EFW	No or Insufficient EFW Flow
EFW-L	No or Insufficient EFW Flow During a LOOP
EFW-SGTR	No or Insufficient EFW Flow During a Steam Generator Tube Rupture Event
EP	Failure of Both Trains of Emergency Power
HPI	No or Insufficient HPI System Flow
HPI-L	No or Insufficient HPI System Flow During a LOOP
HPR	No or Insufficient HPR Flow
HPR-L	No or Insufficient HPR Flow During a LOOP
RCS-SG	Failure to Lower RCS Pressure to Less Than SG Relief-Valve Set Point
RCSCOOL	Failure to Cooldown RCS to Less Than RCS Pressure
RHR	No or Insufficient RHR System Flow
RHR-L	No or Insufficient RHR System Flow During a LOOP
RT	Reactor Fails to Trip During a Transient
RT-L	Reactor Fails to Trip During a LOOP
RWSPREFIL	Operator Fails to Refill RWSP
SGISOL	Failure to Isolate Ruptured SG Before RWSP Depletion
SRV	SRVs Open During a Transient
SRV-L	SRVs Open During a LOOP
SRV-RES	SRVs Fail to Reseat

Table B.9.10. Conditional Cut Sets for Higher Probability Sequences for the Condition Assessment for LER 382/95-002

Cut set number	Percent contribution	Change in CCDP (Importance)[a]	Cut sets[b]
SLOCA Sequence 03		1.1E-006	
1	53.4	6.0E-007	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
2	26.7	3.0E-007	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
3	13.3	1.5E-007	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-SMP-FC-SUMP, HPR-XHE-NOREC
4	2.0	2.3E-008	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPI-MDP-FC-B, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC
5	1.1	1.2E-008	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPI-MDP-FC-B, HPR-AOV-CC-SMPA, HPR-XHE-NOREC
6	1.0	1.1E-008	RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-HDV-OO-RWSPA, HPR-HDV-OO-RWSPB, HPR-XHE-NOREC
TRANS Sequence 05		4.8E-007	
1	26.7	1.2E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
2	26.7	1.2E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-HDV-CF-RWSP, HPR-XHE-NOREC
3	13.3	6.5E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
4	13.3	6.5E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-AOV-CF-SMP, HPR-XHE-NOREC
5	6.6	3.2E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-SMP-FC-SUMP, HPR-XHE-NOREC
6	6.6	3.2E-008	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPR-SMP-FC-SUMP, HPR-XHE-NOREC
7	1.0	5.1E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPI-MDP-FC-B, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC
8	1.0	5.1E-009	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, HPI-MDP-FC-B, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC

Table B.9.10. Conditional Cut Sets for Higher Probability Sequences for the Condition Assessment for LER 382/95-002

Cut set number	Percent contribution	Change in CCDP (Importance)[a]	Cut sets[b]
LOOP Sequence 05		4.5E-008	
1	26.7	1.3E-008	PPR-SRV-CO-L, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-HDV-CF-RWSP, HPR-XHE-NOREC-L
2	26.7	1.3E-008	PPR-SRV-CO-L, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-HDV-CF-RWSP, HPR-XHE-NOREC-L
3	13.3	6.6E-009	PPR-SRV-CO-L, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-AOV-CF-SMP, HPR-XHE-NOREC-L
4	13.3	6.6E-009	PPR-SRV-CO-L, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-AOV-CF-SMP, HPR-XHE-NOREC-L
5	6.6	3.2E-009	PPR-SRV-CO-L, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-SMP-FC-SUMP, HPR-XHE-NOREC-L
6	6.6	3.2E-009	PPR-SRV-CO-L, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPR-SMP-FC-SUMP, HPR-XHE-NOREC-L
7	1.0	5.1E-010	PPR-SRV-CO-L, PPR-SRV-OO-1, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPI-MDP-FC-B, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
8	1.0	5.1E-010	PPR-SRV-CO-L, PPR-SRV-OO-2, RHR-MOV-CF-SUCT, RHR-XHE-NOREC-L, HPI-MDP-FC-B, HPR-HDV-OO-RWSPA, HPR-XHE-NOREC-L
SGTR Sequence 08		4.1E-008	
1	99.7	4.1E-008	MSS-VCF-HW-ISOL, MSS-XHE-NOREC, RHR-MOV-CF-SUCT, RHR-XHE-NOREC, RWSP-REFILL
Total (all sequences)		1.9E-005	

[a]The change in conditional probability (importance) is determined by calculating the conditional probability for the period in which the condition existed and given the condition, and subtracting the conditional probability for the same period but with plant equipment assumed to be operating nominally. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per hour basis), and it is the duration time of the event (in this case, 6760 h). This approximation is conservative for precursors made visible by the initiating event. The frequencies of interest for this event are: $\lambda_{TRANS} = 6.8 \times 10^{-4}$/h, $\lambda_{LOOP} = 8.5 \times 10^{-6}$/h, $\lambda_{SLOCA} = 1.0 \times 10^{-6}$/h, and $\lambda_{SGTR} = 1.6 \times 10^{-6}$/h.

[b]Basic events RHR-MOV-CF-SUCT is a type TRUE event which is not normally included in the output of fault tree reduction programs. This event has been added to aid in understanding the sequences to potential core damage associated with the event.

B.10 LER No. 389/95-005

Event Description: Failure of one emergency diesel generator with common-cause failure implications

Date of Event: November 20, 1995

Plant: St. Lucie, Unit 2

B.10.1 Event Summary

The 2A Emergency Diesel Generator (EDG) failed to start with the unit shutdown in Mode 6 following routine 18-month preventive maintenance. Several relay sockets were identified to be loose and were replaced. The 2A EDG subsequently failed a 24-h test run because of loose socket connections, and 48 of 54 relay sockets were replaced. The 2B EDG was determined to be subject to failure because of a common cause. The unavailability of the 2A EDG and the increased potential for a common cause failure of the 2B EDG affects the Unit 2 response to a loss of offsite power (LOOP). The estimated conditional core damage probability (CCDP) for this event is 1.4×10^{-5}. The nominal core damage probability (CDP) for the same period is 9.9×10^{-7}. Hence, the importance (CCDP–CDP) for this event is 1.3×10^{-5}.

B.10.2 Event Description

Unit 2 entered a refueling outage on October 9, 1995. On November 3, 1995, the 2A EDG failed to start following routine 18-month preventive maintenance. The shutdown relay socket was found to have a cracked solder joint and was replaced. On November 4, 1995, the 2A EDG was paralleled with the grid. The load was unstable, and the 2A EDG was unloaded and secured. The relay controlling governor operation was identified to have a loose socket connection, causing a high resistance at the connection. All 54 relays were tested in place, and two additional loose sockets were identified and replaced. The 2A EDG was started and loaded for a 24-h surveillance run. Approximately 17 h into the run, a loss of remote control occurred, and the EDG was shutdown. A failed solder joint connection was identified on the load control relay socket. All 54 relay sockets were removed from the 2A EDG and inspected. A total of 48 sockets were replaced with new sockets, and the 2A EDG was returned to service.

On November 20, 1995, the 2B EDG was removed from service for routine 18-month preventive maintenance. A single, inadequate relay socket connection was identified, and all 54 relay sockets were replaced as a precaution. The inspection of the 2B EDG indicated the possibility of a common-cause failure of the 2B EDG.

B.10.3 Additional Event-Related Information

The 1A and 1B EDG critical relays were removed and replaced. The removed relay sockets showed no signs of degradation. The orientation of the relays relative to the EDGs on Unit 1 was different than on Unit 2. Therefore, the 1A and 1B EDGs were determined not to be at increased risk of common-cause failure resulting from the 2A EDG failure. Subsequent vibration readings in the vicinity of the relay panels on the 1A EDG and 2B EDG supported this conclusion.

B.10.4 Modeling Assumptions

The 2A EDG failure was discovered during Mode 6 operation. However, the failure could have occurred with the unit in Mode 1 operation. Therefore, the event was analyzed as though the EDG failure occurred at power. The 2A EDG had successfully completed the previous monthly surveillance, so a failure period of 15 days was assumed.

A conditional assessment for 360 h (15 days) was performed with the 2A EDG failure probability (EPS-DGN-FC-DGA) set to TRUE. Because the 2A EDG was failed, the common-cause failure probability for the diesel generators (EPS-DGN-CF-AB) was set to the Beta factor for the Unit 2 EDGs. This accounts for the increased probability of the 2B EDG failing from a common cause as a result of the failure of the 2A EDG. The basic event representing the probability of not recovering the EDGs, if failed, in the short term, EPS-XHE-NOREC, was set to TRUE to reflect the expected inability to recover from the observed failures.

LOOP probabilities for offsite power recovery (accounted for in basic events OEP-XHE-NOREC-BD and OEP-XHE-NOREC-SL) and the probability of a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) following a postulated station blackout were developed based on data distributions in NUREG-1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*. The capability to provide power to Unit 2 from Unit 1 via a blackout cross-tie was simulated using a lognormal distribution of the operator response. The lognormal parameters were combined with the methodology described in the document *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, to produce LOOP parameters that accounted for use of the blackout cross-tie for a plant-centered LOOP.

B.10.5 Analysis Results

The estimated CCDP for the 360-h period that the 2A EDG was unavailable is 1.4×10^{-5}. Because the nominal CDP for the same period is 9.9×10^{-7}, the importance is also 1.3×10^{-5}. The dominant core damage sequence, highlighted as sequence number 41 on the LOOP event tree in Fig. B.10.1 contributes approximately 37% to the CCDP estimate. Sequence 41 involves:

- a LOOP,
- the successful trip of the reactor,
- the failure of emergency power, and
- the failure of the auxiliary feedwater system.

Definitions and probabilities for selected basic events are shown in Table B.10.1. The conditional probabilities associated with the highest probability sequences for the condition assessment are shown in Table B.10.2. The sequence logic associated with the sequences listed in Table B.10.2 are given in Table B.10.3. Table B.10.4 describes the system names associated with the dominant sequences for the condition assessment. Minimal cut sets associated with the dominant sequences for the condition assessment are listed in Table B.10.5.

B.10.6 References

1. LER 389/95-005, Rev 0, "2A Emergency Diesel Generator Relay Socket Failures Due to High Cycle Fatigue," December 20, 1995.

2. ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989.

3. Florida Power and Light Company, *St. Lucie Unit 2 Final Safety Analysis Report*.

4. NUREG 1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*.

5. *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989.

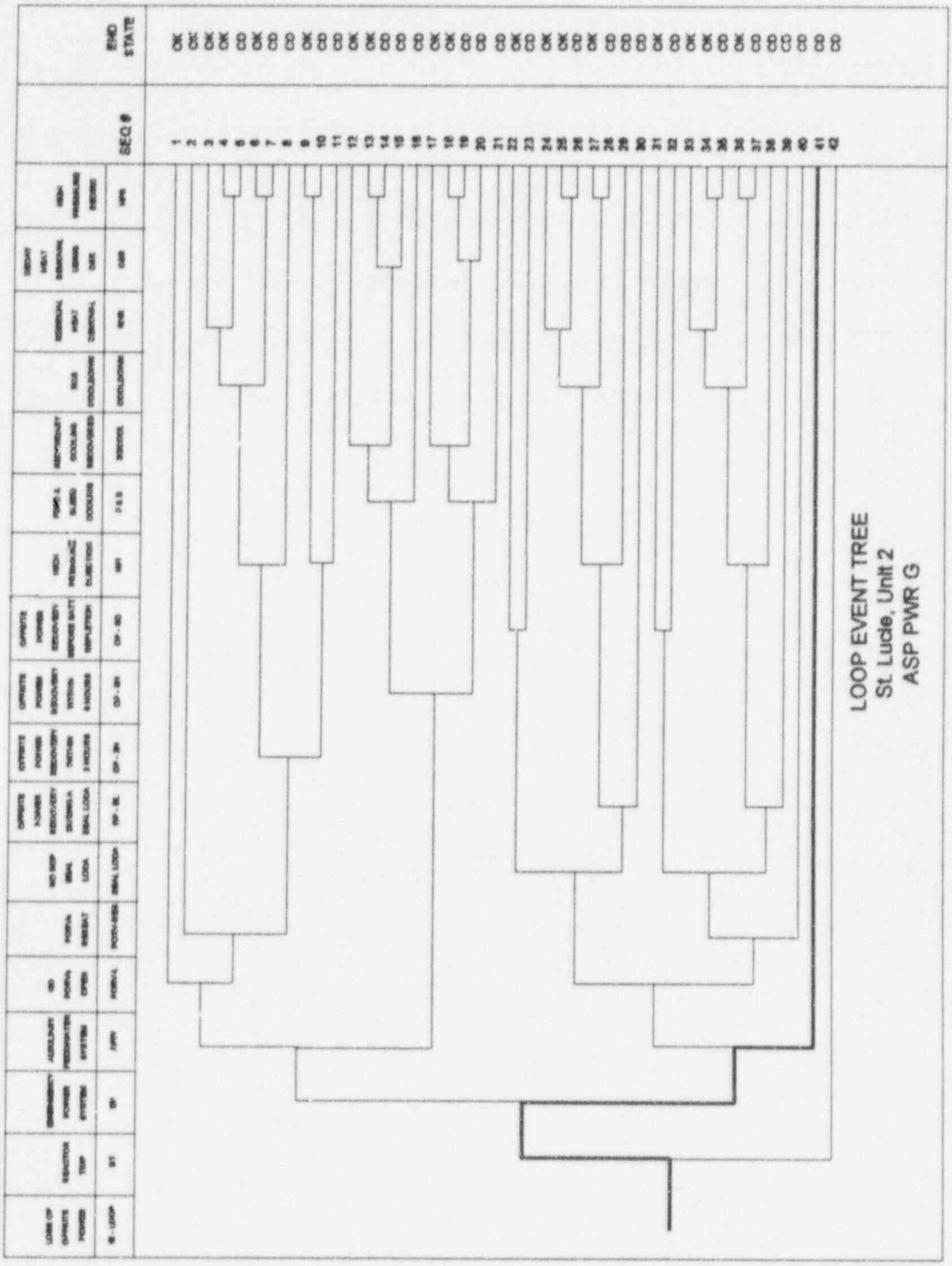

Fig. B.10.1. Dominant core damage sequence given a LOOP for LER 389/95-005.

Table B.10.1. Definitions and Probabilities for Selected Basic Events for LER No. 389/95-005

Event name	Description	Base probability	Current probability	Type	Modified for this event
AFW-TDP-FC-1C	Auxiliary Feedwater (AFW) Turbine-Driven Pump 1C Failure	3.2E-002	3.2E-002		No
AFW-XHE-NOREC-EP	Operator Fails to Recover AFW during a Station Blackout (SBO)	3.4E-001	3.4E-001		No
AFW-XHE-XA-CST2E	Operator Fails to Initiate Backup Water Source	1.0E-003	1.0E-003		No
EPS-DGN-CF-AB	Common-Cause Failure of Diesel Generators	1.6E-003	3.8E-002		Yes
EPS-DGN-FC-DGA	Diesel Generator A Failure	4.2E-002	1.0E+000	TRUE	Yes
EPS-DGN-FC-DGB	Diesel Generator B Failure	4.2E-002	4.2E-002		No
EPS-XHE-NOREC	Operator Fails to Recover Emergency Power	8.0E-001	1.0E+000	TRUE	Yes
OEP-XHE-NOREC-BD	Operator Fails to Recover Off-Site Power Before Battery Depletion	8.8E-003	8.8E-003		No
OEP-XHE-NOREC-SL	Operator Fails to Recover Off-Site Power Before Seal LOCA	5.4E-001	5.4E-001		No
PPR-SRV-CO-SBO	Safety Relief Valves Open During a SBO	3.7E-001	3.7E-001		No
PPR-SRV-OO-1	Power Operated Relief Valve (PORV) 1 Fails to Reclose After Opening	2.0E-003	2.0E-003		No
PPR-SRV-OO-2	PORV 2 Fails to Reclose After Opening	2.0E-003	2.0E-003		No
PPR-XHE-NOREC-L	Operator Fails to Close Block Valves	1.1E-002	1.1E-002		No
RCS-MDP-LK-SEALS	RCP Seals Fail Without Cooling and Injection	7.4E-003	7.4E-003		No

Table B.10.2. Sequence Conditional Probabilities for LER No. 389/95-005

Event tree name	Sequence name	Conditional core damage probabiliy (CCDP)	Core damage probability (CDP)	Importance (CCDP-CDP)	Percent contribution[b]
LOOP	41	5.3E-006	1.7E-007	5.1E-006	38.6
LOOP	23	4.1E-006	1.3E-007	3.9E-006	29.5
LOOP	30	1.8E-006	6.3E-008	1.8E-006	13.6
LOOP	32	1.5E-006	5.1E-008	1.4E-006	10.6
LOOP	39	6.9E-007	2.3E-008	6.7E-007	5.0
LOOP	40	3.4E-007	7.7E-010	3.4E-007	2.5
Total (all sequences)[a]		**1.4E-005**	**9.9E-007**	**1.3E-005**	

[a] This analysis represents the conditional core damage probability because of the long-term unavailability (15 days) of the 2A EDG and the increased potential for common cause failure of the 2B EDG.
[b] Percent contribution to the total Importance.

Table B.10.3. Sequence Logic for Dominant Sequences for LER No. 389/95-005

Event tree name	Sequence name	Logic
LOOP	41	/RT-L, EP, AFW-L-EP
LOOP	23	/RT-L, EP, /AFW-L, /PORV-SBO, /SEALLOCA, OP-BD
LOOP	30	/RT-L, EP, /AFW-L, /PORV-SBO, SEALLOCA, OP-SL
LOOP	32	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, /SEALLOCA, OP-BD
LOOP	39	/RT-L, EP, /AFW-L, PORV-SBO, /PRVL-RES, SEALLOCA, OP-SL
LOOP	40	/RT-L, EP, /AFW-L, PORV-SBO, PRVL-RES

Table B.10.4. System Names for LER No. 389/S5-005

System name	Logic
AFW-L	No or Insufficient AFW Flow During a LOOP event
AFW-L-EP	No or Insufficient AFW Flow During SBO
EP	Failure of Both Trains of Emergency Power
OP-BD	Operator Fails to Recover Off-Site Power Before Battery Depletion
OP-SL	Operator Fails to Recover Off-Site Power Before Core Uncovery Following a Seal LOCA on a RCP
PORV-SBO	PORVs Open During a SBO
PRVL-RES	PORVs and Block Valves Fail to Reseat
RT-L	Reactor Fails to Trip During a LOOP
SEALLOCA	RCP Seals Fail During a LOOP

Table B.10.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 389/95-005

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
LOOP Sequence 41		5.3E-006	
1	50.2	2.7E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
2	45.5	2.4E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
3	1.5	8.3E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, AFW-XHE-XA-CST2E, AFW-XHE-NOREC-EP
4	1.4	7.6E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, AFW-XHE-XA-CST2E, AFW-XHE-NOREC-EP
LOOP Sequence 23		4.1E-006	
1	52.5	2.2E-006	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, OEP-XHE-NOREC-BD
2	47.5	1.9E-006	EPS-DGN-CF-AB, EPS-XHE-NOREC, OEP-XHE-NOREC-BD
LOOP Sequence 30		1.8E-006	
1	52.5	9.7E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	47.5	8.6E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
LOOP Sequence 32		1.5E-006	
1	52.5	7.9E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, OEP-XHE-NOREC-BD
2	47.5	7.2E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, OEP-XHE-NOREC-BD
LOOP Sequence 39		6.9E-007	
1	52.5	3.6E-007	EPS-DGN-FC-DGA, EPS-DGN-FC-DGB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	47.5	3.3E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL

Table B.10.5. Conditional Cut Sets for Higher Probability Sequences for LER No. 389/95-005

Cut set no.	Percent contribution	Conditional probability[a]	Cut sets[b]
LOOP Sequence 40		3.4E-007	
1	48.9	1.7E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-1
2	48.9	1.7E-007	EPS-DGN-CF-AB, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-2
Total (all sequences)		1.4E-005	

[a]The conditional probability is determined by calculating the conditional probability for the period in which the condition existed. The conditional probability for each cut set within a sequence is determined by multiplying the probability that the portion of the sequence that makes the precursor visible (e.g., the system with a failure is demanded) will occur during the duration of the event by the probabilities of the remaining basic events in the minimal cut set. This can be approximated by $1 - e^{-p}$, where p is determined by multiplying the expected number of initiators that occur during the duration of the event by the probabilities of the basic events in that minimal cut set. The expected number of initiators is given by λt, where λ is the frequency of the initiating event (given on a per-hour basis), and t is the duration time of the event (in this case, 360 h). This approximation is conservative for precursors made visible by the initiating event. The frequency of interest for this event is $\lambda_{LOOP} = 1.6 \times 10^{-5}$/h.

[b]Basic events EPS-DGN-FC-DGA and EPS-XHE-NOREC are TRUE type events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

B.11 LER Nos. 445/95-003, -004

Event Description: Reactor trip, auxiliary feedwater (AFW) pump trip, second AFW pump unavailable

Date of Event: June 11, 1995

Plant: Comanche Peak 1

B.11.1 Event Summary

While at 100% power on June 11, 1995, Comanche Peak 1 experienced a control power supply failure resulting in both main feedwater pumps (MFPs) tripping and operators subsequently initiating an anticipatory reactor trip. Flow from one of two motor-driven auxiliary feedwater pumps (MDAFWP) was initially unavailable and the turbine-driven auxiliary feedwater pump (TDAFWP) started on low-low steam generator level but tripped on overspeed. The conditional core damage probability (CCDP) estimated for this event is 6.5×10^{-5}.

B.11.2 Event Description

While at 100% power on June 11, 1995, Comanche Peak 1 experienced a control power supply failure resulting in both MFPs tripping and operators subsequently initiating an anticipatory reactor trip. Slave relay testing was under way when a nonsafety related inverter transferred from its normal inverter ac power supply to its alternate power supply. The alternate ac power supply was deenergized as required by the test procedure at the time, so associated loads were deenergized. The specific cause of the transfer is not certain but it may have been caused by an electrical transient in a static transfer switch control circuit. Loss of the power supply caused a spurious "MFP oil pressure low" signal when auxiliary relays in pump supervisory instrumentation deenergized and actuated. This change caused the condensate pumps to trip; loss of the condensate pumps caused both MFPs to trip. Operators then initiated a manual reactor trip in anticipation of an automatic one.

The MFP trips caused an auto-actuation of the MDAFWPs. MDAFWP 1-02 (Train B) started and supplied water to steam generators (SGs) 3 and 4 (Fig. B.11.1). MDAFWP 1-01 (Train A) was aligned to its test header at the time and was not immediately available to supply water to the SGs. The TDAFWP started on low-low SG level but tripped on overspeed, caused by a failure of the governor valve to control turbine speed. The governor valve stem was found to be corroded and binding against the valve packing. Operators realigned MDAFWP 1-01 from the test header to its normal configuration, and the pump supplied cooling to SGs 1 and 2 within about 8 min.

B.11.3 Additional Event-Related Information

The licensee event report (LER) provided additional information concerning the thermal-hydraulic effects of having only one AFW pump available immediately after a plant trip. Plant safety analyses assume for a "Loss of Normal Feedwater Flow" transient that the TDAFWP or both MDAFWPs provide a flow rate of at least 3,260 l/m (860 gpm) to the SGs. During this transient, only one MDAFWP was initially available, providing a reduced flow rate to the SGs. However, the LER indicated that the reduced flow rate was adequate to remove plant decay heat from the SGs because of the early manual trip of the reactor and because initial water levels in the SGs were greater than the assumption used in the FSAR analysis. Because sufficient heat removal capability was available, the thermal expansion of the reactor coolant system inventory did not fill the pressurizer completely.

B.11.4 Modeling Assumptions

This event was modeled as a reactor trip with the TDAFWP failed and flow from MDAFWP 1-01 initially unavailable. Basic event AFW-TDP-FC-1C was set to "TRUE" (failed). (Table 1 provides a description of the basic event names.) It was assumed that if the remaining AFW pump had failed, operators would have attempted to recover the system by realigning MDAFWP 1-01 (as they did). Recovery of MDAFWP 1-01 was incorporated into the models using the methodology described in Reference 4. This methodology suggests a nonrecovery probability of 0.1 when "[f]ailure appeared recoverable in the required period from the control room, but recovery was not routine or involved substantial stress." A similar nonrecovery value was estimated by assuming that nonrecovery as a function of time was lognormally distributed with a median response time of 8 min and a recovery window of 30 min. Assuming a burdened-recovery error factor of 6.4, the probability of nonrecovery within 30 min is approximately 0.1, which is the same value as obtained using Ref. 4. Consequently, the nonrecovery probability for MDAFWP 1-01 was incorporated by setting the probability for event AFW-MDP-FC-1A equal to 0.1. In addition, because AFW is required without delay during anticipated transient without scram (ATWS) sequences, a new event, AFW-MDP-FC-AA, with a nonrecovery probability of 1.0 was substituted for AFW-MDP-FC-1A in the ATWS model. Because it was assumed that the entire 30 min would be dedicated to recovery of AFW-MDP-FC-1A, the system nonrecovery, AFW-XHE-NOREC, was set to 1.0.

Because main feedwater (MFW) apparently could not have been recovered without correcting the inverter problem, restarting the condensate system, and restoring a feedwater pump to service, the feedwater system was assumed not to be recoverable (MFW-XHE-NOREC = "TRUE").

The failures in this event increase the potential significance of failure to trip/ATWS sequences. To model potential reactor trip failures more accurately, the reactor trip model was modified (as shown in Fig. B.11.2) to account for recoverable versus nonrecoverable reactor protection system (RPS) failures.

The event trees for Comanche Peak assume that conditions requiring a reactor trip will first result in an automatic reactor trip demand and, if the automatic trip fails, a manual reactor trip demand. During this event, once operators recognized that a loss of main feedwater flow had occurred, they initiated a manual reactor trip. Because of the operators' quick response, consideration was given to the potenti·l impacts of the early reactor trip on ATWS sequences. The Comanche Peak Final Safety Analysis Report (FSAR) indicates that 1 to 1½ min may elapse between a loss of feedwater and an automatic reactor trip. The additional 1 min of response time available to operators during postulated ATWS sequences in this event was not believed to materially affect the event sequences or probabilities, and no related model changes were indicated.

B.11.5 Analysis Results

The CCDP estimated for this event is 6.5×10^{-5}. The dominant core damage sequence (sequence 20 on Fig. B.11.3) involves

- a successful reactor trip,
- failure of AFW
- failure of MFW, and
- failure of feed-and-bleed cooling.

The second highest core damage sequence (sequence 21-8 on Figs. B.11.3 and B.11.4) involves

- failure to successfully trip,
- successful control of reactor pressure, and
- failure of AFW.

Definitions and probabilities for selected basic events are shown in Table B.11.1. The conditional probabilities associated with the highest probability sequences are shown in Table B.11.2. Table B.11.3 lists the sequence logic associated with the sequences listed in Table B.11.2. Table B.11.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table B.11.5.

B.11.6 References

1. LER 445/95-003, Rev. 1, "Loss of Both Condensate and Both Feedwater Pumps Due to Failure of Non-Safety Related Inverter Resulted in a Manual Reactor Trip," August 14, 1995.

2. LER 445/95-004, Rev. 1, "Allowed Outage Time Was Exceeded on Turbine-Driven Auxiliary Feedwater Pump Which Tripped on Overspend," September 8, 1995.

3. Texas Utilities Generating Company, *Comanche Peak Steam Electric Station Final Safety Analysis Report*.

4. M. B. Sattison et al., "Methods Improvements Incorporated into the SAPHIRE ASP Models," in *Proceedings of the U.S. Nuclear Regulatory Commission, Twenty-Second Water Reactor Safety Information Meeting*, NUREG/CP-0140, Vol. 1, April 1995.

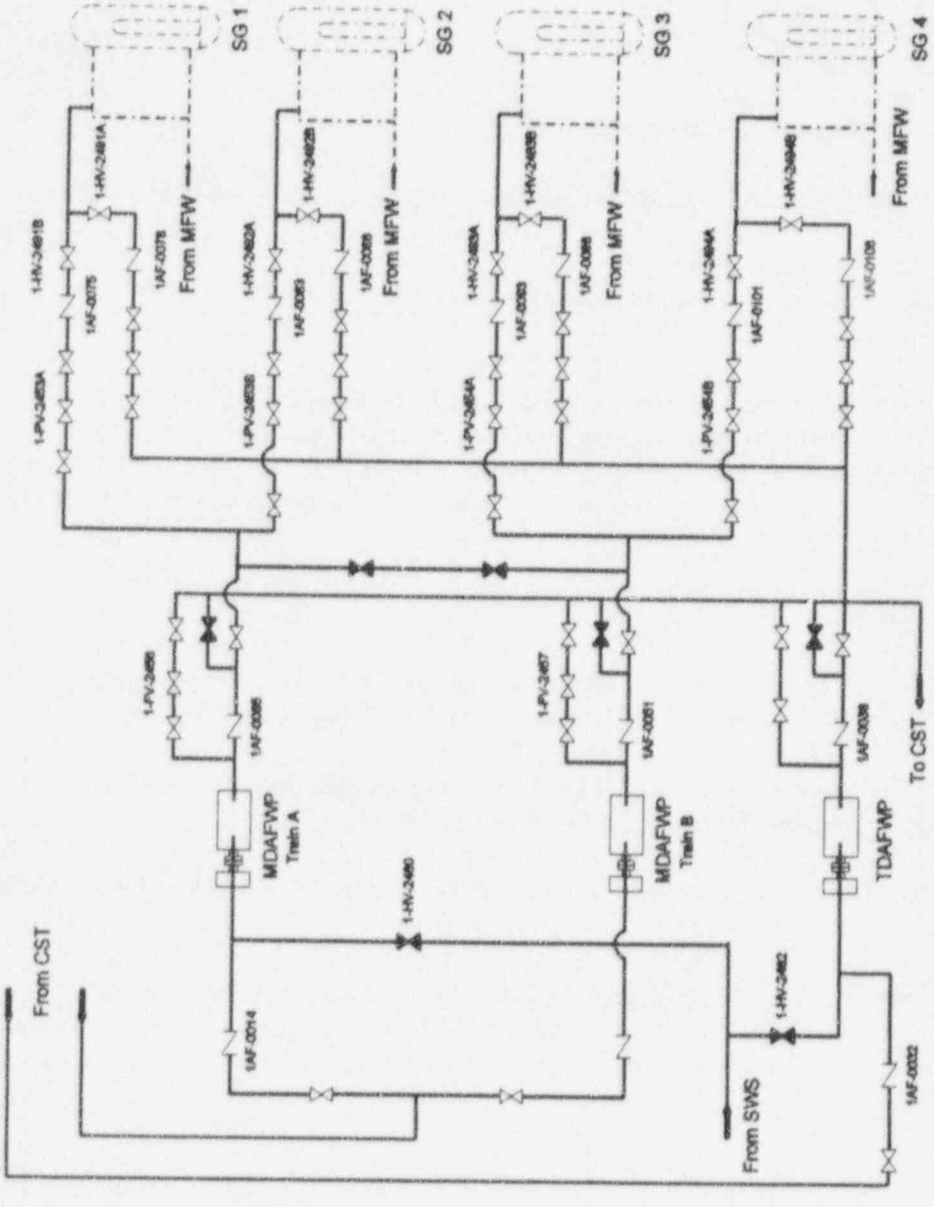

Fig. B.11.1. Auxiliary feedwater system for Comanche Peak (Source: Texas Utilities Electric Co., *Comanche Peak Steam Electric Station Final Safety Analysis Report*).

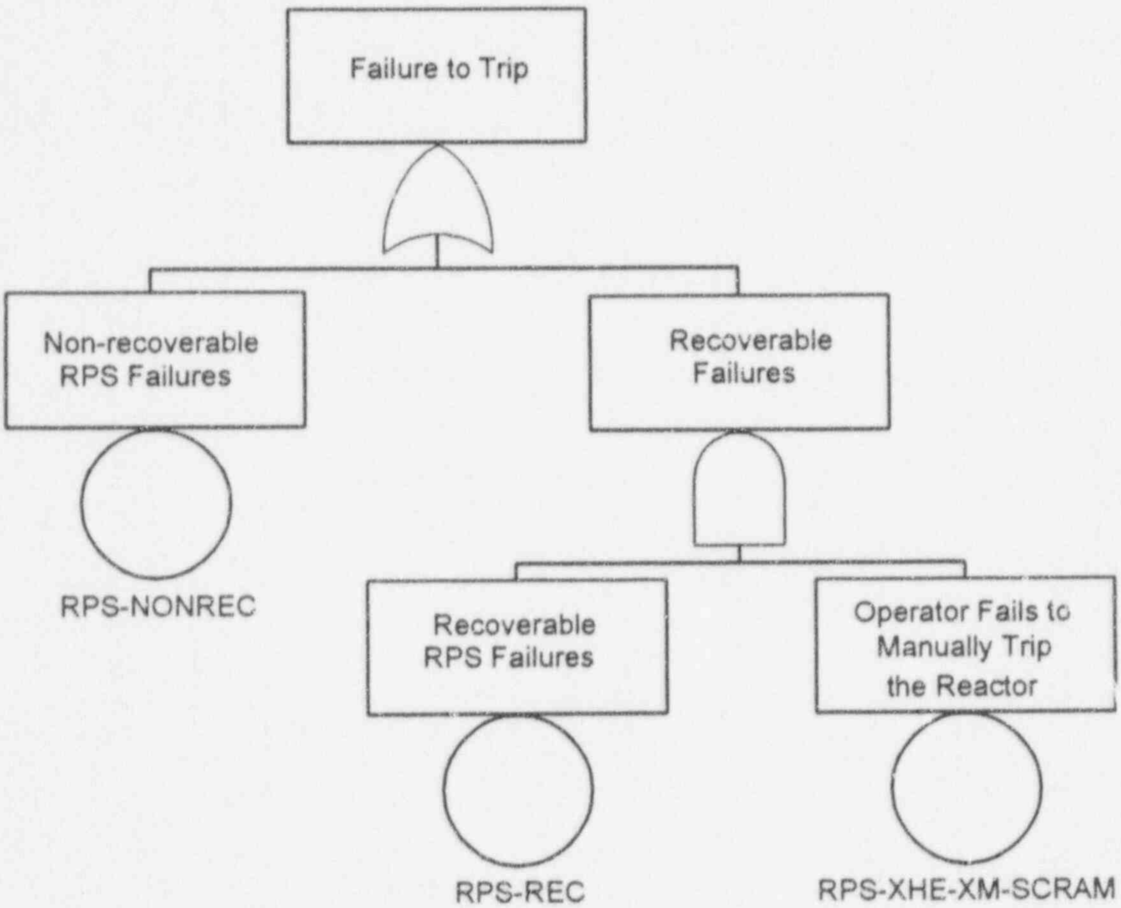

Fig. B.11.2. Fault tree modeling recoverable and nonrecoverable failures for the failure to trip.

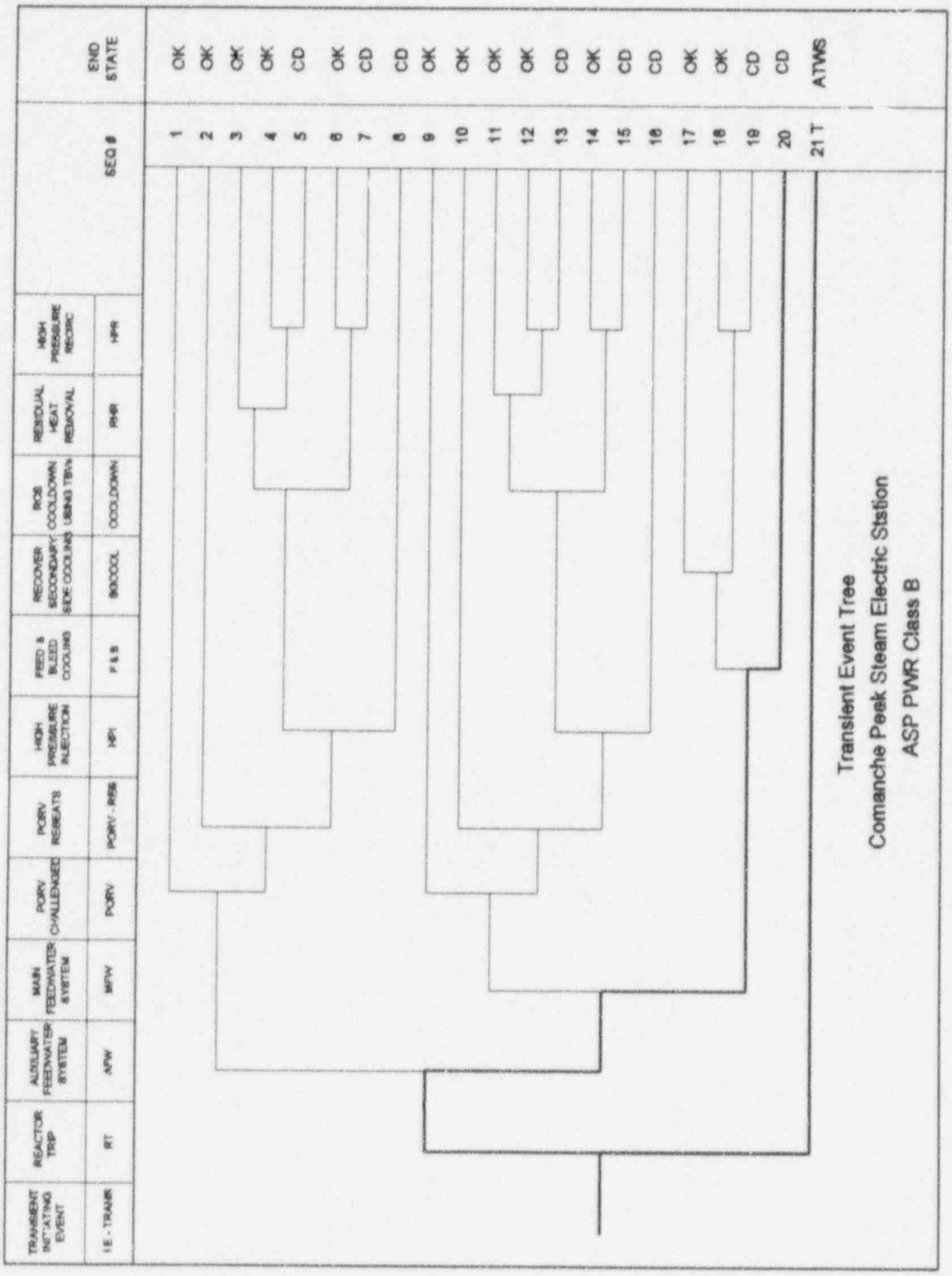

Fig. B.11.3. Dominant core damage sequences for LERs 445/95-003, -004.

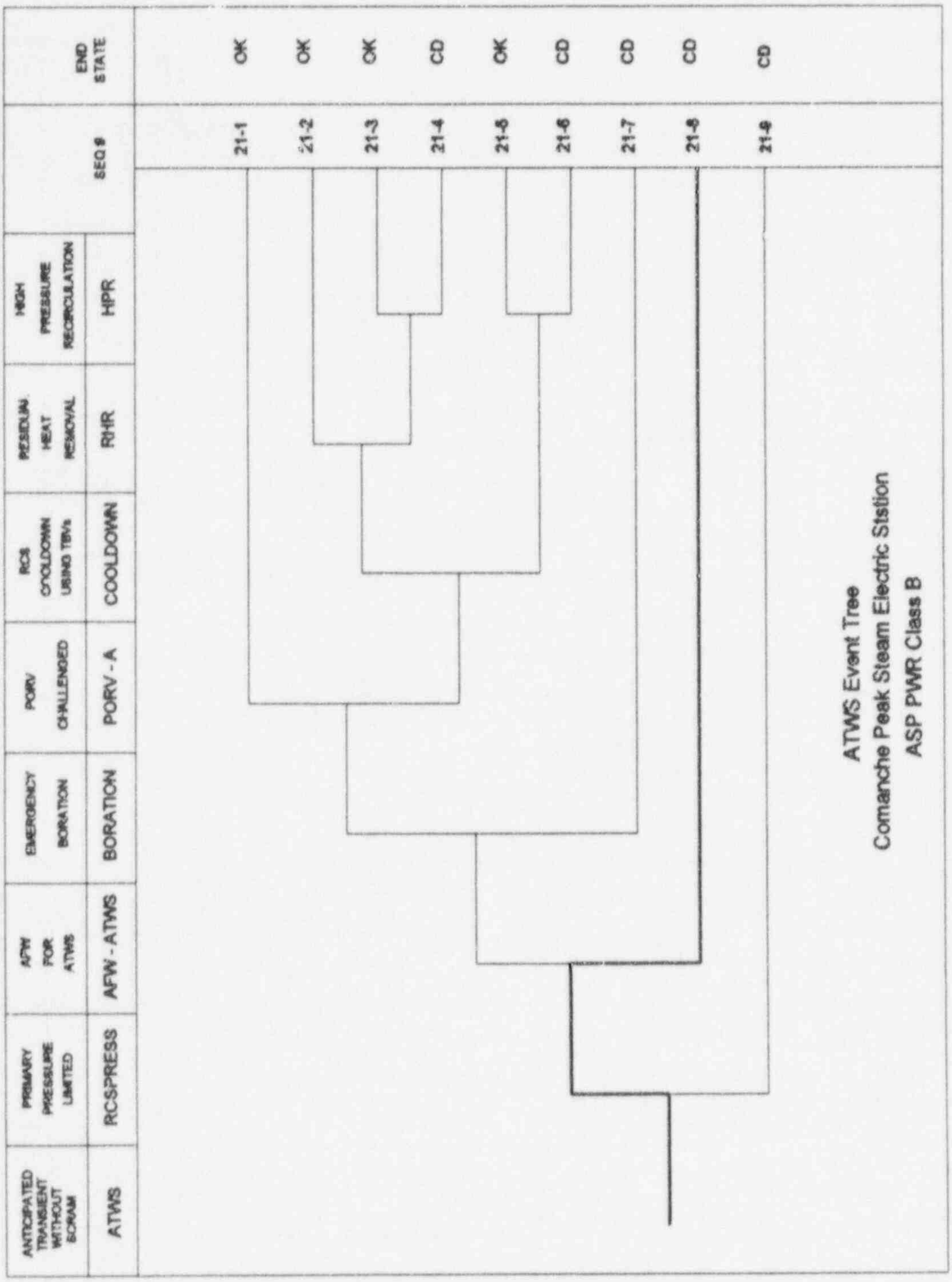

Fig. B.11.4. Anticipated transient without scram (ATWS) event tree for Comanche Peak.

Table B.11.1. Definitions and probabilities for selected basic events for LERs 445/95-003, -004

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss-of-Offsite Power Initiating Event	8.5E-006	0.0E+000	IGNORE	No
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6E-006	0.0E+000	IGNORE	No
IE-SLOCA	Small Loss-of-Coolant Accident Initiating Event	1.0E-006	0.0E+000	IGNORE	No
IE-TRANS	Transient Initiating Event	5.3E-004	1.0E+000		Yes
AFW-MDP -CF-AB	Common-Cause Failure (CCF) of Motor-Driven Pumps	2.1E-004	2.1E-004		No
AFW-MDP-FC-AA	AFW Motor-Driven Pump A Fails During ATWS	4.0E-003	1.0E+000	TRUE	Yes
AFW-MDP-FC-1A	AFW Motor-Driven Pump A Fails	4.0E-003	1.0E-001		Yes
AFW-MDP-FC-1B	AFW Motor-Driven Pump B Fails	4.0E-003	4.0E-003		No
AFW-PMP-CF-ALL	AFW Serial Component Common to all Trains Fails (i.e., Common-Cause Failure)	2.8E-004	2.8E-004		No
AFW-TDP-FC-1C	AFW Turbine-Driven Pump Fails	3.2E-002	1.0E+000	TRUE	Yes
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6E-001	1.0E+000	TRUE	Yes
AFW-XHE-NREC-ATW	Operator Fails to Recover AFW System During an ATWS	1.0E+000	1.0E+000		No
AFW-XHE-XA-SSW	Operator Fails to Align Suction to Service Water System (SSW)	1.0E-003	1.0E-003		No
HPI-XHE-XM-FB	Operator Fails to Initiate Feed-and-Bleed Cooling	1.0E-002	1.0E-002		No
MFW-SYS-TRIP	MFW System Trips	1.0E+000	1.0E+000		No
MFW-XHE-NOREC	Operator Fails to Recover MFW	2.6E-001	1.0E+000	TRUE	Yes

Table B.11.1. Definitions and probabilities for selected basic events for LERs 445/95-003, -004

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-SRV-CC-1	Power-Operated Relied Valve (PORV) 1 Fails to Open on Demand	6.3E-003	6.3E-003		No
PPR-SRV-CC-2	PORV 2 Fails to Open on Demand	6.3E-003	6.3E-003		No
RPS-NONREC	Nonrecoverable RPS Trip Failures	2.0E-005	2.0E-005	NEW	Yes
RPS-REC	Recoverable RPS Failures	4.0E-005	4.0E-005	NEW	Yes
RPS-XHE-XM-SCRAM	Operator Fails to Manually Trip the Reactor	1.0E-002	1.0E-002	NEW	Yes

Table B.11.2. Sequence conditional probabilities for LER 445/95-003, -004

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
TRANS	20	4.3E-005	66.8
TRANS	21-8	2.0E-005	31.2
Total (all sequences)		6.5E-005	

Table B.11.3. Sequence logic for dominant sequences for LER 445/95-003, -004

Event tree name	Sequence name	Logic
TRANS	20	/RT, AFW, MFW, F&B
TRANS	21-8	RT, /RCSPRESS, AFW-ATWS

Table B.11.4. System names for LER 445/95-003, -004

System name	Logic
AFW	No or Insufficient AFW Flow
AFW-ATWS	No or Insufficient AFW Flow–ATWS
F&B	Failure to Provide Feed-and-Bleed Cooling
MFW	Failure of the MFW System
RCSPRESS	Failure to Limit RCS Pressure to <3200 psi
RT	Reactor Fails to Trip During Transient

Table B.11.5. Conditional cut sets for higher probability sequences for LER 445/95-003, -004

Cut set number	Percent contribution	Conditional probability[a]	Cut sets[b]
TRANS Sequence 20		4.3E-005	
1	22.9	1.0E-005	AFW-XHE-XA-SSW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
2	14.4	6.3E-006	AFW-XHE-XA-SSW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1
3	14.4	6.3E-006	AFW-XHE-XA-SSW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-2
4	9.2	4.0E-006	AFW-MDP-FC-1A, AFW-MDP-FC-1B, AFW-TDP-FC-1C, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
5	6.4	2.8E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
6	5.8	2.5E-006	AFW-MDP-FC-1A, AFW-MDP-FC-1B, AFW-TDP-FC-1C, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1
7	5.8	2.5E-006	AFW-MDP-FC-1A, AFW-TDP-FC-1C, AFW-MDP-FC-1B, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-2
8	4.8	2.1E-006	AFW-PMP-CF-AB, AFW-MDP-FC-1C, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
9	4.0	1.7E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1
10	4.0	1.7E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-2
11	3.0	1.3E-006	AFW-MDP-CF-AB, AFW-TDP-FC-1C, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1
12	3.0	1.3E-006	AFW-MDP-CF-AB, AFW-TDP-FC-1C, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-2
TRANS Sequence 21-8		2.0E-005	
1	98.0	2.0E-005	RPS-NONREC, AFW-MDP-FC-AA, AFW-TDP-FC-1C, AFW-XHE-NREC-ATW
2	1.9	4.0E-007	RPS-REC, RPS-XHE-XM-SCRAM, AFW-MDP-FC-AA, AFW-TDP-FC-1C, AFW-XHE-NREC-ATW
Total (all sequences)		**6.5E-005**	

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilies for the initiating events and the basic events are given in Table B.11.1.

[b]Basic events AFW-MDP-FC-AA, AFW-TDP-FC-1C, AFW-XHE-NOREC, and MFW-XHE-NOREC are all type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

Appendix C:

Potentially Significant Events Considered Impractical to Analyze

C.1 Potentially Significant Events Considered Impractical to Analyze

One licensee event report (LER) has been identified as potentially significant but impractical to analyze. It is believed that events considered impractical are capable of impacting core damage sequences. However, the events usually involve component degradations in which the extent of the degradation could not be determined or the impact of the degradation on plant response could not be ascertained.

The event identified for 1995 are shown in Table C.1. A summary, event description, and any additional event-related information are provided for this event.

Table C.1 Event identified as potentially significant but impractical to analyze

Event number	Plant	Event descriptions	Page
LER 313/95-002	Arkansas Nuclear One, Unit 1	Service Water Valve Leakage Could Cause Depletion of the Emergency Cooling Pond	C.2-1

C.2 LER No. 313/95-002

Event Description: Service water valve leakage could cause depletion of the emergency cooling pond

Date of Event: March 4, 1995

Plant: Arkansas Nuclear One, Unit 1

C.2.1 Event Summary

The seat on an Arkansas Nuclear One, Unit 1 (ANO-1) service water (SW) valve was found to be degraded to the point that leakage through the valve could have resulted in insufficient Emergency Cooling Pond (ECP) inventory following a postulated loss of the Dardanelle Reservoir, which could be caused by a dam failure resulting from an earthquake.

C.2.2 Event Description

On March 4, 1995, with ANO-1 in a refueling outage and ANO-2 operating at 98% power, the seat on a Unit 1 SW valve was found to be degraded to the point that leakage through the valve could have resulted in insufficient ECP inventory following a postulated loss of the Dardanelle Reservoir, which could be caused by a dam failure resulting from an earthquake.

At ANO-1, the SW system receives cooling water from the Dardanelle Reservoir and supplies it to cool heat exchangers and miscellaneous load in two safety-related loops. The system consists of an Intake Structure and its associated equipment, a 14 acre ECP as a backup supply of cooling water, a series of sluice gates which direct water from the Intake Canal or ECP, three SW pumps, a discharge flume, and various system loads. During normal operation, SW is pumped from the reservoir, through the system loads, and into a return header common to both loops. Water in the return header flows into the circulating water discharge flume via CV-3824, an 18-in. motor-operated butterfly valve.

The ECP serves as an ultimate heat sink for both units if reservoir inventory were to be lost, for example, from a dam failure caused by an earthquake. The ECP is sized for the 30-day heat loads from both units, without makeup, assuming one unit has suffered a design-basis loss of coolant accident and the other has been shut down. In order to realign the ANO-1 SW system to the ECP, CV-3824 must be shut to prevent discharge of water to the reservoir (a separate valve is provided for Unit 2).

On March 1, 1995, a visual inspection of CV-3824 was conducted following its removal from the SW system for piping modifications. This inspection revealed that the rubber seat was missing from approximately one-half of the valve seating surface. The licensee concluded that the ECP could be depleted in approximately six days with this valve leakage instead of the 30 days required by the design, using conservative assumptions concerning weather conditions at the site. Loss of inventory via valve CV-3824 would impact both units.

C.2.3 Basis for Selection as an Impractical to Analyze Event

Because the probability of failure of the Dardanelle Reservoir dam due to an earthquake and the resulting long-term need for the ECP cannot be quantified within the resources available to the ASP Program, this event is impractical to analyze.

C.2.4 References

1. LER 313/95-002, Rev. 0, "Service Water Seat Leakage Resulted in Inability to Maintain Emergency Cooling Pond Inventory for Thirty Days Following a Design Basis Accident Without Additional Action," March 31, 1995.

Appendix D:

Containment-Related Events

D.1 Containment-Related Events

No reactor plant operational event for 1995 was selected as a containment-related event. Such events involve unavailability of containment function, containment isolation, containment cooling, containment spray, or postaccident hydrogen control. Containment-related events are not currently considered precursor events as defined by the Accident Sequence Precursor Program; however, the potential for increased exposure to the public justifies their inclusion in the report. Containment models have not been developed as part of the Accident Sequence Precursor Program. Again, no containment-related events were identified for 1995.

Appendix E:

"Interesting" Events

E.1 "Interesting" Events

Six reactor plant operational events for 1995 were selected as "interesting" events. These events are documented in this section. "Interesting" events are not normally precursor events as defined by the Accident Sequence Precursor Program; however, they provide insight into unusual failure modes with the potential to compromise continued core cooling. The events identified for 1995 are shown in Table E.1.

A summary, event description, and any additional event-related information are provided for these events.

Table E.1 Index of "Interesting" Events

E.2 LER No. 275/95-014

Event Description: Loss-of-offsite power and fire

Date of Event: October 11, 1995

Plant: Diablo Canyon 1

E.2.1 Event Summary

On October 21, 1995, personnel were backfeeding offsite power to Unit 1 via the auxiliary transformer while performing maintenance on the startup (SU) bus. Attempting to reenergize the bus with a grounding device still installed caused auxiliary transformer 1-1 to catastrophically fail and offsite power to be lost. The three emergency diesel generators (EDGs) started and loaded, and residual heat removal (RHR) cooling was restored. At the time of the event, refueling operations had been completed and the vessel head was reinstalled, although it was not yet tensioned. The licensee estimated that without restoration of RHR cooling, boiling in the core would occur in about 1.3 h. The SU bus was reenergized and offsite power restored to the safety-related buses ~16 h later.

E.2.2 Event Description

On October 21, 1995, Diablo Canyon 1 was in Mode 6 (refueling) with core reload complete and the reactor head on but not tensioned. Offsite power was being backfed through the main transformer and auxiliary transformer while the 12 kV bus D startup power source was cleared for maintenance. In support of maintenance activities, a grounding device "ground buggy" had been installed on the "load" or "bus" side of breaker 52-VD-4, and caution tags had been placed on control board breaker switches. A "ground installed" tag was hung on the breaker cubicle. (Breaker 52-VD-4 is the startup feeder breaker to 12 kV bus D. Ground buggies are personnel and equipment protecting grounding devices that replace the breaker in the breaker cubicle and can be aligned to ground either the load or the bus side of the breaker.)

At approximately 0400 on October 21, 1995, a Technical Maintenance foreman, in response to a request from operations, electronically verified that the work on bus D was complete and that all red tags had been removed. While physically walking down the clearance, he noted two "ground installed" tags and verified that the ground buggies were installed on the load side of their associated cubicles. He did not notice a "ground installed" tag on the 52-VD-4 cubicle and reported off the clearance (e.g., reported that the equipment was cleared for operation).

Two hours later, operations personnel removed additional bus D clearance tags and racked in breakers in preparation for reenergizing bus D from the auxiliary transformer. They noted that 52-VD-4 was racked out with an additional maintenance tag in effect as a result of the startup bus clearance. They did not recall seeing a "ground installed" tag on the cubicle door. At 0620, an operator removed the control board caution tags from the 52-VD-4 and 52-VD-8 breaker switches in the control room. (Breaker 52-VD-8 is the auxiliary feeder breaker to 12 kV bus D.)

Later that morning the day shift crew made final preparations for reenergizing bus D for an uncoupled run of a reactor coolant pump. Prior to closing auxiliary feeder breaker 52-VD-8, the operators discussed the "ground installed" lamacoid attached to the switch plate for breaker 52-VD-4. The operators understood that if the ground buggy was installed on the 12 kV bus D side of the breaker, a direct path to ground would exist when the bus was reenergized. The operators erroneously concluded that the ground buggy was located on the startup bus side of 52-VD-4. This conclusion was based on the fact that the 12 kV bus D clearance had been reported off, and the associated control board caution tag had been removed from the 52-VD-4 operating switch. The fact that a separate clearance had recently been issued for work on the startup bus also supported the existence of the ground buggy on the startup bus side of breaker 52-VD-4. The operators did not physically check the 52-VD-4 cubicle to verify their assumptions.

At approximately 0938, an attempt was made to energize 12 kV bus D. When the auxiliary transformer feeder breaker, 52-VD-8, was closed to energize the bus, a catastrophic failure of auxiliary transformer 1-1 occurred. All relays and breakers responded to the instantaneous overload condition, but not soon enough to prevent the damage that occurred. The rupture of the transformer case released the contained coolant oil which then ignited. The transformer deluge systems actuated as designed. The newly installed main transformers were slightly damaged by the fire (paint damage and a coating of oil and fire-fighting foam). The iso-phase bus ducting was ruptured at the transformer, and one of the glass viewing ports was blown out at the motor-operated disconnect switch. Due to the fire, smoke, and loss of lighting, the turbine, containment, and administrative buildings were evacuated.

The event caused a loss-of-offsite power (LOOP) to Unit 1. All three EDGs at Unit 1 started and loaded their respective buses. RHR pump 1-1 was restarted following the loadshed. This still left the nonvital buses deenergized. Technical maintenance and substation maintenance personnel were allowed to perform initial inspections and to complete maintenance activities already begun on the SU transformers and buses prior to initiating switching to restore offsite power to the unit.

At 1010, the fire was reported to be out and the transformer deluge system was secured. At 0022 the next morning SU transformer 1-1 was energized. By 0128, offsite power had been restored to all three safety-related buses. The licensee believed startup power could have been restored, if needed, within 30 min at any time during the event. Unit 2 was not affected and continued to operate at 100% power throughout the event.

E.2.3 Basis for Selection as an "Interesting" Event

After the LOOP and the successful start and load of all three EDGs, the operators restarted the RHR system and chose to continue maintenance on the SU transformers and buses that was in progress at the time of the event. The LOOP lasted almost 16 h, but the licensee believed the SU transformers could be made available at any time with a 30-min delay.

A LOOP in any mode is of interest to the ASP Program because of the need to utilize the emergency power system to power safety-related systems and the reduced number of systems that were available to provide core cooling. Almost all LOOPs that occur at power are documented as precursors. In this event, the potential to recover the SU buses, utilize any one of the three EDGs to power the RHR or safety injection pumps, and utilize gravity feed to provide makeup water to keep the core covered, if all ac power had failed, results in an estimated conditional core damage probability below the ASP documentation threshold of 1×10^{-6}. This event was, therefore, documented as an "interesting" event instead of as a precursor.

E.2.4 Factors of Interest

This event is of interest because of the plant electrical status at the time of the event and the length of time required to recover offsite power.

E.2.5 References

1. LER 275/95-014, Rev. 0, "Diesel Generators Started and Loaded as Designed Upon Failure of Auxiliary Transformer 1-1 Due to Inadequate/Ineffective Procedures Related to the Control of Grounding Devices," November 20, 1995.

E.3 LER No. 354/95-016

Event Description: Partial core flow bypass during shutdown

Date of Event: July 9, 1995

Plant: Hope Creek 1

E.3.1 Event Summary

For a period of approximately 19 h, the shutdown cooling flow at Hope Creek was misaligned such that insufficient decay heat was removed from the reactor core. Localized core boiling occurred on two occasions before the condition was recognized and corrected.

E.3.2 Event Description

Hope Creek was removed from service on July 8, 1995, due to problems associated with the control room ventilation system. The plant was cooled down and the residual heat removal (RHR) system was aligned to remove decay heat. While the unit was shut down, operators periodically cycled the recirculation pump discharge valves, valves 1BBHV-F031A ("31A") and 1BBHV-F031B ("31B"), to prevent thermal binding of the valves.

At 0940 and again at 0950 on July 8, operators attempted to cycle the 31A valve but were unable to do so. At 1100, the 31B valve was cracked open and left in that position to prevent it from binding. This action, which was inconsistent with plant procedures, allowed RHR return water to bypass the reactor and return directly to the shutdown cooling suction supply line. At 1152, operators opened the reactor vessel head vent valves. At 1635, believing that the indicated RHR heat exchanger inlet temperature of 72.8°C (163°F) accurately reflected reactor coolant temperature, operators removed RHR loop B from service.

The temperature of the reactor coolant quickly reached saturation temperature, and reactor pressure rose to about 0.12 MPa (17 psig). At 1709, B train RHR was returned to service. The reactor coolant temperature was initially indicated at 83.3°C (182°F), and indication subsequently dropped to 72.8°C (163°F). Throughout this time the 31B valve remained open, allowing some reactor coolant to recirculate through the RHR system instead of passing through the reactor core. At about this time operators entered the drywell to perform several tasks, including cracking open the 31A valve by hand. During the drywell entry, operators observed that the drywell atmosphere was excessively humid and that water droplets were visible on equipment surfaces.

After shift turnover, the oncoming shift supervisor observed recirculation loop flow instrumentation indicating a 7570 l/m (2000 gpm) flow, and it was decided to close the discharge valves for the recirculation pumps. Valve 31 A was closed but difficulties were encountered with 31B. By cycling the 31B valve, operators opened it further, allowing an estimated 15,140 l/m (4000 gpm) of bypass flow. Around that time, increased input to the drywell floor drain sump was noted, but the cause was not correctly understood. Later, it was determined that the flow increase detected by the drywell leak detection system was caused by steam from the reactor vessel head vent condensing in the drywell. Presumably, the releases through the vent on the reactor vessel head were also responsible for the increased humidity reported in the drywell.

At 0100 on July 9, a reactor pressure trip unit was observed indicating high. Further investigation found that multiple reactor pressure channels were indicating unexpectedly high, in the range of 0.14 MPa (20 psig). After several unsuccessful attempts to remotely manipulate valve 31B, operators manually closed it and RHR loop B was returned to full operability around 0550. Heat exchanger inlet temperature rose to 88.3°C (191°F) and then began falling. A review of the data from the event indicated that the reactor core had boiled on two occasions during the event causing inadvertent mode changes and Technical Specification violations.

E.3.3 Basis for Selection as an "Interesting" Event

During the event, recirculation pump discharge valve 31B stuck in a partially opened position, degrading the capability of RHR train B. For a time during the event, valve 31A was also "cracked" open. However, there is no information to indicate that the capability of train A of RHR was degraded or that the 31A valve could not have been closed on demand at any time. As equipment in only one train of a safety-related system was reported to be degraded during this event (B RHR), this event does not meet criteria for analysis as an accident sequence precursor. However, the event is summarized for general interest.

E.3.4 Factors of Interest

Subsequent to the events described in LER 354/95-016, it was reported that procedures exist at Hope Creek which direct the bypass of automatic shutdown cooling (SDC) high-pressure isolation signals during SDC system operation in order to prevent inadvertent system isolation. These procedures, which were implemented during the event, appear to defeat the purpose of the isolation function. With the isolation function disabled, the low-pressure SDC piping was not protected from increasing reactor pressure. Had reactor pressure increased above SDC operating limits, operator action would have been required to isolate and protect the system.

E.3.5 References

1. LER 354/95-016, Rev. 2, "Shutdown Cooling Bypass Event—Residual Heat Removal System B Loop Flow Bypass," March 6, 1996.

2. Inspection Report No. 50-354/95-81, "Special Team Inspection to Review Shutdown Cooling Bypass Event," September 25, 1995.

E.4 LER No. 361/95-005

Event Description: Loss of pressurizer level due to operator error

Date of Event: April 6, 1995

Plant: San Onofre 2

E.4.1 Event Summary

On April 6, 1995, while realigning the shutdown cooling (SDC) system for low-pressure safety injection (LPSI) prior to proceeding from Mode 5 to Mode 4, a control power fuse blew on SDC suction isolation valve 2HV-9379 and the valve did not close. Prior to ensuring the valve was closed, the LPSI pump mini-flow valves were opened, which created a path from the reactor coolant system (RCS) to the refueling water storage tank (RWST). Pressurizer level dropped at a rate beyond the capacity of the charging system. The control room operators responded by starting a second charging pump and reclosing the LPSI pump mini-flow valves. Pressurizer level was restored to normal within 10 min.

E.4.2 Event Description

On April 6, 1995, with the unit at the end of a refueling outage, operators were increasing RCS temperature to take the unit from Mode 5 to Mode 4. Operators were completing steps to isolate the SDC system from the RCS and realign the LPSI pumps to the emergency core cooling system. While attempting to close SDC suction isolation valve 2HV-9379, a control power fuse blew and the valve did not close. Before ensuring the valve was closed, the Control Room supervisor directed the assistant Control Room operator to continue with the procedure to terminate shutdown cooling.

At approximately 0205, the LPSI mini-flow isolation valves were opened before 2HV-9379 was closed. This created a flow path from the RCS to the RWST through 2HV-9379 and the LPSI mini-flow isolation valves. Pressurizer level began to decrease and the "PZR Level Error Lo" alarm actuated. The control room operators responded by starting a second charging pump and reclosing the LPSI mini-flow isolation valves that had just been opened. Pressurizer level was restored to normal within 10 min.

A review of control room charts and computer printouts indicated ~2540 l (~670 gal) were transferred to the RWST in the 2 min that the mini-flow valves were open, an effective flowrate of 1270 l/m (335 gpm). While this flowrate exceeded the available charging pump capacity, a single high-pressure injection system pump would have provided adequate makeup if required.

E.4.3 Basis for Selection as an "Interesting" Event

Operators recognized the leak path was associated with their last valve manipulation and took action within 2 min. Based on data in the licensee's Final Safety Analysis report for San Onofre 2, ~22,200 l (~5860 gal) are available in the pressurizer after drawing a bubble in preparation for proceeding to Mode 4. The initial leak rate of 1,270 l/m (335 gpm) indicates the operators had ~17.5 min prior to losing pressure control via the pressurizer. This time period is associated with operator failure probabilities on the order of 1.0×10^{-2} to 1.0×10^{-3} for a strongly cued event such as this.

If the operators failed to isolate the leak path, the RCS would have continued to drain to the bottom of the RCS loops. At this point, following a refueling as in this event, many hours would exist before the core was uncovered due to boil-off. Multiple valves were available to isolate the flow from the RCS to the RWST, as were multiple sources of makeup: the HPSI pumps, the non-SDC LPSI pump, and the accumulators. If the SDC system could not have been recovered, the steam generators could have been used in a reflux cooling mode for decay heat removal. The combined probability of failing to isolate the leak path before the pressurizer emptied and failing to provide core cooling once the RCS was drained to the RCS loops is less than the ASP documentation threshold of 1×10^{-6}. This event was, therefore, documented as an "interesting" event.

E.4.4 Factors of Interest

This is an interesting event because of the operational error that continued through a procedure with an incomplete step and because of the initial rate at which coolant was lost. The licensee indicated that, had the actual leak rate been known at the time, a Site Area Emergency would have had to have been declared because charging pump capacity was exceeded.

E.4.5 References

1. LER 361/95-005, "Loss of Pressurizer Level Due to a Valve Alignment Error," May 8, 1995.

E.5 LER No. 366/95-008

Event Description: Twelve thousand gallons transferred to the torus due to a valve-lineup error

Date of Event: November 2, 1995

Plant: Hatch 2

E.5.1 Event Summary

While the unit was shut down for refueling, personnel performed a test using the remote shutdown panel (RSP). When the B train Residual Heat Removal (RHR) reactor shutdown cooling suction valve was opened from the RSP, an incorrectly wired limit switch in the panel caused the suppression pool suction valve to open as well. This aligned the reactor vessel directly to the suppression pool and approximately 45,000 l (12,000 gal) of reactor coolant drained to the suppression pool before a low reactor water level automatic isolation signal isolated the flow path.

E.5.2 Event Description

On October 30, 1995, when plant operators attempted to open the B train RHR torus suction valve, valve 2E11-F004B ("4B"), at the conclusion of an RHR system logic functional test, they noted that the valve position light indication had been lost. On November 2, 1995, plant maintenance electricians began troubleshooting the valve. In support of the electricians' investigation, operators separately stroked open and closed the 4B valve and the B train RHR reactor vessel suction valve, valve 2E11-F006B ("6B"), from the control room. Both valves worked properly, and normal valve position indication was observed.

The maintenance electricians then asked the operators to stroke the valves from the RSP and two plant equipment operators (PEOs) were dispatched. In its standby configuration, the RSP "Emerg/Norm" switch was in "Norm," the control switches for valves 2E11-F006B and 2E11-[illegible]5D were in the "close" position, and the control switch for valve 4B was in the "open" position. When a PEO transferred the "Emerg/Norm" switch to the "Emerg" position, control was transferred to the RSP. At that time, valve 4B should have opened but an undetected wiring error prevented it from opening.

A PEO then switched the control switch for valve 6B to "open." At that time, valves 4B and 6B both began to open, creating a direct flow path from the reactor vessel to the suppression pool. Observing this, the PEO switched both control switches to "close." However, since both valves were designed to stroke fully open before closing, this did not immediately stop the draindown. Neither the PEO nor the control room operator were able to terminate the draindown and, after approximately 32 s, the primary containment isolation system (PCIS) Group 2/6 reactor vessel low-water level setpoint was reached, initiating an isolation. RHR PCIS isolation valves 2E11-F008 and 2E11-F009 closed, terminating the event. The minimum reactor water level achieved during the event was about 15 cm (6 in.) below instrument zero, or about 386 cm (152 in.) above the top of active fuel.

An investigation revealed that the RSP control circuits for valve 6B were miswired. An interlock intended to prevent simultaneous opening of valves 4B and 6B instead caused valve 4B to open automatically when 6B was opened. It was not determined when the wiring error occurred, but a records search determined that the valves were last demonstrated to operate correctly in 1978.

E.5.3 Basis for Selection as an "Interesting" Event

This event occurred 42 days after a shutdown for refueling, during which time one-third of the core had been replaced with new fuel. Accordingly, the reactor decay heat load at the time of the event was minimal. Because of this, and because redundant capability to automatically isolate the reactor draindown existed, the draindown event itself was judged to have limited safety significance.

E.5.4 Factors of Interest

This event reveals an apparent long-standing latent failure in the remote shutdown panel. Had a fire or other emergency requiring control room evacuation occurred during that time, the wiring error could have greatly exacerbated an already difficult situation.

E.5.5 References

1. LER 366/95-008, "Reactor Vessel Inventory Loss Results in Unplanned Engineered Safety Feature Systems Actuations," November 28, 1995.

2. Operating Reactors Events Briefing Summary 95-13, "Inadvertent Draining of Reactor Vessel and Isolation of Shutdown Cooling System," November 8, 1995, U.S. Nuclear Regulatory Commission/NRR Events Assessment and Generic Communications Branch.

E.6 LER No. 369/95-003

Event Description: Common-cause failure of all site emergency diesel generators

Date of Event: June 27, 1995

Plant: McGuire 1 and 2

E.6.1 Event Summary

The turbochargers for Unit 2 emergency diesel generator (EDG) 2A and EDG 2B failed during operability testing. The failures resulted from high-cycle fatigue due to resonance-induced vibration in recently installed turbochargers that used a different jet-assist design than the original turbochargers. The failure mode impacted the Unit 1 EDGs as well.

The new turbochargers were commercial-grade components. As part of the commercial-grade evaluation of the new turbochargers, the vendor and licensee concluded that the jet-assist design change was insignificant and that no additional vendor proof testing was required. Instead, 1-h operability runs were performed on each EDG following the installation of the new turbochargers to demonstrate the acceptability of the commercial design. These operability runs did not reveal the resonance-induced vibration problems, which only occurred at high EDG loadings.

E.6.2 Event Description

On June 12, 1995, the turbocharger for EDG 2A failed during operability testing following the loss of a compressor impeller blade. Damage included a single, failed compressor impeller blade section [approximately 13 cm^2 (2 $in.^2$)]; a damaged bearing; and a damaged diffuser ring. The EDG was repaired and returned to service. On June 27, 1995, before the results of a root-cause analysis of the first failure were confirmed, the turbocharger on EDG 2B failed from the same cause during monthly surveillance testing. Analysis of the failed compressor impellers indicated the failures resulted from high-cycle fatigue caused by resonance-induced vibration.

The four EDGs at McGuire 1 and 2 originally were equipped with ABB Turbo Systems Model VTR-500 turbochargers, which had a continuous slot machined in the compressor wall insert to admit air to the compressor for rapid response. This feature is not used at McGuire. Engineering personnel were informed by ABB Turbo Systems that parts for the original Model VTR-500 turbocharger would not be available after 1996, and the decision was made to install four new Model VTR-500 turbochargers and to return the old turbochargers to ABB Turbo Systems for refurbishment.

The new turbochargers have a jet-assist feature consisting of 17 inlet nozzles in the compressor wall instead of the slot design. The new turbochargers could not be procured as 10CFR50, Appendix B components, but were procured through the commercial-grade program at ABB Turbo Systems. As part of a commercial-grade evaluation of the new turbochargers, ABB Turbo Systems concluded that, based on past experience with the

Model VTR-500 and VTR-340 turbochargers, the wall insert change was insignificant and that no additional vendor proof testing was required. Instead, the licensee and ABB Turbo Systems personnel concluded that the 1-h operability run of each EDG following installation of the new turbochargers would provide an adequate performance test and was, in fact, preferable to a vendor test because it would eliminate the effect of slight differences in the design of other components and result in a test using the exact configuration of the new turbochargers. One-hour operability runs were completed on all four EDGs following installation of the new turbochargers during the previous refueling outages. In addition, 24-h runs were performed on EDGs 1A and 1B.

Because of the potential for common-cause failure, EDG 2A and both Unit 1 EDGs were declared inoperable one day after the EDG 2B failure and Unit 1 shutdown began. Unit 2 shutdown was initiated 30 min later but was delayed so that an on-site power source could be maintained while the Unit 2 EDG was repaired. EDG 2B was repaired and returned to service during the morning of June 29, 1995. Both Unit 1 EDGs were repaired by the morning of July 2, 1995.

Analysis of the failed Unit 2 EDG turbochargers indicated that the high-cycle fatigue failures were caused by resonance-induced vibration at EDG loads of between 3700–4200 kW. Acoustic/vibration testing of the compressor blades revealed a natural frequency of approximately 3750 Hz, which, in conjunction with the 17 inlet-nozzle wall insert, resulted in a resonant condition at or near the normal EDG surveillance test operating speed. Crack growth calculations performed by Failure Analysis Associates indicated that a resonance-induced crack would propagate from initiation to blade failure in 4–8 min.

E.6.3 Additional Event-Related Information

The McGuire design includes two features that can provide protection against core damage in the event of a LOOP and failure of both EDGs [or a station blackout (SBO)]. A separate standby shutdown facility (SSF), which normally is not manned, can provide limited high-pressure injection for Reactor Coolant System (RCS) makeup and reactor coolant pump (RCP) seal cooling assuming an RCP seal LOCA does not occur. The SSF includes a separate diesel generator that can power SSF loads in the event of an SBO. The SSF systems are single trains and, therefore, are susceptible to a single failure. In conjunction with the turbine-driven auxiliary feedwater (AFW) pump, the SSF can maintain hot standby conditions in both units.

In addition, the ability exists to cross-tie the safety-related buses in one unit to the startup transformers at the other unit. In the event of a plant-centered LOOP and blackout at one unit, this cross-tie can be used to recover ac power from the other unit.

E.6.4 Basis for Selection as an "Interesting" Event

The event was not documented as an accident sequence precursor because the estimated increase in core damage probability due to the potential common-cause failure of both EDGs was below the documentation limit of 1.0×10^{-6}. This small increase in core damage probability was a result of the large difference at McGuire between the expected EDG loading following a LOOP and the loading required for the turbochargers to fail, which limited the potential impact of the defective turbochargers. Only sequences involving a LOOP and LOCA would have been impacted by the degraded turbochargers, and these sequences do not appreciably impact the risk associated with either a LOOP or a LOCA. This event would have been more significant if it had occurred at a plant with less margin between expected loading and EDG design load.

E.6.5 Factors of Interest

The event involves the potential common-cause failure of multiple EDGs due to defective replacement turbochargers. The new turbochargers were commercial-grade components. As part of the commercial-grade evaluation of the new turbochargers, the vendor and licensee concluded that a change in jet-assist design was insignificant, and that no additional vendor proof testing was required. Instead, 1-h operability runs were performed on each EDG following the installation of the new turbochargers to demonstrate the acceptability of the commercial design. These operability runs did not reveal the resonance-induced vibration problems, which only occurred at high EDG loadings.

E.6.6 References

1. LER No. 369/95-003, Rev. 1, "Failure of the Turbochargers Associated with the Emergency Diesel Generators Due to an NRC Cause Code of Design Oversight," August 31, 1995.

E.7 LER No. 387/95-013

Event Description: Thermally induced pressure locking of high pressure coolant injection system valves

Date of Event: November 19, 1995

Plant: Susquehanna 1

E.7.1 Summary

Pennsylvania Power & Light's (PP&L) review of Generic Letter 95-07 concluded that the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) system injection valves at Susquehanna 1 and 2 were subject to pressure locking, which could preclude system operation. During disassembly of the Unit 1 HPCI injection valve to perform a modification that would preclude pressure locking, deformation of the valve's internals indicative of extremely high valve bonnet pressure was found.

E.7.2 Event Description

PP&L's review of Generic Letter 95-07 (Ref. 2) identified both the HPCI and RCIC injection valves for both units as susceptible to thermally-induced pressure locking. On November 11, 1995, Unit 1 was shut down to perform a repair of the main generator. During this outage, a modification to prevent thermally-induced pressure locking was performed on the HPCI and RCIC injection valves. This modification consisted of drilling a pressure relief hole in the downstream side of each valve disk. There were no provisions for pressure relief or equalization in the original valve designs.

During disassembly of the HPCI injection valve, the following damage was observed: the valve bonnet pressure seal segmented retaining ring was bent approximately 0.343 cm (0.135 in.), the pressure seal spacer ring was bent, and the packing follower flange was bent approximately 0.64 cm (0.25 in.). The damage was caused by pressure in the valve bonnet, which resulted in forces great enough to deform these components.

PP&L determined that valve damage was caused by thermally-induced pressure locking. The internal bonnet pressure required to cause the observed valve damage was estimated to have been between 21–48 MPa (3000–7000 psig). These pressures would prevent the HPCI injection valve from opening if it had been demanded. The valve was considered unavailable for an indeterminate amount of time between April 1992 (when the valve was previously disassembled) and November 11, 1995. The HPCI injection valve was not challenged, except for testing with the unit shut down and depressurized, during this time period. The valve was successfully "VOTES" tested during shutdown. Based on the successful shutdown testing, it was concluded that the valve would have been capable of operating, if demanded, except during plant heatup.

No damage was observed when the RCIC valve was disassembled for its modification. The Unit 2 HPCI and RCIC injection valves were stroked to confirm operability. These valves were to have holes drilled to prevent pressure locking at a future date. Unit 2 procedures were also revised to minimize the likelihood of HPCI and RCIC injection valve pressure locking.

E.7.3 Additional Event-Related Information

Reference 3 provides additional information concerning this event. The HPCI injection valve is a 35.6-cm (14-in.) flexible-wedge, motor-operated pressure seal gate valve. The valve is installed downstream from the HPCI pump, about three piping diameters from the feedwater system piping. The licensee believes heat from the feedwater system caused the thermally induced pressure locking and valve damage.

Pressure locking is a phenomenon where water trapped in the bonnet cavity and in the space between the two disks of a parallel-disk gate valve is pressurized above the pressure assumed when sizing the valve's motor operator. This prevents the valve operator from opening the valve when required. Water can enter a valve bonnet during normal valve cycling or when a differential pressure moves a disk away from its seat, creating a path to either increase fluid pressure or fill the bonnet with high-pressure fluid. A subsequent increase in the temperature of the fluid in the valve bonnet will cause an increase in bonnet cavity pressure due to thermal expansion of the fluid.

The bonnet pressure that damaged the pressure seal spacer and segmented retaining ring was estimated from the bending observed in the retaining ring. The retaining ring consists of four segments and has an inner diameter of 34.5 cm (13.6 in.), an outer diameter of 39.6 cm (15.6 in.), and is 2.22 cm (0.875 in.) thick. The ring was bent approximately 0.343 cm (0.135 in.). The valve vendor calculated the load required to bend the ring to this extent to be approximately one million pounds, which corresponds to the 21–48 MPa (3000–7000 psig) estimated internal bonnet pressure. The licensee considered these pressures to be threshold values for physical damage to the valve. An engineering analysis by the licensee demonstrated that heatup of fluid trapped in the valve bonnet could be sufficient to cause a pressure of this magnitude. At these differential pressures, the HPCI injection valve actuator did not have sufficient thrust capability to open the valve.

No inservice testing was performed on the HPCI injection valve during power operation because the licensee had a cold shutdown justification for this valve that supported operational testing only when the unit was shut down. The valve was successfully "VOTES" tested when the unit was shut down.

E.7.4 Basis for Selection as an "Interesting" Event

The event was not documented as an accident sequence precursor because it involved the short-term unavailability of a single-train system. Based on information provided by the licensee and the operating profile of the plant, the HPCI valve was estimated to be unavailable for between 8 days and 1.3 months. The maximum estimated increase in core damage probability for such a time period is on the order of 3×10^{-6}. Such low-probability, short-term, single-train unavailabilities are not considered risk significant and are typically not analyzed in the ASP Program. If the HPCI valve had been damaged to the point of inoperability by the overpressurization, the HPCI system would have been unavailable for more than 1 year, with a resulting increase in core damage probability on the order of 2×10^{-5}. The event would also have been more significant if the RCIC valve had been found to be damaged.

E.7.5 Factors of Interest

The event involves the failure of the HPCI system injection valve due to thermally induced pressure locking, an unusual failure mode.

E.7.6 References

1. LER 387/95-013, Rev. 0, "Thermally Induced Pressure Locking of the HPCI Injection Valve," January 2, 1996.

2. Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," August 17, 1995.

3. NRC Information Notice 96-08, "Thermally Induced Pressure Locking of a High Pressure Coolant Injection Gate Valve," February 5, 1996.

Appendix F:

Resolution of Comments on the

Preliminary 1995 ASP Analyses

F.1 Comments

This appendix contains the comments received from the applicable licensees and the Nuclear Regulatory Commission (NRC) staff for each of the potential precursors. The comments for each potential precursor are listed and discussed in docket number order, where the docket number refers to the plant that reported the problem. Comments are further separated between licensee and NRC comments. Only comments considered pertinent to the accident sequence precursor analysis are addressed. Because of the length of the comments received, they are paraphrased in this appendix. Comments simply pointing grammatical or spelling errors were addressed in the revision of the analyses, but are not listed or addressed in this appendix. The reanalysis of some potential precursors resulted in the elimination of the event from the final set of precursors contained in Appendix B of this report; these events are noted in Table F.1.

Table F.1 List of Comments on Preliminary ASP Analyses

Event number	Plant	Event descriptions	Page
LER 213/95-010	Haddam Neck	Multiple Safety Injection Valves are Susceptible to Pressure Locking	F.2-1
LER 313/95-005	Arkansas Nuclear One, Unit 1	Trip with One Emergency Feedwater Train Unavailable	F.3-1
LER 315/95-011	Cook 1	One Safety Injection Pump Unavailable for Six Months	F.4-1
LERs 335/95-004, -005, -006	St. Lucie 1	Failed Power-Operated Relief Valve, Reactor Coolant Pump Seal Failure, Relief Valve Failure, and Subsequent Shutdown Cooling Unavailability, Plus Other Problems	F.5-1
LER 336/95-002	Millstone 2	Containment Sump Isolation Valves Potentially Unavailable Due to Pressure Locking	F.6-1
LER 352/95-008	Limerick 1	Safety Relief Valve Fails Open, Reactor Scram, Suppression Pool Strainer Fails	F.7-1
LER 368/95-001	Arkansas Nuclear One, Unit 2	Loss of dc Bus Could Fail Both EFW Trains	F.8-1
LER 382/95-002	Waterford 3	Reactor Trip with a Loss of Train A of the Essential Service Water and the Turbine-Driven Auxiliary Feedwater Pump	F.9-1
LER 389/95-005	St. Lucie 2	Failure of One Emergency Diesel Generator with Common-Cause Failure Implications	F.10-1
LERs 445/95-003, -004	Comanche Peak	Reactor Trip, Auxiliary Feedwater (AFW) Pump Trip, Second AFW Pump Unavailable	F.11-1

F.2 LER No. 213/95-010

Event Description: Multiple safety injection valves are susceptible to pressure locking

Date of Event: March 9, 1995

Plant: Haddam Neck

F.2.1 Licensee Comments

Reference: Letter from T. C. Feigenbaum, Connecticut Yankee Atomic Power Company, to the U.S. Nuclear Regulatory Commission, transmitting "Haddam Neck Plant Comments on Preliminary Accident Sequence Precursor Analysis," letter no. 50-213-B15951, October 30, 1996.

Comment 1: Connecticut Yankee Atomic Power Company (CYAPCO) did not provide specific comments on the Accident Sequence Precursor analysis of event LER 213/95-010, but rather forwarded an assessment of the event performed by Northeast Utilities Services Company (NUSCO), which used different assumptions. Regarding the ASP analysis, Feigenbaum's letter states:

> CYAPCO believes that the ASP report is too conservative in estimating the conditional core damage probability. The NUSCO quantification assumed a conditional probability of valve failure other than 1.0. The basis for this assumption was provided in the LER as to why the valves would likely have functioned for a large break LOCA without loss-of-offsite power.

Response 1: Instead of commenting directly on the ASP analysis, the licensee for Haddam Neck submitted a report prepared by NUSCO: "An Analysis of the Risk Impact Due to Pressure Locking and Thermal Binding of CY ECCS MOVs." Because the ASP analysis and NUSCO's analysis could not be directly compared due to the different approaches taken to estimate the importance of pressure locking, a series of conference calls were held between personnel at ORNL, AEOD, and CYAPCO. Through these conference calls, sufficient information necessary to realistically estimate the likelihood that those valves susceptible to pressure locking would fail, given the existence of the conditions expected to cause pressure locking, was obtained. Consequently, the ASP analysis no longer assumes the conditional probability of valve failure to be 1.0. Although NUSCO's analysis and the ASP analysis still cannot be directly compared due to the different approaches taken to estimate the importance of pressure locking, the results should be comparable. An increase in the core damage probability (CDP) (an importance measure) during the time that the necessary conditions for pressure locking these valves exists is 4.7×10^{-6}. This compares to a change of core damage frequency (CDF) calculated by NUSCO of 1.76×10^{-5}. Based on the ASP analysis, the nominal CDP for a 1-year period is 1.1×10^{-4}, which compares favorably with NUSCOs estimate of 1.3×10^{-4}. The uncertainty in the frequency of LBLOCAs and the uncertainty in the likelihood that the pressure locking conditions will exist contribute to the uncertainty in this estimate.

F.2.2 NRC Comments

Reference I. Jung, U.S. Nuclear Regulatory Commission, NRR, to P. D. O'Reilly, NRC AEOD, transmitting via e-mail "Haddam Neck Preliminary ASP Analysis Peer Review," September 19, 1996.

Comment 1: In addition to large-break LOCA, medium-break LOCA is also very susceptible to pressure locking and thermal binding (PLTB). In fact, the CDF change by medium-break LOCA due to PLTB (worst case = 6.1E-4/yr; best estimate = 1E-5/yr) is greater than that by large-break LOCA (worst case = 3.9E-4/yr; best estimate of 6.4E-6/yr).

Response 1: The CDF values are apparently derived from the 8/9/95 NUSCO letter report, "Thermal Binding of CY ECCS MOVs." Discussion of the NUSCO report may be found in the response to licensee comments for this event.

Licensee Event Report 213/95-010 addressed the potential failure of safety injection (SI) valves SI-MOV-861A, -861B, -861C, -861D, -871A, and -871B during a large-break LOCA coincident with a loss-of-offsite power (LOOP). The LER states that a rapid drop in RCS pressure would be required in order to cause pressure locking of these valves. According to the LER, the LOOP would delay the open signal to the affected valves for 10 seconds. During this time, RCS pressure could drop substantially. The resulting increase in differential pressure on the valve disks could prevent the valves from opening.

According to the Haddam Neck *Final Safety Analysis Report*, the RCS would depressurize very rapidly given a design basis LOCA involving a full break of an RCS loop. Figure 15.3.1-5 in the FSAR indicates that the pressure in the RCS will fall by approximately 6.9MPa (1000 psi) during the first two seconds after a break. Because of the rapid depressurization of the RCS and the delay until the valves actually lift, the ASP analysis assumed that pressure locking of the aforementioned valves also could occur during a large-break LOCA without a coincident LOOP. This assumption may be conservative. Hence, the ASP analysis only considered large-break LOCAs which would result in a rapid decrease of RCS pressure. This has been clarified in the ASP section on **Modeling Assumptions**. It is possible that some medium-break LOCAs could result in pressure locking but, since no information is available to indicate when this might be the case, medium-break LOCAs were neglected in the ASP analysis.

Comment 2: CH-MOV-292B and -292C are flexible wedge gate valves that are susceptible to both PL and TB. The licensee indicates that the only transient accident applicable is the loss of control air. The best estimate for the CDF change due to PLTB is approximately 6E-7/yr and no worst case has been calculated.

Response 2: Because these valves (apparently in the charging line to the RCS) were not mentioned in LER 213/95-010, they were not considered in the ASP analysis, which is based on that report. Nevertheless, the charging pumps were assumed to be incapable of providing adequate makeup during the large-break LOCA scenarios postulated to lead to pressure locking.

Comment 3: SGTR also contributed to the change in CDF due to PLTB, and the best estimate is approximately 6E-7/yr. No worst case has been calculated.

Response 3: The ASP analysis assumed that pressure locking would primarily be of concern during events involving rapid RCS depressurization. Most SGTR scenarios would involve a slower depressurization.

Comment 4: The licensee indicates that the following valves are also susceptible to either PL or TB and are considered in its analysis:

SI-MOV-871A & B
RHR-MOV-780, 781, 803, & 804
SI-MOV-854A & B

Response 4: The ASP analysis does assume that SI-MOV-871A and -871B will fail due to pressure locking during a large-break LOCA. The other valves listed were not discussed in

LER 213/95-010 and, hence, were not considered in the preliminary ASP analysis. The NUSCO report, however, notes that RHR-MOV-780/781/803/804 are the RCS to RHR suction and return valves, and these valves have been routinely exercised by the plant without observing pressure-locking failures (p. 14 of the NUSCO report). The final ASP analysis therefore assumes that these valves were operable.

Valves SI-MOV-845A and -845B are normally open and can only experience pressure locking if they are closed during an event and then are required to be reopened. This potential failure is only significant if valves SI-MOV-871A and -871B function correctly, which was assumed not to be the case in the ASP analysis.

F.3 LER No. 313/95-005

Event Description: Trip with one emergency feedwater train unavailable

Date of Event: April 20, 1995

Plant: Arkansas Nuclear One, Unit 1

F.3.1 Licensee Comments

Reference: Letter from D. C. Mims, Director, Nuclear Safety, Entergy Operations, Inc., to the U.S. Nuclear Regulatory Commission, "Review of Preliminary Accident Sequence Precursor Analysis, ICAN059606," May 31, 1996.

Comment 1: The event description incorrectly states that PSV-2684 "remained open longer than operators expected." The root cause section of the LER states that subsequent review verified that the valve responded normally on blowdown and reseat.

Response 1: As the comment itself notes, the ASP analysis event description did not report that PSV-2684 behaved abnormally, only that the operators believed that it was behaving abnormally. This is supported by the statement in the LER, "However, one valve (PSV-2684) appeared to remain open longer than normal." Operators initiated action to reduce the B Once-Through Steam Generator (OTSG) pressure to assist the MSSV [main steam safety valve] in closing. To reflect that the valve operated properly during subsequent tests, the first paragraph in the **Event Description** section was changed to (changes noted in italics):

Arkansas 1 was operating at full power when a ground fault on the B phase of the current transformer supplying the negative sequence relay (NSR) caused a generator lockout followed by turbine and reactor trips. (The NSR protects the main generator from thermal damage due to negative sequence current caused by system faults or an open phase condition.) During the post-trip response, one main steam safety valve, PSV-2684 (see Fig. B.3.1), *appeared to remain* open longer than operators expected. To reduce the pressure in the B Once-Through Steam Generator (OTSG), operators opened the B turbine bypass valve to approximately 50%. As pressure in the B steam generator (SG) dropped, PSV-2684 seated and the B turbine bypass valve closed. PSV-2684 reopened and operators again opened the B turbine bypass valve, thereby allowing PSV-2684 to reclose. *Subsequent review verified that valve PSV-2684 responded normally on blowdown and reseat.*

Comment 2: The event description states that control of the atmospheric dump valve was lost. Adding the word "remote" to the description clarifies that local control was still available. The same clarification may be added in the **Additional Event-Related Information** section.

Response 2: This clarification has been made. The sentence in the **Event Description** has been changed to (change noted in italics): "Train A SG level indication was lost, as was *remote* control of atmospheric dump valve (ADV) CV-2668 and emergency feedwater valves CV-2646 and CV-2648 (see Fig. 2)." The sentence in the **Additional Event-Related Information** section has been changed to "The failure of the +5-volt power supply resulted in the loss of EFW flow control valves in the MDEFWP train (CV-2646 and CV-2648) and ADV CV-2668 control in either automatic or manual control *(local control of the ADV was still possible).*"

Comment 3: The **Modeling Assumptions** section states that the EFW control valves were not declared unavailable until about one hour after the trip, leaving the impression that they were unavailable previous to that time. A clarification that the valves actually became unavailable at that time would seem appropriate.

Response 3: This has been clarified by deleting the sentence in question.

Comment 4: Upon evaluating the event description and reviewing the Event Tree and resulting cut sets, it was identified that credit was not given for use of ANO-1's Auxiliary (Startup) Feedwater Pump (P-75). The Auxiliary Feedwater pump is an electric, motor-driven, centrifugal pump that is normally used during startup and shutdown conditions when there is insufficient steam available to run the main feed pumps. This pump is credited in the ANO-1 PSA as a recovery....

The auxiliary feedwater pump can be credited in all transient sequences except for Loss-of-Offsite Power and Loss-of-Power Conversion System. The probability of failure for this recovery includes a mechanical failure probability as well as an operator failure. ANO-1's success criteria regarding the transient sequences involving loss of all feedwater defines an available time of 36 min for Loss-of-Power Conversion System sequences with reactor coolant pumps still running.

Response 4: The event has been reanalyzed, giving credit for recovering the main feedwater supply using the motor-driven startup feedwater pump. The nonrecovery probability for the main feedwater system (MFW-XHE-NOREC) was changed to reflect this. The procedures supplied with the comment letter indicate that two valves must close, at least one of these valves must re-open, and the motor-driven pump must start and run for the recovery to be successful. In addition, adequate suction supply must be provided and operators must manually (remotely) align and start the system. The system failure probability given in Attachment 1 to the comment letter is 1.6E-02. This is a bit lower than the value which might be estimated by an ASP analyst, but it was accepted for use in the reanalysis. Since the required support by the condensate system was neglected, the 1.6E-02 value may be slightly nonconservative.

Comment 5: TRANS Sequence 20: The probability of failure for the Aux. Feed pump as a recovery can be applied to all cut sets in this sequence. . . .

TRANS Sequence 21-8: The cut set for this sequence includes a failure of the EFW system. Therefore, the Aux. Feedwater recovery can be applied.

TRANS Sequence 08: The common-cause failure probability assumed for the HPI-CKV-OO-MST is conservatively high based upon the ANO-1 common-cause failure probability for these valves. The ANO-1 common-cause probability for these valves is 7.38E-04 based upon a beta factor of 0.08 . . . and a probability of failure for the MOV of 9.23E-03.

For HPI-MOV-CF-SUCT, the CCF probability is also higher than is representative for ANO-1. The HPI suction valves are stop check valves...the beta factor for check valves is 0.06. Using ANO-1's failure to open probability for these valves of 4.93E-04, yields a common-cause failure probability of 2.96E-05 when the beta factor is applied.

Response 5: Credit for the MDSFWP is accounted for in TRANS Sequence 20 through the recovery of the MFW system (MFW-XHE-NOREC). The nonrecovery probability provided by ANO-1 (0.016—see Comment 4) was used rather than a typical recovery class R2 nonrecovery probability (0.34), as given in Appendix A in NUREG/CR-4674, Vol. 21.

ATWS sequences, such as TRANS Sequence 21-8, require emergency feedwater in a very short amount of time. The procedures supplied with the comment letter indicate that two valves must close, at least one of these valves must re-open, and the motor-driven pump must start and run for the recovery to be successful. In addition, adequate suction supply must be provided and operators must manually (remotely) align and start the system. Because of the time available for recovery actions, credit for the MDSFWP was given in the recovery of MFW but not in the recovery of EFW.

With respect to the common-cause failure probabilities (CCF) for basic events HPI-CKV-OO-MST and HPI-MOV-CF-SUCT, data from many plants must be combined to estimate the probability of low- and moderate-frequency events because of the sparseness of data.

Because of this, the model values will tend toward an average response for a group of plants. Regardless, because basic events HPI-CKV-OO-MST and HPI-MOV-CF-SUCT do not appear in TRANS Sequences 21-8 and 21-9 (which contribute to almost 90% of the total CCDP), any change in the CCF for these basic events will not significantly affect the overall CCDP. In fact, based on TRANS Sequence 21-8 alone, this event qualifies as an ASP event (i.e., CCDP $\geq 10^{-6}$).

F.3.2 NRC Comments

Reference: Letter from P. Wilson, NRR, to P. D. O'Reilly, AEOD, "Comments from SPSB Regarding the Preliminary ASP Analysis of 1995 Operational Event at Arkansas Nuclear One Plant," April 23, 1996.

Comment 1: After discussions with the ANO resident inspectors who performed a special inspection of this event and consulting the ANO-1 UFSAR, the flow to the steam generators via motor driven emergency feedwater (EFW) pump was never unavailable. The failure of the 5-volt power supply only rendered the automatic control of CV-2646 and CV-2648 nonfunctional. Operators could still operate these valves from the control room. Therefore, the conditional core damage probability (CCDP) should be made much closer to 4.0E-6 (CCDP for an uncomplicated plant transient).

Response 1: See response to licensee comment number 2.

Comment 2: The flow control valves are not modeled in ANO-1's ASP model. It is not clear why basic event EFW-MOV-CF-DISAL was set to false. According to the model this basic event involves the common-cause failure of the motor operated valves on the discharge lines to each steam generator that shut on a EFW isolation signal. These valves were unaffected by the event.

Response 2: The motor-operated valves were set to "FAILED" in the model to fail both flow paths associated with the motor-driven AFW pump. It will be suggested that the flow control valves should be added to the ANO-1 ASP model in the next revision. Event EFW-MOV-CF-DISAL has been restored to its base probability.

Comment 3: Since the failure of the 5-volt power supply occurred an hour after the unit had tripped, more credit (due to reduced decay heat) should have been given for the additional time available to recover failed components.

Response 3: The affected trains were assumed failed because they were not capable of successfully performing their safety function, presumed to be that of supplying EFW for 24 hours after trip.

Based on comments provided by the licensee, substantial credit has now been given for recovering of flow to the steam generators using the motor-driven startup feedwater pump.

Comment 4: It is not clear what was the source of the base probability values for two basic events. The values for basic events EFW-TDP-FC-1B and EFW-XHE-XA-CST used in the evaluation are different from the values contained in the ANO-1, revision 1, ASP model.

Response 4: The values for these two basic events were adjusted in an attempt to use values which were more realistic and less conservative than those embedded in the base model.

F.4 LER No. 315/95-011

Event Description: One safety injection pump unavailable for 6 months

Date of Event: September 12, 1995

Plant: D. C. Cook, Unit 1

F.4.1 Licensee Comments

No comments were provided by the licensee.

F.4.2 NRC Comments

Reference: E-mail from P. D. O'Reilly, AEOD, to M. D. Muhlheim, ORNL, "Comments on Cook 1 Preliminary ASP Analysis," July 24, 1996.

Comment 1: The last sentence of the first section of the report in the **Event Summary** should be rewritten to clarify what the terminology "nominal value" refers to. As the sentence is now written, one can get the impression that the plant was safer (7.7E-6) with the fault than it was before the fault occurred. Or does the sentence really mean that the fault resulted in a 20% increase (0.77/2.9) over the nominal core damage probability?

Response 1: The wording has been changed to indicate that the value is an increase above a base value and is, therefore, an importance value.

F.5 LER Nos. 335/95-004, -005, -006

Event Description: Failed power-operated relief valves, reactor coolant pump seal failure, relief valve failure, and subsequent shutdown cooling unavailability, plus other problems

Date of Event: August 2, 1995

Plant: St. Lucie 1

F.5.1 Licensee Comments

Reference: Letter from J. A. Stall, Florida Power & Light Company, to the U.S. Nuclear Regulatory Commission, "Comments on the Preliminary Accident Sequence Precursor Analysis," L-96-155, June 20, 1996.

Comment 1: (Summary) The conditional core damage probability (CCDP), as calculated in the NRC evaluation, represents the total core damage probability (CDP) given the PORVs are unavailable. Presenting the results in this manner can make it difficult to compare the precursor evaluation results to the screening value of 1E-6 since the baseline CDP for many of the dominant sequences identified are not impacted by the PORV unavailability and have baseline values above 1E-6. It is recommended that both the CCDP and the change in CDP be described, as discussed in the 1994 precursor report for condition assessments.

Response 1: The PORV unavailability analysis has been revised to provide the CCDP and change in CDP (importance) for the event.

Comment 2: (Summary) The **Event Summary** section discusses three primary events that are addressed in the draft precursor analysis (reactor coolant pump seal stage failures, PORV unavailability, and removal of the shutdown cooling system from service for 22 h). This section states that "The conditional core damage probability estimated for this event is 1.3E-4." The CCDP is actually the total CCDP for three different events. It is recommended that the **Event Summary** should (1) identify that the total CCDP represents a combination of multiple events and (2) provide the contribution from each event so that it is clear what is the dominant contributor to the total CCDP.

Response 2: The **Event Summary** has been revised to describe the contribution from the individual failures by adding the following:

The conditional core damage probability estimated for the PORV unavailability is 1.1×10^{-4}. This is an increase of 9.3×10^{-5} over the nominal core damage probability for the same period. The conditional core damage probability associated with the potential RCP seal LOCA is 5.3×10^{-6}. The increase in core damage probability associated with the removal of the SDC system from service to replace the thermal relief valve is less than the ASP screening value of 1.0×10^{-6}.

Comment 3a: (Summary) LOOP sequences 16 and 21 are essentially the same except for whether offsite power is recovered within 6 h. The representation of these sequences in the event tree is confusing. It appears that the sequence for feed-and-bleed failure is not correct in that it occurs after the attempted recovery of offsite power at 6 h is either successful or fails. Feed-and-bleed is a short-term action (less than 30 min) after a complete loss of feedwater. It is recommended that since LOOP 16 is a dominant contributor to the total CCDP, that the actual sequence of events represented by sequences LOOP 16 and LOOP 21 be more clearly explained and that the potential for recovery of MFW and/or condensate pumps be evaluated.

Response 3a: The representation of offsite power recovery in the LOOP event tree is not necessarily chronological. In the blackout sequences, the probability of an RCP seal LOCA and the probability of failing to recover ac power are calculated using a convolution approach that recognizes that both probabilities are a function of time. The model recognizes that offsite power will likely be recovered after feed-and-bleed is demanded and requires EDG success for feed-and-bleed success. The intent of the 6 h recovery of offsite power branch is to address the potential for recovery of an initially failed AFW system before transfer to sump recirculation. Since feed-and-bleed has been demanded and has failed in this sequence before this time because of the unavailable PORVs, the potential recovery of offsite power by 6 h has no effect on the overall analysis results (LOOP 16 and LOOP 21 together represent the dominant sequence for the event). The description of the LOOP 16 sequence in **Analysis Results** has been clarified to address this by adding the following footnote:

[6] The LOOP event tree includes the successful recovery of offsite power within 6 h in the dominant sequence. This is an artifice of the top event ordering. Feed-and-bleed challenge would occur about 20 min after the trip, and core damage would begin shortly thereafter. Sequences 16 and 21 together represent the core damage sequence involving emergency power success and AFW and feed-and-bleed failure.

Comment 3b: (Summary) In LOOP sequences 40, 30, 39, 41, 23, and 32, the basic event for failure to recover emergency power (EPS-XHE-NOREC) does not give proper credit for the capability to tie a diesel generator from Unit 2 to Unit 1 via the blackout cross-tie.

Response 3b: The potential use of the blackout cross-tie has been added to the ASP model for the event for plant-centered LOOPs, consistent with the treatment of dual-unit crossties in other 1995 precursor analyses. The potential recovery of ac power through recovery of offsite power or use of the unit 1/unit 2 cross-tie is addressed in basic events OEP-XHE-NOREC-BD (operator fails to recover offsite power before batteries are depleted) and OEP-XHE-NOREC-SL [operator fails to recover offsite power (seal LOCA)]. Consideration of the cross-tie had little effect on the analysis results; the cross-tie-related basic events are in sequences that contribute to less than 1% of the total CCDP and do not appear in Table B.5.1, which provides definitions and probabilities for basic events that appear in the dominant sequences, or Table B.5.5, which lists the dominant sequences and their cut sets.

F.5.2 NRC Comments

Reference: Undated note to P. D. O'Reilly from Eric Benner (EAGCB, NNR), forwarding an undated John Flack (PSAB, NRR) note to John Goodwin (EAGCB, NRR) that forwarded an SPSB Assessment of the Inoperable Pressurizer PORVs at St. Lucie Unit 1.

Comment 1: The SPSB assessment estimated the importance of the event, assuming a 9-month unavailability, to be 1.2E-5 using the old ASP model and 4.4E-6 using the newer IRRAS-based model. No details of the analysis were provided. The assessment also noted than a licensee scoping analysis estimated a modified core damage frequency due to the failed PORVs of 7.6E-5/yr and an importance of 5.3E-5 for a 1-year period.

Response 1: The SPSB estimate of 4.4E-6 using the IRRAS-based model could not be confirmed. The Rev. 2 models are currently undergoing a QA review and are not used in the ASP assessments. Note that, if the SPSB analysis was performed using the Rev. 2 models, that an error exists in these models for LOOP which prevents the correct assessment of sequences involving emergency power success and long-term offsite power recovery. This error will affect analysis results for this event.

Neither the SPSB or licensee's analysis considered the potential for SRV lift, as was done in the ASP analysis.

Comment 2: NRR also contracted Battelle Pacific Northwest Laboratories to evaluate the risk significance of the unavailable St. Lucie 1 PORVs. PNL estimated a change in the core damage frequency over a 1-year period of 3.4E-5. As with the SPSB and licensee assessments, the potential for SRV lift was not addressed.

Response 2: The assumption that there would be no relief valve challenge eliminated several sequences that substantially contribute to the overall risk estimate. This assumption is considered nonconservative.

F.6 LER No. 336/95-002

Event Description: Containment sump isolation valves potentially unavailable due to pressure locking

Date of Event: January 25, 1995

Plant: Millstone 2

The preliminary analysis of this event was transmitted to the Millstone 2 licensee via letter to Ted C. Feigenbaum, Northeast Utilities Service Company, from Daniel G. McDonald, Jr., NRC Project Manager for Millstone 2, dated September 20, 1996, which requested that the licensee review the analysis and provide comments on a voluntary basis. Upon receipt of our letter, the licensee initially indicated to the NRC Project Manager that, although any response to our request on their part was voluntary, they intended to provide comments on the analysis. However, given the current situation at the Millstone plant and the extent to which the licensee's resources have been committed to the resolution of higher priority licensing issues that have been identified regarding the Millstone units, the licensee reevaluated their ability to respond to our request in a timely manner. They recently informed the NRC Project Manager that they could not provide comments on the preliminary analysis in a time frame consistent with our schedule for issuance of the final precursor analysis and the 1995 Precursor Report. Since we did receive comments from the independent review performed by our contractor at Sandia National Laboratories (SNL), these comments were resolved and the final analysis prepared. Preparation of the final analysis was accomplished without any comments from the licensee.

F.7 LER No. 352/95-008

Event Description: Safety/relief valve fails open, reactor scram, suppression pool strainer fails

Date of Event: September 11, 1995

Plant: Limerick 1

F.7.1 Licensee Comments

Reference: Letter from G. A. Hunger, Jr., Director–Licensing, PECO Nuclear, to U. S. Nuclear Regulatory Commission, "Limerick Generating Station, Unit 1, Comments Concerning Preliminary Accident Sequence Precursor Analysis of Suction Strainer Clogging Event," July 25, 1996.

Comment 1: First paragraph in the **Event Summary**, third sentence—Change "RHR pump A was declared inoperable when . . . ." to "RHR pump A was secured and declared inoperable when . . . ."

Response 1: Word change was made as requested.

Comment 2: Third paragraph in the **Event Summary**, first sentence—Change "operators observed a decrease in flow from the A RHR pump . . . ." to "operators observed a decrease and fluctuations in flow from the A RHR pump . . . ."

Response 2: The sentence was changed to "operators observed a decrease and fluctuations in flow from the A RHR pump . . . ."

Comment 3: First paragraph in the **Event Description**, third and forth sentences—Delete ". . . at low flow rates. As operators increased flow through the A RHR pump, they observed a pressure drop across the pump's suction strainer." Per the text of the LER, page 2 of 5, "At 1345 hours, following initial evaluation by the System Manager, Shift Supervision directed a restart of the "A" RHR pump (i.e. in SPC mode), and **no abnormal indications** were observed," [emphasis added]. In addition, plant records indicate that the A RHR pump was restarted and ramped up to 8500 gpm and returned to SPC mode, which is not a "low flow rate." Finally, pressure drop across the pump's suction strainer would be expected with increasing flow rate, but did not hinder operation of the A RHR pump.

Response 3: This section was based on information in the LER and also on information in NRC Bulletin (NRCB) 95-02. NRCB 95-02 states (p. 2, second paragraph):

> After it was checked the "A" pump was restarted, but at a reduced flowrate of 7,570 l/m (2,000 gpm). No problems were observed, so the flow rate was gradually increased back to 32,170 l/m (8,500 gpm) and no problems were observed. A pressure gauge located on the pump suction was observed to have a gradually lower reading, which was believed to be indicative of an increased pressure drop across the pump suction strainers located in the suppression pool.

The third paragraph in the **Event Description** was changed to (changes shown in italics):

> At 1320, operators observed a decrease and fluctuations in flow from the A RHR pump as well as oscillations in its motor current. Operators, attributing these signs to suction strainer fouling, secured the A RHR pump and declared it inoperable. *After it was checked, the A pump was restarted but at a reduced flow rate of 7,570 l/m (2,000 gpm). No problems were observed so the flow rate was gradually increased to 32,170 l/m (8,500 gpm) and no problems were observed. A pressure gauge located on the pump suction was observed to have a gradually lower reading, which was believed to be indicative of an increased pressure drop across the pump suction strainers located in the suppression pool (Ref. 2).* At 0227 on September 12, 1995, reactor pressure was reduced below 0.52 MPa (75 psig), with one loop of shutdown cooling in service. By 0430, the unit was in cold shutdown with a reactor coolant temperature of 90°C (194°F.)

which is consistent with NRCB 95-02.

Comment 4: Second paragraph in **Additional Event-Related Information**—After the third sentence starting, "Upon inspection, personnel . . ." Add the sentence "However, the B RHR pump ran normally during and after the event."

Response 4: The sentence was added. Note that this specific information was not given in the LER.

Comment 5: Second paragraph in **Additional Event-Related Information**—Reword the fifth sentence from "Utility personnel reported that they were unable to determine if effects attributable to the SRV blowdown increased the rate of accumulation of debris on the strainers." to "Utility personnel reported that the SRV blowdown resulted in deposition of additional material on the strainer." per the first paragraph of page 5 of 5 of the LER 352/95-008.

Response 5: This statement was based upon the following information from NRC Bulletin 95-02 (p. 3, para. 2):

> Limerick concluded that the blowdown caused by the SRV opening did not significantly increase the rate of debris accumulation on the strainer.

The second paragraph in the **Additional Event-Related Information** section was changed to (change shown in italics):

> During an inspection of the A RHR pump suction strainer assembly, a mat of brown, fibrous material and a sludge of oxide corrosion products were found covering most of the assembly. The sludge material was determined to have come from the suppression pool. Upon inspection, personnel discovered that most of the suction strainer assembly for the B RHR pump was covered with a thinner layer of the same material. However, the B RHR pump ran normally during and after the event. The other strainers in the suppression pool for the pumps which were not employed during this event also had minor sludge accumulations. *Limerick concluded that the blowdown caused by the SRV opening did not significantly increase the rate of debris accumulation on the strainer.* Approximately 635 kg (1,400 lb) of debris (wet weight, dry weight would be less) was removed from the suppression pool. A similar amount of material had been removed previously from the Unit 2 suppression pool.

Comment 6: Second paragraph in **Additional Event-Related Information**—Finally, second to last sentence, change "Approximately 1,400 lb of debris was removed from the suppression pool." to "Approximately 1,400 lb (wet weight, dry weight is roughly one-third of wet weight) of debris was removed from the suppression pool." The 1,400 lb reported was a net weight value. BWROG investigations have shown that the dry weight is roughly one-third of the wet weight.

Response 6: It would seem likely that the ratio of dry weight to wet weight would be dependent upon the type of debris encountered. Presumably this ratio would be smaller for fibrous material and larger for metal oxides. The dry weight of the debris was not reported in the LER and the comment implies that the net weight of the debris found in the Limerick suppression pool was not actually measured. Therefore, it would seem difficult to determine what the ratio of dry weight to wet weight might have been for this event. However, a sentence has been added to indicate that the dry weight could be expected to be less than the wet weight. (The response to comment 5 provides the revised paragraph in question.)

Comment 7: Second paragraph in **Modeling Assumptions**—Change the first sentence "and one train of RHR unavailable in all modes because. . . ." to "and one train of RHR unavailable in all modes except SDC because. . . ."

Response 7: This change has been incorporated.

Comment 8: Second paragraph in **Modeling Assumptions**—Also change second sentence "Similar debris was found on other strainers and 1,400 lb of debris . . . ." to "Debris was also found on other strainers and 1,400 lb (wet weight, dry weight is roughly one-third of wet weight) of debris...." for the same explanation as given above.

Response 8: Consistent with the response to comment 6, the sentence in question has been revised to indicate that the 635 kg (1,400 lb) was wet weight.

Comment 9: Second paragraph in **Modeling Assumptions**, last sentence—Finally, add "the amount of debris in the suppression pool" to the list of factors in the last sentence.

Response 9: This change has been incorporated.

Comment 10: Third paragraph in **Modeling Assumptions**—The low pressure core spray (LPCS) system should not be grouped with the RHR system since LPCS can also take suction from the CST, similar to the RCIC and HPCI systems (see Figures 6.3-7 and 6.3-9 in the Limerick Generating Station's Updated Final Safety Analysis Report). The standard LPCS system operating procedure provides direction for alignment of LPCS to the CST. Thus the "RHRSTRAINERS" event should not be added to the LPCS model.

Response 10: The LPCS system is normally aligned to the suppression pool and operator actions would be required to align the system to the CST, including the opening of manual valves which may be normally kept locked closed. Therefore, it would be inappropriate to model the system as not being impacted by the potential strainer failure. Switching to take suction on the CST could be incorporated into the LPCS model as a recovery, but the approach used in the ASP Program to estimate nonrecovery probabilities suggests that if "a failure appeared recoverable in required period at failed equipment, and equipment was accessible [and] recovery from control room did not appear possible" then a nonrecovery probability of 0.55 should be employed ("Methods Improvements Incorporated into the SAPHIRE ASP

Models," Sattison, M. B. et al., NUREG/CP-0140, *Proceedings of the Twenty-Second Water Reactor Safety Information Meeting*, U.S. Nuclear Regulatory Commission, October, 1994). This change would not materially affect the analysis results.

Comment 11: Fourth paragraph in **Modeling Assumptions**—The common-cause strainer failure probability should be modeled as two populations of two strainers each, RHR A and B, and RHR C and D, rather than as a single group which contains all four strainers. This is due to the distinctly different operating histories of the two groups. RHR A and B are normally used for suppression pool cooling in routine operations, whereas RHR C and D are only run for required pump, valve, and flow tests. As the failure mode is dependent upon the collection of material on the strainers over time as the pumps are used, these different profiles would clearly separate the two groups from common-cause perspective. The analysis for both the event and condition assessment should be reperformed with the increased common-cause value affecting only the A and B strainers, and with a much lower common-cause failure value affecting the C and D strainers (e.g., $\alpha_2 Qt \approx 0.2 \times 1E\text{-}4$, or $\approx$ 2E-5). Each group of RHR, the RHR A and B group and the RHR C and D group, can be used in each mode of RHR operation, LPCI, SPC, SDC, and Containment Spray.

Response 11: The pumps all relied on the same pool of water containing the same contaminants, and all pumps were assumed to be exposed to the same potential common-cause failure mechanism.

It was assumed that all four pumps were/would be simultaneously exposed to a common hazard which would increase the probability of failure. Therefore, it was believed to be appropriate to model all of the pumps as subject to failure from the same common cause.

Comment 12: Fourth paragraph in **Modeling Assumptions**, second sentence—The statement "Research cited in Reference 4 indicates that the sludge concentration . . . were easily sufficient to obstruct multiple ECCS system strainers" is incorrect. Sludge by itself cannot cause the failure of an ECCS strainer due to the small particle size relative to the hole size of the strainer. A layer of fiber must be present to trap the sludge. From the results of diver inspections, it was found that no strainers other than the A and B RHR had any fiber matting the strainer surfaces. Therefore, initially, the strainers could not have plugged. A preliminary BWROG report indicates that appreciable settling of corrosion products could be expected in as little as 15 to 30 min following the end of a LOCA blowdown. Based on this analysis, it would be expected that by the time a fiber bed formed on any other strainers, the corrosion products required to foul the bed would have largely settled out. Therefore, no other ECCS suction strainers would be expected to plug. Therefore, a common-cause strainer failure could not occur.

Response 12: The word "debris" has been substituted for "sludge" in the subject sentence, since both fibrous material and oxide/sludge material were present.

The above discussion apparently pertains to large- or medium-break LOCA events. It is unclear how this information applies to other events such as that modeled in the analysis. Note that in the discussion above, blowdown to the suppression pool is assumed to suspend corrosion products. This would tend to support the assumption that a single common hazard could potentially impact some or all of the pumps taking suction from the pool.

The ASP analysis assumed that the same fibers and corrosion products which caused A RHR pump to be declared inoperable and which were found in lesser amounts on the B pump strainers could have led to failure of the B pump and then the other exposed pumps as well. Presumably, failure of B pump would have cued operators to start C or D pump, failure of that pump would have prompted them to start the remaining unaffected pump, and so on.

Comment 13: Fourth paragraph in **Modeling Assumptions**, third sentence—The alpha factor used from Reference 5 should be recalculated for the event assessment using the actual failure situation found at the plant [i.e., 1 failed (A), 1 could fail (B), and with the remaining two strainers (C and D) having an extremely low likelihood of failing in the same manner].

Response 13: As previously described, the same material which obstructed the A pump strainers, causing the pump to be declared inoperable, did deposit to a lesser extent on the B pump strainers and could have deposited on the C and D pump strainers had these pumps operated. Therefore, the modeling of the event assumed that the one pump which was reported to be inoperable was inoperable, and it was assumed that the other pumps could have failed with a probability of 0.135. (The probability that three or more pumps might fail due to a common-cause given that two failed due to that sam. cause should be approximately unity.)

Comment 14: Fifth paragraph in **Modeling Assumptions**, last sentence—The common-cause strainer failure probability should not be the same as in the event assessment unless the A strainer is considered to be clogged in the condition assessment as well. The common-cause strainer failure probability should be 0.135 × Qt, Qt being the random failure probability for the strainers. Unless the A RHR is assumed to be failed (as in the event assessment), Qt is less than 1.

Response 14: Since the A strainer did apparently obstruct sufficiently to cause the A pump to be declared inoperable during the actual demand, the A pump was assumed to be inoperable in the condition assessment.

Comment 15: **Analysis Results**—Considering the previous comments of

(a) the appropriate use of the debris dry weight to estimate the strainer failure probability;

(b) the grouping of LPCS with HPCI and RCIC instead of with RHR since LPCS can also take suction from the CST; and

(c) modeling the common-cause strainer failure probability as two populations of two strainers each (RHR A and B, and RHR C and D) with a much lower common-cause failure value affecting the RHR C and D strainers of 2E-5,

a more realistic core damage probability for the transient event assessment below the current value would be obtained, and a more realistic core damage probability for the condition assessment would be less than 1.0E-5.

Response 15: These comments have been addressed as noted

(a) see Responses 6 and 8,

(b) see Response 10, and

(c) see Responses 11 and 13.

The CCDP estimate for the 1-year potential unavailability of ECCS systems dependent upon the suppression pool is 1.3×10^{-5}, an increase of 9.0×10^{-6} over the nominal CDP of 4.0×10^{-6}. The CCDP for the actual transient event is 2.5×10^{-6}.

F.7.2 NRC Comments

No comments were provided.

F.8 LER No. 368/95-001

Event Description: Loss of direct current bus could fail both emergency feedwater trains

Date of Event: July 19, 1995

Plant: Arkansas Nuclear One, Unit 2

F.8.1 Licensee Comments

Reference: Letter from D. C. Mims, Director, Nuclear Safety, Entergy Operations, Inc., to U. S. Nuclear Regulatory Commission, transmitting Arkansas Nuclear One–Unit 2, Docket No. 50-368, License No. NPF-6, "Preliminary Accident Sequence Precursor Analysis, 2CAN099607," September 9, 1996.

Comment 1: (Summary) The **Event Description** is accurate in that it reflects the results of the simulator run. The LER stated that there is no conclusive evidence that the actual plant response to the condition would have resulted in a generator coast down of sufficient duration to allow green train valves to close completely and block all EFW flow. Subsequent investigation has failed to establish a duration of valve motion. A detailed analysis of the voltage decay has not been performed due to the cost. If the EFW performance had been able to exceed the minimum requirements to preclude core uncovery, the event would not have proceeded to core damage via the event sequence originally postulated, and this condition would result in no net change in Core Damage Frequency (CDF). To preclude this from being the case, the valve would have had to travel at its normal speed (which would require its normal voltage) for 16 seconds after the generator tripped.

Response 1: Because a detailed analysis of expected voltage decay was not developed by the licensee, the analysis was based on the assumption that the plant performance would be similar to that of its simulator. This is noted among the modeling assumptions.

Comment 2: While flow blockage due to valve closure is uncertain, potential operator recoveries were examined in order to provide a complete evaluation of the significance of this condition. Two operator recovery actions were identified that would each be successful in restoring EFW flow to the steam generators. These recoveries would have been attempted in parallel to increase the EFW flow and either would have been adequate if successful. Therefore, in order to have core damage, both recoveries would have to fail.

These recoveries are:

1. Restore power to electrical buses 2A2/2A4 by manually aligning offsite power to 2A2. Reset Main Steam Isolation Signal (MSIS). Open Emergency Feed Water (EFW) discharge valve(s) from the control room.

2. Open EFW discharge valve(s) locally using the handwheel(s).

Only one valve must be opened because heat removal by one steam generator is adequate. The local manipulations for both recoveries are provided with specific lighting that is battery powered and is, therefore, unaffected by the loss of power situation. In addition, adequate power is available through 2A1 such that adequate lighting is available to permit ingress to the local station without impediment. Both recoveries are addressed in procedures 2202.001, "Standard Post Trip Actions," and 2203.037, "Loss of 125V DC," with the specific details of the MSIS reset in procedure 2202.010, "Standard Attachments," Attachment 14, "MSIS Reset." All these actions are a routine part of training received by operators in completing their qualification cards.

Recovery #1 is partially accomplished in the control room and partially in a location that requires entry through a security door. Recovery #2 is accomplished in a location that requires entry into the radiologically controlled access area.

Recovery #1 requires manually opening one breaker and manually closing one breaker outside the control room and electrically opening one valve after resetting MSIS in the control room....

The portion of recovery #1 requiring action outside the control room has been determined in the ANO-2 Human Reliability Analysis Work Package (HRAWP) to take 5 min and the default value of 4 min for the control room portion of the recovery will be conservatively used in series with the portion of the time requirement for actions outside the control room. The time required to accomplish recovery #2 has been determined in the HRAWP to be 10 min.

ANO-2 analysis has determined that core uncovery would not begin for at least 40 min following steam generator dryout. Values established in ANO-2 analyses indicate that 38 min would elapse from the time of reactor trip to the time of steam generator dryout for this scenario with no EFW flow and four Reactor Coolant Pumps (RCPs) running (based on 4.5 MWt into the Reactor Coolant System from each RCP). Therefore, if the EFW valve receives adequate power to completely close, 78 min are available to accomplish the recovery. If the valve does not receive adequate power to close, the additional EFW flow that occurs during the post-trip time frame will significantly lengthen the available recovery time even if there is not enough flow to prevent core uncovery without recovery action....

Using the Human Recovery Action numerical models developed in the Individual Plant Evaluation (IPE) model with these three input parameters the failure probabilities for recovery are:

Recovery	*Failure Probability*
#1 with 78 min available time	4.24E-2
#2 with 78 min available time	3.98E-2
Both #1 and #2 with 78 min available time	1.69E-3

For these recoveries, a combined failure probability of 1.69E-03 was determined. Since the failure of electrical bus 2D01 was already modeled in the IPE with the exception of this postulated EFW failure, the change in CDF due to the loss of 2D02 initiator (T11) is estimated to be essentially the T11 frequency times the operator failure to recover EFW Train B or 6.66E-07/rx-yr. This is a small increase in the ANO-2 CDF from its estimated value of 3.29E-5/rx-yr, as reported in the ANO-2 IPE/PRA. Note that none of these evaluations, either the original IPE or this re-evaluation, account for the availability of the Station Blackout Diesel generator or the Auxiliary Feedwater train which were installed after the IPE freeze date. The availability of these systems for use in recovering from the T11 initiator could even further reduce the contribution of this new failure mode to CDF.

Considering the additional information presented above that is a result of a more detailed evaluation, the section of the NRC letter concerning "Modeling Assumptions" should be reconsidered.

Response 2: The ANO-2 IPE was reviewed to develop an understanding of the recovery approach employed following a loss of dc power. The five most dominant cut sets (as well as eight of the first ten most dominant cut sets, based on the use of plant-specific data) involve the loss of a dc bus, either as the initiating event or as a failure following a reactor trip and loss of an ac bus. Following the loss of a dc bus, main feedwater is lost and EFW is required to feed water to the steam generators (SGs). If EFW is initially unavailable, the water level in the SG will drop to 178 cm (70 in.) in about 25 min. At this water level, once-through cooling is specified by the emergency operating procedures (EOPs) for removing decay heat (IPE pp. 3.1-19, -20). Since the loss of either dc bus results in the unavailability of once-through cooling (IPE pp. 3.7-2, -3), secondary-side cooling must be recovered if core damage is to be prevented. Core uncovery is estimated to begin 70 min following a transient with initially normal SG water levels, such as a loss-of-dc power (IPE p. 3.1-20).

The IPE recovery analysis assumes different recovery actions, depending on the particular dc bus and subsequent failures included in each cut set. Following the loss of the "green" dc bus and EFW pump train B (including the EFW ac-powered discharge valves), the IPE addresses the failure of the operators to manually control the turbine-driven EFW pump and discharge valves [basic event P7AMANREC (IPE Table 3.4-1)]. The time required for this action is 20 min (IPE Table 3.4-2). The IPE estimated a failure probability of 0.2 for this action following a loss-of-feedwater initiating event (55 min to core uncovery). A similar action for the motor-driven EFW pump, that only involves the manual control of the pump discharge valves (basic event P7BMANREC), was estimated to require 10 min. The failure probability reported for this basic event (recovery #2) is 8.4E-2.

In licensee comment 2, two alternate recovery actions are proposed following the loss of the green dc bus:

Recovery #1: Recovery of ac power to bus 2A2. This recovery would allow the EFW discharge valves to be opened from the control room. The estimated time to complete this action is 9 min according to licensee comment 2 and 18 min according to the ANO-2 IPE. (The IPE reports this basic event as MANOSPREC, with a 0.13 failure probability for a 70 min available time period.)

Recovery #2: Local manual opening of the EFW discharge valves. The time required for this action is 10 min, which is the same as reported in licensee comment 2 and in the ANO-2 IPE.

These two recovery actions, combined with the potential recovery of EFW through manual control of the turbine-driven EFW pump (based on the IPE, this is the recovery of choice) and the need to recover dc power to provide once-through cooling, as required by the EOPs about 25 min into the event, would compete for available resources. Resources and time expended on one recovery action would not be available for other actions. For this particular event, the licensee's proposed recovery actions are interrelated since they both involve the recovery of the EFW discharge valves and could proceed in parallel, if resources were available, only to the point of valve manipulation. The ANO-2 IPE recovery analysis assumed all ex-control room recovery actions were performed sequentially by a single person (IPE p. 3.4-5). While conservative if additional resources are available, the IPE analysis avoided modeling issues associated with the parallel recovery of failed components in a cut set.

Based on information provided by the licensee and the timing information and recovery analysis documented in the IPE, a revised probability of operators failing to recover EFW was calculated. This calculation recognizes the potential for multiple concurrent recovery actions but does not consider such actions proceeding in a completely independent manner, as assumed in licensee comment 2. The nonrecovery probability of the EFW was calculated by determining:

(a) the nonrecovery probability of operators failing to manually open the EFW discharge valves (recovery #2 given above) and

(b) failure to initiate once-through cooling given EFW is not recovered within 25 min (called recovery #3).

The model used to estimate these failure probabilities is the time-reliability correlation given by Dougherty and Fragola in *Human Reliability Analysis* (Wiley and Sons, New York, 1988). These two failure probabilities are then combined to determine the overall probability of operators failing to recover EFW by considering the availability of personnel throughout a 24-h period.

It was assumed that the EFW discharge valves being closed would be apparent to the operators, and that the initial attempt to recover EFW would be by manually opening these valves (recovery #2 in licensee comment 2). Assuming 70 min to core uncovery (as documented in the IPE), 10 min to implement the EOPs, diagnose the event and determine a recovery strategy, and 10 min for response, a failure probability of 0.056 is estimated for recovery #2. Because of the degree of stress expected during such an event, a time-reliability correlation involving "recovery with hesitancy" was used to model the operator response (again, see Dougherty and Fragola, *Human Reliability Analysis*, Wiley and Sons, New York, 1988). This probability is consistent with the probability reported in licensee comment 2 (0.0398) and with the ANO-2 IPE (0.084).

If EFW is not recovered within 25 min of the start of the transient, the water level in the SG is expected to drop to a value where once-through cooling is required to be initiated. This requirement, which cannot be met because of the loss of dc power, will provide additional emphasis for EFW recovery. Shortly thereafter, additional resources, if available, are assumed to be used to manually control the turbine-driven EFW pump and its discharge valves in a further attempt to feed water to the SGs (recovery #3). A failure probability of 0.27 is estimated for this action using a time-reliability correlation, assuming the demand occurs 30 min into the event (5 min after the cue for once-through cooling) and requires a 20 min response time as specified in the IPE. This failure probability is consistent with the probability reported in the IPE (0.2).

The failure probabilities for the two recovery actions are:

	Recovery	*Failure Probability*
recovery #2:	operators fail to manually open the EFW discharge valves	0.056
recovery #3:	failure to initiate once-through cooling within time required	0.27

Assuming additional resources are available for recovery #3 except on the back shift (resources are assumed to be available two-thirds of the time) provides an overall probability of failing to recover EFW of:

$$\text{probability of operators failing to recover EFW} = [(0.056)(0.27)(2/3)] + [(0.056)(1/3)] = 0.028.$$

These estimates result in the following increase in the CDP over a 1-year period:

$$3.9 \times 10^{-4} \begin{Bmatrix}\text{prob of a loss of} \\ \text{the green dc bus}\end{Bmatrix} \times \left[1.0 \begin{Bmatrix}\text{prob of EFW failure} \\ \text{due to wiring error}\end{Bmatrix} \times \right.$$

$$\left. 0.028 \begin{Bmatrix}\text{prob of failure} \\ \text{to recover EFW}\end{Bmatrix} - 1.1 \times 10^{-3} \begin{Bmatrix}\text{nominal failure prob} \\ \text{for EFW train B}\end{Bmatrix} \right] =$$

$$1.1 \times 10^{-5} \begin{Bmatrix}\text{increase in CDP due} \\ \text{to wiring logic error}\end{Bmatrix}.$$

This compares to the original estimate of 3.9E-5 as reported in the preliminary ASP analysis.

The revised EFW nonrecovery probability involves substantial uncertainty and may be optimistic. An assumption that the operators would not initially attempt to open the EFW discharge valves and instead attempt to manually control the turbine-driven pump (as utilized in the IPE for green bus dc failures) and that separate action to open the closed EFW discharge valves would be cued at the time that once-through cooling is demanded results in an estimated nonrecovery probability twice as high as developed above (6.6E-2).

The IPE estimates the time required to recover EFW by restoring ac power to bus 2A2 (recovery #1) to be 18 min (licensee comment 2 provides an estimate of 9 min for this action); recovery using this approach would, therefore, be no more reliable than manually opening the EFW discharge valves and may involve additional operator burden since ac power would be recovered to a train without dc control power. If resources were diverted to recover dc power at the time that once-through cooling was cued, then recovery of EFW could be further delayed.

As noted by the licensee, the nonsafety auxiliary feedwater pump may provide an alternate method to feed the SGs following a loss of the green dc bus. However, its use would require crew resources that would have to be diverted from the direct recovery of the EFW system. Response time and crew resources are the major factors that influence the probability of failing to recover EFW, and the potential use of a further recovery path within the same time period would be expected to provide little additional benefit. Since the nonsafety AFW pump discharge is routed to the EFW system upstream of the EFW discharge valves, the problems related to these valves would still have to be addressed by the crew. For these reasons, the potential use of the nonsafety AFW pump was not explicitly considered when developing the revised EFW nonrecovery probability.

F.8.2 NRC Comments

No comments were provided.

F.9 LER No. 382/95-002

Event Description: Reactor trip, breaker failure and fire, degraded offsite power, and degraded shutdown cooling

Date of Event: June 10, 1995

Plant: Waterford 3

F.9.1 Licensee Comments

Reference: Letter from J. J. Fisicaro, Entergy Operations, Inc., to the U.S. Nuclear Regulatory Commission, "Review of Preliminary Accident Sequence Precursor Analysis," W3F1-96-0140, August 15, 1996.

Comment 1: The licensee provided many specific comments on the text of the **Event Summary**, **Event Description**, and **Additional Event-Related Information** sections of the analysis documentation concerning the cause of the breaker failure, plant response to that failure, and the design of the bus transfer scheme at Waterford.

Response 1: With the exception of comment 4, the clarifications and corrections provided by the licensee were incorporated into the analysis documentation. Because most of the comments were editorial in nature, they have not been repeated below. Those comments of a technical nature are discussed below.

Comment 2: The second paragraph, third sentence in the **Event Description** is not correct. There is nothing to support the UAT tripping on overcurrent. The overcurrent relays were set to trip at >1 second for a current of 30,000 amps. The event was less than 29,000 amps for approximately 0.3 seconds. The power would not have been lost to the A2 bus unless the SUT breaker had also tripped.

Response 2: The reference to the UAT feeder breaker tipping on overcurrent was changed to indicate that both the UAT and the SUT breakers tripped, and power was lost to bus A2.

Comment 3: The sixth paragraph, first sentence in the **Event Description** states that the A1 bus de-energized and all of its loads de-energized at the beginning of the event. This sentence should be moved to the beginning of the event.

Response 3: To preserve the sequence of events, this sentence was moved to the third paragraph in the **Event Description**.

Comment 4: The ninth paragraph in the **Event Description** discusses the use of water on the fire. The recommendation to use water was not made solely by the Volunteer Fire Department. The decision to use water was the result of a methodical analysis performed by the Waterford 3 Fire Brigade Leader and the Voluntary Fire Department Chief. Also, the Fire Brigade was not "reluctant" to use water. They had been trained to consider gas and dry chemical as the preferred options.

Response 4: This comment pertains to the reluctance of the fire brigade to use water on the fire when carbon dioxide and dry chemical fire extinguishers were proving to be ineffective. The AIT report for the event (Reference 2 to the analysis documentation) noted that all operators indicated in later interviews that they were reluctant to use water on the electrical fire. The applicable paragraph in the **Event Description** was reworded instead to indicate that the source of this information was the AIT report.

Comment 5: The tenth paragraph, second sentence in the **Event Description** states that a condenser low vacuum alarm had actuated at 0940 hours, "42 min after the 6.9 kV . . . ." The 6.9 kV bus de-energized at 0858 hours when the transfer to the SUT failed.

Response 5: This part of the sentence was deleted.

Comment 6: The fifth paragraph in the **Additional Event-Related Information** section discusses "fire stops." The design of the Calvert Bus used at Waterford 3 does not employ the use of "fire stops." Thus, the statement regarding the ineffectiveness of the vertical fire stops is inaccurate. Additionally, the statement that fire damage was limited by the fire stop in the horizontal section is also inaccurate.

Response 6: All references to fire stops at Waterford 3 have been removed.

F.9.2 NRC Comments

No comments were provided.

F.10 LER No. 389/95-005

Event Description: Failure of one emergency diesel generator with common-cause failure implications

Date of Event: November 20, 1995

Plant: St. Lucie, Unit 2

F.10.1 Licensee Comments

Reference: Letter from J. A. Stall, Florida Power and Light Company, to U.S. Nuclear Regulatory Commission, transmitting St. Lucie Plant–Unit 2 Docket No. 50-389 "Comments on Preliminary Accident Sequence Precursor Analysis of 2A EDG Relay Socket Failures Due to High Cycle Fatigue at St. Lucie Unit 2 on November 20, 1995, L-96-218," September 3, 1996.

Comment 1: The NRC evaluation did not give credit for recovery of emergency power to Unit 2 following a blackout via the blackout cross-tie. The cross-tie failure probability is approximately 9.0E-002 (including hardware failures, operator failure to align cross-tie, and unavailability of the cross-tie).

Response 1: The blackout cross-tie capability was not previously modeled separately by the IRRAS model. The base model for St. Lucie was revised to address the cross-tie for plant-centered LOOPs by assuming a lognormal distribution for the operator response. It was assumed that the operations personnel could provide power via the blackout cross-tie within one hour 5% of the time and within two hours 95% of the time. These response times were chosen based on operator response following a recent LOOP at Catawba, when a dual-unit cross-tie was used in mitigating the event. This assumption results in an estimated cross-tie failure probability of 0.09 at 1.9 hours instead of the 1 hour assumed in IPE Table 3.4-2 (basic event REPS1XTIE). The lognormal distribution was combined with the Weibull distribution used to predict the LOOP-related parameters for St. Lucie Unit 2 as defined in ORNL/NRC/LTR-89/14. Although the ASP model does not include the potential use of the cross-tie for dual-unit LOOPs, it assumes a higher probability of recovering offsite power than in the IPE (based on data in IPE Tables 3.3-3, 3.3-6, 3.3-7, and 3.4-2 as applied to selected cut sets in Table 3.7-4). Note that basic event EPS-XHE-NOREC in the ASP model is intended to address short-term recovery of the diesel generators and not longer-term recovery of offsite power, which is addressed in basic events OEP-XHE-NOREC-BD and OEP-XHE-NOREC-SL.

Comment 2: The probability of a reactor coolant pump (RCP) seal loss-of-coolant accident (LOCA) used by the NRC is overestimated for Byron-Jackson four (4) stage seals. The St. Lucie Unit 2 RCPs, by design and field experience, are not susceptible to seal failure resulting from loss-of-seal cooling water if the pumps are idle.

Response 2: The probability of RCP seal LOCA (RCS-MDP-LK-SEALS) was revised to be consistent with the seal LOCA model developed for Combustion Engineering (CE) plants during the analysis of a 1994 event at Calvert Cliffs (see the analysis and resolution of comments on precursor event 318/94-001 in the 1994 precursor report, NUREG/CR-4674, Vol. 21). This model used data provided by the CE operating group as described in Appendix H to NUREG/CR-4674, Vol. 22. Based on this, the probability of a seal LOCA was revised from 4.8E-002 to 7.4E-003.

Comment 3: The estimated CCDP and change in core damage probability (CDP) is less than the 1.0E-06 precursor screening criteria. The FPL estimate is 6.3E-007 to 7.0E-007 vs the NRC estimate of 1.7E-005.

Response 3: The model was reevaluated with revised LOOP parameters to account for the blackout cross-tie capability and ASP analysis CE RCP seal failure distribution. The revised CCDP estimated for this precursor event is 1.4E-005 vs the preliminary estimate of 1.7E-005.

F.10.2 NRC Comments

Reference: Note from B. Jones, AEOD, to P. D. O'Reilly, AEOD, July 25, 1996.

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omment 1: Is there any indication that the 18-month maintenance interval contributed to the problem?

Response 1: This was not the conclusion presented in the LER.

F.11 LER No. 445/95-003, -004

Event Description: Reactor trip, auxiliary feedwater (AFW) pump trip, second AFW pump unavailable

Date of Event: June 11, 1995

Plant: Comanche Peak 1

F.11.1 Licensee Comments

Reference: Letter from C. L. Terry, Texas Utilities Electric Company, to U.S. Nuclear Regulatory Commission, transmitting Comanche Peak Steam Electric Station (CPSES)–Unit 1 Docket No. 50-445 "Comments on Preliminary Accident Sequence Precursor Analysis of Reactor Trip at CPSES Unit 1 on June 11, 1995, TTX-96397," July 15, 1996.

Comment 1: The quantitative values presented in this analysis are, in some cases, different from the values used in the CPSES Individual Plant Examination (IPE) study. In general, the core damage frequency contributions in the Preliminary Accident Sequence Precursor Analysis are based on somewhat conservative assumptions and more simplified models. Therefore, the numerical values should not be considered as accurate contributions to total core damage frequency. Rather, they should be used to determine the relative importance of various accident sequence precursors.

Response 1: Since its inception, this has been one of the primary objectives of the accident sequence precursor program. Over time, efforts have been made to make the models which are employed more realistic. However, it remains true that the ASP models are more simplified and potentially more conservative than those found in some IPEs.

Comment 2: The failure probabilities for the following events appear to be significantly higher than the values used in the CPSES IPE study.

- Operator fails to initiate feed-and-bleed cooling: a value of 1.0E-2 was used in this study vs 1.0E-3 used in the CPSES IPE.
- Failure of nonrecoverable RPS trip: a value of 2.0E-5 was used in this study vs 1.0E-5 used in the CPSES IPE.

Response 2: Because of the sparseness of system failure events, data from many plants must be combined to estimate the failure probability of a multitrain system or the frequency of low- and moderate-frequency events (such as LOOPs and small-break LOCAs). Because of this, the modeled response for each event will tend toward an average response for the plant class (refer to Table B.1 in NUREG/CR-4674, Vol. 21, for a listing of plants and their respective plant class). If systems at the plant at which the event occurred are better or worse than average (difficult to ascertain without extensive operating experience), the actual conditional probability for an event could be higher or lower than that calculated in the analysis. Regardless, the nonrecoverable RPS trip value and the operator failure to initiate feed-and-bleed value are consistent with those values used in other probabilistic risk assessments (e.g., the Sequoyah PRA, the Farley IPE, the McGuire IPE) for all ASP plant classes for PWRs. Nevertheless, if the values for HPI-XHE-XM-FB (operator fails to initiate feed-and-bleed) and RPS-NONRFC (nonrecoverable RPS trip failures) are changed to match the CPSES IPE values, the CCDP would be 3.7×10^{-5}. Even with these changes, the resulting CCDP is on the same order of magnitude, and the event still meets the selection criteria as an ASP event (i.e., CCDP $> 10^{-6}$).

Comment 3: This event demonstrated that the CPSES operating crew was capable of recovering the Train A Motor-Driven Auxiliary Feedwater Pump (MDAFWP1-01) within 8 min and safely shutting down the plant. As a result, the failure probability to realign the Train A pump from a test configuration to the operating configuration should be very low. It should be noted that the Train A pump did not fail to operate, and, therefore, the recovery here did not require repairing a failed pump but rather realigning Train A to an operating configuration. Consequently, the probability of not successfully realigning the pump under the given conditions should be between 1E-2 and 1E-4.

This recovery, on the other hand, should have a failure probability of 1.0 for an Anticipated Transient Without Scram (ATWS) event since the pump is required to be available almost immediately.

Response 3: The nonrecovery value was estimated using the methodology described by Sattison ("Methods Improvements Incorporated into the SAPHIRE ASP Models," Sattison et al., NUREG/CP-0140, Vol. 1, *Proceedings of the Twenty-Second Water Reactor Safety Information Meeting*, October 1994, U.S. Nuclear Regulatory Commission).

In response to this comment, a more rigorous approach was taken. Nonrecovery as a function of time was modeled as being lognormally distributed (see E. M. Dougherty and J. R. Fragola, *Human Reliability Analysis*, Wiley and Sons, 1988), with a median response time of 8 min (actual response time) and a window of 30 min. Assuming a burdened-recovery error factor of 6.4, the probability of nonrecovery within 30 min is approximately 0.1, the same as estimated by the Sattison approach.

Since it was assumed that the entire 30 min would be dedicated to recovery of AFW-MDP-FC-1A, the system nonrecovery, AFW-XHE-NOREC, was set to 1.0.

As described in the modeling assumptions section, motor-driven AFW pump A was assumed to be inoperable for ATWS events.

Comment 4: The cut set numbers 1, 2, and 3 of TRANS Sequence 20 in Table B.11.5 have the basic event AFW-XHE-XA-SSW for which there is no definition. This basic event appears to be the failure of the operator to align the suction of the AFW pumps to the Station Service Water (SSW) system. This capability exists at CPSES Units 1 and 2. However, it is normally in a locked closed position, and it is only required when the normal water source of the Condensate Storage Tank (CST) is not available. Since the failure probability of the CST is very low, the alternate SSW water source was not credited in the CPSES IPE study. Nevertheless, if it is modeled, the corresponding cut sets should also include the failure of CST. In cut sets 1, 2, and 3, the CST term is not included, but SSW alignment is included.

Response 4: Basic event AFW-XHE-XA-SSW is defined in Table B11.1 as "Operator Fails to Align Suction to the Service Water System (SSW)." However, this event would be better described as "Operator Fails to Align Makeup to the CST."

Comanche Peak's condensate storage tank (CST) has a volume of approximately 1.9×10^6 l (500,000 gal). Technical Specifications (3.7.1.3) require a minimum tank level of 53% be maintained. Assuming that tank level correlates linearly with volume, this corresponds to about 1.0×10^6 l (265,000 gal). The FSAR indicates that 1.1×10^6 l (282,000 gal) will be dedicated for AFW operation and the IPE makes a similar assumption. This reserved capacity of the CST is good for 9 h—maintaining hot standby for 4 h and then to cooling down to conditions which would permit alignment to the RHR.

The ASP model for AFW success requires sufficient inventory for up to 24 h of operation. A simple calculation was performed using the Untermyer–Weills decay heat correlation to estimate the amount of CST inventory that would be required to remove this decay heat without replenishment (Reference: S. Glasstone and A. Sesonske, *Nuclear Reactor Engineering*, D. van Nostrand, 1967). About 2.3×10^{12} J (2.2×10^9 BTUs) would be rejected, requiring about 1.2×10^6 (330,000 gal) of CST inventory. This quantity is significantly more than the amount required by Technical Specifications or assumed in the IPE.

The actual level in the CST will fluctuate from near maximum 1.9×10^6 l or (500,000 gal) to near the technical specification limit. Without further knowledge of Comanche Peak's operating practices, it is impossible to determine when sufficient inventory exists in the CST and when it does not. Regardless, any reasonable assumption will not greatly affect the

CCDP calculated for this event. For example, if it is assumed that the CST inventory would be inadequate 50% of the time, those cut sets containing the basic event AFW-XHE-XA-SSW would be weighted by 0.5 (specifically, cut set numbers 1, 2, and 3 in TRANS Sequence 20). This change would reduce the estimated CCDP from 6.5E-5 to 5.2E-5. Hence, the event still qualifies as an ASP-type event.

F.11.2 NRC Comments

No comments were provided.

Appendix G:

At-Power Precursors for 1996

G.1 1996 Events

Two events that occurred during 1996 were analyzed by the ASP Program; both are considered to be important precursors. The Catawba 2 LOOP event with an emergency diesel-generator (EDG) in maintenance (LER 414/96-001) had a CCDP > 1.0×10^{-3}, which was higher than the CCDP for any of the 1995 precursor events. The other precursor for 1996 involved the degradation of the essential service water system at Wolf Creek due to the formation of frazil ice under severely cold weather conditions (LER 414/96-001, -002). The turbine-driven auxiliary feedwater pump was also out of service due to maintenance when the event occurred, making the plant vulnerable to a loss-of-offsite power event in addition to the potential for a loss of decay heat removal capability if the remaining operable essential service water pump had failed. The CCDP for this event was >1.0×10^{-4}, which is considered to be an important precursor in the ASP Program.

G.1.1 Event Documentation

Analysis documentation and precursor calculation information for each precursor are attached. The precursors are in docket/LER number order.

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

A figure is included which highlights the dominant core damage sequence associated with the event. Conditional core damage calculation information is also provided. This includes the following tables:

- Probabilities for selected basic events
- Sequence logic, sequence probabilities, and importances and system names for higher probability sequences
- Higher probability cutsets for higher probability sequences

G.2 LER No. 414/96-001

Event Description: Loss-of-offsite power with emergency diesel generator B unavailable

Date of Event: February 6, 1996

Plant: Catawba 2

G.2.1 Event Summary

At 1231 on February 6, 1996, Unit 2 was at 100% power when ground faults on the 2A main transformer X-hase and 2B main transformer Z-phase potential transformers resulted in a loss-of-offsite power (LOOP). The reactor scrammed and emergency diesel generator (EDG) 2A (train A) started and loaded. EDG 2B was out-of-service because of a faulty ac capacitor in the battery charger for that diesel generator. EDG 2B (train B) was returned to service and its emergency bus (2ETB) energized at 1522 (2 h 51 min into the event). Using parts from the 2A main transformer, the 2B main transformer was repaired and offsite power restored to Unit 2 on February 8, 1996, at 0120 (36 h 49 min into the event). The conditional core damage probability estimated for this event is 2.1×10^{-3}.

G.2.2 Event Description

At 1231 on February 6, 1996, Unit 2 was at 100% power when ground faults on the resistor bushings for the 2A main transformer X-phase and 2B main transformer Z-phase potential transformers resulted in a LOOP. The reactor scrammed, and EDG 2A started and loaded. EDG 2B was out-of-service because of a faulty ac capacitor in the diesel battery charger. EDG 2B was returned to service and its emergency bus (2ETB) energized at 1522 (2 h 51 min into the event). Not all emergency loads on bus 2ETB were energized due to activities in progress to implement a cross-tie to Unit 1. At 1800 (5 h 29 min into the event), the cross-tie activities for train B were completed, and the source for bus 2ETB was transferred to transformer SATB (a Unit 1 B-train offsite power source supplied power to Unit 2 transformer SATB). Initial efforts to complete the cross-tie to bus 2 ETB were unsuccessful because of a procedural inadequacy. At 2000 (7 h 29 min into the event), cross-tie activities were completed for EDG Train A and power was transferred to transformer SATA (a Unit 1 A-train offsite power source supplied power to Unit 2 transformer SATA). Personnel repaired the 2B main transformer using parts from the 2A transformer and restored offsite power to Unit 2 on February 8, 1996, at 0120 (36 h 49 min into the event). Repairs on the 2A main transformer were not completed until 0327 on February 11, 1996 (62 h 56 min from the start of the event).

At 1236, or 5 min after the LOOP, operators manually closed the Main Steam Isolation Valves (MSIVs). At 1238, a safety injection (SI) actuation occurred because of low steam line pressure in the 2A steam generator (SG). At 1247, the pressurizer power-operated relief valve (PORV) 2NC34A began to cycle; at 1310 (39 min into the event), the pressurizer level went off-scale high as the reactor coolant system (RCS) became water solid. At 1320, the pressurizer relief tank (PRT) pressure increased and the PRT rupture disc ruptured as PORV 2NC34A continued to cycle. A steam bubble was reestablished in the pressurizer at 1926 (6 h 55 min into the event or 6 h 16 min after becoming water solid). PORV 2NC34A fully stroked approximately 43 times on steam and an additional 31 times on water. A Nuclear Regulatory Commission (NRC) Inspection Team estimated that this PORV came off its closed seat about 110 times. (Evaluations by the licensee of stroke-time tests and visual external inspection concluded that no damage to PORV 2NC34A occurred. The PORV was supplied by Control Components Incorporated. The PRT rupture disc was replaced on February 9, 1996, at 1428.)

At 1641 (4 h 11 min into the event), control room operators received a report of a leak in the penetration room. [It was subsequently determined that three pit sump check valves from the turbine-driven auxiliary feedwater pump (TDAFWP) were leaking into the penetration room.] The TDAFWP was secured at 1759 (5 h 29 min into the event). Water in the pit sump for the TDAFWP was pumped to the turbine building sump. Back leakage through check valves 2WL894, 2WL836, and 2WL834 allowed the discharge from the sump for the TDAFWP to fill floor drain sump "C," which overflowed onto the Auxiliary Feedwater (AFW) pump room floor to a level of several inches. (This area is separated from the AFW pump pits by a concrete curb approximately 46 cm (18 in. high). The floor drain sump "C" is not powered by emergency power and, therefore, would be unavailable until offsite power is restored.) Operators manually closed valves 2WL835 and 2WL836, thereby stopping the water leakage.

Because of a leak in the instrument air system, the containment was purged by using the Containment Air Release and Addition System on February 7, 1996, at 1033. Air leakage was a recurring problem, as shown by venting data. This data shows that Unit 2 was being vented every 12 h prior to this event. During this event, containment temperature increased in response to the loss of containment chilled water to the ventilation units (containment chilled water is not a diesel-backed load). When the PRT rupture disc ruptured, containment pressure increased further [pressure peaked at .0062 MPa (0.9 psig]). This pressure increase was sufficient to partially open some, but not all, of the ice condenser lower inlet doors. Energy absorption was limited to contact with ice in the lowest portion of the ice condenser. Because there was no flow through the ice condenser, the intermediate and upper deck doors did not open.

G.2.3 Additional Event-Related Information

Each AFW pump is mounted in a separate pit for Net Positive Suction Head (NPSH) requirements. To prevent flooding of these pits, each motor-driven pump pit is supplied with a 190 l/m (50-gpm) sump pump that discharges to the Liquid Radwaste System. For the TDAFWP, the turbine oil is cooled through the lube oil cooler by a small portion of the discharge flow. The TDAFWP turbine oil cooler flow and a portion of the turbine seal water empties directly into the pit for the TDAFWP. If the sump is not drained, failure of the TDAFWP could occur in as early as three hours. To provide extra assurance that the TDAFWP will not fail as a result of flooding, the pit for the TDAFWP is outfitted with two 190 l/m (50-gpm) sump pumps. One of these sump pumps can be powered during a LOOP from either EDG 2A or from the standby shutdown facility; the other sump pump is powered from EDG 2B.

A standby shutdown facility (SSF) is located in a separate building on the Catawba site. This facility, which is not normally manned, is capable of providing limited high-pressure injection for RCS makeup and reactor coolant pump (RCP) seal cooling [provided an RCP seal loss-of-coolant accident (LOCA) does not occur]. The SSF includes a separate diesel generator that can power SSFB loads in the event of a station blackout. The diesel generator for the SSFC can also power one of the sump pumps for the TDAFWP. The SSF systems are single trains and, therefore, are susceptible to a single failure. In conjunction with the TDAFWP and the availability of SGs, the SSFs can maintain hot standby conditions for both units. An operator was sent to man the SSF facility during this event; however, the SSF was never started.

The licensee evaluated the flooding of the AFW pump room in its Individual Plant Examination (IPE). (Recall, the AFW pump room was in danger of being flooded by operating the TDAFWP.) The IPE flood analysis for the AFW pump room evaluates a break in a pipe outside of the sump pits. Water will reach the base of the Auxiliary Shutdown Panel at the same time it reaches the top of the curb around the AFW pump pits. [The curb walls around the pit are 46 cm (18 in. high.)] The lowest point of switches, fuses, or terminal strips within the Auxiliary Shutdown Panel is 20 cm (8 in.) from the base. When water reaches this level, the IPE assumes that equipment controlled from the Auxiliary Shutdown Panel is unavailable. Because the floor area outside the AFW pump room is about 207 m^2 (2,231.6 ft^2), and the curb is 46 cm (18 in.) high, the estimated time to flood the turbine-driven pump pit area is about 33 h. The leakage into the turbine-driven pump pit is within the capability of the operating sump pump. If this pump failed, an additional 3 h would be available before the leakage or the water accumulation in the turbine driven pump pit could fail the pump. After the pump pits are flooded, there is an additional area of 103 m^2 (1,110 ft^2) in the room for water to cover. The IPE further estimates that there is 41.6 min available to isolate a flood of 9,194 l/m (2,429 gpm). Therefore, flooding of the TDAFWP is not considered credible because considerable time was available to mitigate the flooding.

G.2.4 Modeling Assumptions

This event was modeled as a LOOP initiator with failure of train B of the emergency power system. Because offsite power was not restored for about 1½ days and both offsite power transformers required major repairs before power could be restored through these transformers, it was assumed that operators could not have restored offsite power during the event. Therefore, the following basic events were set to "TRUE" (i.e., failed):

(1) operator fails to recover offsite power within 2 h (OEP-XHE-NOREC-2H),
(2) operator fails to recover offsite power within 6 h (OEP-XHE-NOREC-6H),
(3) operator fails to recover offsite power before battery depletion (OEP-XHE-NOREC-BD) , and
(4) operator fails to recover offsite power given a seal LOCA (OEP-XHE-NOREC-SL).

In addition, the probability that the PORVs open during a transient (PORV) was set to "TRUE" because one PORV (2NC34A) lifted more than 74 times.

AC power to the emergency buses was assumed to be potentially recoverable to the emergency buses by implementing a cross-tie to Unit 1 and by recovering EDG 2B. These actions were assumed to be independent for this analysis given that the event occurred during the day shift. (This assumption would have to be confirmed for an event occurring outside the day shift because it was unknown if sufficient personnel would be available during the period between 5:00 p.m. and 8:00 a.m. to perform all the actions in parallel that were performed during this event.)

The LOOP event tree for Catawba is shown in Fig. G.2.1. Credit for the SSF at Catawba was accounted for by adding the fault tree shown in Fig. G.2.2 at the SSF branch point in the event tree shown in Fig. G.2.1. The failure probabilities for the basic events SSFB and SSFC were obtained from the Catawba IPE. Basic event SSFB is the failure to provide seal cooling to the reactor coolant pumps; basic event SSFC is the failure to provide power to the sump pump for the TDAFWP.

The recovery of power by implementing a cross-tie to Unit 1 was modeled by adding the basic event *failure to cross-tie EDG B emergency bus within 3 h* [OEP-XHE-NOCRS-B] to the Catawba fault trees for failure to recover power prior to core uncovery given an RCP seal LOCA (OP-SL, see Fig. G.2.3) and prior to battery depletion given no seal LOCA (OP-BD, see Fig. G.2.4). Failure to cross-tie to Unit 1 was modeled as a time-reliability correlation (TRC) as described in *Human Reliability Analysis*, E. M. Dougherty and J. R. Fragola, John Wiley and Sons, New York, 1988. Because sequences of concern in the analysis involve a station blackout, the "recovery with hesitancy" TRC, as described in Chapter 11 of the reference, was used in the analysis. The probability distribution for this TRC is lognormal, with an error factor of 6.4. To reflect the observed time to implement the cross-tie, a median response of 60 min was assumed, following a 30-min delay. The probability of crew failure at 3 h, estimated using this TRC and response time, is 0.27.

A single sump pump must be available (requiring emergency power or power from the SSF) within 3 h to prevent failure of the TDAFWP as a result of flooding.

The probability of a seal LOCA was obtained from NUREG-1032, *Evaluation of Station Blackout at Nuclear Power Plants*, and RCP seal LOCA models were developed as part of the NUREG-1150 probabilistic risk assessment efforts, as described in *Revised LOOP Recovery and PWR Seal LOCA Models* (ORNL/NRC/LTR-9/11, August 1989). This model assumes that it would take 2 h to uncover the core given a seal LOCA and that the seal LOCA would occur within 1 h of the station blackout. Therefore, the assumption was made that the core would be uncovered 3 h after the initiation of the station blackout.

The basic event for failing to recover EDG 2B was developed with an exponential repair model with a median repair time of 140 min and a delay of 30 min (EPS-XHE-EDGB-NOR). (EDG 2B was recovered within 3 h.) Based on this repair model, the probability of failing to recover EDG 2B is 0.48.

To account for the longer run time of EDG 2A during this event, the failure probability was modified from 0.042 to 0.045. Hence, the mission time for this event was increased from 6 h to 7.5 h while maintaining the same failure to start probability (0.03) and the same failure to run failure rate (0.002/h), as reported in the "ASP Models, PWR B, Catawba Units 1 and 2," Revision 1, November 1994.

Although, the AFW pump room was flooding and the source of the flooding was bearing and oil cooling water from the TDAFWP via the sump to the TDAFWP, the TDAFWP was considered operable with no change in the failure probability because (1) operators isolated the leak and (2) operators would have had at least 33 h to isolate the leak if the TDAFWP had been required to run. The 33 h estimate was obtained by multiplying the time provided in the IPE for isolating a flood (41.6 min) by the assumed flooding rate in the IPE 9,194 l/m [(2,429 gpm)] and dividing by the maximum sump pump flow for the TDAFWP. This result is then converted to hours by dividing by 60 min/h [i.e., (41.6 min) × (9,194 l/m) ÷ (190 l/m) ÷ (60 min/h) ≈ 33 h].

G.2.5 Analysis Results

The conditional core damage probability estimated for this event is 2.1×10^{-3}. The dominant core damage sequence, highlighted as sequence number 39 on the event tree in Fig. G.2.1, involves the following:

- given the loss-of-offsite power, the reactor successfully trips;
- both trains of emergency power fail;
- AFW provides sufficient flow;
- the PORVs open and then successfully reseat;
- the safe shutdown facility fails;
- the RCP seals fail; and
- offsite power is not recovered after the RCP seal failure.

The second highest core damage sequence (No. 41) involves the following:

- given the loss of offsite power, the reactor successfully trips;
- both trains of emergency power fail; and
- AFW fails to provide sufficient flow.

Definitions and probabilities for selected basic events are shown in Table G.2.1. The conditional probabilities associated with the highest probability sequences are shown in Table G.2.2. Table G.2.3 lists the sequence logic associated with the sequences listed in Table G.2.2. Table G.2.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table G.2.5.

G.2.6 References

1. Memorandum from S. D. Ebneter, Regional Administrator, to E. L. Jordan, Director, Office for Analysis and Evaluation of Operational Data, transmitting "Supporting Documents for the Catawba Loss of Offsite Power Event (February 6–8, 1996)," February 15, 1996.

2. U.S. Nuclear Regulatory Commission, "NRC Inspection Report Nos. 50-413/96-03 and 50-414/96-03 and Notice of Violation," March 12, 1996.

3. U.S. Nuclear Regulatory Commission, "Preliminary Notification of Event or Unusual Occurrence PNO-II-6-006," February 6, 1996.

4. U.S. Nuclear Regulatory Commission, "Preliminary Notification of Event or Unusual Occurrence PNO-II-6-006A," February 7, 1996.

5. U.S. Nuclear Regulatory Commission, "Preliminary Notification of Event or Unusual Occurrence PNO-II-6-006B," February 7, 1996.

6. U.S. Nuclear Regulatory Commission, "Preliminary Notification of Event or Unusual Occurrence PNO-II-96-006C," February 8, 1996.

7. 50.72 Report Number 29945, February 6, 1996.

8. LER 414/96-001, "Loss-of-Offsite Power Due to Electrical Component Failures," March 7, 1996.

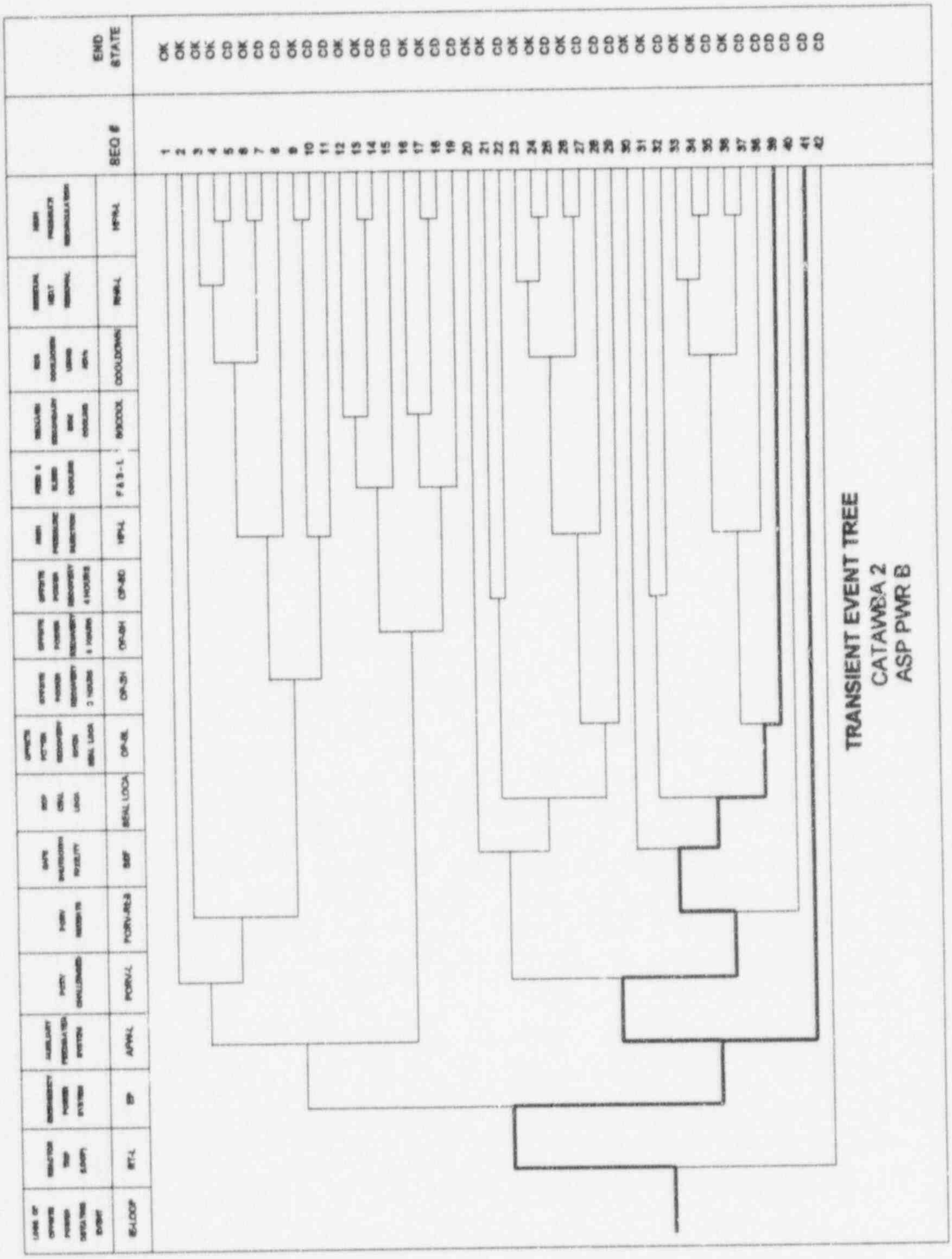

Fig. G.2.1. Dominant core damage sequences for LER No. 414/96-001.

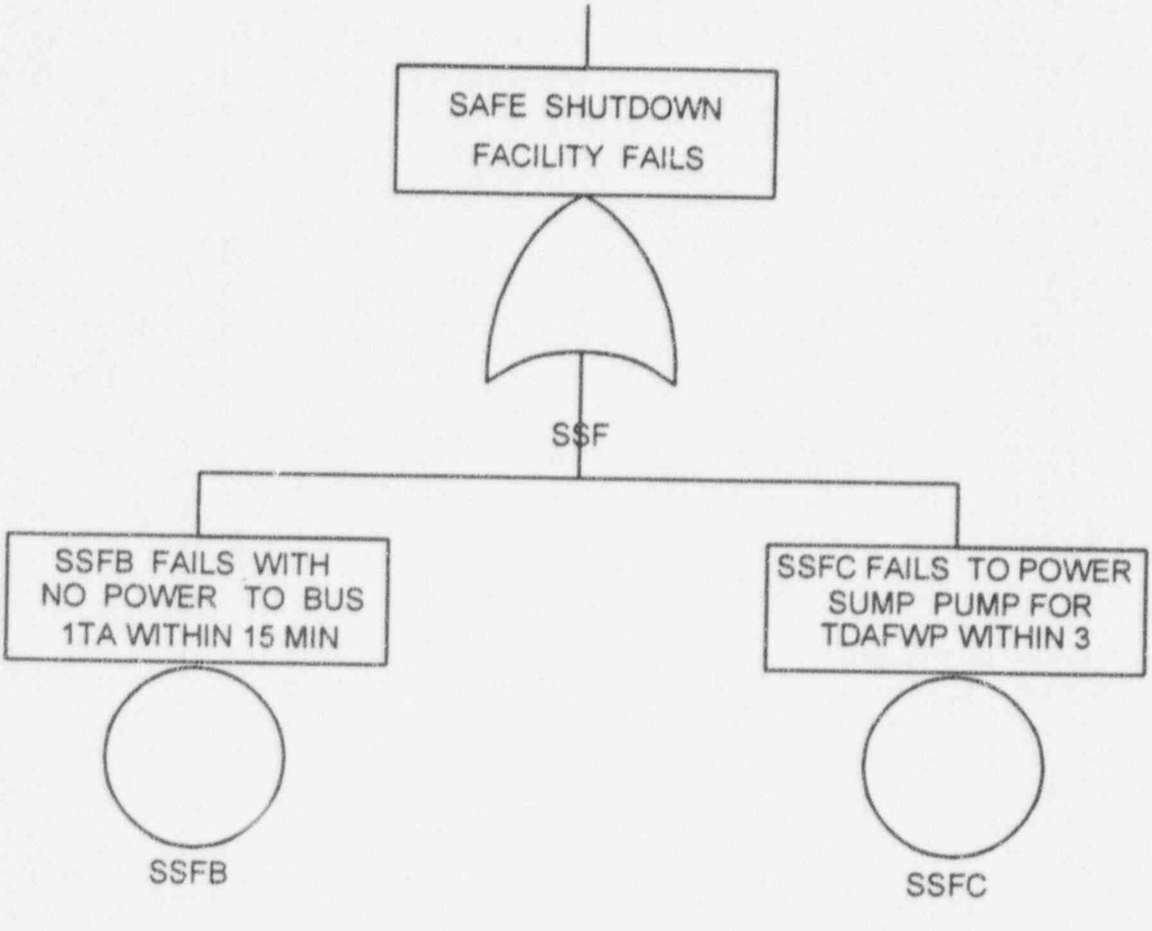

Fig. G.2.2. Fault tree modeling the Standby Shutdown Facility (SSF).

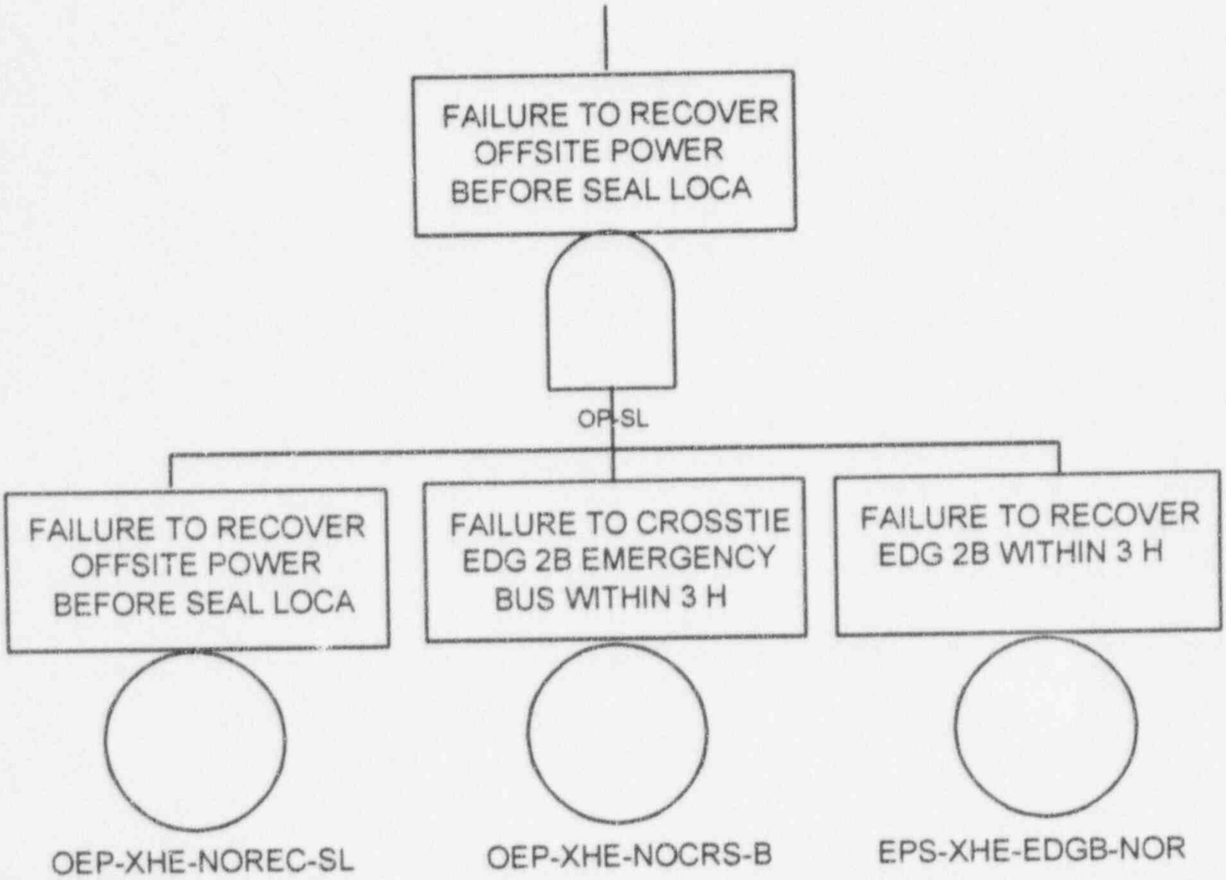

Fig. G.2.3. Fault tree modeling the recovery of offsite power before the core becomes uncovered given a seal LOCA (OP-SL).

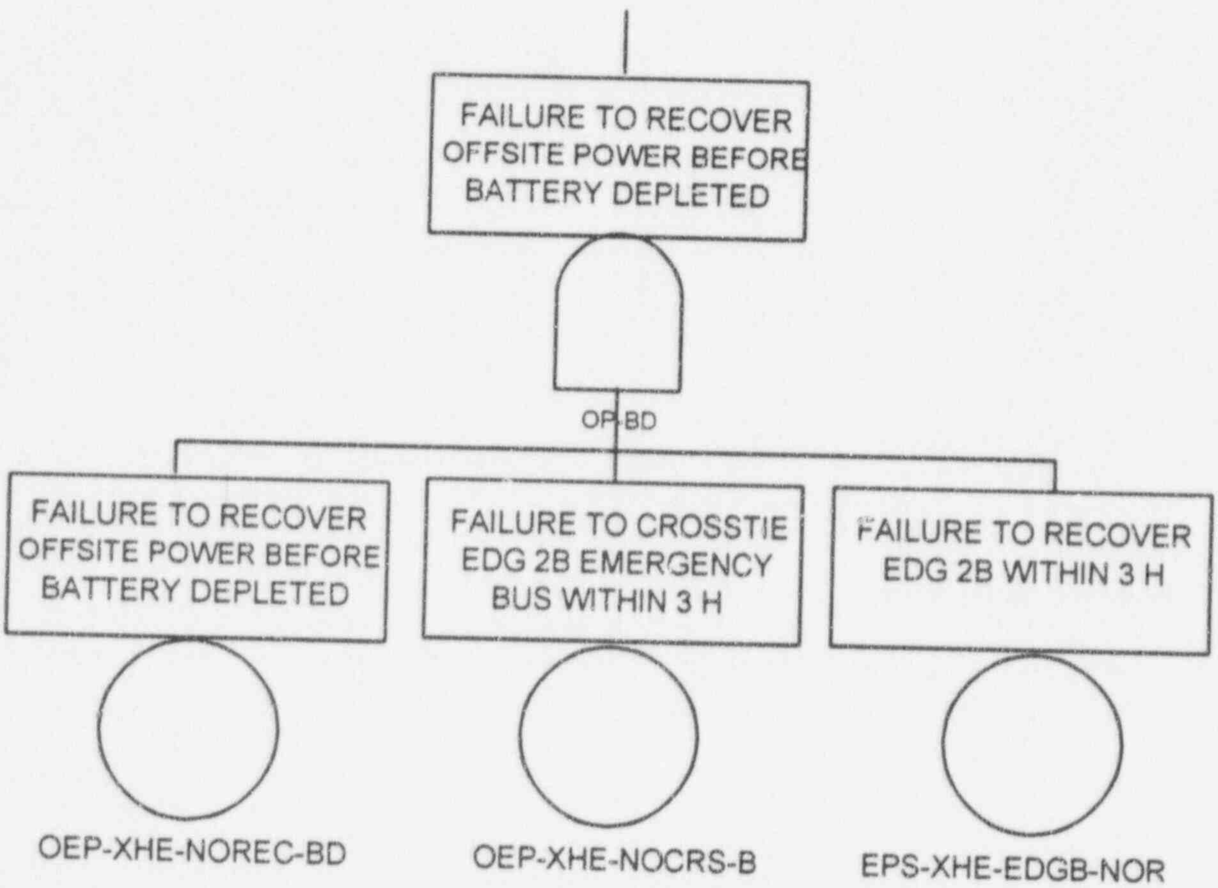

Fig. G.2.4. Fault tree modeling the recovery of offsite power before the batteries are depleted (OP-BD).

Table G.2.1. Definitions and Probabilities for Selected Basic Events for LER 414/96-001

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss-of-Offsite Power Initiating Event	6.9E-006	1.0E+000	TRUE	Yes
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6E-006	0.0E+000	IGNORE	No
IE-SLOCA	Small Loss-of-Coolant Accident Initiating Event	1.0E-006	0.0E+000	IGNORE	No
IE-TRANS	Transient Initiating Event	5.3E-004	0.0E+000	IGNORE	No
AFW-TDP-FC-1A	AFW Turbine-Driven Pump Fails	3.2E-002	3.2E-002		No
AFW-XHE-NOREC-EP	Operator Fails to Recover AFW During Station Blackout	3.4E-001	3.4E-001		No
AFW-XHE-XA-NWS	Operator Fails to Align Nuclear Service Water	1.0E-003	1.0E-003		No
EPS-DGN-CF-ALL	Common-Cause Failure of EDGs	1.1E-003	1.1E-003		No
EPS-DGN-FC-1A	EDG A Fails	4.2E-002	4.5E-002		Yes
EPS-DGN-FC-1B	EDG B Fails	4.2E-002	1.0E+000	TRUE	Yes
EPS-XHE-EDGB-NOR	Operator Fails to Recover EDG B Within 3 h	1.0E+000	3.1E-001	NEW	Yes
EPS-XHE-NOREC	Operator Fails to Recover Emergency Power	8.0E-001	1.0E+000		Yes
HPI-MDP-CF-ALL	Common-Cause Failure of the High Pressure Injection (HPI) Pumps	7.8E-004	7.8E-004		No
HPI-MDP-FC-1A	HPI Motor-Driven Pump Train A Fails	4.0E-003	4.0E-003		No
HPI-MOV-CC-DISCH	HPI Cold Leg Injection Valve Fails	3.0E-003	3.0E-003		No
HPR-MOV-CC-RHRB	Residual Heat Removal (RHR) Discharge Motor-Operated Valve (MOV) into HPI Train B Fails	3.1E-003	3.1E-003		No
HPR-MOV-CC-SMPA	Sump Isolation MOV 185A Fails to Open	3.0E-003	3.0E-003		No

Table G.2.1. Definitions and Probabilities for Selected Basic Events for LER 414/96-001

Event name	Description	Base probability	Current probability	Type	Modified for this event
HPR-MOV-CF-SUCA	High Pressure Recirc (HPR) Suction MOVs from RHR Train A Fail to Open Due to Common Cause	1.0E+000	1.0E+000		No
HPR-XHE-NOREC-L	Operator Fails to Recover the HPR System During a LOOP	1.0E+000	1.0E+000		No
HPR-XHE-XM-L	Operator Fails to Initiate HPR During a LOOP	1.0E-003	1.0E-003		No
OEP-XHE-NOCRS-B	Failure to Cross-Tie EDG B Emergency Bus Within 3 Hours	1.0E+000	2.7E-001	NEW	Yes
OEP-XHE-NOREC-2H	Operator Fails to Recover Offsite Power Within 2 h	1.4E-001	1.0E+000	TRUE	Yes
OEP-XHE-NOREC-6H	Operator Fails to Recover Offsite Power Within 6 h	9.9E-004	1.0E+000	TRUE	Yes
OEP-XHE-NOREC-BD	Operator Fails to Recover Offsite Power Before Battery Depleted	2.3E-002	1.0E+000	TRUE	Yes
OEP-XHE-NOREC-SL	Operator Fails to Recover Offsite Power (Seal LOCA)	4.8E-001	1.0E+000	TRUE	Yes
PORV	PORVs Open During Transient	7.0E-001	1.0E+000	TRUE	Yes
PPR-SRV-OO-PRV1	PORV 1 Fails to Reclose After Opening	2.0E-003	2.0E-003		No
PPR-SRV-OO-PRV2	PORV 2 Fails to Reclose After Opening	2.0E-003	2.0E-003		No
PPR-SRV-OO-PRV3	PORV 3 Fails to Reclose After Opening	2.0E-003	2.0E-003		No
RCS-MDP-LK-SEALS	RCP Seals Fail Without Cooling and Injection	2.4E-001	7.0E-001		Yes
RHR-MDP-CF-ALL	RHR Pump Common-Cause Failures	4.5E-004	4.5E-004		No
RHR-MDP-FC-1A	RHR MDP 1A Fails	4.1E-003	4.1E-003		No
SEALLOCA	RCP Seals Fail During LOOP	2.4E-001	7.0E-001		Yes

Table G.2.1. Definitions and Probabilities for Selected Basic Events for LER 414/96-001

Event name	Description	Base probability	Current probability	Type	Modified for this event
SSFB	SSF Fails with No Power to Bus 1TA	2.2E-001	2.2E-001	NEW	Yes
SSFC	SSF Fails to Power Sump Pump of TDAFW Pump	9.5E-002	9.5E-002	NEW	Yes

Table G.2.2. Sequence Conditional Probabilities for LER 414/96-001

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
LOOP	39	8.5E-004	40.1
LOOP	41	5.3E-004	25.0
LOOP	32	3.6E-004	17.2
LOOP	40	2.7E-004	13.0
LOOP	10	7.8E-005	3.7
Total (all sequences)		2.1E-003	

Table G.2.3. Sequence Logic for Dominant Sequences for LER 414/96-001

Event tree name	Sequence name	Logic
LOOP	39	/RT-L, EP, /AFW-L, PORV-L, /PORV-RES, SSF, SEALLOCA, OP-SL
LOOP	41	/RT-L, EP, AFW-L-EP
LOOP	32	/RT-L, EP, /AFW-L, PORV-L, /PORV-RES, SSF, /SEALLOCA, OP-BD
LOOP	40	/RT-L, EP, /AFW-L, PORV-L, PORV-EP
LOOP	10	/RT-L, /EP, /AFW-L, PORV-L, PRV-L-EP, OP-2H, /HPI-L, HPR-L

Table G.2.4. System Names for LER 414/96-001

System name	Logic
AFW-L	No or Insufficient AFW Flow During LOOP
AFW-L-EP	No or Insufficient AFW Flow During Station Blackout
EP	Failure of Both Trains of Emergency Power
HPI-L	No or Insufficient Flow from HPI System During a LOOP
HPR-L	No or Insufficient Flow from HPR System During a LOOP
OP-2H	Operator Fails to Recover Offsite Power Within 2 Hours
OP-BD	Operator Fails to Recover Offsite Power Before Battery is Depleted
OP-SL	Operator Fails to Recover Offsite Power (Seal LOCA)
PORV-EP	PORVs Fail to Reclose (No Electric Power)
PORV-L	PORVs Open During LOOP
PORV-RES	PORVs Fail to Reseat
PRV-L-EP	PORVs and Block Valves Fail to Reclose [Electric Power (EP) Succeeds]
RT-L	Reactor Fails to Trip During LOOP
SEALLOCA	RCP Seals Fail During LOOP
SSF	Safe Shutdown Facility Fails

Table G.2.5. Conditional Cut Sets for Higher Probability Sequences for LER 414/96-001

Cut set No.	Percent contribution	Conditional probability[a]	Cut sets[b]
LOOP Sequence 39		8.5E-004	
1	68.1	5.8E-004	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, SSFB, OEP-XHE-NOCRS-B, PORV, SEALLOCA, OEP-XHE-NOREC-SL, EPS-XHE-EDGB-NOR
2	29.4	2.5E-004	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, SSFC, OEP-XHE-NOCRS-B, PORV, SEALLOCA, OEP-XHE-NOREC-SL, EPS-XHE-EDGB-NOR
3	1.7	1.4E-005	EPS-DGN-CF-ALL, EPS-XHE-NOREC, SSFB, OEP-XHE-NOCRS-B, PORV, SEALLOCA, OEP-XHE-NOREC-SL, EPS-XHE-EDGB-NOR
LOOP Sequence 41		5.3E-004	
1	94.6	5.0E-004	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, AFW-TDP-FC-1A, AFW-XHE-NOREC-EP
2	2.8	1.5E-005	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC AFW-XHE-NOREC-EP, AFW-XHE-XA-NWS
3	2.4	1.2E-005	EPS-DGN-CF-ALL, EPS-XHE-NOREC, AFW-TDP-FC-1A, AFW-XHE-NOREC-EP
LOOP Sequence 32		3.6E-004	
1	68.1	2.4E-004	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, SSFB, OEP-XHE-NOCRS-B, /SEALLOCA, OEP-XHE-NOREC-BD, EPS-XHE-EDGB-NOR
2	29.4	1.0E-004	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, SSFC, OEP-XHE-NOCRS-B, /SEALLOCA, OEP-XHE-NOREC-BD, EPS-XHE-EDGB-NOR
3	1.7	6.3E-006	EPS-DGN-CF-ALL, EPS-XHE-NOREC, SSFB, OEP-XHE-NOCRS-B, /SEALLOCA, OEP-XHE-NOREC-BD, EPS-XHE-EDGB-NOR
LOOP Sequence 40		2.7E-004	
1	32.5	9.0E-005	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PORV, PPR-SRV-OO-PRV1
2	32.5	9.0E-005	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PORV, PPR-SRV-OO-PRV2
3	32.5	9.0E-005	EPS-DGN-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PORV PPR-SRV-OO-PRV3

Table G.2.5. Conditional Cut Sets for Higher Probability Sequences for LER 414/96-001

Cut set No.	Percent contribution	Conditional probability[a]	Cut sets[b]
LOOP Sequence 10		7.8E-005	
1	9.9	7.8E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, RHR-MDP-FC-1A, HPR-XHE-NOREC-L
2	9.9	7.8E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, RHR-MDP-FC-1A, HPR-XHE-NOREC-L
3	9.7	7.6E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MDP-FC-1A, HPR-XHE-NOREC-L
4	9.7	7.6E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MDP-FC-1A, HPR-XHE-NOREC-L
5	7.5	5.9E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-MOV-CF-SUCA, HPR-MOV-CC-RHRB, HPR-XHE-NOREC-L
6	7.5	5.9E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-MOV-CF-SUCA, HPR-MOV-CC-RHRB, HPR-XHE-NOREC-L
7	7.2	5.7E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-MOV-CC-SMPA, HPR-XHE-NOREC-L
8	7.2	5.7E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-MOV-CC-SMPA, HPR-XHE-NOREC-L
9	7.2	5.7E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MOV-CC-DISCH, HPR-XHE-NOREC-L
10	7.2	5.7E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MOV-CC-DISCH, HPR-XHE-NOREC-L
11	2.4	1.9E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-XHE-XM-L
12	2.4	1.9E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPR-XHE-XM-L

Table G.2.5. Conditional Cut Sets for Higher Probability Sequences for LER 414/96-001

Cut set No.	Percent contribution	Conditional probability[a]	Cut sets[b]
13	1.8	1.4E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MDP-CF-ALL, HPR-XHE-NOREC-L
14	1.8	1.4E-006	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, HPI-MDP-CF-ALL, HPR-XHE-NOREC-L
15	1.0	8.6E-007	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV1, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, RHR-MDP-CF-ALL, HPR-XHE-NOREC-L
16	1.0	8.6E-007	/EPS-DGN-FC-1A, PORV, PPR-SRV-OO-PRV3, OEP-XHE-NOREC-2H, EPS-DGN-FC-1B, RHR-MDP-CF-ALL, HPR-XHE-NOREC-L
Total (all sequences)		2.1E-003	

[a]The conditional probability for each cut set is determined by multiplying the probability of the initiating event by the probabilities of the basic events in that minimal cut set. The probabilities for the initiating events and the basic events are given in Table G.2.1.

[b]Basic events IE-LOOP, EPS-DGN-FC-1B, OPE-XHE-NOREC-2H, OEP-XHE-NOREC-6H, OEP-XHE-NOREC-BD, PORV, and OEP-XHE-NOREC-SL are all type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

G.3 LER Nos. 482/96-001, -002

Event Description: Reactor trip with a loss of train A of the essential service water and the turbine-driven auxiliary feedwater pump

Date of Event: January 30, 1996

Plant: Wolf Creek

G.3.1 Event Summary

With the unit at 98% power, cold air caused ice to build on the circulating water system traveling screens. The decreased circulating water flow caused the pressure in the condenser to increase. The operators began a controlled shutdown; however, they were eventually forced to manually trip the unit from approximately 80% power in anticipation of a loss of vacuum in the condenser. Later, a frazil ice buildup on the trash racks forced operators to secure the A essential service water system (ESWS) pump and declare ESWS Train A out of service. Unrelated to the icing conditions, the turbine-driven auxiliary feedwater pump (TDAFWP) was declared out of service for 9 h when the inboard packing failed following the reactor trip. The unavailability of the ESWS pump and the TDAFWP affected the unit's response to a transient event; these unavailabilities would have affected the units' response to a transient induced loss-of-offsite power (LOOP) event. The conditional core damage (CCDP) probability estimated for this event is 2.1×10^{-4}.

G.3.2 Event Description

On January 30, 1996, the plant was operating at 98% power at the beginning of a coast-down to a refueling outage. Ice began to block the circulating water traveling screens, which caused the pressure in the condenser to increase. Approximately 1 h later, operators began a controlled shutdown. Operators manually tripped the reactor when a loss of vacuum in the condenser became imminent. The circulating water pumps were then secured due to the low water level in the intake bay for the circulating water pumps. During the reactor trip, five control rods failed to insert fully. Indications showed that the five control rods stopped inserting between 9.53 and 28.58 cm (3.75 and 11.25 in.) from the bottom of the core. As required by the emergency operating procedures, operators began an emergency boration of the core. All five control rods drifted to the bottom of the core over the next 80 min.

Approximately 90 min after the reactor trip, the TDAFWP was reported to have an inboard shaft gland leak. The pump was secured and declared out of service, and, as required by Technical Specifications, the operators proceeded to take the plant to Mode 4. The TDAFWP was repaired in 9 h and returned to a functional status, though operational testing was still required. Complicating the situation, the auxiliary boiler tripped on at least two occasions. The auxiliary boiler provides heating to both the reactor water storage tank (RWST) and the condensate storage tank (CST) to prevent the water in the tanks from freezing. The lowest temperature that the water in the CST reached was 8.40°C (47.1°F) as recorded by the plant computer. The emergency backup water supply to the CST is the ESWS.

Four hours after the reactor trip, inadequate ESWS warming line flow—caused by original design errors and further reduced by an improper system alignment—resulted in a frazil ice buildup on the trash racks for the A and B ESWS pump intake bays. This condition eventually forced the A ESWS pump to be secured due to low water level in its intake bay. Operations personnel were confused about the actual cause of the fluctuating water level in the ESWS intake bays and, after the water level in the intake bay for train A recovered, the operators attempted to continue pump operation. However, the water level in the intake bay did not remain high enough to allow continuous pump operation. The level in the B ESWS pump intake bay was also quite low due to a frazil ice buildup. At one point, the water level in the intake bay for the B ESWS pump was only 12 m (4 ft) above the minimum water level required for sufficient net positive suction head (NPSH) and likely was moments from a failure of ESWS Train B. Fortunately, the control room operators increased the heat load on ESWS Train B at this point and the intake water level for Train B began to recover. Ultimately, the ESWS Train A was out of service for 37 h, while ESWS Train B pump and one of three one-half-capacity service water pumps remained in operation.

The operators were unable to enter Mode 4 within the time required by Technical Specifications because of the inefficient use of the cooldown procedure. The licensee eventually melted the ice blockage and restored ESWS Train A to normal standby alignment using sparging air to better mix the ESWS return water with the cold water in the intake bay. Cooling flow to Train A components was eventually reestablished by the nonsafety-related service water system (SWS). After evaluating the situation, the utility opted to enter the scheduled refueling outage early.

G.3.3 Additional Event-Related Information

During normal plant operation, the nonsafety-related SWS provides cooling to the ESWS loads and the turbine building loads, including the main feedwater (MFW) pump lube oil coolers. The SWS draws water from the same intake bays as the circulating water pumps. The nonsafety-related SWS consists of three half-capacity pumps and one low-flow startup pump. One SWS half-capacity pump remained in operation after the trip and throughout the event.

The ESWS is a two-train safety-related system started and isolated from the SWS following a safety injection (SI) signal or a LOOP event. The ESWS loads are normally split and include the component cooling water (CCW) heat exchangers and the coolers for the diesel generators. The ESWS loads also include the room coolers for the emergency core cooling system (ECCS) pumps, the charging pumps, the CCW pumps, the Auxiliary Feedwater (AFW) pumps, the control room, switchgear rooms, and containment. Additionally, the ESWS provides the backup water supply to the AFW system in case of a condensate storage tank failure. The CCW system normally operates in a split mode and cools the residual heat removal (RHR) system heat exchanger, the RHR seal cooler, the charging pump bearing oil cooler, the safety injection pump bearing oil cooler, and the reactor coolant pumps.

The ESWS was intended to be able to provide a flow of warm water (via a "warming line") to the ESWS intake bay. Design input assumption errors resulted in inadequate warming line flow and lower warming line temperature than intended. After the initial indication of an ice buildup in the circulating water bays, the operators manually started the A and B trains of the ESWS system. Operators failed to align the ESWS properly and to isolate it from the SWS when, for expediency, they were directed to align the ESWS from memory. Although the expedient lineup was appropriate for the circumstances, a subsequent independent verification of the ESWS lineup with the procedure was not performed as required. The improper alignment resulted in further reductions of warming line flow to the ESWS intake bays for the pumps. This allowed frazil ice to build up on the trash racks and added to the confusion of the operators. While the Train A ESWS pump was declared inoperable due to the ice buildup, the water level in the Train B ESWS intake bay oscillated 1.8 to 4.6 m (6 to 15 ft) below normal as a result of the ice buildup on its trash rack. This situation was not fully communicated to the shift supervisor.

The icing on the ESWS trash racks was the result of a phenomenon known as frazil ice. According to the Augmented Inspection Report, the process starts when a body of water having a large surface area, such as the intake bay area, is subcooled by a loss of heat (as can happen on a very clear, windy, cold night). This condition, which existed at Wolf Creek, allowed tiny crystals of ice to form on the surface of the water. The heavy wind that existed on January 30 propelled the ice crystals below the intake surface. The water flow induced by the running ESWS pumps allowed the tiny ice crystals to readily accumulate on the metal surface of the trash racks.

G.3.4 Modeling Assumptions

This event is modeled as a transient event with the TDAFWP and one train of the ESWS unavailable. The five control rods that failed to insert fully eventually drifted to the bottom of the core. The model was not specifically altered to reflect the control rod problem. The five control rods were considered fully inserted for modeling purposes based on their proximity to the bottom of the core and because the operators commenced an emergency boration as directed by the emergency procedures.

Room cooling for all the ECCS equipment is provided by the ESWS. Procedures are in place to provide alternate room cooling in the event of the loss of the normal room coolers. Considering the inclement cold and windy weather contributing to the event, the loss of any room cooler was not considered a factor in considering a component failed for analysis purposes. The ESWS also removes heat from the CCW system via the CCW heat exchangers. The loss of the ability to remove heat via the CCW heat exchangers causes a loss of bearing oil or seal cooling to the SI pumps and the RHR pumps. However, in the injection mode, ECCS pump cooling was presumed to be adequate based on the flow of cold RWST water into the core. The ECCS injection system operator nonrecovery basic events were maintained at their nominal values to reflect increased operator attention to these systems during continued operation with degraded cooling. A "place-holder" basic event (HPI-WS-FAIL) was used to reflect a failure of the HPI system as a result of the failure of the ESWS where appropriate for clarity. The recirculation mode of RHR would be impacted by the potential loss of heat removal through the RHR heat exchangers. This potential loss is accounted for in the models by increasing the common-cause failure probability of the RHR heat exchangers (RHR-HTX-CF-ALL) to 0.1 based on the failure of ESWS Train A and the similar failure symptoms affecting Train B.

The SWS system provides cooling to the feedwater pump lube oil coolers. Because only one of three one-half-capacity SWS pumps remained in operation and the water supply from the intake bay was seriously threatened, the ability of the operators to recover main feedwater was not considered possible. The operator nonrecovery value (MFW-XHE-NOREC), therefore, is raised to 1.0 from the nominal value of 0.34 to reflect the inability of the operators to recover the main feedwater system if it were to fail. [The probability of the main feedwater system tripping (MFW-SYS-TRIP) is not changed because the lube oil coolers for the MFW pumps are cooled by the SWS, which still had one half-capacity pump running.]

Two basic events are added to the Wolf Creek model to account for both trains of the ESWS. Both events (EWS-MDP-FC-1A and EWS-MDP-FC-1B) are assigned a nominal failure probability of 1.78×10^{-3} based on data from the Wolf Creek Individual Plant Examination (IPE). Basic event ESW-MDP-FC-1A is set to "TRUE" (i.e., failed) based on the unavailability of the ESWS Train A pump due to the inability to maintain the water level in the ESWS Train A pump intake bay. Because ESWS provides cooling to the emergency diesel generators (EDG), the ESWS Train A failure causes the model to recognize the A EDG as failed. The failure probability for ESW-MDP-FC-1B is not adjusted from the nominal failure probability given in the IPE because there is no means to indicate that an otherwise operable component is in jeopardy of imminent failure from an external cause. However, two sensitivity studies explore the impact of the degraded operating condition of the B ESWS pump: (1) the failure probability of ESWS Train B is increased by a factor of ten to 1.78×10^{-2} and (2) the failure probability is changed to 0.1.

A common cause failure event is also added for the ESWS (EWS-MDP-CF-ALL). Based on the failure of the ESWS Train A pump and the operating condition of the ESWS Train B pump, the basic event probability is increased to 0.15 (based on the beta factor for the RHR pump). Finally, an event is added to account for the operator's failure to recover the ESWS if it should fail (EWS-XHE-NOREC). Because of the extreme operating conditions, however, this probability is set to TRUE (i.e., no recovery).

The TDAFWP failure (AFW-TDP-FC-1C) is also set to TRUE. The pump may have operated for the entire 24-h mission time with the inboard packing failure; however, predicting how long the pump could have continued to provide feedwater flow to the steam generators is difficult. Therefore, considering the pump was physically disabled for repairs after the operators declared the pump to be out of service, it is appropriate to consider the pump to be failed. Based on the initial operability of the TDAFW pump (97 min) and the subsequent unavailability of the pump (537 min), a combined operator nonrecovery value for a station blackout (SBO) (AFW-XHE-NOREC-EP) is projected as follows:

$$P(\text{Operator fails to recover AFW}) = [97(0.34) + 537(1.0)] \div 634 = 0.899,$$

where the nominal value of AFW-XHE-NOREC-EP is 0.34; while the pump is undergoing repairs, the value can be assumed to be 1.0 for an SBO. If the entire 24-h mission time is considered, AFW-XHE-NOREC-EP can be projected to be 0.586 by a similar calculation. A sensitivity study is explored for this value. For the case with no LOOP, the operator nonrecovery value (AFW-XHE-NOREC) is left at its nominal value of 0.26. This method is appropriate considering both motor-driven AFW pumps were available and the TDAFWP was available for at least the initial 97 min of the event.

The emergency power system is directly affected by the ESWS support system. As previously noted, the event circumstances made it appear appropriate to adjust the ESWS operator nonrecovery value (EWS-XHE-NOREC) to 1.0. This adjustment seems to dictate that the operator nonrecovery value for the emergency power system (EPS-XHE-NOREC) also be adjusted to 1.0. However, not all possible EDG failures involve a loss of ESWS support. Therefore, EPS-XHE-NOREC is left at the nominal value of 0.80. A sensitivity case was reviewed adjusting the emergency power operator nonrecovery value to 1.0.

The *Reactor Safety Study* reports the probability of a LOOP being induced by a LOCA (transient) as 1.0×10^{-3} (*Reactor Safety Study*, WASH-1400, NUREG-75/014, Table II 5-3). Additionally, a search of the Sequence Coding and Search System[5] for transient-induced LOOPs over a 10-year period between 1984 and 1993 revealed five transient-induced LOOPs out of 3985 trips. This calculation yields a rate of 1.25×10^{-3} per transient, which tends to substantiate the WASH-1400 value. The grid-based LOOP probability of short-term and long-term offsite power recovery and the probability of a reactor coolant pump (RCP) seal LOCA following a postulated station blackout were developed based on data distributions contained in NUREG-1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*. The RCP seal LOCA models were developed as part of the NUREG-1150 PRA efforts. Both are described in *Revised LOOP Recovery and PWR Seal LOCA Models*, ORNL/NRC/LTR-89/11, August 1989. The initiating cause of a LOOP is assumed to be a grid-related disturbance caused by the plant trip. Because of the severe cold and wind, it was further assumed that if a LOOP were to occur because of the transient, offsite power would not be restored within 30 min. The possibility of a LOOP is added to the transient initiating event tree following a reactor trip (OFFSITE Fault tree). This possibility leads to a transfer to an event tree similar to the LOOP initiating event tree (TRANLOOP).

G.3.5 Analysis Results

The estimated CCDP associated with this event is 2.1×10^{-4}. The dominant core damage sequence, highlighted as sequence number 21-39 on the event tree in Figs. G.3.1 and G.3.2, contributes approximately 66% to the CCDP estimate. This event involves

- a successful reactor trip,
- subsequent loss-of-offsite power,
- both trains of emergency power fail, and
- AFW fails to provide sufficient flow.

This sequence is driven by the loss of the TDAFWP and the common-cause failure of the ESWS pumps. In an actual station blackout, the operators would likely have continued to operate the TDAFWP with the gland leak until it failed, while working in parallel to restore emergency power. The combined transient-induced LOOP sequences contribute 89% of the total estimated CCDP.

The most significant transient sequence that does not involve a LOOP contributes approximately 6% to the CCDP estimate. This transient sequence (sequence number 20 on the event tree in Fig. G.3.1) involves

- a successful reactor trip,
- failure of AFW,
- failure of MFW, and
- failure of feed-and-bleed.

This transient sequence is driven by the common-cause failure of the ESWS pumps and by a failure of the operator to establish make-up water to the CST (AFW-XHE-XA-MW).

A sensitivity study assumes the failure rate of ESWS Train B is increased by a factor of ten to 1.78×10^{-2}. This was an attempt to reflect the increased (time dependent) possibility of the remaining ESWS pump failing when intake water levels decreased to 1.2 m (4 ft) above the minimum required to maintain NPSH, and poor communications did not allow this information to be properly relayed to shift management. The ESWS pump common-cause failure factor due to the frazil ice buildup was left at the previously increased value (0.15). The estimated CCDP associated with this case increases to 2.3×10^{-4}. The dominant transient sequence remains the same, and the relative contribution that transient-induced LOOP sequences add to the estimated CCDP remain about the same.

Further sensitivity studies indicate the increasing likelihood of core damage as the reliability of the second pump is decreased. If the probability of ESWS Train B pump failure is assumed to be 0.1, the estimated CCDP associated with this case increases to 3.4×10^{-4}. Further, if the probability of ESWS Train B pump failure is assumed to be 0.5, the estimated CCDP associated with this case increases to 6.9×10^{-4}. Both of these cases are intended to capture the time sensitivity of the situation regarding the possible imminent failure of the B ESWS pump. Again, the ESWS pump common-cause failure factor due to the frazil ice buildup was left at the previously increased value (0.15). This sensitivity case is calculated to reflect the potential for failure of the ESWS Train B pump. The dominant transient sequence remains the same as the base case (i.e., sequence 21-39) for both cases.

When the operator nonrecovery value for emergency power (EWS-XHE-NOREC) is assumed to be 1.0, the CCDP increases to 2.6×10^{-4} compared with the base case value of 2.1×10^{-4}. If the operator nonrecovery value for AFW during a station blackout (SBO) (AFW-XHE-NOREC-EP) is reduced to 0.586 based on the TDAFWP availability during the 24-h mission period, then the CCDP is reduced to 1.6×10^{-4}.

Definitions and probabilities for selected basic events are shown in Table G.3.1. The conditional probabilities associated with the highest probability sequences are shown in Table G.3.2. Table G.3.3 lists the sequence logic associated with the sequences listed in Table G.3.2. Table G.3.4 describes the system names associated with the dominant sequences. Minimal cut sets associated with the dominant sequences are shown in Table G.3.5.

G.3.6 References

1. LER 482/96-001, Rev. 0, "Loss of Circulating Water Due to Icing on Traveling Screens Causes Reactor Trip," February 28, 1996.

2. LER 482/96-002, Rev. 0, "Loss of A Train Essential Service Water Due to Icing on the Trash Racks," February 29, 1996.

3. NRC Inspection Report 50-482/96-05, March 7, 1996.

4. WASH-1400, NUREG-75/014, Table II 5-3, *Reactor Safety Study*, October 1975.

5. *Sequence Coding and Search System for Licensee Event Reports*, NUREG/CR-3905 LD, August 1984.

6. *Wolf Creek Generating Station Individual Plant Examination Summary Report*, September 1992.

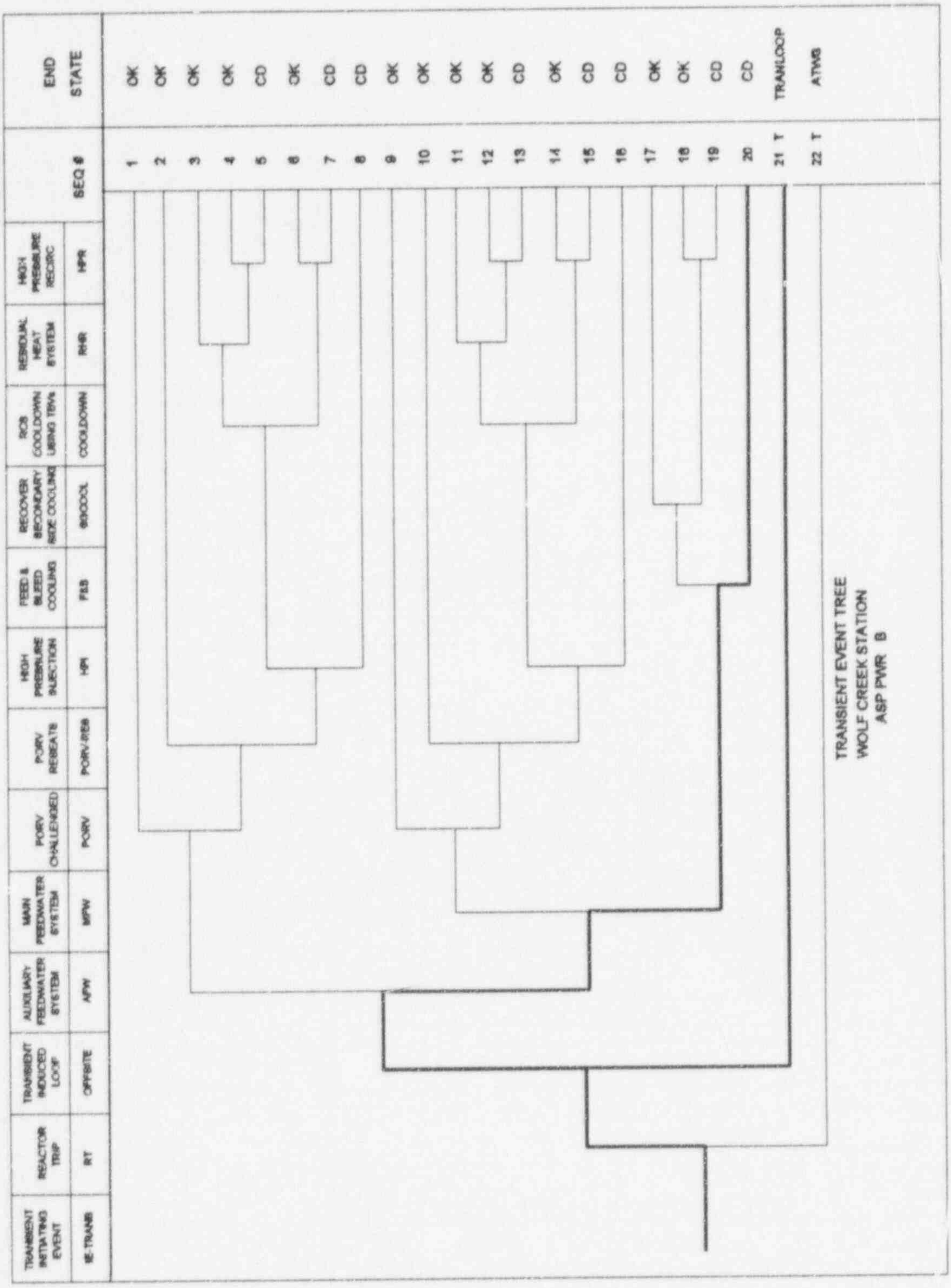

Fig. G.3.1. Dominant core damage sequence given a LOOP for LER Nos. 482/96-001, -002.

Table G.3.1. Definitions and Probabilities for Selected Basic Events for LER Nos. 482/96-001, -002

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Loss-of-Offsite Power Initiating Event	6.9E-006	0.0E+000	IGNORE	Yes
IE-SGTR	Steam Generator Tube Rupture Initiating Event	1.6E-006	0.0E+000	IGNORE	Yes
IE-SLOCA	Small Loss-of-Coolant Accident Initiating Event	1.0E-006	0.0E+000	IGNORE	Yes
IE-TRANS	Transient Initiating Event	5.3E-004	1.0E+000	TRUE	Yes
AFW-MDP-CF-AB	Common-Cause Failure of All Motor-Driven AFW Pumps	2.1E-004	2.1E-004		No
AFW-PMP-CF-ALL	Common-Cause Failure of AFW Pumps	2.8E-004	2.8E-004		No
AFW-TDP-FC-1C	AFW Turbine-Driven Pump Fails	3.2E-002	1.0E+000	TRUE	Yes
AFW-TNK-FC-CST1	Failure of the CST	4.1E-005	4.1E-005		No
AFW-XHE-NOREC	Operator Fails to Recover AFW System	2.6E-001	2.6E-001		No
AFW-XHE-NOREC-EP	Operator Fails to Recover AFW During a SBO	3.4E-001	9.0E-001		Yes
AFW-XHE-XA-MW	Operator Fails to Initiate Makeup Water	1.0E-003	1.0E-003		No
CVC-MDP-FC-1A	Charging Train A Fails	3.9E-003	3.9E-003		No
CVC-MDP-FC-1B	Charging Train B Fails	6.8E-003	6.8E-003		No
EPS-DGN-FC-1B	EDG B Fails	4.2E-002	4.2E-002		No
EPS-XHE-NOREC	Operator Fails to Recover Emergency Power	8.0E-001	8.0E-001		No
EWS-MDP-CF-ALL	Common-Cause Failure of ESWS Motor-Driven Pumps	2.6E-004	1.5E-001		Yes
EWS-MDP-FC-1A	Failure of ESWS Train A	1.7E-003	1.0E+000	TRUE	Yes
EWS-MDP-FC-1B	Failure of ESWS Train B	1.7E-003	1.7E-003		No

Table G.3.1. Definitions and Probabilities for Selected Basic Events for LER Nos. 482/96-001, -002

Event name	Description	Base probability	Current probability	Type	Modified for this event
EWS-XHE-NOREC	Operator Fails to Recover ESWS	8.4E-001	1.0E+000	TRUE	Yes
HPI-EWS-FAIL	High Pressure Injection (HPI) System Fails in Injection Mode Given ESWS is Failed	1.0E+000	1.0E+000	TRUE	Yes
HPI-XHE-NOREC	Operator Fails to Recover the HPI System	8.4E-001	8.4E-001		No
HPI-XHE-XM-FB	Operator Fails to Initiate Feed-and-Bleed Cooling	1.0E-002	1.0E-002		No
HPR-XHE-NOREC	Operator Fails to Recover the High Pressure Recirculation (HPR) System	1.0E+000	1.0E+000		No
LOOP	Transient-Induced LOOP	1.0E-003	1.0E-003		No
MFW-SYS-TRIP	MFW System Trips	2.0E-001	2.0E-001		No
MFW-XHE-NOREC	Operator Fails to Recover MFW	3.4E-001	1.0E+000	TRUE	Yes
OEP-XHE-NOREC-2H	Operator Fails to Recover Offsite Power Within 2 h	2.2E-001	1.1E-001		Yes
OEP-XHE-NOREC-6H	Operator Fails to Recover Offsite Power Within 6 h	6.7E-002	3.6E-004		Yes
OEP-XHE-NOREC-BD	Operator Fails to Recover Offsite Power Before Batteries Deplete	2.5E-002	3.6E-003		Yes
OEP XHE-NOREC-SL	Operator Fails to Recover Offsite Power (Seal LOCA)	5.8E-001	4.4E-001		Yes
PPR-MOV-OO-BLK1	PORV 1 Block Valve Fails to Close	3.0E-003	3.0E-003		No
PPR-MOV-OO-BLK2	PORV 2 Block Valve Fails to Close	3.0E-003	3.0E-003		No
PPR-SRV-CC-1	PORV 1 Fails to Open on Demand	6.3E-003	6.3E-003		No
PPR-SRV-CC-2	PORV 2 Fails to Open on Demand	6.3E-003	6.3E-003		No
PPR-SRV-CO-SBO	PORVs Open During SBO	1.0E+000	1.0E+000		No

Table G.3.1. Definitions and Probabilities for Selected Basic Events for LER Nos. 482/96-001, -002

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-SRV-CO-TRAN	PORVs Open During Transient	4.0E-002	4.0E-002		No
PPR-SRV-OO-1	PORV 1 Fails to Reclose After Opening	3.0E-002	3.0E-002		No
PPR-SRV-OO-2	PORV 2 Fails to Reclose After Opening	3.0E-002	3.0E-002		No
PPR-XHE-NOREC	Operator Fails to Close Block Valve	1.1E-002	1.1E-002		No
RCS-MDP-LK-SEALS	RCP Seals Fail Without Cooling and Injection	2.7E-002	2.1E-001		Yes
RHR-HTX-CF-ALL	Common-Cause Failure of RHR Heat Exchangers	1.4E-005	1.0E-001		Yes
RHR-MDP-FC-1A	RHR Train A Fails	3.9E-003	3.9E-003		No
RHR-XHE-NOREC	Operator Fails to Recover the RHR System	1.0E+000	1.0E+000		No

Table G.3.2. Sequence Conditional Probabilities for LER Nos. 482/96-001, -002

Event tree name	Sequence name	Conditional core damage probability (CCDP)	Percent contribution
TRANS	21-39	1.4E-004	65.9
TRANS	21-36	2.1E-005	10.0
TRANS	21-37	1.4E-005	6.7
TRANS	20	1.2E-005	5.6
TRANS	21-38	9.3E-006	4.4
TRANS	08	4.2E-006	2.0
TRANS	21-33	4.1E-006	1.9
TRANS	05	3.5E-006	1.6
Total (all sequences)		2.1E-004	

Table G.3.3. Sequence Logic for Dominant Sequences for LER Nos. 482/96-001, -002

Event tree name	Sequence name	Logic
TRANS	21-39	/RT-L, OFFSITE, EP, AFW-L-EP
TRANS	21-36	/RT-L, OFFSITE, EP, /AFW-L-EP, PORV-SBO, /PORV-EP, SEALLOCA, /OP-SL, HPI
TRANS	21-37	/RT-L, OFFSITE, EP, /AFW-L-EP, PORV-SBO, /PORV-EP, SEALLOCA, OP-SL
TRANS	20	/RT, /OFFSITE, AFW, MFW, F&B
TRANS	21-38	/RT-L, OFFSITE, EP, /AFW-L-EP, PORV-SBO, PORV-EP
TRANS	08	/RT, /OFFSITE, /AFW, PORV, PORV-RES, HPI
TRANS	21-33	/RT-L, OFFSITE, EP, /AFW-L-EP, PORV-SBO, /PORV-EP, SEALLOCA, /OP-SL, /HPI, /COOLDOWN, RHR, HPR
TRANS	05	/RT, /OFFSITE, /AFW, PORV, PORV-RES, /HPI, /COOLDOWN, RHR, HPR

Table G.3.4. System Names for LER Nos. 482/96-001, -002

System name	Logic
AFW	No or Insufficient AFW
AFW-L-EP	No or Insufficient AFW Flow During Station Blackout
COOLDOWN	Reactor Coolant System Cooldown to RHR Pressure Using Turbine Bypass Valves, etc.
EP	Failure of Both Trains of Emergency Power
F&B	Failure of Feed-and-Bleed Cooling
HPI	No or Insufficient Flow from the HPI System
HPR	No or Insufficient Flow from the HPR System
MFW	Failure of the MFW System
OFFSITE	Transient-Induced LOOP
OP-SL	Operator Fails to Recover Offsite Power (Seal LOCA)
PORV	PORVs Open During Transient
PORV-EP	PORVs Fail to Reclose (No Electric Power)
PORV-RES	PORVs Fail to Reseat
PORV-SBO	PORVs Open During SBO
RHR	No or Insufficient Flow from the RHR System
RT	Reactor Fails to Trip During Transient
SEALLOCA	RCP Seals Fail During LOOP

Table G.3.5. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 482/96-001, -002

Cut set number	Percent contribution	Conditional probability	Cut sets[a]
TRANS Sequence 21-39		1.4E-004	
1	76.8	1.1E-004	LOOP, EWS-MDP-CF-ALL, EWS-XHE-NOREC, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
2	21.5	3.0E-005	LOOP, EPS-DGN-FC-1B, EWS-MDP-FC-1A, EPS-XHE-NOREC, AFW-TDP-FC-1C, AFW-XHE-NOREC-EP
TRANS Sequence 21-36		2.1E-005	
1	98.8	2.1E-005	LOOP, EWS-MDP-CF-ALL, EWS-XHE-NOREC, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, HPI-EWS-FAIL, HPI-XHE-NOREC
2	1.2	2.5E-007	LOOP, EPS-MDP-FC-1A, EWS-MDP-FC-1B, EWS-XHE-NOREC, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, HPI-EWS-FAIL, HPI-XHE-NOREC
TRANS Sequence 21-37		1.4E-005	
1	76.8	1.1E-005	LOOP, EWS-MDP-CF-ALL, EWS-XHE-NOREC, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
2	21.5	3.1E-006	LOOP, EPS-DGN-FC-1B, EWS-MDP-FC-1A, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, OEP-XHE-NOREC-SL
TRANS Sequence 20		1.2E-005	
1	54.2	6.6E-006	AFW-XHE-XA-MW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
2	15.2	1.8E-006	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
3	11.4	1.4E-006	AFW-MDP-CF-AB, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
4	4.3	5.2E-007	AFW-XHE-XA-MW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
5	2.7	3.3E-007	AFW-XHE-XA-MW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-2
6	2.7	3.3E-007	AFW-XHE-XA-MW, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, PPR-SRV-CC-1

Table G.3.5. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 482/96-001, -002

Cut set number	Percent contribution	Conditional probability	Cut sets[a]
7	2.2	2.7E-007	AFW-TNK-FC-CST1, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
8	1.2	1.5E-007	AFW-PMP-CF-ALL, AFW-XHE-NOREC, MFW-SYS-TRIP, MFW-XHE-NOREC, HPI-XHE-XM-FB
TRANS Sequence 21-38		9.3E-006	
1	38.4	3.6E-006	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-2
2	38.4	3.6E-006	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-1
3	10.7	1.0E-006	LOOP, EWS-MDP-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-2
4	10.7	1.0E-006	LOOP, EWS-MDP-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PPR-SRV-CO-SBO, PPR-SRV-OO-1
TRANS Sequence 08		4.2E-006	
1	38.8	1.7E-006	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, PPR-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
2	38.8	1.7E-006	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, PPR-XHE-NOREC, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
3	10.6	4.5E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, PPR-MOV-OO-BLK2, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
4	10.6	4.5E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, PPR-MOV-OO-BLK1, EWS-MDP-CF-ALL, EWS-XHE-NOREC, HPI-EWS-FAIL, HPI-XHE-NOREC
TRANS Sequence 21-33		4.1E-006	
1	63.1	2.5E-006	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-HTX-CF-ALL, RHR-XHE-NOREC, HPR-XHE-NOREC
2	17.6	7.1E-007	LOOP, EWS-MDP-FC-1A, EPS-DGN-FC-1B, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-HTX-CF-ALL, RHR-XHE-NOREC, HPR-XHE-NOREC

Table G.3.5. Conditional Cut Sets for Higher Probability Sequences for LER Nos. 482/96-001, -002

Cut set number	Percent contribution	Conditional probability	Cut sets[a]
3	7.4	3.0E-007	LOOP, EWS-MDP-FC-1A, EWS-MDP-FC-1B, EWS-XHE-NOREC, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-XHE-NOREC, HPR-XHE-NOREC
4	4.2	1.7E-007	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-XHE-NOREC, CVC-MDP-FC-1B, HPR-XHE-NOREC
5	2.4	9.8E-008	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-MDP-FC-1A, RHR-XHE-NOREC, HPR-XHE-NOREC
6	2.4	9.8E-008	LOOP, EWS-MDP-CF-ALL, EPS-XHE-NOREC, PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, RHR-XHE-NOREC, CVC-MDP-FC-1A HPR-XHE-NOREC
TRANS Sequence 05		3.5E-006	
1	37.1	1.3E-006	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, PPR-XHE-NOREC, RHR-XHE-NOREC, RHR-HTX-CF-ALL, HPR-XHE-NOREC
2	37.1	1.3E-006	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, PPR-XHE-NOREC, RHR-XHE-NOREC, RHR-HTX-CF-ALL, HPR-XHE-NOREC
3	10.1	3.6E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-2, RHR-XHE-NOREC, PPR-MOV-OO-BLK2, RHR-HTX-CF-ALL, HPR-XHE-NOREC
4	10.1	3.6E-007	PPR-SRV-CO-TRAN, PPR-SRV-OO-1, RHR-XHE-NOREC, PPR-MOV-OO-BLK1, RHR-HTX-CF-ALL, HPR-XHE-NOREC
Total (all sequences)		**2.1E-004**	

[a]Basic events AFW-TDP-FC-1C, EWS-MDP-FC-1A, EWS-XHE-NOREC, and MFW-XHE-NOREC are all type TRUE events which are not normally included in the output of fault tree reduction programs. These events have been added to aid in understanding the sequences to potential core damage associated with the event.

Appendix H:

Resolution of Comments on the Preliminary 1996 ASP Analyses

H.1 Comments

This appendix contains the comments received from the applicable licensees and the Nuclear Regulatory Commission (NRC) staff for the two 1996 potential precursors. The comments for each potential precursor are listed and discussed in docket number order, where the docket number refers to the plant that reported the problem. Comments are further separated between licensee and NRC comments. Only comments considered pertinent to the accident sequence precursor analysis are addressed. Because of the length of the comments received, they are paraphrased. if necessary, in this appendix. Comments simply pointing grammatical or spelling errors were addressed in the revision of the analyses but are not listed or addressed in this appendix. The reanalysis of the potential precursors resulted in revisions to the preliminary precursor analyses contained in Appendix G of this report; these events are noted in Table H.1.

Table H.1 List of Comments on Preliminary ASP Analyses

Event number	Plant	Event descriptions	Page
LER 414/96-001	Catawba 2	Loss-of-offsite power with emergency diesel generator B unavailable	H.2-1
LERs 482/96-001, -002	Wolf Creek	Reactor trip with a loss of train A of the essential service water and the turbine-driven auxiliary feedwater pump	H.3-1

H.2 LER No. 414/96-001

Event Description: Loss-of-offsite power with emergency diesel generator B unavailable

Date of Event: February 6, 1996

Plant: Catawba 2

H.2.1 Licensee Comments

Reference: Letter from W. R. McCollum, Jr., Catawba Nuclear Station, to U.S. Nuclear Regulatory Commission, transmitting "Response to the Preliminary Accident Sequence Precursor Analysis of Loss of Offsite Power Event at Catawba Unit 2 (TAC M95254)," Duke Power, June 11, 1996.

Comment 1: In the preliminary ORNL analysis only Emergency Diesel Generator (EDG) 2A was considered available for the mission time (7.5 h) of interest. EDG 2B, which was in maintenance at the time of the event but returned to service at about 3 h, is treated as in maintenance but potentially recoverable, with a recovery probability of 0.48. [This is basic event EPS-XHE-EDGB-NOR.]

An alternate approach, which perhaps more closely resembles the actual post-event condition, would be to consider only one EDG to be available during the first 3 h, with potential recovery of the other EDG, and both EDGs to be available subsequently. Attachment B [of McCollum's letter] presents the development of the dominant-related sequence.

At the time of the event, EDG 2B was out of service to perform maintenance on the EDG 2B battery charger. In the event EDG 2B was needed after the LOOP event because no other source of ac power was readily available, plant personnel would have attempted to place EDG 2B into service by clearing the out-of-service tags and closing the breakers. EDG 2B battery is considered to have adequate capacity to start the EDG without the charger. The estimated time to place EDG 2B into a functional status for this scenario is estimated to be in the range of 1 to 1.5 h. Since EDG 2A was supplying the load, EDG 2B was not needed. It was placed into operation at 2 h and 51 min after the initiating event.

Response 1: The modeling approach taken assumes that EDG 2A is available with a failure probability of 0.045 (EPS-DGN-FC-1A). Not only is the ability to recover EDG 2B within the first 3 h of the event considered (EPS-XHE-EDGB-NOR) but also credits the potential for restoring offsite power (OEP-XHE-NOREC-SL and OPE-XHE-NOREC-BD) and for powering the Unit 2 emergency bus by EDG 2B from the corresponding Unit 1 emergency power bus (OEP-XHE-NOCRS-B) (see Figs. G.2-3 and G.2-4). The Unit 1 emergency power bus remained powered from its normal offsite ac power source.

The nonrecovery probability of 0.48 for EPS-XHE-EDGB-NOR was obtained using a value of 140 min as the median time to repair EDG 2B with a 30-min delay to allow for the decision process to decide to repair EDG 2B. Based on Comment 1, this repair time was adjusted to 90 min with a 30-min delay required for the decision process to reach completion. The value of 3 h for the time available to restore EDG 2B (in case EDG 2A becomes unavailable) was based on the ability of the Standby Shutdown Facility (SSF) to prevent a seal-LOCA and the turbine-driven AFW pump to provide feedwater for decay heat removal. Using the exponential repair model with a repair time of 90 min and a 30-min delay, in combination with the time available to restore EDG 2B (3 h), results in a revised nonrecovery probability of 0.31 for EPS-XHE-EDGB-NOR.

Modeling the event in two phases would require revising all basic event (super component) failure probabilities that are dominated by failure to start and failure to run to account for the shorter mission times for the first phase (0 to 3 h). The second phase analysis (3 to 7.5 h) would require revising all basic event failure probabilities that are dominated by failure to start and failure to run to account for this mission time and removing the failure to start probability for those basic events that would be running at the end of the first phase. The final core damage probability would be the sum of the probabilities for each phase developed. Based on an approach *identical* to that provided in Attachment B of McCollum's letter, cut set number 1 in Sequence 39 would be

First 3 h following LOOP event		Next 4.5 h		7.5 h mission
Basic event	Probability	Basic event	Probability	Current value
EPS-DGN-FC-1A EDG 2A fails to start or run 0.03 + (3 h * 0.002/h)	0.036	EPS-DGN-FC-1A EDG 2A fails to run (4.5 h * 0.002/h)	0.009	0.045
EPS-XHE-EDGB-NOR recovery of EDG 2B	0.31	EPS-XHE-EDGB-NOR recovery of EDG 2B	n/a	0.31
EPS-DGN-FC-1B EDG 2B is in maintenance	1.0	EPS-DGN-FC-1B EDG 2B fails to start or run 0.03 + (4.5 h * 0.002/h)	0.039	1.0
OEP-XHE-NOCRS-B failure to recover using Unit 1 power	0.27	OEP-XHE-NOCRS-B failure to recover using Unit 1 power	0.27	0.27
SSFB SSF fails to provide seal injection	0.22	SSFB SSF fails to provide seal injection	0.22	0.22
PORV	1.0	PORV	1.0	1.0
SEALLOCA	0.7	SEALLOCA	0.7	0.7
OEP-XHE-NOREC-SL failure to recover offsite power	1.0	OEP-XHE-NOREC-SL failure to recover offsite power	1.0	1.0
	4.6E-004		1.5E-005	
	4.8E-004			5.8E-004

The difference in the total cut set probability from an unphased approach (5.8×10^{-4}) to a phased approach (4.8×10^{-4}) for this cut set is 17%. Because the other cut sets that are affected by this phased approach are similar to the above cut set, it is expected that the CCDP would be affected similarly (e.g., about 17%). The sequences affected by this approach (sequences 39 and 32) contribute 57.3% to the overall CCDP. A phased approach then, would result in a new CCDP of

$$\text{CCDP} = 1.9 \times 10^{-3} = [(1 - 0.17)(0.573) + (1 - 0.573)] \times 2.1 \times 10^{-3}.$$

Using the Catawba IPE values for EDG start and run probabilities (0.007 and 0.0046/h) with a phased approach reduces the CCDP by 46% for cut set 1 for Sequence 39 (to 2.9×10^{-4}). Because the other cut sets that are affected by this phased approach are similar to the above cut set, it is expected that the CCDP would be affected similarly (e.g., about 46%). The sequences affected by this approach (sequences 39 and 32) contribute 57.3% to the overall CCDP. A phased approach, then, would result in a new CCDP of

$$\text{CCDP} = 1.6 \times 10^{-3} = [(1 - 0.46)(0.573) + (1 - 0.573)] \times 2.1 \times 10^{-3}.$$

However, if IPE values are accepted, then the failure probability of the TDAFWP must be adjusted to the IPE value of 0.083 vs the 0.032 used in this analysis. This affects LOOP Sequence 41, cut sets 1 and 3. The CCDP for Sequence 41 becomes 1.3×10^{-3} versus 5.3×10^{-4}. The total CCDP then becomes

$$\text{TOTAL CCDP} = 2.9 \times 10^{-3} = 1.6 \times 10^{-3} + 1.3 \times 10^{-3}.$$

Hence, using a "phased" approach appears to provide no more accurate a core damage probability, yet requires considerably more effort.

Comment 2: The preliminary ORNL analysis uses the EDG start and run failure probabilities of 0.03 and 0.002/h, respectively. The estimated Catawba EDG start and run failure probabilities, as reported in the Catawba IPE are 0.007 and 0.0046/h, respectively. In fact, the current 3-year average values, as shown in Attachment C, are 0.003 and 0.0015/h. Use of the current plant-specific values should change the preliminary conditional core damage probability from 0.0033 to approximately 0.001 without any other changes.

Response 2: The basic event for EDG 2A in the ASP model (EPS-DGN-FC-1A) has an EDG failure probability based on its failure to start (0.03/d) and its failure to run [(0.002/h)(7.5h)]. However, this is really a "super component" because the failure to start probability includes the contribution of all other major components in the safety system train and the contribution from any support systems (e.g., EDG in maintenance, fuel unavailabilities, load sequencer, etc.). Therefore, the 0.03/d is appropriate. The failure to run probability of 0.002/h is consistent with the current 3-year average and about one-half the Catawba IPE value. Regardless, use of the IPE values themselves provides a failure probability consistent with the ORNL analysis (0.0415 vs 0.045).

Comment 3a: The preliminary ORNL analysis attempts to include the Standby Shutdown Facility (SSF) feature to mitigate a loss of all ac power condition. However, inclusion of both the SSFB and SSFC logic is not correct. The SSFC cut sets are a subset of the SSFB cut sets. (Please see Table A. 18-7 of the Catawba IPE.) The main differences between SSFB and SSFC are that (1) SSFB requires operator action within 15 min, while for the SSFC case, action can be delayed for up to 3 h, and (2) SSFB contains additional failure modes involving the Reactor Coolant pump seal injection components. In the Catawba Probabilistic Risk Assessment (PRA), success of SSFC does not prevent a core melt, it simply changes the plant damage state.

Comment 3b: In addition, cut sets representing unavailability of the SSF due to maintenance (2.57E-2) and maintenance on the SSF diesel generator (2.96E-3) could be deleted when determining the probability associated with SSFB, since this equipment was available during the event.

Comment 3c: Thus SSFC cut sets and SSF maintenance events should be deleted from the ORNL preliminary analysis. Incorporating these suggestions results in an SSF failure probability of 0.19.

Response 3a: The original fault tree model of the SSF was misleading. The original figure (Fig. G.2.2) simply had "SSF" without identifying "B" or "C." This has been corrected. The placement of the SSF in the event tree (Fig. G.2.1) is such that the SSF is not needed to mitigate core damage until the remaining EDG fails (EDG 2A) and the turbine-driven AFW pump starts and runs successfully. As indicated on page 35 of Figure A.5-7 in the AFW system fault tree for the Catawba IPE, SSFC is used to ensure power to the turbine-driven pump (TDAFWP) pit sump pump (sump pump 1A1) given a station blackout (SBO) condition. A station blackout would have occurred if EDG 2A failed during this event. Because the motor-driven AFW pumps are unavailable, success of the AFW is dependent on the success of the TDAFWP. The success of the TDAFWP is now dependent on the SSFC to provide power to the TDAFWP pit sump pump because the TDAFWP oil cooler flow and a portion of the turbine seal water empties directly into the pit for the TDAFWP. SSFC must be available within 3 h before the leakage or the water accumulation in the TDAFWP pit would fail the pump. The SSFB, on the other hand, is modeled as providing seal cooling in the event of a station blackout. Specifically, page A.18-15 in the SSF insight section for the Catawba IPE indicates that SSFB is used to provide a means of seal cooling to prevent a seal LOCA in the event of an SBO. SSFB must be available within 15 min of station blackout. The ORNL analysis is consistent with the Catawba PRA.

Response 3b: Because a component successfully performed its function during an event is no reason to reduce or change the failure probability or unavailability of that component. Similarly, it is inappropriate to remove the unavailability due to potential maintenance activities on these components just because no maintenance was being performed on them during the event.

Response 3c: Based on the responses to 3a and 3b, the SSF model appears to be appropriate, and no changes were made to that portion of the analysis.

Comment 4: Catawba has two 4 kV transformers (SATA and SATB) which can power the two essential 4 kV switchgears in one unit from the ac power system from the other unit. The operator action to make use of this feature is contained in the plant emergency procedure, and operators are trained on this action. Catawba's estimate to perform this action is 30 min to 1 h. Considering that this action is required in the emergency procedure, that the operators are given training on it, and that the available time is about 3 h, the operator failure probability is not considered to be significant. The Duke calculations use 0.17 as the failure probability of this event, derived primarily from the data on LOOP events where more than one unit suffered a LOOP in multiunit sites. Even with the assumption of a 30 min cognitive time and a 90 min action time, the Human Cognitive reliability model (Hannaman et al., *Human Cognitive Reliability Model for PRA Analysis*, NUS-4531, December 1994) yields the operator failure probability as 0.03, with the 3 h available time. Therefore, the value of 0.35 used in the preliminary ORNL analysis for failure probability of using the Unit 1 ac power when it was indeed available seems a bit conservative. It should be noted that the procedural difficulty encountered during the event should not be viewed as a significant factor since one EDG was operating and supplying necessary loads and the use of Unit 1 ac power was not critically needed at that time.

The Duke analysis of this event, based on Catawba-specific EDG reliability data, the two distinct EDG availability representations, and the applicable SSF failure modes, yielded a conditional core damage probability of approximately 4E-4. This calculation is based on a base case failure probability of Unit 1 power of 0.17. Since offsite power was available through Unit 1 throughout the mission time, the 0.17 value is conservative. As a sensitivity analysis, changing this value to 0.03 and then to 0.5 produces results of 7E-5 and 1E-3, respectively.

Response 4: ORNL assumed that the recovery of emergency power by cross-tieing to the other unit would have been necessary only following the failure of EDG 2A. However, the time required to perform the cross-tie was changed from 90 min to 60 min. The parameters of interest in determining the failure probability are

Parameters	ORNL
available time	3 h
action time	90 min
delay time	30 min
model	E. M. Dougherty and J. R. Fragola, *Human Reliability Analysis*, Ch. 10 and 11, John Wiley and Sons, New York, 1988
"Recovery without Hesitancy" time-reliability correlation	0.16
"Recovery with Hesitancy" time-reliability correlation	0.27

If the operator responds without hesitancy (i.e., although the problem is uncommon, procedures exist), the operator failure probability would be 0.16. This is essentially the same number reported by Duke (i.e., 0.17). The "recovery with hesitancy" time-reliability correlation is appropriate because it considers that, although the problem is uncommon, the procedures are weak or sketchy. Because initial efforts to complete the cross-tie to bus 2ETB were unsuccessful due to a procedural inadequacy and cross-tie activities were not completed until 7 h 29 min into the event, the recovery with hesitancy is appropriate. The resultant failure probability is 0.27 given that the cross-tie is an uncommon problem and an error existed in the procedure.

Comment 5: The **Modeling Assumptions** section states that a mission time of 7.5 h was used for EDG 2B. It appears that this mission time was actually used to compute the failure probability of the EDG 2A.

Response 5: This is correct. The mission time was increased from 6 h to 7.5 h for calculating the failure rate of EDG 2A, not EDG 2B. EDG 2B was classified as a TRUE event because it was out-of-service due to a faulty ac capacitor in the battery charger for that EDG.

Comment 6: The following description of the auxiliary feedwater (CA) pump room and associated floor drain system is provided to understand the significance of leakage found in the floor drain sump.

The three CA pumps are located in the CA pump room, which has a floor drain sump [1.2 × 0.9 × 2.1 m (4 × 3 × 7 ft)] with two load-shed floor drain sump pumps. Each CA pump is located in a pit [5.2 × 5.2 × 4.42 m (17 × 17 × 14.5 ft)] with two sump pumps for the turbine driven pump and one sump pump for each of the motor driven CA pumps. The CA pump pit sump pumps (each with 50-gpm capacity) are powered by the essential ac power system, and one of the turbine driven CA pump sump pumps is backed up by the SSF power.

The CA pump pit sump pumps and the CA pump room sump pumps discharge into a common header.

During the LOOP event some water was found to be accumulating in the CA pump room floor and is attributed to leakage of check valves between the room sump pumps and the common header for this floor drain system. The leakage was estimated to be no greater than 76.8 m (20 gpm), the expected maximum floor drain requirement for the turbine driven CA pump pit. Considering that the floor area outside the CA pump pits is about 207.5 m^2 (2,231.6 ft^2) and that the curb is about 0.46 m (1.5 ft) high, the estimated time for the leakage to spill into the CA pump pits is about 22 h. The leakage into the turbine driven pump pit is within the capability of the operating sump pump. If this pump failed, an additional 3 h would be available before the leakage or the water accumulation in the turbine driven pump pit could fail the pump.

For the motor driven CA pump B pit, the estimated time to fill the pump pit is about 26 h once the leakage starts into the pit and if the sump pump is not operating.

Thus the leakage into the CA pump room from part of the CA pump pit floor discharge should not influence the mission times and success criteria for CA pumps or battery depletion time considerations.

Response 6: The ORNL analysis assumed that the CA pump room flooding had no influence on the mission times, success criteria for the CA pumps, or battery depletion time considerations. The **Additional Event-Related Information** section states that "Because the floor area outside the AFW pump room is about 207.5 m^2 (2,231.6 ft^2) and the curb is 46 cm (18 in.) high, the estimated time to flood the turbine-driven pump pit area is about 33 h." The leakage into the turbine-driven pump pit is within the capability of the operating sump pump. If this pump failed, an additional 3 h would be available before the leakage or the water accumulation in the turbine driven pump pit could fail the pump. After the pump pits are flooded, there is an additional area of 103 m^2 (1,110 ft^2) in the room for water to cover. The IPE further estimates that there is 41.6 min available to isolate a flood of 9,194 l/m (2,429 gpm). Therefore, flooding of the TDAFWP is not considered credible because considerable time was available to mitigate the flooding. The concern with flooding the pump pit was that given a LOOP and failure of the remaining EDG, the only means of decay heat removal was use of the turbine-driven AFW pump to provide makeup to the steam generators. The LER and preliminary information about the CA pump room flooding were sketchy; however, it was determined that the CA pump room flooding was of little consequence to this event.

H.2.1 NRC Comments

No comments were provided.

H.3 LER Nos. 482/96-001, -002

Event Description: Reactor trip with a loss of train A of the essential service water and the turbine-diven auxiliary feedwater pump

Date of Event: January 30, 1996

Plant: Wolf Creek

H.3.1 Licensee Comments

Reference: Letter from N. S. Carns, Wolf Creek Nuclear Operating Corporation, to the U.S. Nuclear Regulatory Commission, WM 96-0075.

Comment 1: (Summary) The analysis states that, "The lowest temperature for the CST was not reported." The temperature in the CST would not have added to the LER. However, the lowest temperature of the CST during the event was 8.40°C (47.1°F) (2/2/96, 1719 h).

Response 1: The CST temperature was referenced because the ESWS is the backup water source for the AFW system. With the ESWS in jeopardy, the status of the CST is more prominent. The sentence was changed to reflect that the lowest temperature recorded during the event was 8.40°C (47.1°F).

Comment 2: (Summary) The report states that the operators were directed to align the ESWS from memory which severely restricted warming line flow to the ESWS intake. This statement is not completely accurate. The design warming line flow requirement was 15,140 l/m (4,000 gpm), but the as-built warming line flow is approximately 9,500 l/m (2,500 gpm). The improper alignment initially established in the event resulted in a warming line flow of 6,430 l/m (1,700 gpm). Therefore, it is more properly the inadequate design and not the improper lineup that resulted in the restricted warming line flow during the event. Additionally, the WNOC operators were not directed to align the ESWS from memory. The system does not have an auto-start capability under the event circumstances. The operator did not have the proper procedure with him and made what he believed was the correct lineup; however, the operator incorrectly established the warm weather ESWS alignment. Making a system realignment in this manner is appropriate for urgent situations provided the system is checked with the proper procedure after completing the realignment. This follow-up check with the procedure was not performed.

Response 2: The inadequate warming line flow that existed prior to the event was not appropriately addressed in the analysis. This area has now been addressed. It is felt that if the operator was directed to urgently line up the ESWS for the cold weather alignment and check this against the procedure afterward, then the operator was essentially directed to perform the lineup from memory. The lack of follow-up by the operator with the procedure or by shift management in expecting to see a completed procedure confirms that the lineup was left to the operator's memory. The analysis was revised to read, "Design input assumption errors resulted in inadequate warming line flow and lower warming line temperature than intended. After the initial indication of ice buildup in the circulating water bays, the operators manually started the B train of the ESWS system. Operators failed to properly align the ESWS and to isolate it from the SWS when, for expediency, they were directed to align the ESWS from memory. The improper alignment resulted in further reductions of warming line flow to the ESWS intake bays for the pumps."

Comment 3: (Summary) The discussion in the report concerning the icing conditions in the intake area is confusing. There are three separate items discussed: (1) the process by which frazil ice is formed, (2) icing on the trash racks (ESWS pump house), and (3) icing on the intake screens (circulating water pump house). The icing began at two different locations from two different mechanisms. The icing problem in the ESWS was due to the frazil ice phenomenon. The icing problem in the circulating water intake was the result of spraying water on the traveling screens with an ambient air temperature of −14°C (7°F).

Response 3: The paragraph was not clear on the distinction between the icing in the circulating water intake bay and the icing in the ESWS intake bay. The paragraph was reworded to exclude any reference to the circulating water intake bays or pumps.

H.3.2 NRC Comments

Reference: Memorandum from William D. Johnson, Chief, Project Branch B, Division of Reactor Projects, June 4, 1996.

Comment 1: (Summary) Under the **Summary** section, insert "traveling" before "screens" in the first sentence. Change the fourth sentence to "Later frazil ice buildup on the trash racks forced operators ...."

Response 1: These recommended changes were inserted to help clarify the difference in ice buildup mechanisms on the circulating water system traveling screens and the ESWS trash screens.

Comment 2: (Summary) Under the **Event Description** section, change the first sentence of the third paragraph to "Four hours after the reactor trip, inadequate ESWS warming line flow, caused by original design errors and further reduced by an improper system alignment, resulted in frazil ice buildup on the trash rack in front of the traveling screen for the A ESWS pump intake bay and forced that pump...." In the fourth paragraph, delete "equipment problems, the cold weather, and" from the first sentence. Delete "portable heaters and" from the second sentence.

Response 2: These changes were inserted to help clarify the difference in responding to the ice buildup mechanisms on the circulating water system traveling screens and the ESWS trash screens. These changes also introduce the original inadequate ESWS warming line flow as part of the discussion.

Comment 3: (Summary) Under the **Additional Event-Related Information** section, insert "nonsafety-related" before "service water system" in the first sentence of the first paragraph.

Response 3: This change was inserted for clarity.

Comment 4: (Summary) Under the **Additional Event-Related Information** section, change the first sentence of the third paragraph and add a new second sentence as follows: "The ESWS design was intended to have the capability.... Design input assumption errors resulted in inadequate warming line flow and lower warming line temperature than intended." Change the fourth sentence of the third paragraph to "The improper alignment resulted in further reductions of warming line flow to the ESWS intake bays for the pumps." Change the fifth sentence in the third paragraph to "This allowed frazil ice to build up on the trash racks." before "service water system" in the first sentence of the first paragraph.

Response 4: These changes were inserted to help clarify the compound effects of the inadequate design and the improper valve line-up on the inadequate ESWS warming line flow that occurred over the course of the event.

Comment 5: (Summary) Under the **Additional Event-Related Information** section, change the second sentence in the fourth paragraph to ". . . very clear, windy, cold night)." Change the fifth sentence of the fourth paragraph to "The water flow induced by the running ESWS pumps allowed the tiny ice crystals to readily accumulate on the metal surface of the trash racks." Delete the remainder of the fourth paragraph.

Response 5: The paragraph was not clear on the distinction between the icing in the circulating water intake bay and the icing in the ESWS intake bay. The paragraph was reworded as recommended to exclude any reference to the circulating water intake bays or pumps.

H.3.3 NRC Comments

Reference: Facsimile from Jim Tatum, NRR/SPLB, to the U.S. Nuclear Regulatory Commission, "Regarding Preliminary ASP Analysis of 1/30/96 Frazil Icing Event at Wolf Creek Plant," July 9, 1996.

Comment 1: The licensee had absolutely no idea what frazil ice was and how to deal with the problem that existed at the time of the event.

Response 1: This is likely true and the inadequacy of the design flow in the warm-up line compounded by the improper valve line-up is currently addressed in the ASP analysis. For modeling purposes, the impending failure of the second train of the ESWS is handled as a series of sensitivity studies. The second train did not actually fail, and there is no algorithm to project the probability of the second train failing as a result of operating under less than optimum conditions. Therefore, the base analysis utilizes the nominal failure rate of the system and the sensitivity studies arbitrarily analyze higher failure probabilities for the second ESWS train. Though the actual failure probability of the second train is likely greater than the nominal case, a defensible value is not available.

Comment 2: Compensatory measures that were taken by the licensee were inappropriate for mitigating the effects of frazil ice and restoring cooling water flow.

Response 2: This is the basis for performing an ASP analysis and determining this to be a precursor event.

Comment 3: While the licensee's outage control center had devised a number of contingency plans for the potential loss-of-offsite power and train B of the ESW system, these contingencies were developed over the course of the event as the licensee began to recognize the significance of the situation.

Response 3: This is true of many serious events. There is nothing in the ASP model that supports or disputes this comment.

Comment 4: It is highly questionable as to how well the licensee would have carried out these measures that were supposed to be implemented had they been needed and just how effective these measures would have been.

Response 4: The compensatory measures proposed by the licensee were not considered for modeling purposes. The nonrecovery values in the model for ESWS and the main feedwater system were adjusted to 1.0 (True) to reflect the likely inability of the operators to recover these systems in a timely manner in the event the system failed. Also, the common-cause failure probability for the ESWS pumps was increased to the beta factor (0.15) assigned to the system. This would increase the likelihood that the second pump would fail from the same cause as the first pump. Finally, it was assumed that a loss-of-offsite power would not be recovered in the short term due to the weather conditions.

Comment 5: The one data point that the AIT had in this regard is the compensatory measures that were supposed to be implemented at the service water intake were not well planned, proceduralized, coordinated and, ultimately, were not fully implemented such that the operators were aware of continuing frazil ice problems until annunciation was received in the control room.

Response 5: Response 4 above applies to this comment also.

Comment 6: The mechanism of the ice formation on the circulating water traveling screens vs the ice formation on the ESW trash racks was not the same.

Response 6: The difference is currently addressed in the ASP analysis. The draft analysis was revised to be more specific in the description of the different mechanisms of ice formation involved. There is no impact on the modeling since the initiation of the modeled event is the transient that followed the icing of the circulating pump traveling screens.

Comment 7: The situation at the site was that one train of ESW was lost, and, at one point, the other ESW train was within a few minutes of being lost.

Response 7: This is addressed by the response to Comment 1.

Comment 8: Just about at the last possible instant, the control room operators directed additional heat into the warming line flow, and it was this very timely and fortuitous action on the part of the plant operators that allowed the B ESW train to be recovered.

Response 8: This is addressed by the response to Comment 1.

Comment 9: It would be a good idea to include the NRC inspection team members (e.g., AIT members, IIT members, etc.) on distribution for the preliminary ASP reports.

Response 9: This is done at the discretion of the program manager.

After consideration of all comments received, the model was revised slightly and the resulting base case CCDP for this event increased to 1.2E-04.

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11. ABSTRACT (200 words or less)

Ten operational events that affected ten commercial light-water reactors (LWRs) during 1995 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 1995 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 1984-1994 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.

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