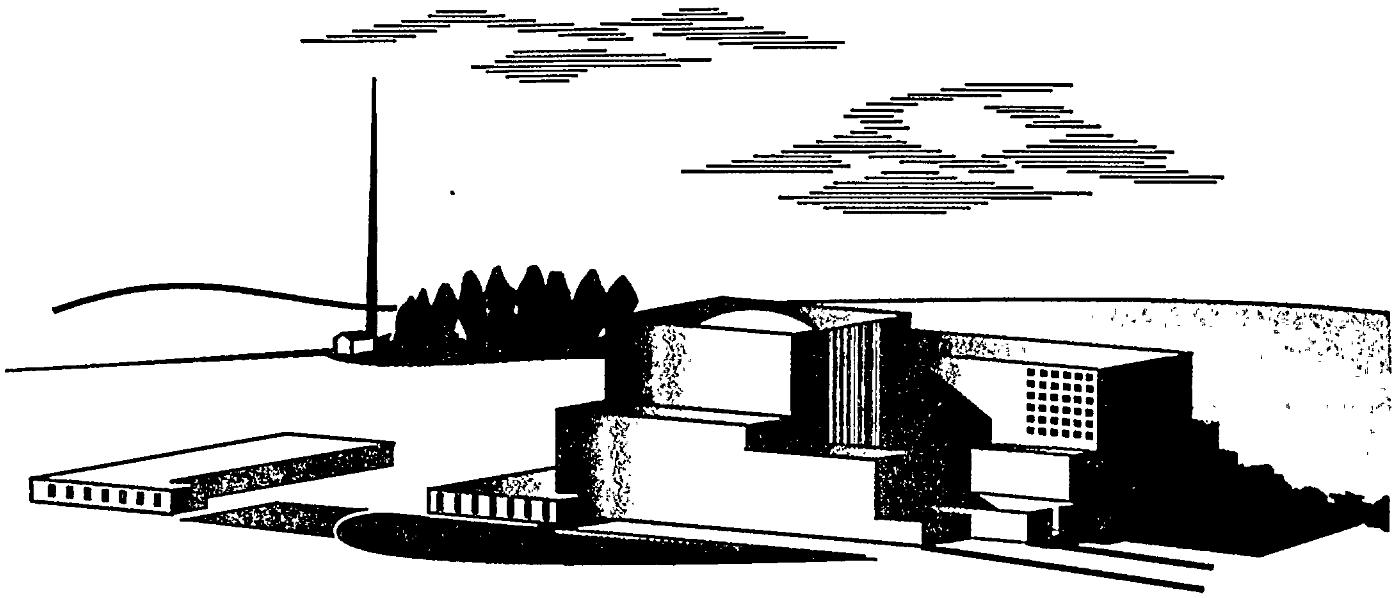

. Ginna Nuclear Power Plant

·bilistic Safety Assessment

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R.E. Ginna Nuclear Power Plant

Probabilistic Safety Assessment

RG AND E

R.E. Ginna Nuclear Power Plant

Probabilistic Safety Assessment

4 inch binders

Attachment B

Level 1 PSA Final Report, Revision 1

R.E. Ginna Nuclear Power Plant

Probabilistic Safety Assessment

Final Report

Revision 1

January 1997

Rochester Gas and Electric Corporation
Nuclear Safety & Licensing

REVISION CONTROL

Revision Number	Affected Sections	Description of Revision
1	All	Complete Rewrite of Level 1 PSA.

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AFW	auxiliary feedwater
AMSAC	ATWS mitigating systems actuation circuitry
ARV	atmospheric relief valve
ATWS	anticipated transient without scram
CI	containment isolation
CCW	component cooling water
CS	containment spray
CVCS	chemical and volume control system
EOP	emergency operating procedure
HRA	human reliability analysis
IPE	individual plant examination
ISLOCA	interfacing system LOCA
ITS	improved technical specifications
LOCA	loss of coolant accident
LOSP	loss of offsite power
MFW	main feedwater
MG	motor-generator
MLOCA	medium LOCA (1.5" - 5.5")
LLOCA	large LOCA (> 5.5")
PDS	plant damage state
PORV	power operated relief valve
PRZR	pressurizer
PSA	probabilistic safety assessment
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RTP	rated thermal power
RTS	reactor trip system
SAFW	standby auxiliary feedwater
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SLOCA	small LOCA (1" - 1.5")
SSLOCA	small-small LOCA (< 1")
SV	safety valve
SW	service water

1.0 EXECUTIVE SUMMARY

The following sections provide the objectives of the Ginna Station Probabilistic Safety Assessment (PSA), a brief description of the methodology which was used, and a summary of the final results.

1.1 Background and Objectives

In November of 1988, the NRC issued Generic Letter (GL) 88-20 which requested that all nuclear power reactor licensees perform an individual plant examination (IPE) of their facilities to identify potential severe accident vulnerabilities due to internal hazards. RG&E responded to this generic letter by forming an in-house IPE team with support from an outside contractor. In March of 1994, RG&E submitted a report to the NRC documenting the methodology which was used and a summary of the final results. Since that time, RG&E has expanded the original models and factored into the analysis a change to 18 month fuel cycles, replacement of the steam generators (SGs), and a conversion to the improved technical specifications (ITS). In addition, the NRC raised several questions concerning the original models that have since been addressed by RG&E. The majority of the new effort was performed in-house with minimal contractor support (e.g., areas such as human reliability analysis). Revision 1 of this report documents the findings of the revised analysis.

The purpose of an IPE per GL 88-20 was to achieve the following objectives:

a. Develop an appreciation of severe accident behavior;

b. Understand the most likely severe accident sequences which could occur;

c. Gain a more quantitative understanding of the overall probabilities of core damage and fission product releases; and

d. Reduce, if necessary, the overall probabilities of core damage and fission product releases by modifying, where appropriate, hardware and procedures that would prevent or mitigate severe accidents.

An IPE can require significant resources to develop the necessary results. In addition, the information obtained through achievement of the above objectives can be used for many other purposes (e.g., on-line maintenance). As such, RG&E incorporated many other features and attempted to address additional issues beyond those required by GL 88-20. This formed the basis for the Ginna Station PSA as documented within this report. Consequently, for the purpose of this report, an IPE is considered to be a subset of a PSA since the PSA is intended to be used for future issues and concerns.

1.2 Plant Familiarization

Ginna Station is RG&E's only fully owned and operated nuclear generating unit and features a two-loop Westinghouse pressurized water reactor nuclear steam supply system. Ginna Station achieved commercial operation on June 1, 1970 and is licensed for a power level of 1520 MWt until September 18, 2009. With the steam generators (SGs) being replaced during the 1996 refueling outage, the station can now achieve approximately 525 MW gross electric.

The reactor coolant system (RCS) at Ginna Station consists of two hot legs, two U-tube SGs, a pressurizer, and two cold legs with a reactor coolant pump (RCP) in each cold leg. The secondary system consists of a turbine generator, a condenser, circulating water system, and a feedwater and condensate system. The RCS, turbine generator, and condenser systems were supplied by Westinghouse. Other plant structures and the balance of plant and auxiliary systems were designed either by Gilbert Associates or RG&E personnel. A simplified plant layout with major structures is shown in Figure 1-1.

The reactor containment building was designed by Gilbert Associates and is a reinforced concrete, vertical right cylinder with a flat base and a hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to provide leaktightness. The concrete cylinder is founded on rock by post-tensioned rock anchors. The cylinder wall is pre-stressed vertically by tendons coupled to the rock anchors.

Additional details on these systems and components are provided within the report (see Sections 6 and 10).

1.3 Methodology

There were three distinct technical activities in the Ginna Station PSA: Level 1 analysis for internal initiating events; Level 1 analysis for external events (e.g., plant flooding); and, Level 2 analysis. Each of these is briefly described below. For each activity, a freeze date of June 15, 1996 was used which is essentially the completion of the 1996 refueling outage. There are no major plant modifications currently scheduled after this date such that the Ginna Station PSA essentially reflects the existing plant design and configuration.

1.3.1 Level 1 Analysis for Internal Initiating Events

The Ginna Station PSA Project utilized standard small event tree / large linked fault tree Level 1 methodology. Event trees were developed for each unique class of identified internal initiating events, and top logic was developed to link these functional failures to system-level failure criteria using the Computer Aided Fault Tree Analysis (CAFTA) code. Fault trees comprised of component and human failure events were developed for each of the systems identified in the top logic with the exception of the Main Feedwater (MFW) System and the Reactor Trip System (RTS); these two systems were modeled using simplified Boolean expressions. Fault trees were also developed for systems required to support those systems identified in the top logic (e.g., electric power).

Fault tree hardware-related events were quantified with a mixture of generic data from throughout the nuclear industry and Ginna Station specific data. An eight-year (January 1, 1980 through December 31, 1988) data window was established for quantifying component failure rates. Licensee Event Reports and other in-house event reporting systems were also reviewed to ensure completeness.

Human failure events were quantified in two phases. In the first phase, conservative screening values were assigned to all human failure events identified in the logic models prior to model quantification. In the second phase, refined values were assigned only to those human failure events that appeared in the initial results. In this manner, only risk significant human failure events were addressed in detail.

Solution of the event trees yielded "cutsets" or those combination of events which lead to core damage. Sensitivity analyses of the final results were also performed to help identify risk significance.

1.3.2 Level 1 Analysis for External Initiating Events

[LATER]

1.3.3 Level 2 Analyses

[LATER]

1.4 Summary of Major Findings

The following sections describe the major findings of the Ginna Station PSA for the three types of analyses.

1.4.1 Level 1 Internal Event Findings

The calculated core damage frequency (CDF) from internal initiating events was 5.021E-05/ryr. The dominating accident sequences are from LOCAs (59%), steam generator tube ruptures (SGTRs) (16%), station blackout (SBO) events (12%), and transients (9%). The most risk significant components are related to the Residual Heat Removal (RHR) system (including its primary support system, component cooling water) during both the injection and recirculation phases of an accident, and the diesel generators. Other important systems include service water (SW), reactor trip system, DC electrical power, engineered safety features actuation system, safety injection, standby auxiliary feedwater (SAFW), and offsite power. Significant operator actions include placing the RHR system into recirculation following a LOCA, terminating the break flow out the ruptured tube during a SGTR, starting the SAFW system, starting additional SW pumps when coincident undervoltage and safety injection signals do not exist, and initiating feed and bleed upon loss of all feedwater. Also important was the ability to restore offsite power following a SBO event.

Several vulnerabilities were identified as a result of the Level 1 PSA. These are being tracked by action reports to ensure they are appropriately addressed.

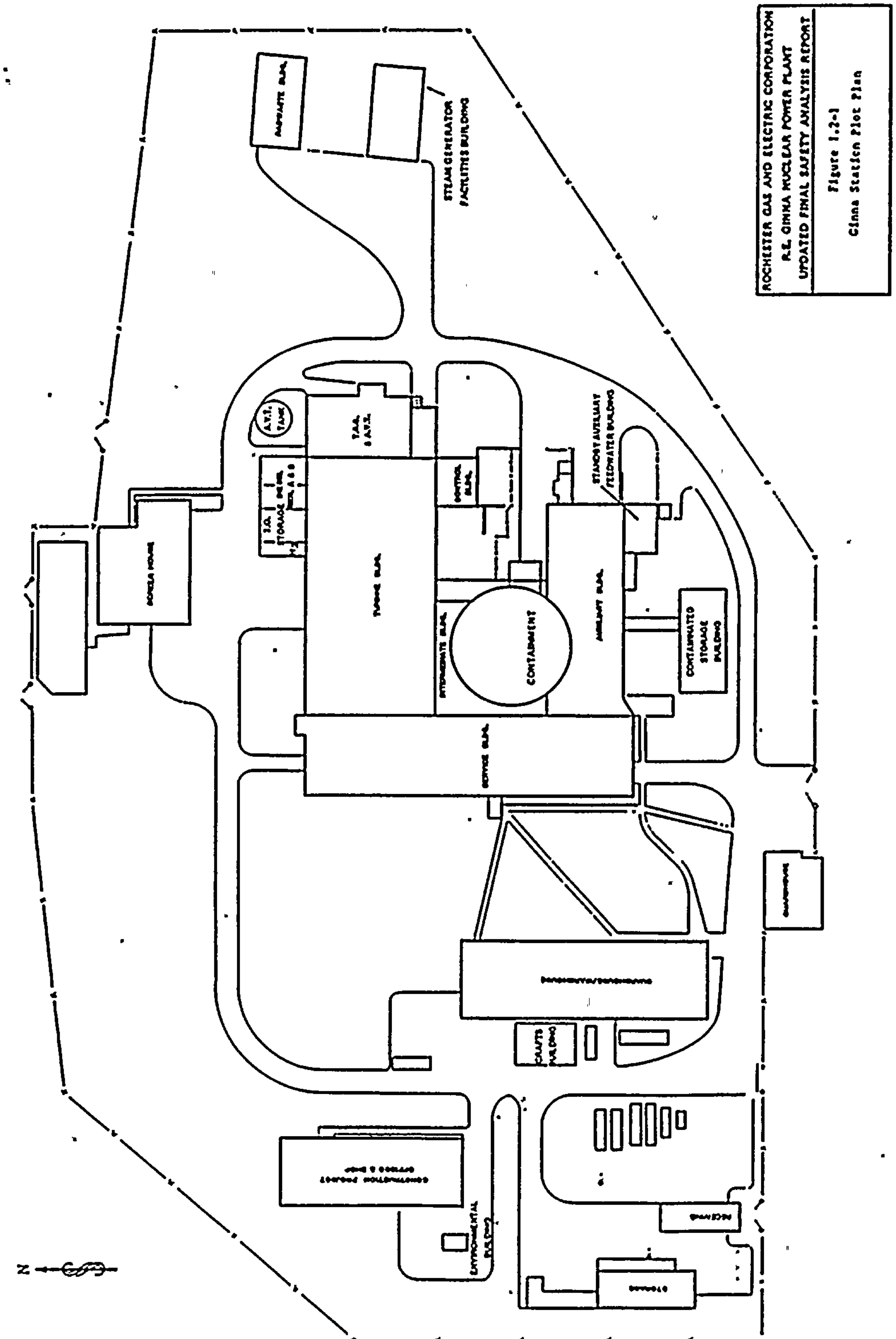
1.4.2 Level 1 External Event Findings

[LATER]

1.4.3 Level 2 Findings

[LATER]

Figure 1-1
Plant Layout



2.0 EXAMINATION DESCRIPTION

2.1 Introduction

This report provides the results of the probabilistic safety assessment (PSA) performed by Rochester Gas and Electric (RG&E) Corporation of the R.E. Ginna Nuclear Power Plant. Specifically, this document reports the results (and the methodology used to generate the results) of the Level 1 and Level 2 PSA. Also included within the report is an evaluation of certain external events (e.g., internal plant flooding).

This section of the report describes how the primary objectives of GL 88-20 are met as specified in Section 1.1. The remainder of the report provides additional details on the methodology which was used and the calculated results.

2.2 Conformance with Generic Letter 88-20 and Supporting Material

Generic Letter (GL) 88-20 requested that all licensees perform an individual plant examination (IPE) for severe accident vulnerabilities. Supplement 1 to GL 88-20 initiated this examination and provided submittal guidance in the form of NUREG-1335, *Individual Plant Examination Submittal Guidance* [Ref. 1]. The primary objectives of GL 88-20 are restated in Section 1.1 with Section 1.4 demonstrating that these objectives have been met. However, there are additional guidelines and objectives in Generic Letter 88-20 which include:

a. *The licensee staff should be used to the maximum extent possible in the performance of the IPE.* As discussed in Section 11, RG&E personnel contributed significantly to this project, filling many key roles.

b. *Unresolved Safety Issue (USI) A-45 should be resolved as part of the IPE.* Consideration of decay heat removal is basic to the performance of a PSA. As can be seen from the discussion in Section 9, this issue has been resolved for Ginna Station.

c. *Vulnerabilities identified during the IPE process should be corrected where appropriate.* Sections 9 and 11 discuss the results of the Ginna Station PSA, any vulnerabilities which have been identified, and how these vulnerabilities have been addressed.

d. *The containment analysis should include consideration of the insights gained from the NRC's Containment Performance Improvement Program.* These insights have been fully considered in the Level 2 PSA. See Section 10 for details.

e. *The results of the IPE should be reported in a format consistent with NUREG-1335.* This document follows the table of contents and the guidelines given in NUREG-1335 except as follows. First, sections related to support state methodology were omitted since the Ginna Station PSA utilizes the large linked fault tree approach, and not the support state approach. Second, sections were organized slightly different from NUREG-1335 to support future applications of the PSA without requiring a new final report. All information requested by the NRC per NUREG-1335 is contained in this report. However, to support NRC review, the following comparison is provided:

NUREG-1335		Ginna Station PSA Final Report	
3.1.1	Initiation Events	3.0	Initiating Events
		4.0	Success Criteria Determination
		7.0	Data Analysis
3.1.2	Front-Line Event Trees	5.0	Event Trees
3.1.3	Special Event Trees	5.0	Event Trees
3.1.4	Support System Event Trees	N/A	
3.1.5	Sequence Grouping and Back-End	10.0	Level 2 Analysis
3.2	System Analysis	6.0	System Analysis
3.3	Sequence Quantification	8.0	Sequence Quantification
3.4	Results and Screening Process	9.0	Level 1 Results
4.0	Back-End Analysis	10.0	Level 2 Analysis
5.0	Utility Participation and Review	11.0	Summary and Conclusions
6.0	Plant Improvements and Safety Features	11.0	Summary and Conclusions
7.0	Summary and Conclusions	11.0	Summary and Conclusions

2.3 General Methodology

In simple terms, a PSA is the evaluation of plant systems under various upset conditions to determine which systems and functions are risk significant with respect to preventing and/or mitigating core damage. The purpose of a PSA is not to justify system configurations or performance characteristics (e.g., pump net positive suction head (NPSH)). A PSA is also not intended to justify assumptions made in the accident analyses [Ref. 2]. Instead, a PSA uses information from other sources (e.g., UFSAR, plant drawings, procedures), supplemented with additional "best-estimate" analyses, to model plant systems and their expected response to plant transients in order to evaluate their risk significance.

It is important to note that the PSA does not typically use the assumptions found in the accident analyses which are conservative in nature based on various regulatory requirements. Attempting to develop a risk profile based on these assumptions could prove very misleading based on the degree of conservatism which was applied. Therefore, a PSA must utilize "best-estimate" assumptions and evaluations. As such, a PSA is not an operability evaluation with respect to plant technical specifications that are based on the accident analyses; however, a PSA can be used as an input to focus attention on those structures, systems, and components which are considered risk significant with respect to core damage.

For the Ginna Station PSA project, a core damage accident sequence is defined by an initiating event and the consequent and subsequent successes and failures of plant systems called upon to protect the reactor core from damage. It is not possible to identify and evaluate the frequency of every possible core damage sequence due to their large number and the incomplete knowledge of the plant behavior under certain beyond design basis conditions. Therefore, core damage "categories" (versus individual sequences) are evaluated using detailed system logic models supplemented with a thorough review of plant operating history and industry events. This technique gives confidence that all important risk contributors have been identified and that the identified risk profile is, overall, representative of Ginna Station. As such, a PSA is a series of iterative steps; each step, or task, is described below.

2.3.1 Initiating Event Analysis

The first step of the PSA is to identify the initiating events which must be considered with respect to generating a reactor trip that could potentially lead to core damage. This task began by identifying potential initiating events using plant experience and other PSAs and generating a list of transients and loss of coolant accidents to consider. Additional initiating events were later added as a result of insights from the Systems Analysis task. Section 3 provides a detailed discussion of the initiating event analysis process and results.

2.3.2 Success Criteria Determination

Following the identification of initiating events, success criteria were developed to determine the minimal combination of plant systems and equipment that must function in order to prevent core damage for each initiator. Essentially, the success criteria were developed with respect to four functions:

a. Control of reactitivty;
b. Control of Reactor Coolant System (RCS) pressure;
c. Preservation of RCS inventory; and
d. Heat removal from the RCS.

The necessary success criteria for each initiator was developed using the UFSAR [Ref. 2], simulator and plant experience, and other sources. Only "front-line" systems were identified in this task since individual system success criteria are provided in the System Analysis Task. Section 4 provides a detailed discussion of the process for determining the success criteria used in the Ginna Station PSA.

2.3.3 Event Trees

Once success criteria have been determined for each initiating event, initiators with common success criteria can be grouped together and evaluated. This evaluation process was comprised of using event trees which model the various successes and failures of systems and components following an initiator or group of initiators. The event trees were solved to generate "cutsets" or those combinations of events which can lead to core damage. Section 5 provides a detailed discussion of the event trees used in the Ginna Station PSA.

2.3.4 Systems Analysis

The Systems Analysis task is traditionally the major focus of the Level 1 portion of the PSA. Using the success criteria defined earlier, analysts prepare detailed logic models for each required system. These logic or fault tree models were developed down to a component level to determine the possible methods by which a system could fail to perform its required function. Random failure, test and maintenance unavailabilities, human errors, failure to restore following test or maintenance, and common cause failure events were modeled for each component as necessary. Necessary support systems (e.g., electric power, instrument air) were also developed to support the identified "front-line" systems. Section 6 provides a detailed discussion of the system analysis task and the resulting fault tree models.

2.3.5 Data Analysis

In conjunction with the system analysis task, data was generated to support every event in the fault tree models and event trees. There are essentially two types of data: (1) component data (e.g., failure rates, test and maintenance unavailability, initiating event frequencies) and (2) human reliability data (e.g., failure to restore following maintenance, failure to implement procedure correctly). For the component data, Ginna Station records for a period from January 1980 through December 1988 were reviewed and compiled with generic failure data from throughout the industry to generate a set of Ginna-specific failure data. For human reliability data, conservative screening values were used during the initial quantification of the fault trees to identify the most risk significant events. Following the initial quantification, the dominant human failure events were evaluated in more detail based on analysis of the accident sequence and appropriate procedures, and interviews with Ginna Station licensed operators. The data analysis task is described in more detail in Section 7.

2.3.6 Quantification

Once the fault tree models have been developed with associated data for each event, the event trees are solved via a process referred to as quantification. This is a very iterative process which involves solving the fault tree model repeatedly to identify those combination of events which lead to core damage. This process also assists in identifying "bugs" or errors in the system fault tree models since each dominate core damage sequence is evaluated and confirmed. When possible, recovery actions were added to each sequence to provide the opportunity for operator responses. Sensitivity studies of the final results were also performed. For the Ginna Station PSA, quantification was performed using the Computer Aided Fault Tree Analysis (CAFTA) suite of codes. Section 8 provides the details of this task while Section 9 provides the results.

2.3.7 Level 2 Analysis

[LATER]

2.3.8 Internal Flooding Analysis

[LATER]

2.4 Information Assembly

The information which follows is being provided in accordance with NUREG-1335.

2.4.1 Plant Layout and Containment Building Information

The plant layout and containment building information used in the Ginna Station PSA Project is found in the Updated Safety Analysis Report (UFSAR) [Ref. 2]. Additional information, when used, is specifically provided in the appropriate section within the report.

2.4.2 Other PSAs Reviewed

The Ginna Station PSA team reviewed many of the PSA studies available in the literature (WASH-1400, NUREG-1150, NSAC/60, etc.) during this project. In addition, the initial GL 88-20 responses for the other two-loop Westinghouse plants [Ref. 3] [Ref. 4] [Ref. 5] were reviewed with comparisons provided throughout this report as appropriate (e.g., comparisons of initiating events is provided in Section 3).

It should be noted that the original Ginna Station PSA was conducted primarily by two individuals with extensive PSA experience. One of these individuals has continued on this project providing a strong degree of PSA knowledge.

2.4.3 PSA Reference Documentation

A vast quantity of information was used during the Ginna PSA project, including:

a. Updated Final Safety Analysis Report (UFSAR) [Ref. 2];
b. Improved Technical Specifications (ITS) [Ref. 6];
c. Plant procedures;
d Licensee Event Reports (LERs) since 1980;
e. Plant maintenance and operating records;
f. RG&E controlled drawings;
g. System Training Descriptions;
h. Interviews with operators and many other experienced Ginna personnel;
i. Plant walkdowns; and,
j. Control room simulator observations.

2.4.4 Plant Walkdowns

Walkdowns were conducted throughout the Ginna Station PSA Project as a primary source of information on plant configuration, operations and maintenance. System walkdowns were also conducted during the Systems Analysis task by each of the analysts. Information gathered during these walkdowns was used to judge the appropriateness of some aspects of the plant logic models, including such things as proper electric power interfaces. The close proximity of Ginna Station to the RG&E engineering offices (about a 30 minute drive) meant that the RG&E systems analysts could conduct walkdowns as required.

Containment walkdowns were conducted during the 1991 and 1992 refueling outages. Information from these walkdowns was used in the Level 2 analysis for such things as selected dimensions required by the MAAP input model.

3.0 INITIATING EVENT ANALYSIS

As discussed in Section 2.3, the first step in evaluating each core damage sequence is the determination of potential initiating events. For the purposes of the Ginna Station PSA project, an initiating event is an upset condition which results in either a manual or automatic reactor trip. These upset conditions may be generated within the plant systems, such as a turbine trip or loss of coolant accident (LOCA), or may result from a shock outside the plant, such as a flood or fire. Any upset condition which does not result in the need for a plant trip is not considered in the Ginna Station PSA since the incident has not challenged any safety functions which could potentially result in core damage. In addition, only upset conditions which begin at or near 100% rated thermal power are evaluated.

An initiating event may be a component failure or a human action that causes a demand for an automatic or manual reactor trip. With rare exceptions, such an event will be safely accommodated using safety grade or other plant equipment as documented in the emergency operating procedures (EOPs) or other procedures. Only in those instances in which multiple systems or components are postulated to fail will there arise the possibility of inadequate core cooling so as to challenge the integrity of the core and, even less likely, simultaneously propagate to a challenge to containment integrity. These later instances are the core damage accident sequences of interest in the Ginna Station PSA.

Normal power operations is based on the premise of maintaining adequate cooling of the reactor core through the use of various systems and components which can transform this energy into electrical power generation. Any moderate or large deviation in this plant system balance results in a plant trip. However, core cooling must also be maintained following a reactor trip to prevent core damage. Adequate core cooling following a trip is a matter of shutting down the reactor (i.e., control of reactivity), and transferring the residual decay heat from the core to an ultimate heat sink. The latter is accomplished by maintaining control of RCS pressure and inventory, and providing a means of removing the heat from the primary system. A failure to shutdown the reactor when demanded (i.e., anticipated transient without scram or ATWS) and a failure in the heat sink path (e.g., a LOCA or steam generator tube rupture (SGTR)) are two potential kinds of core damage opportunities.

Ginna Station is not only a diversely arranged collection of systems, but is complexly interlinked, with each major system redundantly designed to enhance its reliability. As a result, challenges to the core are not only rare, but must be convoluted, in the sense that multiple failures or propagating failures, such as common-cause failures, must arise in order to challenge the highly buffered safety barriers of the plant. Hence, some important initiators may not at first appear to be as great of a challenge as the "classical" initiating events, such as LOCAs. But due to system interactions, these transients may in fact dominate the risk importance ranking of sequences and must be identified and evaluated.

3.1 General Analysis Approach

The process of identifying initiating events for consideration in the Ginna Station PSA first begins with reviewing previously published and accepted industry reports and documents to develop a preliminary list (Section 3.2). This list is then revised based on Ginna Station specific information (Section 3.3) such that a comprehensive listing of potential initiators is obtained (Section 3.4). Finally, the listing of initiating events is compared to other similar plant designs and industry sources to ensure a complete listing (Section 3.5). This process is described in detail below.

3.2 Generic Initiating Event List

The first step in creating a comprehensive list of potential initiating events to consider is to review previously published and accepted industry reports and documents. Generic Letter 88-20 [Ref. 7], NUREG-1335 [Ref. 1], and NUREG/CR-3485 [Ref. 8] provide a common set of PRA initiator classes which can be considered standard for a PWR as summarized below:

a. LOCAs;
b. SGTRs;
c. Intersystem LOCAs (ISLOCAs) or LOCA outside containment;
d. Loss of offsite power;
e. "Other transients" (e.g., turbine trips, loss of main feedwater, etc.); and
f. External events (e.g., seismic, flooding, fire)

As can be seen, all initiating events involve either the loss of primary system integrity (i.e., LOCAs, SGTRs, and ISLOCAs), or transients that automatically trip the reactor or induce procedurally directed manual reactor trips. These transients all involve some form of heat balance problems (overcooling, undercooling, and overpower) such that normal power operation cannot be safely maintained. Since the above list is "generic," it must be supplemented with Ginna Station specific information, especially with respect to the "other transients" category.

3.3 Ginna Station Specific Initiating Events

In order to create an accurate and comprehensive listing of initiating events, the preliminary list must be evaluated against the following sources of information:

a. UFSAR Chapter 15 accident analyses;
b. Ginna Station system design and actuation logic;
c. Ginna Station EOPs; and
d. Ginna Station Licensee Event Reports (LERs).

The first step performed was a review of the Reactor Trip System (RTS) for Ginna Station. Table 3-1 summarizes the reactor trips which are required to be operable in MODES 1 and 2 per the technical specifications. As can be seen from this table, certain trip functions are blocked below 100% rated thermal power and are excluded from further consideration.

Table 3-2 provides a summary of the accident analyses presented in UFSAR Chapter 15 [Ref. 2]. The UFSAR, in general, only provides an evaluation of the most limiting accidents. As discussed above, some important initiators may not be identified as a "classical" initiating events. Consequently, to obtain a complete listing of initiating events, the installed systems at Ginna Station were evaluated with respect to Table 3-1 and Table 3-2 to determine if a reactor trip would occur if the system were lost or otherwise failed. This evaluation is presented below for each system identified in the Ginna Station Q-List. This is followed by an evaluation of the EOPs and LERs for Ginna Station.

3.3.1 Equipment and Fluid Systems

Included within this category are the following systems:

a. Reactor Core and Internals System
b. Reactor Coolant System (RCS)
c. Residual Heat Removal (RHR) System
d. Auxiliary Feedwater (AFW) System
e. Safety Injection (SI) System
f. Containment Spray (CS) System
g. Chemical and Volume Control System (CVCS)
h. Service Water (SW) System
i. Component Cooling Water (CCW) System
j. Spent Fuel Pool (SFP) and Cooling System
k. Instrument Air (IA) System
l. Service Air System
m. Radioactive Waste Processing System
n. Plant Sampling Systems
o. Hydrogen Recombiner System
p. Refueling and Fuel Handling Equipment System
q. Fire Protection System

Except for a few components, the Reactor Core Internals System and RCS are passive systems, which if they were to fail, would directly result in a reactor trip (e.g., LOCA). In addition, the failure of the active components in these systems (e.g., reactor coolant pumps (RCPs), rod control) could also directly result in a reactor trip. Therefore, failure of these systems must be included as initiating events.

The RHR, AFW, SI, and CS systems are standby systems which are only operated for testing purposes during normal operation (SI can also be used to refill the accumulators but this is typically a rare occurrence at power). Therefore, the failure of these systems in the standby state, except for those portions of the system which interface with the RCS or steam generators (SGs), will not cause a reactor trip. The spurious operation of these systems will not directly cause a reactor trip since the shutoff head for the SI and RHR pumps (1400 and 150 psig, respectively) is below the reactor high pressure trip setpoint and PORV opening setpoint, the advanced digital feedwater control system (ADFCS) is designed to compensate for the additional AFW flow, and CS does not interface with any fluid or control system. In addition, the CS system is designed to require two distinct actions before actuation (i.e., the system does not actuate on loss of DC control power and two manual push buttons must be depressed at the same time for manual actuation). As such, the failure or spurious actuation of these systems is excluded from further consideration.

The loss of the CVCS, including a pipe rupture, is expected to result in a reactor trip in response to the loss of cooling to the RCPs or the loss of RCS inventory control [Ref. 9]. Therefore, the loss of the CVCS must be considered as an initiator.

The loss of SW or CCW is expected to result in a reactor trip due to operator action in response to the loss of cooling to the RCPs. The loss of SW will also eventually cause a reactor trip due to the loss of cooling water to various plant auxiliaries (e.g., instrument air). Therefore, the loss of the SW or CCW systems must be considered as an initiator.

The loss of the SFP Cooling and Refueling and Fuel-Handling Equipment Systems will not result in a reactor trip since SFP cooling does not interface with the RCS while Refueling systems are normally only used during MODE 6 (or while preparing for MODE 6) and do not interface with the RCS or any system capable of initiating a reactor trip. Therefore, the spurious actuation of these systems is also not of concern and they are excluded from further consideration.

The loss of the IA System is expected to result in a reactor trip due to secondary system perturbations, especially with respect to the condensate and main feedwater systems [Ref. 10]. However, the loss of the Service Air System is not expected to result in a reactor trip unless the system is cross-tied to the IA System (which is not a typical configuration) and a pipe rupture or similar event occurs. Nonetheless, this scenario is bounded by the loss of IA System. Therefore, only the loss of the IA System will be considered as an initiator.

The failure the Radioactive Waste Processing System, Plant Sampling Systems, and Hydrogen Recombiners will not result in a reactor trip since these systems are standby systems which do not directly interface with the RTS or any system capable of initiating a reactor trip. Therefore, the spurious actuation of these systems is also not of concern.

The loss of the Fire Protection System will not result in a reactor trip since this is a standby system. However, the spurious actuation of this system could impact instrumentation and safety related equipment resulting in a reactor trip. This will be considered in the flooding evaluation (i.e., external events).

3.3.2 Major Civil Structures

Included within this category are the following systems:

a. Primary Containment System
b. Screenhouse / Service Water Building and Structures
c. Auxiliary Building
d. Standby Auxiliary Feedwater Building
e. Intermediate Building
f. Control Building
g. Diesel Generator Building
h. Turbine Building
i. Service Building
j. Technical Support Center / Condensate Demineralizer Building
k. Miscellaneous Buildings and Structures

While safety related components are included within these structures and buildings, there is no internally generated failure mechanism. That is, the failure of each structure and building requires an external force (e.g., tornado, seismic event) which will be considered in the external events evaluation.

However, there are several walls within various safety-related structures that are of limited strength (e.g., block walls). These walls have the potential to fail during high energy line breaks and affect other systems. These walls are mainly located in the Intermediate Building which houses the AFW pumps, main steam isolation valves, atmospheric relief valves, and MG sets [Ref. 2, Section 3.6.2]. While not considered as an initiator, the failure of the block walls must be considered with respect to organizing the categories of initiating events.

3.3.3 Instrumentation and Control Systems

Included within this category are the following systems:

a. Reactor Trip System (RTS)
b. Engineered Safety Feature Actuation System (ESFAS)
c. Nuclear Process Instrumentation System
d. Main Control Board Annunciation
e. Plant Process Computer System

f. Safety Assessment System
g. Seismic and Meteorological Instrumentation

A failure (i.e., spurious actuation) of the RTS, ESFAS (SI actuation only), and Nuclear Process Instrumentation System will result in a reactor trip by design. A failure of these systems to actuate when required must also be considered when grouping initiators due to the required response of plant systems (e.g., AFW); however, failure to actuate is not an initiator since these systems actually generate the reactor trip signal.

A loss or failure of the remaining instrumentation systems will not result in a reactor trip since they are support systems which do not directly interface with the RTS. That is, these instrumentation systems typically provide operator indication of various systems and parameters. The failure to provide this indication, of and by itself, does not result in a reactor trip or demand for a reactor trip. However, it may require a controlled reactor shutdown which is not addressed in the PSA (e.g., [Ref. 11]). For ESFAS functions other than SI, Table 3-3 shows several actuations of single containment isolation and containment ventilation isolation trains which do not lead to a reactor trip (e.g., LERs 87-04, 88-07, 89-03). Therefore, failure of these remaining instrumentation systems is not considered further with respect to initiating events.

3.3.4 Electrical Systems

Included within this category are the following systems:

a. Offsite Electrical Power
b. 4160 V Electrical System
c. 480 V Electrical System
d. 120 VAC Electrical System
e. 125 VDC Electrical System
f. Diesel Generator (DG) Electrical Power System
g. Emergency Lighting System

Figure 3-1 shows the offsite and onsite AC power systems for Ginna Station. As can be seen from this figure, the onsite AC power system is organized into two redundant trains comprised of 480 V Bus 14 and 18 for Train A and Bus 16 and 17 for Train B. Each train can be supplied by separate offsite power sources (i.e., from CKT 761 and CKT 767 which is referred to as the "50/50" mode) or by the same offsite power source (i.e., from either CKT 751 or 767 which is referred to as "0/100" and "100/0" modes). Based on previous plant trip history and simulator runs, the loss of offsite power to either or both 480 V trains without a corresponding loss of offsite power in the switchyard (thus causing a turbine / generator trip) will not result in a reactor trip (see LERs 81-07, 88-06, 91-02, 91-06, 92-07, and 94-05). This is due to the fact that the DGs will supply the two 480 V trains within approximately 10 seconds, and there are no components supplied by the trains which require an uninterruptable source of power. Also, the MFW pumps and RCPs are supplied by the 4160 V buses. Therefore, only loss of power events which affect: (1) the switchyard only, (2) both the switchyard and the 480 V buses (i.e., a grid failure), or (3) the two 480 V trains only with subsequent failure of both DGs must be considered. Even though the last event is bounded by the grid failure with respect to being an initiator, operators are instructed to trip the reactor in this instance due to the potential for a seal LOCA; thus this must remain as an initiator.

The 4160 V electrical system supports several systems whose failure directly leads to a reactor trip (e.g., RCP and circulating water pumps). However, the 4160 V system is normally supplied by the Ginna Station turbine / generator by a line located between the turbine / generator and the plant switchyard. Therefore, the events which could result in a loss of the 4160 V system include opening of the generator output breaker with failure of the 4160 V auto transfer logic, a switchyard fault, or a grid failure. Note that a grid failure would also fail the offsite power sources to the 480 V electrical system as discussed above.

The 120 VAC electrical system is comprised of 4 instrument buses as shown on Figure 3-2. Two instrument buses (i.e., A and C) are capable of being supplied by the 480 V electrical system and the 125 VDC electrical system while the remaining instrument buses are supplied by the 480 V electrical system (i.e., B and D). The failure of any one instrument bus will not cause a reactor trip as shown on Figure 3-3. Since there is no common event which can fail two or more instrument buses, this system was excluded from further review as an initiator.

The 125 VDC electrical system is comprised of two trains, each supplied by battery chargers and independent batteries as shown on Figure 3-2. The failure of either 125 VDC electrical train (i.e., Main DC Distribution Panel A or B) will directly lead to a reactor trip since the reactor trip breakers and trip logic fails to the "safe" (i.e., trip) position (see Figure 3-3).

The DG electrical power system and the emergency lighting systems are standby systems whose failure to actuate will not result in a reactor trip. The spurious actuation of these systems will also not generate a reactor trip since neither system directly interfaces with the RTS. Also, as discussed above, the loss of one or both 480 V electrical trains (which the DGs supply) will not automatically lead to a reactor trip.

3.3.5 Heating, Ventilation, and Air Conditioning (HVAC) Systems

Included within this category are the following systems:

a. Condensate Demineralizer Building HVAC System
b. Screenhouse HVAC System
c. Miscellaneous Building HVAC System
d. Containment HVAC System
e. Control Building HVAC System
f. Auxiliary / Intermediate / Standby Auxiliary Feedwater HVAC System
g. Diesel Generator Room Ventilation System
h. Turbine Building HVAC System
i. Service Building HVAC System
j. Technical Support Center HVAC System
k. House Heating Steam System
l. Chilled Water System

Due to the northern location of Ginna Station, heating systems are relatively important, especially with respect to standby systems. In addition, as a result of normal system heat losses, ventilation systems are important during the summer months. However, all rooms and buildings are inspected at least once per shift by operations with respect to temperature. Also, special procedures and actions are implemented during cold weather [Ref. 12] and extreme hot weather conditions [Ref. 13] to ensure room temperatures are adequately maintained. If room temperatures were becoming a concern, then either compensatory measures would be taken (e.g., use of a portable fan or propane heater) or the plant would be manually taken offline. UFSAR analyses show that only the control building, DG building, and SAFW ventilation systems are credited for heating and cooling purposes post-accident. Based on previous plant trip history (see Table 3-3), it is not expected that failure of any HVAC system would <u>directly</u> result in a reactor trip (i.e., operator tours and control room indication would provide initial indication of concerns). Therefore, loss of ventilation will not be identified as an initiator. However, the failure of a HVAC system subsequent to a reactor trip must be considered in the fault tree models.

3.3.6 Steam and Power Conversion Systems

Included within this category are the following systems:

a. Steam Generator (SG) System
b. Main Steam (MS) System
c. Extraction Steam System
d. Steam Generator Blowdown System
e. Condensate and Feedwater System
f. Heater Drain System

g. Turbine-Generator System

The above systems essentially perform the heat sink function by supporting the removal of heat from the RCS. Failure of the SGs (e.g., SGTR), MS System (e.g., steam line break), Condensate and Feedwater Systems (e.g., MFW line break), and the Turbine-Generator System will typically result in either a direct reactor trip or an ESFAS which will generate a reactor trip. Failure of the remaining systems are not expected to directly cause a reactor trip, although their failure may result in a manual or controlled shutdown. In addition, these system failures are bounded by failures of the SGs, MS System, Condensate and Feedwater Systems, and Turbine-Generator System.

It should be noted that even though the January 1982 SGTR at Ginna Station necessitates consideration of this initiator, the replacement of the SGs during the 1996 refueling outage will rebaseline this initiator frequency to generic data. Also, the location of MS and MFW line breaks must be considered since a break inside containment will result in different consequences than a break outside containment due to equipment interaction (e.g., a break outside containment could directly fail the AFW System).

3.3.7 Other Equipment and Fluid Systems

Included with this category are the following systems:

a. Circulating Water System
b. Water Treatment System
c. Site Services and Facility Support System
d. Miscellaneous Non-System Related Equipment

Failure of the Circulating Water System will cause a reactor trip due to the loss of condenser vacuum which is bounded by the Condensate and Feedwater System failures discussed above. However, the remaining systems are minor support systems which do not directly interface with the reactor trip system or any other related system.

3.3.8 Emergency Operating Procedures (EOPs)

The Ginna Station EOPs are symptom based documents that provide the necessary operator actions following a reactor trip or the demand for a reactor trip. While a review of these procedures did not indicate the need to consider any initiators beyond those discussed above, they will be used in organizing the final list of initiators based on expected plant response.

3.3.9 Ginna Station Licensee Event Reports (LERs)

All reactor trips and LERs issued at Ginna Station since 1980 were examined to ensure that the list of potential initiators is complete. A listing of Ginna Station LERs is given in Table 3-3. Additional details are provided below.

There has been one SGTR event at Ginna Station (LER 82-03). This event was determined to be caused by tools previously left in the SG. The replacement SGs being installed in 1996 and the installed foreign material detection system should allow this previous event to be removed from the plant-specific data for initiator frequency. However, the SGTR initiator must still be considered.

There were numerous secondary system transients which lead directly to a reactor trip or lead to a turbine trip and subsequent reactor trip. Trips were typically caused by transients in the main steam or turbine system (including an inadvertent operator closure of a MSIV (LER 86-11) and a steam break (LER 86-04)), circulating water anomalies, or feedwater control issues. The installation of the ADFCS should decrease the frequency of feedwater control transients; however, the initiator must still be considered.

Several reactor trips were the result of testing or personnel errors related to the RTS, ESFAS, or AMSAC instrumentation (LERs 86-08, 89-04, 90-12, 90-13, 93-01, and 93-07). These are included as "spurious" actuations of these systems.

There have been several instances where offsite power has either been completely lost to the 480 V buses or in a degraded condition. The two complete loss of offsite power events occurred prior to the installation of the second offsite power transformer (LERs 81-07 and 88-06). The remaining events (LERs 91-02, 91-06, 92-07, and 94-05) involved the loss of one of the two offsite power sources (i.e., Circuit 751). However, in none of the events did a reactor trip occur since the buses supplying feedwater and reactor coolant pumps were not affected. Therefore, it can be concluded that unless there is a grid failure which results in a generator output breaker trip (i.e., a failure which affects the switchyard), a loss of offsite power does not result in an automatic reactor trip. However, these non-reactor trip offsite power events must still be considered in the fault tree models due to the resulting new plant configurations (i.e., DG starts).

Several reactor trips occurred during startup or shutdown activities which are not expected to occur during normal power operation (LERs 83-27, 86-05, 88-01, 90-03, and 90-16). Since the PSA is only evaluating trips from 100% RTP, these events do not require further consideration.

Finally, Table 3-3 shows that the PORVs only opened following a reactor trip during the 1982 SGTR [LER 82-05] and following a manual turbine trip while the reactor was at zero power in 1983 [LER 83-23]. These events are consistent with the assumption made in the UFSAR [Ref. 2] and simulator information, that PORVs generally will not be challenged following a "typical" reactor trip at power.

3.4 Identification Of Initiators

Based on the evaluation of Ginna Station systems presented above, the list of potential initiators can be identified. It should be noted that this list was updated as necessary following the development of the success criteria described in Section 4. All changes as a result of the success criteria review are included below in parenthesis. The initiators were initially organized based on whether it is a LOCA or transient. These categories will be further separated based on the success criteria described in Section 4. See Table 3-4 for the final listing of initiating events.

3.4.1 Loss Of Coolant Accident Initiating Events

A LOCA affects the Reactor Core Internal System and RCS described in Section 3.3.1 above. LOCAs can be divided into several categories related to the size of the hole or rupture which is created in the RCS piping since the size of the LOCA will determine the rate of RCS depressurization. This in turn determines what systems are required to mitigate the event. For example, a very small LOCA may not depressurize the RCS sufficiently to allow the SI pumps to inject into the primary system. Therefore, AFW may be required to cooldown and depressurize the RCS to below the SI pump shutoff head. However, for larger LOCAs, the SI pumps may not be required since the RCS will rapidly depressurize to below the RHR pump shutoff head. All LOCAs are identified with the prefix "LI."

3.4.1.1 Very Large Break LOCA

A very large break LOCA is defined as a severe breach of the RCS resulting in leakage that is beyond the design capacity of the ECCS. For the purposes of the Ginna Station PSA, and for consistency with past risk assessments, a very large break LOCA will be defined as a reactor vessel rupture. This class of LOCAs is identified as LIRVRUPT.

3.4.1.2 Large Break LOCAs

A large break LOCA is defined as a break in the RCS with leakage that is within the capacity of the ECCS that results in rapidly depressurizing the RCS to the RHR pump shutoff head. UFSAR Section 6.3.3 [Ref. 2] shows that for LOCAs greater than 10" in diameter, one of two RHR pumps and one of two accumulators is successful. The RHR pump would be required for both injection and recirculation phases of the accident. This class of LOCAs is identified as LILBLOCA.

3.4.1.3 Medium Break LOCAs

A medium break LOCA is defined as a break in the RCS that is not large enough to require use of the accumulators since SI will provide necessary cooling until RHR conditions are reached. UFSAR Section 6.3.3 [Ref. 2] shows that for LOCAs between 3" and 10" in diameter, two of three SI pumps and one of two RHR pumps is successful. Only the RHR pump would be required during the recirculation phase of the accident. This class of LOCAs is identified as LIMBLOCA.

3.4.1.4 Small Break LOCAs

A small break LOCA is defined as a break in the RCS which is small enough that RHR will not be required in the injection phase. Flow from the break size alone cannot remove enough decay heat to prevent core damage; however, flow will be large enough to require RCS makeup in excess of the capacity of one positive displacement charging pump. UFSAR Section 6.3.3 [Ref. 2] shows that for LOCAs smaller than 3" in diameter, two of three SI pumps is successful in the injection phase with one of two RHR pumps required in the recirculation phase. This class of LOCAs also includes failures of the reactor coolant pump seals and is identified as LISBLOCA. (Note - this size class was further divided to include a small-small LOCA (LISSLOCA) due to the need for AFW in certain instances to reduce RCS pressure below the SI pump shutoff head - see Section 4).

3.4.1.5 Steam Generator Tube Rupture (SGTR)

A SGTR is defined as a complete severance of a single tube and is actually a special class of LOCA. However, due to the numerous actions required by operations in response to this event and the potential for a direct leakage path from containment to the outside environment, the SGTR will be identified separately. Since a SGTR could occur in either SG, a separate initiator will be provided for each SG as LI0SGTRA and LI0SGTRB.

3.4.1.6 Interfacing Systems LOCAs

Interfacing systems LOCAs are defined as failures of pressure boundaries between high pressure and low pressure systems that occur outside of containment. Interfacing system LOCAs are treated separately via analysis since the LOCA is assumed to directly result in core damage. ISLOCAs are analyzed in detail in Section 6. This class of initiators is identified as a LIPEN###.

3.4.2 Transient Initiating Events

The transient initiating category is comprised of several initiating events as described below. All transient initiators are identified with the prefix "TI."

3.4.2.1 Reactor Trip

The reactor trip category of transient initiating events includes all initiators which cause a reactor trip and recoverable losses of main feedwater, condensate, turbine bypass, and the condenser. This category includes actuations or failures of the following systems described in Section 3.3 above:

a. CVCS
b. RTS.
c. ESFAS (SI actuation only)
d. Nuclear Process Instrumentation System
e. SG System
f. MS System
g. Condensate and Feedwater System
h. Turbine-Generator System
i. Circulating Water System

Following receipt of a valid reactor trip signal, the reactor trip breakers will open, and the control rods will fall into the core. A turbine trip is initiated simultaneously while the MFW regulating valves (MFRVs) automatically go to their full open position; this action helps to overcome the large reduction in steam generator downcomer level that results from the shrink phenomena. The MFRVs are automatically controlled by ADFCS to maintain pre-determined levels. If MFW is unavailable, the AFW pumps will automatically start on low SG level while the condenser steam dump system will automatically operate to maintain the average RCS temperature at the no-load value of 547°F.

RCS volume decreases following a trip, resulting in a drop in pressurizer level. RCS volume is automatically increased by the positive-displacement charging pumps, which will maintain pressurizer level at 35%. If pressurizer level continues to decrease, the pressurizer heaters will be automatically de-energized (to prevent burnout), and the letdown isolation valve will be automatically closed. The electrical distribution system will automatically transfer house loads to offsite power, and the nuclear instrumentation system will automatically energize the source range detectors when appropriate. Finally, control room operators will dispatch auxiliary operators throughout the plant to finish securing the steam plant.

This initiator class is identified by TIRXTRIP.

3.4.2.2 Loss Of Offsite Power - Pre Reactor Trip

A loss of offsite power is defined in the PSA as a complete loss of all alternating current electrical power as follows: 1) a grid failure defined by the loss of the RG&E transmission network up to, but not including, the breaker connecting RG&E Station 204 to Station Auxiliary Transformer (SAT) 12A (i.e., CKT 751) and the breaker connecting Station 13A to SAT 12B (i.e., CKT 767); 2) a failure of the RG&E transmission network up to, and including, RG&E Station 13A only (i.e., a switchyard failure); and (3) failure of CKT 751 and 767 with subsequent failure of the onsite 480 V safeguards trains. Multiple initiators have been identified due to the different impact on plant equipment as described in Sections 3.3.4 and 3.3.9. This initiator class is identified as TIGRLOSP for the grid failure, TISWLOSP for the switchyard fault, and TI48LOSP for the 480 V train failure. As shown in Figure 3-1, TIGRLOSP is equivalent to failure of Station 204 and 13A (two boxes at top of page), TISWLOSP is equivalent to failure of Station 13A only, while TI48LOSP is equivalent to failure of Station 204 and CKT 767 only (Station 13A is still available).

3.4.2.3 Loss Of Offsite Power - Post Reactor Trip

This event is analogous to the loss of offsite power to the 480 V buses described in Section 3.4.2.2 above; however, this event occurs following the occurrence of any of the other initiating events described in this section. A turbine trip / reactor trip may challenge the transient stability of the transmission grid due to the sudden loss of generation at Ginna Station and subsequent loading of large motors on the offsite power circuits. While the Ginna Station switchyard feeding RG&E transmission Circuit 767, and RG&E Station 204 feeding RG&E transmission Circuit 751 are electrically independent, it will be conservatively assumed that a loss of Ginna generating capacity could fail both of the offsite power sources. Partial losses of offsite power (i.e., loss of one circuit) are also considered. While not specifically an initiator, this event is identified as ACLOPRTALL (for complete loss of AC power), ACLOPRT751 (for loss of Circuit 751) and ACLOPRT767 (for loss of Circuit 767).

3.4.2.4 Loss Of Main Feedwater

This event includes any initiating event which results in unrecoverable loss of MFW pumps PFW01A and PFW01B. The ability to recover MFW following a reactor trip is an important consideration with respect to available operator actions (i.e., reactor trips with recoverable MFW are included as TIRXTRIP to provide this distinction). This class of initiators is identified as TIFWLOSS.

3.4.2.5 Main Feedwater Line Breaks

A MFW line break on the feedwater lines to either SG will result in high energy release that could potentially damage and/or destroy equipment and instrumentation located in the general vicinity of the break. As such, this class of initiators must be separate from a loss of MFW event included in TIRXTRIP and TIFWLOSS. Feedwater line breaks could occur on the lines feeding either SG inside Containment; on the lines feeding either SG that run through the Intermediate Building; or, in the Turbine Building for the common line feeding both SGs. Because the isolation points and equipment which could be affected are different for each of these locations and the potential asymmetries which may exist, a total of five initiators are identified for this class as follows: TIFLBACT and TIFLBBCT for feedwater line breaks inside Containment for each SG; TIFLBAIB and TIFLBBIB for feedwater line breaks in the Intermediate Building; and TIFLB0TB for feedwater line breaks in the Turbine Building.

In addition to the above MFW line initiators, there is a section of MFW piping which exits containment and runs within the containment facade structure prior to entering the Intermediate Building. As such, a break location within the facade structure was added as initiator TIFLBSGB.

3.4.2.6 Steam Line Breaks

A main steam line break could result in rapid overcooling of the RCS and actuation of SI. A steam line break also could damage and/or destroy equipment and instrumentation in the area of the break. Steam line breaks could occur on either main steam line inside Containment; on either main steam line inside the Intermediate Building; or, inside the Turbine Building. Because of the isolation points and equipment which could be affected are different for each of these locations and the potential asymmetries which may exist, a total of five initiators are identified for main steam lines that can affect other equipment as follows: TISLBACT and TISLBBCT for steam line breaks inside Containment for each SG; TISLBAIB and TISLBBIB for steam line breaks in the Intermediate Building; and TISLB0TB for steam line breaks in the Turbine Building.

In addition to the above main steam line initiators, there are several break locations that would not be of concern from potentially impacting equipment in the surrounding area. These include the failure (open) of both atmospheric relief valves (ARVs); a break in the portion of the SG B main steam line that runs outside of Containment, from the outer Containment wall to the outer Intermediate Building wall; and, steam dump system actuation. As such, initiators TISLBSVA (ARV failures), TISLBSGB (piping run between Containment and the Intermediate Building), and TIOSLBSD (steam dump system actuation) have been included.

3.4.2.7 Loss Of Instrument Air Pressure

The loss of air pressure to air operated valves and instrumentation throughout the plant would result in a reactor trip mainly due to do upset conditions in the feedwater / condensate systems (e.g., closes the MFW regulating valves). This initiating event would also complicate trip recovery due to air operated valves going to their "fail safe" positions in safety related systems even if no SI signal were present. Therefore, this is identified separately as an initiator (TIIALOSS).

3.4.2.8 Loss Of Service Water

This initiating event is defined as a total loss of flow from the SW System, including failures of the Circulating Water System inlet piping and inlet bays connected to Lake Ontario. The SW System is designed as two pump trains which supply a common loop header. The common loop header is maintained open during power operation to allow either pump train to supply the system loads. However, the loop header can be realigned as needed by manual and motor-operated valves to isolate various portions of the system. As such, the event is divided into three initiators to reflect the potential ability to isolate the affected portions of the SW System for certain events (e.g., pipe breaks). This class is identified as TI0000SW (total loss of SW flow) and TI000SWA and TI000SWB (loss of respective SW headers).

3.4.2.9 Loss Of Component Cooling Water

This initiating event is defined as a complete loss of flow from the CCW System. The CCW System is designed as two pump trains which supply a common loop header similar to the SW System. However, since there is a limited source of water for the CCW System, a pipe failure would rapidly deplete this inventory negating the potential for recovery. Therefore, only one initiator is identified for this class as TI000CCW.

3.4.2.10 Loss Of A 125 VDC Bus

Loss of power on the 125 VDC system would result in a reactor trip due to its effect on the reactor trip breakers and associated logic. Since the failure of each train can result in a reactor trip, separate initiators are provided as TI000DCA and TI000DCB.

3.4.2.11 Locked Reactor Coolant Pump Rotor

A locked RCP rotor would result in a reactor trip due to low RCS flow. It would also result in a significant increase in RCS pressure due to the reduction in RCS flow and heat removal capability. This initiator is identified as TIRCPROT.

3.4.3 External Events

[LATER]

3.5 Industry Initiating Events

In order to ensure the above listing of initiating events is complete, industry sources were also reviewed. This includes consideration of the following sources:

a. Electric Power Research Institute (EPRI) Listing of Initiating Event Types
b. Other Westinghouse 2-Loop Plants

The review of these sources is discussed below.

3.5.1 EPRI Initiating Event Types

In 1982, the EPRI released a list of transient initiating events for both PWRs and BWRs as a result of their review of ATWS events [Ref. 14]. Table 3-5 lists the EPRI transient types for PWRs and how they are addressed with respect to the listing provided in Section 3.4 above. Type 13, startup of inactive coolant pump, is assumed not to be possible, since the technical specifications (LCO 3.4.4) require both RCPs to operate when above 8.5% RTP. Also, Type 43, loss of instrument bus, is not included for the reasons discussed in Section 3.3.4. As can be seen from this table, all relevant initiating events are being addressed.

3.5.2 PSAs For Other Westinghouse Two-Loop Plants

The PSAs for the other Westinghouse two-loop plants which are similar in design to Ginna Station were reviewed. The listing of the transient events assumed in these PSAs is shown in Table 3-6, including a comparison to the listing provided in Table 3-4. As can be seen, the proposed listing of initiating events for the Ginna Station PSA is essentially the same with the only differences due to individual quantification techniques and design issues (e.g., RG&E has elected to separate out steam line and feedwater line breaks based on steam generators and building location due to equipment interaction issues). There are no unique initiators between the four plants, including system initiators, with the exception of the small-small LOCA, locked RCP rotor, and one of the loss of offsite power initiators for Ginna Station.

The extra LOCA category (LISSLOCA) was added based on additional analyses which were performed for the Ginna Station PSA Project as described in Section 4. These analyses showed that for small LOCAs, AFW is potentially required in order to reduce the RCS pressure below the SI pump shutoff head. Only Point Beach has a similar SI System design (i.e., Kewaunee and Prairie Island have SI pumps with higher shutoff head capabilities). The requirement for AFW in these instances is also discussed in the bases for technical specification LCO 3.7.5.

The RCP locked rotor event (TIRCPROT) is treated separately in the Ginna Station PSA due to the resulting high RCS pressure which is similar, though somewhat different, to a loss of MFW or loss of offsite power event since MFW would be available. The loss of offsite power event in which the 480 V trains lose power and the DGs subsequently fail (TI48LOSP) is due to the offsite power design at Ginna Station.

Based on the above, the proposed initiator listing is considered acceptable.

3.6 Summary List Of Initiating Events

The final listing of initiating events is shown in Table 3-4. The next step to be performed is to determine the success criteria for each event and to group the initiators based on common plant response.

Table 3-1
Reactor Trip Functions Required in MODES 1 and 2

Reactor Trip Function	*Comments*
Manual	
Power Range Neutron Flux - High	
Power Range Neutron Flux - Low	Below 6% rated thermal power (RTP)
Intermediate Range Neutron Flux	Below 6% RTP
Source Range	Both IRMs < 5E-11 amps
Overtemperature ΔT	
Overpower ΔT	
Pressurizer Pressure - Low	Above or equal to 8.5% RTP
Pressurizer Pressure - High	
Pressurizer Water Level - High	
RCS Flow - Low - Single Loop	Above or equal to 50% RTP
RCS Flow - Low - Two Loops	Below 50% RTP
RCP Breaker Position - Single Loop	Above or equal to 50% RTP
RCP Breaker Position - Two Loops	Below 50% RTP
Undervoltage - Bus 11A and 11B	Above or equal to 8.5% RTP
Underfrequency - Bus 11A and 11B	Above or equal to 8.5% RTP
SG Water Level - Low Low	
Turbine Trip - Low Autostop Oil Pressure	Above 8% RTP with no heat sink; above 50% with heat sink available
Turbine Trip - Turbine Stop Valve Closure	Above 8% RTP with no heat sink; above 50% with heat sink available
Safety Injection	

Table 3-2
UFSAR Accident Analysis Categories

Increase in Heat Removal By the Secondary System
- Decrease in Feedwater Temperature
- Increase in Feedwater Flow
- Excessive Load Increase
- Main Steam Line Break
- Combined SG Atmospheric Relief Valve and Feedwater Control Valve Failure

Decrease in Heat Removal By the Secondary System
- Steam Pressure Regulator Malfunction
- Loss of External Electrical Load
- Turbine Trip
- Loss of Condenser Vacuum
- Loss of Offsite Power
- Loss of Normal Feedwater Flow
- Feedwater Line Break

Decrease in Reactor Coolant System Flow Rate
- RCP Flow Coastdown
- Locked RCP Rotor

Reactivity and Power Distribution Anomalies
- Uncontrolled Rod Cluster Control Assembly Withdrawal While Subcritical
- Uncontrolled Rod Cluster Control Assembly Withdrawal at Power
- Startup of an Inactive Reactor Coolant Loop
- Chemical and Volume Control System Malfunction
- Rod Ejection Accident
- Rod Cluster Control Assembly Drop

Increase in Reactor Coolant Inventory

Decrease in Reactor Coolant Inventory
- Inadvertent Opening of a Pressurizer Safety Valve or Relief Valve
- SGTR
- LOCA

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
80-01	1/18/80	100	DG governor setting incorrect	
80-02	3/31/80	0	SI sampling frequency too long	Corrected proced
80-03	4/14/80	0	SG plugging due to corrosion	
80-04	5/6/80	0	DC power maintenance error	
80-05	6/3/80	100	Accumulator valve breaker left on	Unknown cause
80-06	7/11/80	100	Titrant saturated with water in CVCS	
80-07	8/29/80	100	Failed amplifier in RPS flux tilt controller	
80-08	9/10/80	100	DG B breaker binds	Found in test
80-09	10/3/80	100	DG A fails test	Maintenance error
80-10	11/12/80	0	Minor weld leak in RHR thermowell	
80-11	12/11/80	100	DG B breaker fails on test	
81-01	1/5/81	100	DG B jacket cooling leak	Found in test
81-02	1/9/81	100	SI Pump C breaker (Bus 16) fails	Found in test
81-03	1/15/81	100	Boric acid pump fails, suction valve misaligned	Maintenance error
81-04	2/11/81	100	Chemical reaction in plug for CRFC unit	
81-05	3/2/81	100	SI Pump C breaker (Bus 16) fails	Repetitive failure
81-06	3/23/81	100	CVCS boration valve leakage	Found by op tour
81-07	4/18/81	95	Loss of offsite power (only had Trans #12)	DGs worked; no RT
81-08	4/2/81	100	Rad monitors seize and backup not used	
81-09	5/15/81	0	SG B tube problems	
81-10	4/20/81	0	Leak in letdown relief valve	
81-11	4/26/81	0	Leak in RHR pump B seal cooler	
81-12	5/4/81	0	High PZR pressure transmitters out of cal.	
81-13	7/14/81	100	CVCS boration valve leakage	
81-14	7/20/81	100	Halon system inoperable too long	Proc. inadequate
81-15	9/24/81	100	Opened CIV while testing PASS component	Proc. inadequate
81-16	11/5/81	100	SI Pump C breaker (Bus 16) fails	Repetitive failure
81-17	11/10/81	100	Fire related reporting error	Needed mod
****(1)	11/14/81	100	Fire suppression actuation; rod drop; manual RT	
81-18	12/2/81	100	Inadvertent operation of fire supp. system	
81-19	11/14/81	100	2 control rods misalign	Personnel error
81-20	11/19/81	100	Fire seals not installed correctly	Personnel error
81-21	12/22/81	100	CNMT gas rad mon not installed correctly	Found in test
81-22	12/21/81	100	Change in LOCA-ECCS calc. on coolers	

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
82-01	1/7/82	100	Leak in CIV	
82-02	1/13/82	100	Weld leak in RC drain tank pump	Found by op tour
82-03	1/25/82	100	SGTR; 1 burst tube in SG B	RT
82-04	1/25/82	0	Fire watches left post causes TS violation	
82-05	1/25/82	0	PORV sticks open in SGTR depress efforts	Block valve used
82-06	1/25/82	0	Injection of water causes reactivity increase	Proc. changed
82-07	2/23/82	0	Analysis shows cooldown exceeded TS	Proc. inadequate
82-08	3/3/82	0	Analysis shows cooldown ΔT exceeded TS	
82-09	3/20/82	0	Bus for fire pump out long enough to report	
82-10	3/23/82	0	Fire watch bail out, local rad emergency	Conflict in TS
82-11	4/23/82	0	Excessive leak in CIVs	
82-12	5/10/82	0	Halon system declared inoperable	Fire watch placed
82-13	5/19/82	0	Fire detection system loses AC on SI test	Fire watch too ate
****(1)	5/23/82	0	Instrument calibration causes RT	RT
82-14	6/24/82	100	CS discharge valve fails to close	Replaced when avail
82-15	6/22/82	100	CNMT gas rad monitor return line leak	
82-16	7/22/82	100	CS discharge valve fails to close	Repetitive failure
82-17	8/3/82	100	RHR Pump B test finds excessive leakage	Seal replaced
****(1)	8/6/82	100	PZR vent line isolated causes RT	Maint error; RT
82-18	8/30/82	100	Rod position indicator for bank A drifts	Adjustments made
82-19	9/1/82	100	Excessive leak in CIV	New vlv installed
82-20	7/12/82	100	Fire system surveillances overdue	Proc. inadequacies
82-21	9/23/82	100	CS check valve 862B fails to close	
82-22	10/1/82	0	Plugging of SG A and B tubes	
82-23	10/16/82	0	CCW Pump B discharge venting pipe leak	Personnel error
82-24	10/21/82	0	Cont Room K-7 position indicator inoperable	Indicator replaced
82-25	10/21/82	0	Fire suppression system out long enough to rpt	
82-26	10/26/82	100	CS check valve 862B fails to close	Repetitive failure
82-27	10/11/82	0	Boric acid xfer pump A discharge line leak	
82-28	12/19/82	55	CIV for N2 to accumulators leaks	
83-01	1/4/83	100	SW to SAFW Pump C found mispositioned	Possible tampering
83-02	1/5/83	100	Failed snubber in MS System	
83-03	1/8/83	100	CNMT sump A isolation valve failed to close	
83-04	1/14/83	100	CS check valve failed	Found in Test

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
****(1)	1/18/83	5	Low level in SG B during startup	RT
****(1)	1/18/83	25	Auto trip on IRM during startup	RT
83-05	1/17/83	100	I-131 concentration spike following trip	
83-06	1/20/83	100	Ice produces loss of sump water for fire	Suppression equip.
83-07	1/17/83	0	Post-trip, PZR level dropped below 12%	RT
83-08	1/25/83	100	DG A lights off, B not started for 2 hrs	Procedure violation
83-09	1/19/83	100	Boric acid transfer pump B fails	Fuse failure
83-10	2/24/83	100	Rod bank indicator inoperable	
83-11	3/11/83	100	Battery charger breaker opens	Accidental bump
83-12	3/23/83	100	Excessive personnel hatch leakage	Proc. inadequate
83-13	4/19/83	0	SG B tube indications	
83-14	3/29/83	0	Miscalibrated A and B SG level transmitters	
83-15	4/12/83	0	Air bubble stops RHR flow; manual stop	RWST used
83-16	4/18/83	0	Leak in boric acid storage tank room	
83-17	5/1/83	0	RHR B pump run 2 hrs without suction	Noticed prior to fail
83-18	4/28/83	0	NRC notes new tech spec not integrated	Procedure rewritten
83-19	6/13/83	0	CS pumps inoperable in mode change	Procedure changed
83-20	6/13/83	0	Excessive chloride concentration	
83-21	6/18/83	0	PRZR level drops below 12%; post 2nd trip	RT
83-22	7/25/83	100	CIV for N2 to accumulators leaks	Repetitive failure
83-23	6/19/83	0	Turbine trip followed by PORV opening	RT
83-24	6/21/83	0	Low SG steam flow transmitter failed	Adjusted xmitter
83-25	6/20/83	0	PRZR sampling isolation valve leak	
83-26	9/15/83	100	Boric acid storage tank solution concentration	
83-27	9/16/83	17	Shutdown produced AC-based trip signal	Operator error, RT
83-28	9/16/83	0	CVCS weld leak	
83-29	11/16/83	100	Heat balance miscalibrations	Proc. inadequacy
83-30	12/16/83	100	P-7 permissive found wrong	Reviewed TS
84-01	2/19/84	98	Accumulator N2 leak causes shutdown	Unusual Event
84-02	3/3/84	0	RCS Loop A RHR suction stop valve failed	
84-03	3/7/84	0	CS suction valve to RHR inadvert. opened	Proc. change
84-04	4/23/84	0	Waste gas system O2 analyzer found failed	
84-05	5/14/84	0	RCS Loop A RHR suction stop valve failed	Repetitive failure
84-06	5/22/84	0	Inadvertent SI at 2000 psig during shutdown	

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
84-07	5/30/84	83	Gasket cooler sucked in electric generator	TT & RT
84-08	7/25/84	100	Error between fire watch & isolation reqts	
84-09	8/17/84	100	DG A start during undervolt system test	Loose wire
84-10	8/31/84	100	Fire protection restoration failure	Halon available
84-11	9/28/84	100	CRD rod position indicator made inoperable	
84-12	10/4/84	100	Aux bldg exh fan C inop during fuel movement	Procedure change
84-13	10/15/84	100	Omitted CRD test step	Procedure change
85-01	1/16/85	100	Failure causes rod position indicator to be missed	
85-02	1/21/85	100	Start both DGs due to low system frequency	
85-03	3/9/85	0	Inadvertent fire system removal during test	
85-04	3/26/85	0	Two inadvertent SI actuations during test	
85-05	4/5/85	0	Inadvertent ESF during calibration	Procedure violation
85-06	4/6/85	5	RT during manual control of FW flow	RT
85-07	4/6/85	12	Manual control of FW leads to RT & failed TT	Local TT reqd, RT
85-08	4/7/85	13	RT while manually controlling FW	RT
85-09	4/8/85	3	TT/RT during turbine test	Error, TT & RT
85-10	4/8/85	0	RT breaker opens and no alarm	Relay failure
85-11	4/11/85	7	CW fail; manual TT failed twice; RT occurs	RT
85-12	5/6/85	100	Analysis shows CRFC units inoperable	
85-13	5/31/85	100	DG A started on tornado warning	
85-14	6/6/85	100	RT/TT during RPS test	Error, RT & TT
85-15	6/20/85	100	AO makes part unavailable in BA tank	Error
85-16	9/15/85	100	Rod position inoperable too long for TS	TS violation
85-17	9/16/85	100	CRD declared inoperable	Faulty firing circuit
85-18	9/28/85	100	Manual RT/TT due to turbine EH problems	RT & TT
85-19	11/23/85	100	Circ Water failure cause TT	Relay drift; RT
86-01	1/18/86	93	Test of CNMT pressure ESF incorrect	Proc. inadequacy
86-02	2/16/86	0	Cognitive difference causes valve faults.	Procedure change
86-03	3/11/86	0	Broken hose in halon system	
86-04	7/29/86	100	Leak and loud noise in Turb Bldg; manual RT	Steam leak; RT
86-05	7/30/86	26	RT on Intermediate range	Relay failure, RT
86-06	8/16/86	0	BA transfer suction valve found closed	
86-07	9/22/86	100	TS fire detection test interval exceeded	
86-08	10/23/86	100	Runback & rod drop led to RT	Personnel error, RT

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
86-09	10/26/86	100	Rod position indication out of specification	Defective proced.
86-10	11/8/86	100	Waste gas analyzer TS violation	Error
86-11	11/28/86	100	MSIVs closes inadvertantly causing RT	Commission error
87-01	2/20/87	0	Day tank problems when using DGs	Offsite power NA
87-02	3/6/87	0	TS violation on RCS O2 analyzer	Training upgrade
87-03	3/16/87	100	Major portion of fire suppression unavail	Restoration error
87-04	4/24/87	100	Inadvertent CNMT Isolation Train B	Bumped cabinet
87-05	5/14/87	100	Spurious signal causes CNMT Vent Isolation	
87-06	11/30/87	100	Cooling to SAFW Pump D unavail too long	Proc. inadequate
87-07	12/18/87	100	Found CCF for SI recirculation valves	Design error
87-08	12/23/87	100	Breaker fault in RHR Pump B & SI Pump B	Inadeq design info
88-01	2/5/88	0	Source range RT due to faulty connector	RT
88-02	3/8/88	0	BAST level indication fault	RT
88-03	3/10/88	27	SF/FF mismatch causes RT; unexpected cond	RT
88-04	3/14/88	85	SG B tube leak (0.14 gpm); manual shutdown	Unusual Event
88-05	6/1/88	98	RT on SS/FF mismatch; SI due to overfeed	RT
88-06	7/16/88	100	Loss of offsite power; DGs both start;	Substation failure
88-07	8/4/88	100	Inadvertent CNMT vent isolation	Failed power supply
88-08	9/3/88	100	Inadvertent DG B start signal; no LOOP	Solid state failure
88-09	9/30/88	100	Faults in fire barrier; fire watch established	
88-10	12/11/88	100	1/3 SG B pressure channels drifted high	Manual shutdown
89-01	4/12/89	0	SG A and B tube indications	Repair
89-02	5/6/89	0	Trip of safeguard 480 bus during test	Typo in procedure
89-03	5/18/89	0	Inadvertent SI Train A actuation	Proc. inadequacy
89-04	6/1/89	53	AMSAC causes TT/RT	Proc. inadequacy
89-05	5/29/89	3	Gas decay tank A started 2 hrs too late	Error
89-06	6/16/89	100	Rad monitors not measuring CNMT air	Proc. inadequacy
89-07	6/19/89	99	SI B & C flow insufficient; shutdown on 2nd	Miscalibration
89-08	7/6/89	99	Spurious rod drop; turbine runback 75%	
89-09	7/29/89	100	Short in CRD position indication causes TS SD	Replaced coil stack
89-10	7/30/89	0	Loose connection starts DG B	Tightened connection
89-11	9/20/89	99	Inadvertent CNMT ventilation isolation	
89-12	10/7/89	99	Rod drop circuit causes turb runback 80%	Used AP-TURB.2
89-13	10/20/89	99	CNMT vent isolation on gas rad monitor	

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
89-14	10/23/89	99	CNMT vent isolation on gas rad monitor	
89-16	11/17/89	99	Report SI block/unblock switch; no shutdown	
90-01	2/25/90	98	Fire watch patrols violate TS	
90-02	2/26/90	98	Fire watch performed on wrong area	
90-03	3/23/90	0	RT from NIS source range during shutdown	RT
90-04	4/16/90	0	SG tube degradation exceeds TS	
90-05	4/25/90	0	DG "A" auto start from low voltage RCP start	
90-06	5/5/90	0	SI while venting PRZR pressure instrument	Personnel error
90-07	5/10/90	88	RT when MFRV failed	RT
90-08	5/24/90	98	Undervoltage relays out of calibration	Proc. inadequacy
90-09	6/9/90	0	DG A start due to personnel error	
90-10	6/9/90	97	RT when MFRV failed	RT
90-11	6/19/90	98	Fire damper not installed correctly	
90-12	9/26/90	97	RT caused by dropped flashlight in relay rack	RT
90-13	12/11/90	97	RT from inadvertent AMSAC actuation	RT
90-14	12/06/90	97	PORVs inoperable during monthly tests	Proc. inadequacy
90-15	12/12/90	3	Start of DG A due for failure in Bus 14 UV	
90-16	12/12/90	3	RT from Intermediate Range during bus xfer	RT
90-17	12/12/90	3	SI sequence initiation disabled	Proc. inadequacy
90-18	12/20/90	22	Dropped rod; turbine runback; start of MDAFW	
90-19	12/21/90	16	RT from lo-lo SG level - misaligned Cond pump	RT
91-01	2/15/91	97	Bus 18 de-energized during monthly test of DG	
91-02	3/4/91	97	Ice storm causes loss of Offsite Ckt 751	DG A starts
91-03	3/14/91	89	Fire watch not posted when required	
91-04	3/28/91	0	Man start of DG B during storm - reduced inv.	
91-05	4/14/91	0	SG tube degradation	
91-06	6/29/91	98	Start of DG A due to voltage dip on Ckt 751	
91-07	7/31/91	98	Start of DG B due of Bus 17 UV failure	2 actual events
91-08	8/5/91	30	Undetectable failure in Bus 14 discovered	Temp issue
91-09	11/11/91	98	FW isolation during troubleshooting of ADFCS	Electronic noise
91-10	12/30/91	98	LEFM input to PPCS calorimetric failed	Computer failed
92-01	1/5/92	98	CNMT ventilation isolation actuation	R-11 failure
92-02	2/3/92	23	RT & TT after lo-lo SG level	RT & TT
92-03	2/29/92	97	RT after MFW Pump A trip due to SG A level	RT

Table 3-3
Ginna Station LERs (1980 Through 1995)

LER #	*Date*	*% Power*	*Description of Event*	*Comment (Rx or (Turbine Trip?)*
92-04	4/4/92	0	Hot particle exposure in excess of report reqts	
92-05	4/20/92	0	SG tube degradation	
92-06	5/18/92	97	MFW isolation due to feedwater oscillations	
92-07	12/24/92	98	DG A start after loss of Offsite Ckt 751	
93-01	3/12/93	0	Source Range failed to energize, manual RT	RT
93-02	4/4/93	0	SG tube degradation	
93-03	3/28/93	0	Part 21 Report for CCW HX flow induced vib.	
93-04	7/7/93	97	Feedwater isolation due to feedwater overfill	
93-05	10/11/93	97	TS surveillance for bus load shedding overdue	
93-06	10/11/93	97	MFRV failure causes RT	RT
93-07	11/22/93	0	RT on Source Range due to burned out light	RT; Operator error
94-01	1/19/94	97	Rad Monitor for Steam Line Inoperable	
94-02	2/2/94	98	Two CNMT pressure transmitter lines plugged	
94-03	2/8/94	98	Loss of CNMT integrity due to swaglok fitting	Personnel error
94-04	2/14/94	98	Missed TS surveillances	
94-05	2/17/94	98	DG A start after loss of Offsite Ckt 751	
95-01	2/3/95	98	PRZR safety valves found out of tolerance	
95-02	2/12/95	98	Loss of individual rod position indication	Electrical short
95-03	4/7/95	0	Inadvertent SI actuation	Personnel error
95-04	4/7/95	0	SG tube degradation	
95-05	7/7/95	97	IA failure causes FW isolation on high SG level	

(1) LER reporting criteria have changed through the years. As such, reactor trips have not always required an LER. This event was added to the table to complete the reactor trip history based on a review of plant historical records.

Table 3-4
Final Listing of Initiating Events

	Description	*Designator*
1.	Reactor Trip	TIRXTRIP
2.	Loss Of Offsite Power - Grid	TIGRLOSP
3.	Loss Of Offsite Power - Switchyard	TISWLOSP
4.	Loss of Offsite Power - 480 V Trains	TI48LOSP
5.	Loss of Main Feedwater	TIFWLOSS
6	Feedwater Line Break In Line For SG A Inside Containment	TIFLBACT
7.	Feedwater Line Break In Line For SG B Inside Containment	TIFLBBCT
8.	Feedwater Line Break In Turbine Building	TIFLB0TB
9.	Feedwater Line Break In Line For SG A Inside Intermediate Building	TIFLBAIB
10.	Feedwater Line Break In Line For SG B Inside Intermediate Building	TIFLBBIB
11.	Exterior MFW Line Break on SG B	TIFLBSGB
12.	Steam Line Break In Line For SG A Inside Containment	TISLBACT
13.	Steam Line Break In Line For SG B Inside Containment	TISLBBCT
14.	Steam Line Break In Turbine Building	TISLB0TB
15.	Steam Line Break In Line For SG A Inside Intermediate Building	TISLBAIB
16.	Steam Line Break In Line For SG B Inside Intermediate Building	TISLBBIB
17.	Steam Line Break Through The Steam Dump System	TI0SLBSD
18.	Inadvertent Safety Valve Operation On Both SGs	TISLBSVA
19.	Exterior Steam Line Break On SG B	TISLBSGB
20.	Loss of Instrument Air	TIIALOSS
21.	Reactor Vessel Rupture	LIRVRUPT
22.	Large LOCA	LILBLOCA
23.	Medium LOCA	LIMBLOCA
24.	Small LOCA	LISBLOCA
25.	Small-Small LOCA	LISSLOCA
26.	Steam Generator Tube Rupture In SG A	LI0SGTRA
27.	Steam Generator Tube Rupture In SG B	LI0SGTRB
28.	Intersystem LOCA	LIPEN###
29.	Loss Of Service Water Header A	TI000SWA
30.	Loss Of Service Water Header B	TI000SWB
31.	Total Loss of Service Water	TI0000SW
32.	Loss Of Component Cooling Water	TI000CCW
33.	Loss Of Main DC Distribution Panel A (DCPDPCB03A)	TI000DCA
34.	Loss Of Main DC Distribution Panel B (DCPDPCB03B)	TI000DCB
35.	Locked RCP Rotor	TIRCPROT

Table 3-5
EPRI Listing of Transient Initiating Events

Item	*Description*	*Ginna Station PSA Name*
1.	Loss of RCS flow (1 loop)	TIRCPROT, TIRXTRIP
2.	Uncontrolled rod withdrawal	TIRXTRIP
3.	CRDM problems and/or rod drop	TIRXTRIP
4.	Leakage from control rods	TIRXTRIP
5.	Leakage in primary system	TIRXTRIP
6.	Low pressurizer pressure	TIRXTRIP
7.	Pressurizer leakage	TIRXTRIP
8.	High pressurizer pressure	TIRXTRIP
9.	Inadvertent safety injection signal	TIRXTRIP
10.	Containment pressure problems	TIRXTRIP
11.	CVCS malfunction - boron dilution	TIRXTRIP
12.	Pressure/temperature/power imbalance - rod position error	TIRXTRIP
13.	Startup of inactive coolant pump	Not possible at Ginna
14.	Total loss of RCS flow	TIRXTRIP
15.	Loss or reduction in feedwater flow (1 loop)	TIRXTRIP
16.	Total loss of feedwater flow (all loops)	TIFWLOSS
17.	Full of partial closure of MSIV (1 loop)	TIRXTRIP
18.	Closure of all MSIVs	TIRXTRIP
19.	Increase in feedwater flow (1 loop)	TIRXTRIP
20.	Increase in feedwater flow (all loops)	TIRXTRIP
21.	Feedwater flow instability - operator error	TIRXTRIP
22.	Feedwater flow instability - miscellaneous mechanical causes	TIRXTRIP
23.	Loss of condensate pumps (1 loop)	TIRXTRIP
24.	Loss of condensate pumps (all loops)	TIFWLOSS
25.	Loss of condenser vacuum	TIFWLOSS
26.	Steam generator leakage (not rupture)	TIRXTRIP
27.	Condenser leakage	TIRXTRIP
28.	Miscellaneous leakage in secondary system	TIRXTRIP
29.	Sudden opening of steam relief valves	TISLBSVA
30.	Loss of circulating water	TIRXTRIP
31.	Loss of component cooling	TI000CCW
32.	Loss of service water system	TI000SWn
33.	Turbine trip, throttle valve closure, EHC problems	TIRXTRIP
34.	Generator trip or generator caused faults	TIRXTRIP

Table 3-5
EPRI Listing of Transient Initiating Events

Item	*Description*	*Ginna Station PSA Name*
35.	Loss of all offsite power	TIGRLOSP
36.	Pressurizer spray failure	TIRXTRIP
37.	Loss of power to necessary plant systems	TISWLOSP, TI48LOSP
38.	Spurious trips - cause unknown.	TIRXTRIP
39.	Automatic trip - no transient condition	TIRXTRIP
40.	Manual trip - no transient condition	TIRXTRIP
41.	Fire within plant	LATER
42.	Loss of MG sets	TIRXTRIP
43.	Loss of instrument bus	Not included
44.	Loss of dc bus	TI000DCn
45.	Loss of instrument air	TIIALOSS

Table 3-6
Comparison of Initiators With Other Westinghouse 2-Loop Plants

Initiator Description	*Ginna Station PSA Name*[1]	*Comparable Initiator for*		
		Point Beach[2]	*Prairie Island*[3]	*Kewaunee*[4]
Reactor Trip	TIRXTRIP	T2 T3	TR1 TR2 TR3	TRA
Loss of Offsite Power	TIGRLOSP TISWLOSP TI48LOSP	T1	LOOP	LSP SBO
Loss of Main Feedwater	TIFWLOSS	T2	TR4	TRS
Main Feedwater Line Breaks	TIFLBACT TIFLBBCT TIFLB0TB TIFLBAIB TIFLBBIB TIFLBSGB	Tfb Tsb	MFLB	SLB
Steam Line Breaks	TISLBACT TISLBBCT TISLB0TB TISLBAIB TISLBBIB TISLBSGB TI0SLBSD	Tfb Tsb	MSLB	SLB
Inadvertent Safety Valve Actuation	TISLBSVA	Tsb	MSLB	SLB

Table 3-6
Comparison of Initiators With Other Westinghouse 2-Loop Plants

Initiator Description	*Ginna Station PSA Name*(1)	*Comparable Initiator for*		
		Point Beach(2)	*Prairie Island*(3)	*Kewaunee*(4)
Loss of Instrument Air	TIIALOSS	Tia	INSTAIR	INA
Reactor Vessel Rupture	LIRVRUPT	X	N/A	VEF
Large LOCA	LILBLOCA	A	LLOCA	LLO
Medium LOCA	LIMBLOCA	S1	MLOCA	MLO
Small LOCA	LISBLOCA	S2	SLOCA	SLO
Small-Small LOCA	LISSLOCA	N/A	N/A	N/A
SGTR	LI0SGTRA LI0SGTRB	R	SGTR	SGR
Intersystem LOCA	LIPEN###	V	ISLOCA	ISL
Loss of Component Cooling Water	TI000CCW	Tcc	LOCC	CCS
Locked RCP Rotor	TIRCPROT	N/A	N/A	N/A
Loss of DC Power	TI000DCA TI000DCB	Td1 Td2	LODCA LODCB	TDC

Table 3-6
Comparison of Initiators With Other Westinghouse 2-Loop Plants

Initiator Description	*Ginna Station PSA Name*[1]	*Comparable Initiator for*		
		Point Beach[2]	*Prairie Island*[3]	*Kewaunee*[4]
Loss of Service Water	TI000SWA TI000SWB TI0000SW	Tsw	LOCL	SWS

Notes:

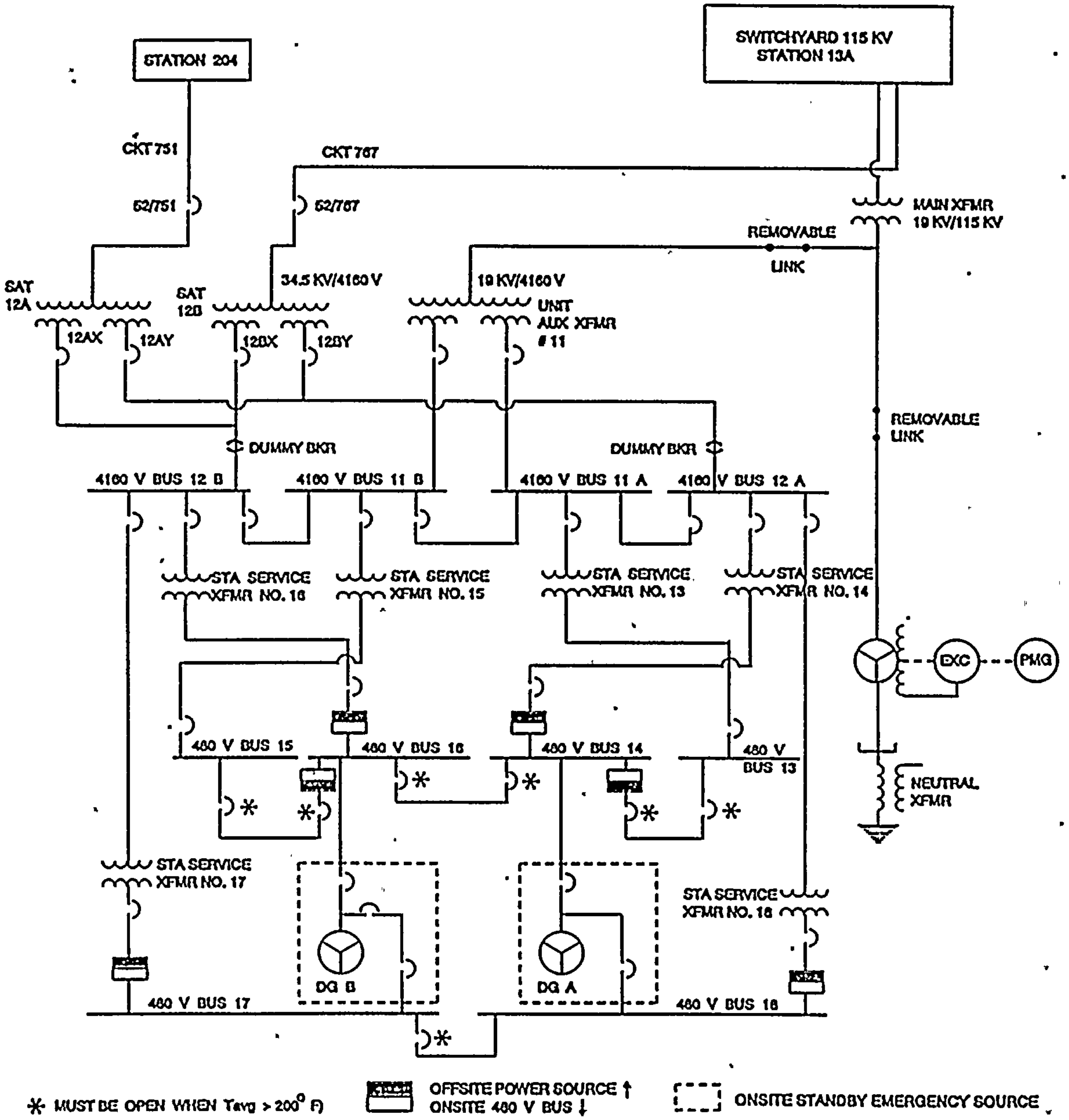
(1) See Table 3-4.

(2) See Table 3.1.1.A-13 of June 30, 1993 Wisconsin Electric Power Company submittal.

(3) See Table 3.1-1 of February 1994 Northern States Power submittal.

(4) See Section 3.1.1 of December 1, 1992 Wisconsin Public Service submittal.

Figure 3-1
AC Power Configuration (TS Base Figure B 3.8.1-1)



For Illustration Only

Figure 3-2
DC Power Configuration (TS Bases Figure B 3.8.4-1)

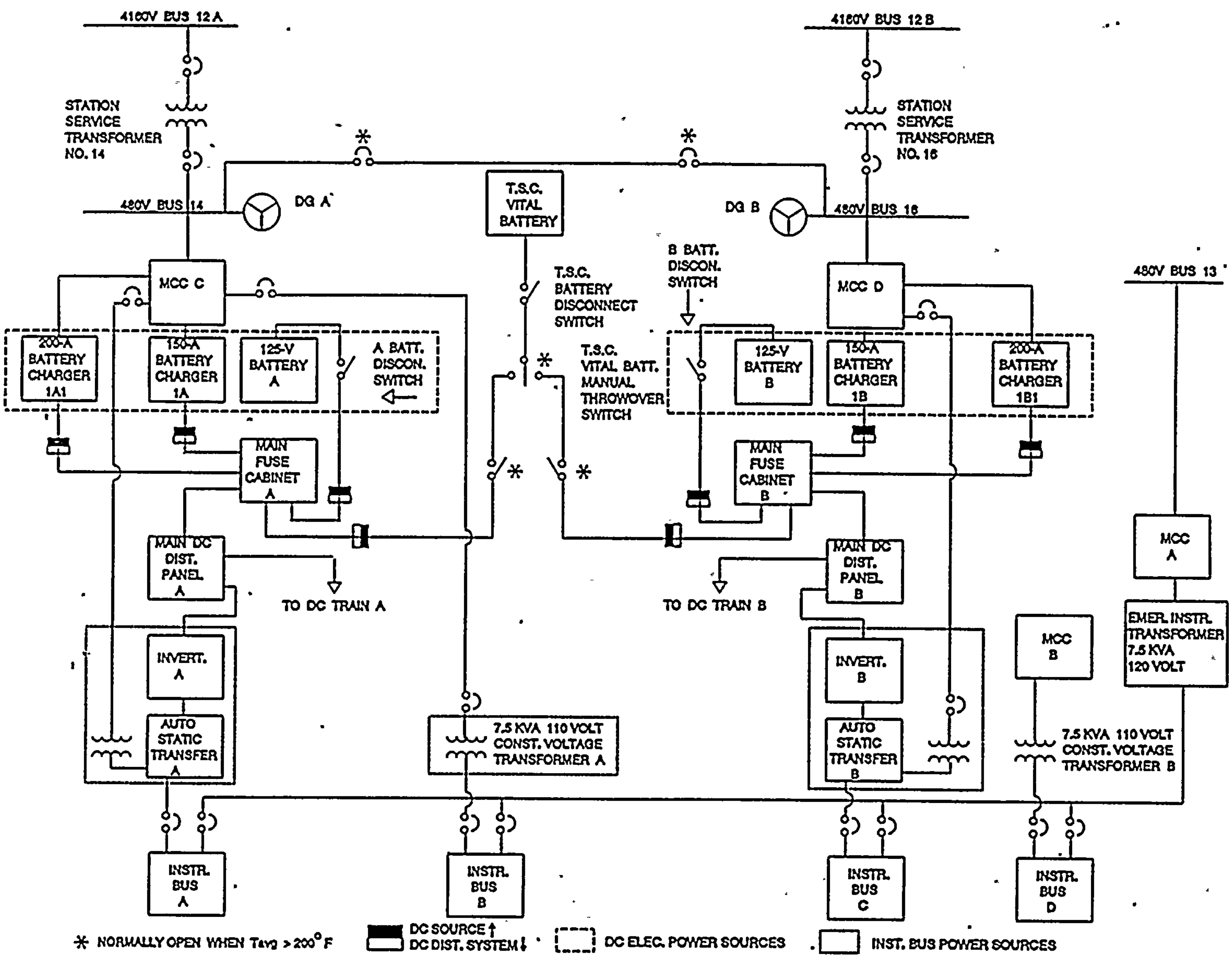
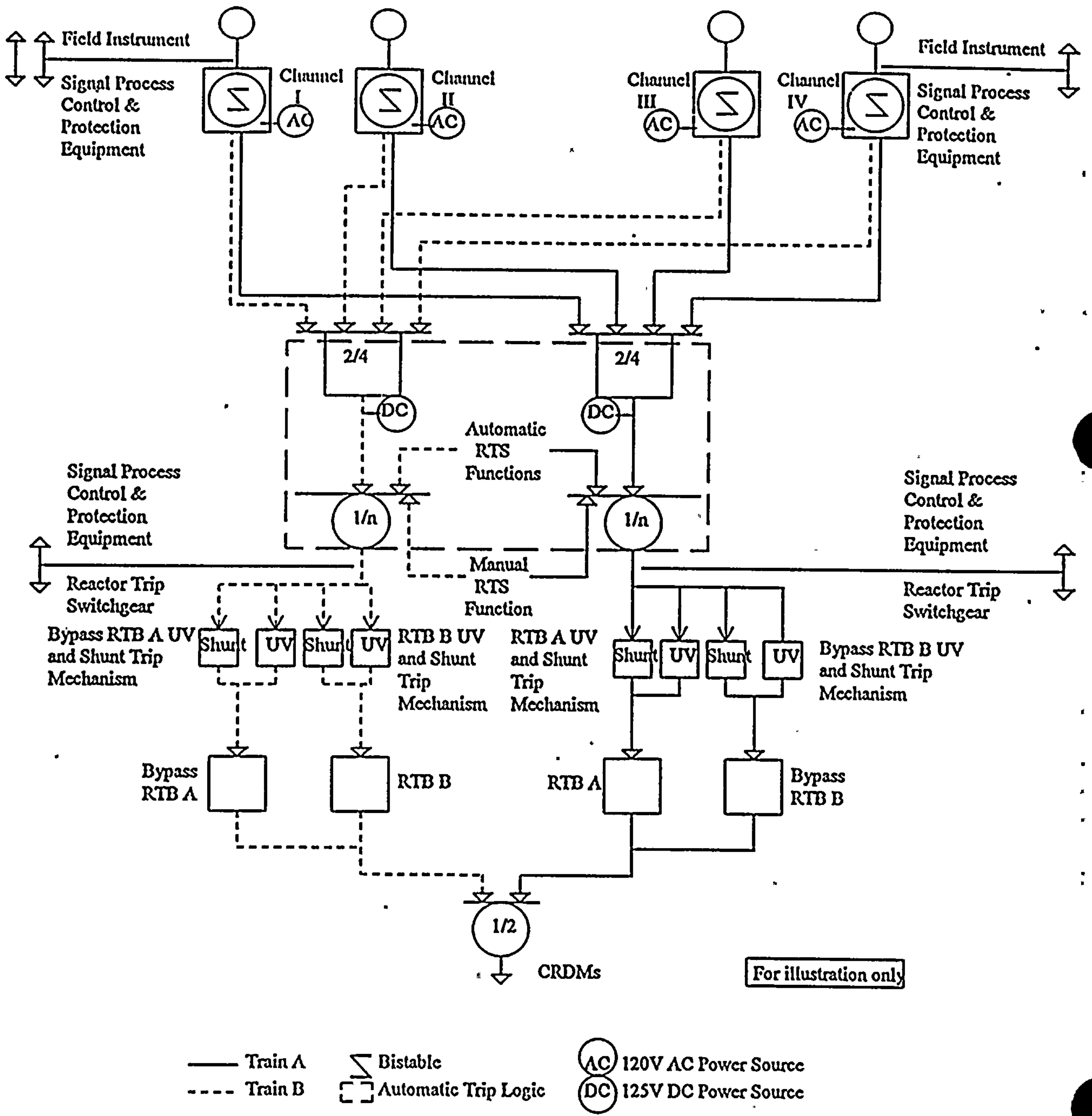


Figure 3-3
Reactor Trip System Diagram (TS Bases Figure B 3.3.1-1)



4.0 SUCCESS CRITERIA DETERMINATION

Following the identification of proposed initiators for use in the Ginna Station PSA, success criteria were developed. The term success criteria refers to the minimal combination of plant systems and equipment that must function in order to prevent core damage following a specified initiator. Two types of success criteria must be considered: (1) sequence level, and (2) system level success criteria. Each of these success criteria types, and how they interface with each other and provide core protection, is described below.

4.1 Core Protection Functions

In simple terms, to prevent core damage, only one function must be accomplished: the preservation of heat removal from the reactor core. This ultimate function can be better understood by developing several intermediate functions that relate reactor core heat removal to the operation of plant systems:

a. Control of reactivity;
b. Control of reactor coolant system (RCS) pressure;
c. Preservation of RCS inventory; and
d. Heat removal from the RCS.

These four intermediate functions are in equilibrium during power operation. An upset of any one of these functions will eventually lead to a reactor trip. However, following the reactor trip, these functions must still be maintained, though to a generally different degree than during power operation. A general description of each of these functions is provided below.

Reactivity control directly relates to the amount of heat being generated within the reactor core, which dictates the rate at which energy must be removed from the core and the RCS. Failure to control reactivity may cause core power generation to exceed the plant's capacity to remove it. Further, failure to limit core power may also challenge the RCS integrity, depending on how well the other functions are performed.

Control of the RCS pressure is important for several reasons. First, the RCS has an upper design limit on pressure (2485 psig [Ref. 6]), which if were to be significantly exceeded, could impact the preservation of the RCS inventory. Second, a subcooling margin must be maintained for an intact RCS to ensure that natural circulation of the RCS can be accomplished, or if the reactor coolant pumps (RCPs) are still operating, that adequate NPSH is available. This ensures that steam bubbles will not form within the reactor vessel. Finally, maintaining RCS pressure ensures that the differential pressure across the SG tubes is maintained within limits. It should be noted that following a loss of coolant accident (LOCA), RCS pressure control becomes less important since the upper RCS design limit will not be exceeded due to the break while subcooling margin may no longer required since the injection systems can provide the necessary heat removal capability (except for very small LOCAs).

The amount of RCS inventory determines in large measure whether core heat removal can be maintained since core damage is assumed to occur for any significant durations of core uncovery. In considering RCS inventory concerns, LOCA break size is the single parameter that dictates the necessary success criteria since break size determines the break flow rate and subsequent RCS pressure which, in turn, determines required system response (e.g., whether high head or low head safety injection is required).

Heat removal from the RCS can be achieved in one of two ways. The typical way following a reactor trip is by using the steam generators (SGs) and either forced or natural circulation of the RCS to transfer heat to the secondary cooling system. The ultimate heat sink in this case is either the atmosphere via steam vented from the secondary side or the condenser via the steam dump system. A second method to remove heat from the RCS may occur unintentionally, namely, by means of primary system cooling following a LOCA whereby plant systems designed to maintain RCS inventory will quickly provide core cooling. In this situation, core heat is transferred to the injected water, which spills out the break into the containment. The ultimate heat sink then becomes Lake Ontario via Service Water (SW), Component Cooling Water (CCW), Containment Recirculation Fan Coolers, and the Residual Heat Removal (RHR) system heat exchangers once the injection systems have been switched to the containment sump during the recirculation mode. Note that this second method of heat removal can also be used following failure of the SGs (i.e., the first method) by opening both power operated relief valves (PORVs), intentionally creating a controlled LOCA.

4.2 Sequence Level and System Level Success Criteria

For each of the four intermediate core protection functions described above, success criteria must be developed. This success criteria is primarily dependant upon the initiating event and the subsequent equipment failures and operator errors (i.e., the accident sequence). In order to determine the success criteria for a given sequence, system level success criteria must also be considered. The system level success criteria provides the interface between the accident sequence analysis and the system modeling tasks. However, for success criteria determination, this interface is typically only general in nature and only applies to major front-line equipment. For example, the success criteria for a given accident sequence could be "one-of-three safety injection (SI) pumps." This statement does not specify how the SI pump flow is routed to the RCS, not does it consider the need for support systems (e.g., electric power). These issues are instead addressed during the development of the system level fault tree models.

The definition of sequence level and system level success criteria is a complex, iterative task that involves consideration of the following items:

a. The impact of initiating events and subsequent system failures upon the core protection functions defined in Section 4.1;

b. The impact of initiating events upon plant system performance (i.e., impact on systems required to mitigate the event);

c. The needs of the Level 2 (containment performance) analysis; and

d. The plant thermal-hydraulic response to combinations of initiating events and subsequent plant system failures.

The performance of each of these tasks is described below.

4.2.1 Initiating Event Grouping

As a beginning step in the identification of success criteria, the initiating events must be grouped. This grouping effort primarily focuses on the first three items listed above. This process yielded groups of initiators that can be expected to have a common core-damage accident sequence progression and, accordingly, a common set of success criteria. Subsequently, sequence level and system level success criteria for each group of initiators were identified using thermal-hydraulic analyses as described Section 4.2.2 below.

The impact of initiating events on the core protection functions is the major consideration in the grouping process. It should be remembered that an initiating event is a combination of equipment failures and/or operator actions that leads to the need for reactor trip. For each grouping of initiating events, a separate accident sequence, or event tree must be developed (see Section 5). Since development and solution of event trees is an involved process, efforts were made to group as many initiators as possible into a common group.

Table 4-1 shows the initial categorization of initiating events with respect to the first three items listed in Section 4.2 above. As can be seen, consistent with the initial identification of initiators in Section 2.4, the initiating events were organized into either a transient or LOCA category. In addition, a third category was created for all initiators that are followed by a subsequent failure of the reactor trip system (RTS). These events have been placed under the Anticipated Transient Without Scram (ATWS) category since for this project, ATWS is not caused by any single initiator; rather, it is the combination of initiator occurrence and RTS failure that leads to ATWS sequences. Therefore, all failures of reactivity control, whether the initiating event was a transient or a LOCA, are separated into the ATWS category.

With respect to RCS inventory control, all initiators leading to RCS inventory control challenges have been placed under the LOCA category. Such initiators may either be direct (i.e., an RCS piping failure) or induced following the occurrence of any transient initiator and subsequent system failures. For example, an uncomplicated reactor trip event may progress to a RCP seal LOCA if all RCP support systems (seal injection and thermal barrier cooling) are lost; such accident sequences are considered to be a subset of LOCAs with respect to success criteria determination.

The impacts of all initiators on the RCS pressure control and heat removal functions are taken into consideration by embedding initiating events into the fault tree models as appropriate. This technique achieves two purposes: (1) it minimizes the number of event trees used to delineate accident sequences (as opposed to constructing an event tree for every initiator), and (2) it allows a detailed treatment of initiator impacts on plant system performance. Thus, accident sequences have not been grouped according to the impact of initiating events on the RCS heat removal or pressure control functions.

For Level 2 considerations, grouping of initiators has only a relatively minor impact since the major issues involved are whether containment has been bypassed and whether containment cooling can still be provided. These issues are typically best addressed on a cutset by cutset basis and not on which initiating event occurred.

Following the initial evaluation as presented in Table 4-1, thermal-hydraulic analyses must be reviewed, and in some cases performed, to determine the specific sequence and system level success criteria.

4.2.2 Thermal-Hydraulic Analyses

The Ginna Station UFSAR [Ref. 2] provided the starting point for determination of sequence and system level success criteria. However, the UFSAR is of limited use for a PSA project since its analyses and results are based on conservative assumptions about system performance and post-trip plant behavior. Also, the UFSAR does not often provide the depth of information required to support the PSA (e.g., detailed accident scenarios timelines which could be used to determine available operator cue times, etc.). Therefore, the UFSAR analyses were supplemented with thermal-hydraulic analyses using the MAAP code as necessary [Ref. 15].

Table 4-2 summarizes these MAAP analyses and their results. It is recognized that the MAAP code is more simplistic in many ways than the codes used for the UFSAR. This is attributed to the fact that the codes used in the UFSAR were developed to take an initiating event from its time of occurrence to the point at which the accident has "turned around" (e.g., containment pressurization has ceased, the RCS has stabilized at hot shutdown conditions). However, the MAAP code was developed to take an initiating event from its time of occurrence to the onset of core damage and the resulting source terms which are released. To accomplish this, the MAAP code must make simplified assumptions in the initial portion of the accident analysis in order to reach core damage conditions.

Therefore, the MAAP code was mainly used to further support, and in some cases, clarify the assumptions in the accident analysis. For example, a working definition of 1800°F for the hottest core node (TCRHOT) was used to indicate the onset of core damage. This is less than the maximum peak cladding temperature allowed by 10 CFR 50.46(b)(1) of 2200°F but allows for compensation for some of the MAAP code simplifying assumptions. As shown on Table 4-2, in most cases, core heat removal was either clearly lost or clearly maintained with respect to this 1800°F limit.

The evaluation of the thermal-hydraulic analyses for each of the four core performance functions is provided below.

4.2.2.1 Reactivity Control Success Criteria

Following generation of a reactor trip signal, negative reactivity is inserted into the reactor core by rod cluster control assemblies (RCCAs), or "rods." These rods are neutron absorbing devices that stop the fission reaction process and bring the reactor core to subcritical conditions. The rods are organized into two categories: (1) a shutdown bank, and (2) control banks. During normal power operation, the single shutdown bank is maintained at the fully withdrawn position [Ref. 6]. Meanwhile, three of the four control banks are also maintained at the fully withdrawn position while the fourth bank is used to control power level (i.e., the fourth bank may be partially inserted into the core depending on the power level). Technical Specification limits exist for the amount that any shutdown or control bank can be inserted into the core during power operation. This ensures that the rods are available to supply the highest amount of negative reactivity following a reactor trip.

The rods are normally moved in and out of the core via control rod drive mechanisms (CRDMs). Following a reactor trip signal, the rods are rapidly dropped into the core (≤ 1.8 seconds). The UFSAR typically assumes that the rods supply 4%Δk of negative reactivity following the reactor trip. This is a conservative value and includes the assumption that the rod of highest reactivity worth remains fully withdrawn following the trip. Therefore, to exceed the assumptions of the accident analysis, at least two rods must remain fully withdrawn such that 4%Δk of negative reactivity is not available. It should be noted that for a large break LOCA, credit for the rods is not taken in the accident analysis. This is due to the presence of boric acid in the emergency core cooling system (ECCS) and the loss of the moderator due to the LOCA.

The failure of all rods to automatically insert when required is referred to as an Anticipated Transient Without Scram (ATWS) event. Following an ATWS event, the primary issue of concern is maintaining RCS pressure within acceptable limits. It should be noted that an ATWS event is the failure of all rods to insert (i.e., 29) while the accident analysis assumes the failure of only one rod. In addition, the insertion of only one RCCA bank (out of the five) adds sufficient reactivity to preclude peak RCS pressure concerns during the limiting ATWS events [Ref. 16]. These differences will be discussed in more detail below.

If an ATWS event were to occur, multiple systems must be initiated to prevent the RCS from becoming overpressurized. The upper design limit of the RCS is 2485 psig [Ref. 6]; however, for ATWS events, the actual limit is assumed to be 3200 psig based on the allowable ASME service limits. Therefore, for an ATWS event, the RCS must be maintained below 3200 psig [Ref. 16].

Due to the potentially significant consequences of an ATWS event, the NRC has required that all plants be capable of responding to such an event following an anticipated operational occurrence (10 CFR 50.62). That is, an ATWS is only required to be mitigated for events which are expected to occur during the life of Ginna Station (i.e., condition I and II events); all other events (e.g., LOCAs) are excluded from evaluation. The Westinghouse analysis of the ATWS event assumes that the plant is initially at nominal power conditions and that all systems are available following the failure of the rods to insert, except for those systems susceptible to a common fault from the RTS [Ref. 16]. The NRC allowed these assumptions since an ATWS event is considered a "beyond design basis event" (i.e., two independent trains of RTS logic must fail to trip the reactor). Based on these assumptions, the only transient which required an independent means from the RTS to prevent reaching the ASME service limit of 3200 psig was related to the loss of main feedwater event from conditions > 40% reactor power (this includes a loss of offsite power event). For all other initiators, the RCS was maintained below 3200 psig assuming that all remaining equipment was available as follows [Ref. 17] (note - not all systems are required, only assumed available):

a. pressurizer pressure control;
b. pressurizer level control;
c. feedwater control;
d. turbine control;

e. pressure relieving devices;
f. steam dump control;
g. auxiliary feedwater;
h. safety injection; and
i. charging system.

In response to 10 CFR 50.62, the ATWS Mitigating System Actuation Circuitry (AMSAC) was installed at Ginna Station specifically for the loss of feedwater event from conditions > 40% reactor power. The purpose of this system is to initiate AFW and a turbine trip independent of the RTS for electrical related RTS failures. If the RTS fails due to a mechanical cause (e.g., breakers fails to open), then the RTS instrumentation will initiate AFW and trip the turbine as designed, thus preventing the RCS from reaching 3200 psig provided that sufficient RCS pressure relief is available and long-term shutdown is maintained. In summary, the Westinghouse analysis assumes the following for an ATWS event [Ref. 16]:

a. AFW must be initiated within 1 minute since MFW is unavailable. The analysis assumes that 50% of AFW flow is equivalent to 400 gpm (i.e., flow from two motor-driven AFW pumps) while 100% is equivalent to 800 gpm (i.e., flow from all three AFW pumps). For electrical failures of the RTS, AFW initiation must occur from AMSAC.

b. A turbine trip must be initiated for events where MFW is not available. For electrical failures of the RTS, this initiation must occur from AMSAC.

c. Sufficient RCS pressure relief must be available for events where MFW is not available. The necessary RCS pressure relief is dependant upon several factors which impact the reactivity feedback (e.g., as RCS pressure and temperature increase, there is a negative reactivity insertion based on the core design and age). Since the incorporation of these factors would require specific analyses of each transient and the point in core life, the information provided in Reference 17, Appendix B was used. This is summarized below:

    i. Two safety valves are required at all times;

    ii. One PORV is required to automatically open for the first 76 days of the cycle if 100% of AFW is available and the rods can be manually inserted;

    iii. One PORV is required to automatically open between the first 19 and 83 days of the cycle if only 50% of AFW is available and the rods can be manually inserted;

    iv. One PORV is required to automatically open between the first 139 and 193 days of the cycle if 100% of AFW is available and the rods are not capable of being manually inserted;

v. One PORV is required to automatically open between the first 155 and 209 days of the cycle if 50% of AFW is available and the rods are not capable manually inserted;

vi. Two PORVs are required to automatically open for the first 19 days of the cycle if only 50% of AFW is available and the rods can be manually inserted;

vii. Two PORVs are required to automatically open between the first 82 and 139 days of the cycle if 100% of AFW is available and the rods are not capable of being manually inserted; and

viii. Two PORVs are required to automatically open between the first 111 and 155 days of the cycle if only 50% of AFW is available and the rods are not capable of being manually inserted.

ix. There is insufficient PORV capability for the first 82 days of the cycle if 100% of AFW is available and the rods are not capable of being manually inserted (i.e., core damage will always occur).

x. There is insufficient PORV capability for the first 111 days of the cycle if only 50% of AFW is available and the rods are not capable of being manually inserted (core damage will always occur).

The success of any of these options results in steam release from the pressurizer PORVs and safety relief valves (i.e., not water).

d. Long-term shutdown via emergency boration from CVCS <u>or</u> locally tripping the MG sets must be initiated within 10 minutes if the rods were not manually inserted.

Therefore, for the purpose of the Ginna Station PSA, the following will be assumed for the reactivity control success criteria:

a. Failure to insert at least one RCCA bank will be considered a failure of the reactivity control function. While this is less restrictive than the accident analysis which only assumes one stuck rod, it provides consistency with the ATWS analysis. The assumption of inserting at least one bank is considered acceptable since reactivity is mainly a concern in the accident analysis only with respect to main steam line breaks. Consideration of this accident is described below. For the remaining accidents, insertion of reactivity is of less a concern and bounded by the use of borated water in the ECCS and CVCS.

b. The systems needed to mitigate an ATWS event as assumed in Reference 17 and summarized above will be required. The following are clarifications to these requirements:

i. The success of MFW includes all necessary power conversion systems (e.g., circulating water, condensate, etc.) and control systems (e.g., pressurizer spray, turbine control).

ii. The success of AFW requires operation of secondary system pressure relief components (e.g., main steam safety valves). These requirements will be provided in Section 4.2.2.4 below.

iii. The Westinghouse analysis does not specify the time frame at which subcriticality must be achieved during the long-term; however, it will be assumed to be within 1 hour. The 1 hour time frame is chosen as being sufficient to allow for the operators to respond to the event and to bring the reactor under stabilized conditions. Locally tripping the MG sets can easily be accomplished within this time frame. The rate at which CVCS will achieve subcriticality is based on the source of water, number of pumps, and whether the pumps are available under full flow conditions. As shown in Table 4-3, either one CVCS pump operating at full speed or 2/3 CVCS pumps at low speed with water from the boric acid storage tanks (BASTs) will be required.

c. All Condition I and II initiators will be covered in the ATWS event tree. However for low probability initiators (Condition III and IV events) which were not analyzed in Reference 18, the following will be assumed with respect to failure of the RTS:

i. For large LOCAs, the ATWS event will be ignored since the RTS is not credited in the accident analysis due to the boron injection systems and loss of moderator. All remaining LOCAs will be treated similar to the Condition I and II initiators. This is a conservative approach since even though MFW will be isolated by the resulting safety injection signal, the RCS will tend to depressurize due to the break while boron is being injected into the primary system from the ECCS. Also, long-term shutdown can be provided by the ECCS in addition to charging for LOCA; however, this will be treated as a potential recovery event if needed.

ii. All main feedwater line breaks will be treated similar to Condition I and II initiators since these events are similar to the limiting loss of MFW event.

iii. All large steam line breaks will be assumed to result in direct core damage. This is due to the fact that with no rod insertion, the reactor core will attempt to match the power level required to sustain the steam release. This could be significantly above 100% power (e.g., factor of 2-5 above). All small steam line breaks will be treated similar to Condition I and II events since inadvertent SG relief valve actuation was considered within the ATWS evaluation.

iv. A locked rotor event will be assumed to directly result in overpressurization of the RCS since the event results in a very high RCS pressure independent of the status of the rods (i.e., RCS pressure of 2900 psig).

These success criteria are summarized in Table 4-4. Table 4-5 summarizes the significant differences from the accident analysis with respect to ATWS events and reactivity control.

4.2.2.2 RCS Pressure Control Success Criteria

As described above in Section 4.1, control of RCS pressure is important for maintaining RCS below its upper design limit (2485 psig), ensuring a subcooling margin for natural cooldown of an intact RCS, providing adequate NPSH for operating RCPs, and to maintain the differential pressure across SG tubes within acceptable limits. However, following a LOCA, RCS pressure control becomes less important since the upper RCS design limit will not be exceeded due to the break while subcooling margin is no longer required since the injection systems can provide the necessary heat removal capability (except for small LOCAs). Therefore, the focus of the success criteria for RCS pressure control is with respect to transients and small LOCAs.

Following an initiating event, RCS pressure may either be increasing or decreasing depending mainly on the ability of the secondary system to remove the energy contained within the primary system. As such, this evaluation will be organized into two categories (i.e., those initiators which require pressure relief and those which require an increase in pressure control). The final success criteria is provided in Table 4-4 with all significant differences from the UFSAR addressed in Table 4-5.

4.2.2.2.1 Initiators Requiring RCS Pressure Relief

Based on a review of Table 3-4, the following initiators are expected to result in the potential need for RCS pressure relief:

a. Reactor Trip (some events)
b. Loss of Offsite Power - Grid (short-term)
c. Loss of Offsite Power - Switchyard (short-term)
d. Loss of MFW
e. MFW Line Breaks
f. Loss of Instrument Air
g. Loss of SW
h. Loss of CCW
i. Loss of DC Power
j. Locked Rotor
k. Steam Generator Tube Rupture (SGTR)
l. Small-Small LOCAs

m. Steam Line Breaks

There are several means of RCS pressure relief which range from providing minor pressure relief to those which provide a rapid and large pressure release. These means include the use of the following components: (1) pressurizer spray, (2) pressurizer PORVs, and (3) pressurizer safety valves. Since each initiator will vary with respect to the amount of pressure relief required, the above initiators must be further broken down and grouped according to common needs. The initial starting point for this effort will be the UFSAR [Ref. 2].

With respect to the initiators listed above, only the loss of offsite power, loss of MFW, MFW line breaks, SGTRs, small-small LOCAs, ARV failures, locked rotor events, steam line breaks, and several of the reactor trips are specifically evaluated in the UFSAR. The remaining initiators are events which are expected to require a system response similar to those evaluated in the UFSAR. Therefore, for the purpose of this analysis, loss of IA, SW, CCW, and DC power will be considered equivalent to the loss of MFW event since these initiators are expected to result in a loss of MFW as a minimum (note that the loss of MFW and loss of offsite power event are treated the same in the accident analysis while the loss of CCW will only result in loss of MFW post-trip when the operators manually remove MFW from service). A reactor trip will be considered equivalent to the loss of electrical load which is the most severe category of transient included within this category (see Table 3-5). As such, there are seven categories of events which must be considered with respect to RCS pressure relief: (1) loss of MFW and offsite power, (2) MFW line break, (3) locked rotor, (4) loss of electrical load, (5) SGTR, (6) small-small LOCA, and (7) ARV failures.

For a loss of MFW or loss of offsite power event, the UFSAR assumes that if one AFW pump is initiated within 10 minutes, then the pressurizer will not become water solid and cause the potential for the PORVs to release water and subsequently stick open. However, the PORVs are expected to lift for a steam release. A review of Table 3-3 does not indicate a trip from at or near 100% power at Ginna Station due to a loss of MFW or loss of offsite power to substantiate this prediction. The only time the PORVs have actually lifted at Ginna Station since 1980 were the result of the SGTR (LER 82-05) and following a turbine trip on January 17, 1983 (LER 83-07) during startup activities, neither of which directly applies to this discussion. Therefore, a more detailed review of the loss of MFW and loss of offsite power event is warranted.

The accident analysis is performed assuming that 15% of the SG tubes are plugged to minimize heat transfer from the RCS with no credit taken for pressurizer spray, steam dump, and ARVs. Several MAAP runs were performed assuming that no tubes are plugged (which is true following the SG replacement project in 1996) and varying which AFW pumps were available and taking no credit for any automatic pressure control system. These runs (FW01T, FW01U, and FW01V from Table 4-2) indicate that the RCS will reach the pressurizer PORV setpoint upon a loss of MFW regardless of the number of AFW pumps available within the first 10 minutes. However, if the PORVs are not able to automatically open, then the main steam safety valves (MSSVs) will prevent the RCS pressure from reaching the pressurizer safety valve setpoint. This was further confirmed by simulator runs performed in January 1995 which demonstrated that RCS pressure was limited to 2360 psig if the PORVs were assumed to be unavailable with no AFW for up to 10 minutes. Therefore, the Ginna Station PSA will assume the following upon a loss of MFW or loss of offsite power event (the required number of AFW pumps for decay heat removal is provided in Section 4.2.2.4):

a. Both pressurizer PORVs will be challenged to release steam if they are in the automatic mode.

b. One or both pressurizer PORVs failing to lift will not result in a challenge, or requirement, for the pressurizer safety valves provided that all eight MSSVs lift or any combination of ARVs and MSSVs lift such that a total of eight valves are available (two ARVs are roughly equivalent to one MSSV per UFSAR Table 10.1-1 [Ref. 2]; but only one will be required based on the conservative accident analysis assumptions, e.g., tube plugging). However, two PORVs or one safety valve is success for pressure relief in the event the necessary MSSVs fail since they provide roughly equivalent energy removal capabilities [Ref. 2].

c. All MSSVs and ARVs will be challenged (the minimum required for decay heat removal purposes is discussed in Section 4.2.2.4).

A MFW line break is similar in many ways to a loss of MFW. As described in the UFSAR, there is a subsequent increase in primary system pressure as the heat transfer capability through the SGs is reduced. This results in a challenge to the pressurizer PORVs, although the challenge will not be as severe as a loss of MFW due to the cooldown effect of the break (i.e., < 5 lbm/sec through the PORV). In addition, AFW is assumed to be unavailable for up to 10 minutes in the accident analysis with MFW isolated within 1 minute to prevent a potential for containment overpressurization. Therefore, the Ginna Station PSA will assume the following for a MFW line break:

a. Both pressurizer PORVs will be challenged to release steam if they are in the automatic mode.

b. One or both pressurizer PORVs failing to lift will not result in a challenge to the pressurizer safety valves due to the feedwater linebreak cooldown effect and available volume in the pressurizer.

c. There is no challenge, or requirement, for the MSSVs or ARVs as a result of the transient.

d. There is no need to isolate the feedwater line break since containment is not postulated to overpressurize at 60 psig as assumed in the accident analysis. However, the failure to isolate the line break may impact the success of individual plant systems (e.g., AFW) which will be addressed in the system models.

A locked rotor event is the most limiting RCS pressure event (other than an ATWS event) evaluated in the UFSAR. This is due to the fact that RCS flow is immediately reduced to one of the two SGs. This results is a rapid primary system pressure increase due to the reduced heat transfer capability through the SGs. The analysis assumes that pressurizer spray and the PORVs are unavailable to reduce pressure; however, the safety valves lift to remove steam and limit the RCS pressure to approximately 2900 psig. Therefore, the Ginna Station PSA will assume the following for a locked rotor event:

a. Both pressurizer PORVs will be challenged to release steam if they are in the automatic mode.

b. Both pressurizer safety valves must lift; however both PORVs in combination with pressurizer spray may replace one safety valve (two PORVs are roughly equivalent to one safety valve per UFSAR Table 5.4-7 [Ref. 2]).

c. All MSSVs and ARVs will be challenged and required for pressure relief. The minimum required for decay heat removal purposes is discussed in Section 4.2.2.4.

For the loss of electrical load event, the UFSAR evaluates two possible conditions: (1) with automatic pressurizer control and PORVs, and (2) without automatic pressurizer control. These two cases are used to address departure from nucleate boiling (DNB) and RCS pressure control considerations, respectively. For both cases, no credit is taken for the steam dump system or ARVs and offsite power is assumed to be available. In addition, MFW is assumed to be lost, AFW is unavailable, and 15% of the SG tubes are plugged to limit the heat transfer from the RCS. Given these assumptions for the automatic pressurizer control event, all MSSVs and pressurizer PORVs will lift. However, only steam is released from both sets of relief valves. For the non-automatic pressurizer control event, all MSSVs and the pressurizer safeties will lift; again, only steam is released from both sets of relief valves. Therefore, the Ginna Station PSA will assume the following for the loss of electrical load event:

a. Both pressurizer PORVs will be challenged to release steam if they are in the automatic mode.

b. The pressurizer safety valves will not be challenged, nor required for pressure relief, provided that:

   i. All eight MSSVs lift or any combination of ARVs and MSSVs lift such that a total of eight valves are available two ARVs are roughly equivalent to one MSSV per UFSAR Table 10.1-1 [Ref. 2]; but only one will be required based on the conservative accident analysis assumptions, e.g., tube plugging);

   ii. Pressurizer spray is available; and

   iii. Both PORVs lift.

   If any of these are not met, then one of two safeties is required since one safety is equivalent to both PORVs per UFSAR Table 5.4-7 [Ref. 2].

c. All MSSVs and ARVs will be challenged (the minimum required for decay heat removal purposes is discussed in Section 4.2.2.4).

The SGTR event is a very complex event with numerous human actions and changing plant responses. Since the primary goal of operators following a SGTR is to equalize pressure between the primary system and secondary system to maintain necessary RCS inventory, the required RCS pressure control response will be discussed in Section 4.2.2.3 below.

For small-small LOCAs, a reduction in primary system pressure is required in order to reach the shutoff head of the SI pumps., Since AFW will provide the necessary RCS pressure reduction, this will be discussed in the decay heat removal section below (Section 4.2.2.4).

The UFSAR considers three types of steam line breaks: (1) inadvertent opening of a ARV while at hot zero power (HZP), (2) inadvertent opening of an ARV coincident with a feedwater valve failure, and (3) a large steam line break. The inadvertant opening of the ARV is bounded by the coincident ARV and feedwater valve failure (the fact that it is only evaluated at HZP is also a consideration) such that only items 2 and 3 are considered further.

The coincident ARV and feedwater valve failure is caused by a common control fault in the advanced digital feedwater control system (ADFCS) which sends a signal to the ARVs and feedwater regulating valves to go full open. This results in a cooldown event on the secondary side with a subsequent increase in reactor power in an attempt to match the heat removal rate. The UFSAR shows that the only event in which a reactor trip signal is generated is when both ARVs and both sets of feedwater control valves fail open. For all other events, there is no primary or secondary system transient large enough which will result in a reactor trip as the control systems continue to match reactor power and SG heat removal rate. This is further confirmed by the fact that Ginna Station was designed to accept a 10% step load increase at 100% power without generating a reactor trip signal (an open ARV would result in less than a 5% load increase). Therefore, the only event which must be considered is both ARVs and feedwater regulating valves failing open from ADFCS.

As additional feedwater is added to the SGs and both ARVs open to relieve steam, the primary system compensates by increasing power. The increase in power is required since the added mass to the SGs must be heated in order to be released through the open ARVs (i.e., more heat must be generated within the primary system). The primary system continues to increase power until a reactor trip setpoint is reached (i.e., Overpower ΔT). However, neither the pressurizer PORVs, safeties, nor MSSVs are challenged following the reactor trip due to the energy release from the open ARVs.

With respect to large steam line breaks, the overcooling effect of the accident initially causes both the secondary and primary system pressures to drop. However, following isolation of all feedwater flow to the affected SG, the primary system begins to heatup due to decay heat. This is expected to result in challenges to the PORVs if pressurizer spray is unavailable. The pressurizer safeties would only be challenged if the PORVs and spray were unavailable. Given the primary system pressure increase, the main steam relief valves on the intact SG would also eventually lift.

4.2.2.2.2 Initiators Requiring RCS Pressure Control

The second category of events which impact RCS pressure control relates to those initiators which potentially require an increase in RCS pressure. Based on a review of Table 3-4, the following initiators are expected to result in decreased RCS pressure which must be subsequently controlled:

a. Large Steam Line Breaks
b. Loss of Offsite Power - Grid (long-term)
c. Loss of Offsite Power - Switchyard (long-term)
d. Loss of Offsite Power - 480 V Trains

It should be noted that LOCAs will also result in a decrease in RCS pressure; however there is no need for a subsequent increase in RCS pressure since it is more desirable to depressurize the primary system in order to reach RHR conditions (see Section 4.2.2.3).

For large steam line breaks, the secondary system attempts to remove a much greater amount of heat than the reactor core was originally providing. This results in a primary system depressurization which must be overcome in order to prevent the potential for a criticality excursion and to ensure that pressure differentials across the SG tubes are maintained within limits. For loss of offsite power events, pressurizer heaters are required to support long-term natural recirculation. There are several means of providing pressure control for these two category of events including use of CVCS, ECCS injection, and the pressurizer heaters. Since each initiator will require a different degree of pressure control, the above initiators were evaluated individually.

The steam line break is most limiting at HZP conditions, with offsite power available (i.e., one or both RCPs are running), and all three AFW pumps running under full flow conditions (for maximum cooldown effects). Following a major steam line break, the RCS is rapidly depressurized as a result of the secondary side cooldown effect. The accident analysis shows that initiation of two of three safety injection (SI) pumps and limiting the cooldown to one SG effectively repressurizes the RCS and provides necessary boron injection to limit the corresponding positive reactivity addition. Limiting the steam line break to one SG also reduces the potential for pressurized thermal shock. However, MAAP runs SLB01D, SLB01E, and SLB01F (see Table 4-2) demonstrate that no SI pumps are necessary. A new assessment of the main steam line break was also performed using the accident analysis codes and assuming no SI was available. This analysis showed that while the containment analysis could be exceeded (i.e., pressure could exceed 60 psig), all core responses where within required limits [Ref. 18]. Therefore, the Ginna Station PSA will assume the following for a steam line break:

a. No SI is required to repressurize the RCS and provide boron injection unless main steam isolation fails.

b. Isolation of the affected SG is required for RCS pressure control following a large steam line break. This is broken down based on the break location as follows:

   i. For breaks inside containment or the Intermediate Building, one of two MSIVs must close, or the non-return check valve on the faulted SG must close to isolate the break from the intact SG.

   ii. For breaks inside the Turbine Building, one of two MSIVs must close to ensure that one SG remains intact.

For long-term loss of offsite power events, the RCPs are unavailable to provide forced recirculation and the plant must rely on natural recirculation. However, natural circulation requires control of primary system pressure since over time, system heat losses will begin to buildup and result in reduced RCS pressure and subsequent loss of subcooling. If this were to occur, no mans of decay heat removal would exist. Westinghouse analyses [Ref. 19] indicate that 100 kW of pressurizer heaters are required within 6 hours following loss of the RCPs to prevent a loss of sub-cooled conditions. This calculation was performed assuming that the pressurizer was at its no-load level with no credit for heat capacity of the metal (i.e., lowest mass and heat capacity which results in the most rapid decrease in RCS pressure due to heat losses). Therefore, the Ginna Station PSA will assume that 100 kW of pressurizer heaters is required within this same 6 hours to prevent loss of subcooling. As an alternative, Reference 20 also states that the control rod shroud ventilation system can be used to provide cooling to the reactor vessel head to prevent the formation of voids; thus maintaining necessary subcooling. This will considered as a recovery action only.

Since the loss of natural circulation is equivalent to the loss of decay heat removal (i.e., loss of SG cooling), the option for bleed and feed exists as described in Section 4.2.2.4.

4.2.2.3 RCS Inventory Success Criteria

As described in Section 4.1, control of RCS inventory is important for maintaining decay heat removal since core damage is assumed to occur for any significant durations of core uncovery. With respect to determining the success criteria for RCS inventory control, the size of the LOCA is the only parameter that must be considered since break size dictates the flow rate and subsequent RCS pressure which in turn, determines the necessary system response. In general, there are three types of LOCAs: (1) stuck open pressurizer PORVs or safety valves as a result of an overpressure transient, (2) failure of RCP seals, and (3) pipe breaks. Each type must be evaluated; however, since the first two types can be equated to a LOCA size, their specific success criteria will be addressed in the pipe break discussion. The final success criteria is provided in Table 4-4 with all significant differences from the UFSAR addressed in Table 4-5.

4.2.2.3.1 Pressurizer Relief Valve LOCA

A pressurizer relief valve LOCA is caused by the failure of the PORVs or safety valves to reseat following an overpressure transient. This creates a small break LOCA that is similar to any other comparable size pipe break. Based on a review of Section 4.2.2.2.1, the following transients will result in a challenge to the PORVs if they are in the automatic mode:

a. Reactor Trip (Loss of Electrical Load)
b. Loss of Offsite Power - Grid (short-term)
c. Loss of Offsite Power - Switchyard (short-term)
d. Loss of MFW
e. MFW Line Breaks

f. Loss of Instrument Air
g. Loss of SW
h. Loss of DC Power
i. Locked Rotor

In addition, the following transients are expected to result in a challenge to the pressurizer safeties:

a. Locked Rotor
b. Reactor Trip (Loss of Electrical Load - assuming MSSVs or both PORVs fail)
c. Loss of MFW (assuming MSSVs and both PORVs fail)
d. Loss of Instrument Air (assuming MSSVs and both PORVs fail)
e. Loss of SW (assuming MSSVs and both PORVs fail)
f. Loss of DC Power (assuming MSSVs and both PORVs fail)

Therefore, following each of the above transients, the PORVs or safety valves must reseat to prevent a transient induced LOCA.

Per WCAP-9804 [Ref. 20], the failure of a PORV or safety valve to reseat results in a < 2 inch LOCA. The failure of two or more relief valves will result in a larger LOCA. In addition, since the PORVs have installed block valves to isolate a failed open PORV, these can be credited for preventing or terminating the LOCA. Reference 21 states that if the failed open PORV is isolated within approximately 3 minutes, a safety injection signal due to low pressurizer pressure will be avoided. The analysis further states that for the Ginna Station SGTR in 1982, a stuck open PORV was isolated within three minutes by control room operators acting in response to available indication (valve position and temperature alarms). While the three minutes is a generic value, it does provide an approximate time fram to assume that the failed open PORC does not have to be classified as a LOCA. The ability to isolate a stuck open PORV after three minutes is a potential recovery action that can be considered to effectively terminate the LOCA; however, the event must initially have the same minimum plant response as any other similarly size LOCA prior to PORV isolation. The success criteria for a PORV or safety valve LOCA will be provided in Section 4.2.2.3.3.

4.2.2.3.2 RCP Seal LOCA

In order to limit leakage from the RCS, the RCPs are designed with a seal package comprised of three seals located in series along the pump shaft. This seal package limits RCS leakage by progressively reducing RCS pressure from 2250 psig to containment atmospheric pressure. Failure of this seal package can result in a LOCA similar to any equivalent sized pipe break.

The first stage seal in the RCP seal assembly is a "control" film-riding seal which limits leakage along the pump shaft by maintaining a hydrostatic force balance. That is, by maintaining the gap between the non-rotating faceplate of the seal design and the rotating faceplate, leakage can be "controlled." Multiple parameters can affect the gap (i.e., cause it to open or close with the corresponding change in leakage rate) including the angle between the non-rotating and rotating faceplates and inlet fluid pressure and temperature. The second stage seal directs the majority of first stage leakoff to the CVCS system via the seal leakoff line while the third stage seal minimizes the leakage of water and vapor from the pump into the containment atmosphere. These last two seal stages are rubbing type seals with the second stage seal designed to hold RCS system pressure for 24 hours with the first seal leakoff isolated and the RCP static. However, if both the first and second stage seals were to fail, then the third stage seal is not expected to limit leakage (i.e., failure of the first two seal stages is essentially a LOCA).

CVCS is used for the first "control" seal with a portion of CVCS being injected into the primary system and the remainder being directed along the pump shaft and out of the pump via the second stage seal. To provide seal cooling, both CVCS injection into the seal package and seal leakoff from the package must be successful in order to maintain the required hydrostatic balance. In addition to CVCS, component cooling water (CCW) is used to provide cooling water to the RCP motor bearing oil coolers and thermal barrier cooling coil. Per UFSAR Section 5.4.1.1.2 [Ref. 2], flow from either CVCS or CCW is sufficient to protect the RCP seals and prevent a possible LOCA. However, if CCW is lost for > 2 minutes, then the RCP must be tripped (if still running) to protect the motor [Ref. 21]. While no specific time limit is provided for loss of both support systems with respect to protecting the seals, it will be assumed that the RCPs must be tripped within the same 2 minutes to prevent seal damage. This 2 minute assumption is also consistent with vendor recommendations per the system engineer.

Westinghouse has extensively studied seal LOCAs during station blackout sequences in which all support systems are lost and the RCPs are not running [Ref. 22]. This includes the development of an event tree model to catalog the failure types of seal ruptures and a thermal hydraulic exercise of a code specifically developed to predict seal flow rates. The net result of this study was that a seal LOCA with a Westinghouse designed pump can result in at most, 480 gpm per pump, or a total flow rate of 960 gpm. This represents the catastrophic failure of all three stages in both RCPs. Using standard conversions (see Tables 4-6 and 4-7), this flow is equivalent to a fixed orifice diameter break of 1.08 inches. The calculation of 1.08 inches is further justified by the fact that a complete severance of a SG tube (0.664 inch inner diameter) results in approximately a 430 gpm leak per the UFSAR which if ratioed to the tube break area, corresponds closely to that for the 960 gpm seal LOCA and 1.08 inches.

The Westinghouse analysis states that leakage through the first stage seal is expected to increase from 3 gpm to approximately 21 gpm per pump if seal cooling is not provided within 30 minutes. Once seal cooling is restored and the seal assembly returns to a thermal equilibrium, leakage will again return to the normal 3 gpm. Without any seal cooling beyond 30 minutes, the seal assembly is vulnerable to failure due to loss of the seal ring geometry (i.e., the seal ring is no longer free to move or "binds") or to degradation of the elastomer material. The Westinghouse analysis predicts a seal failure probability of 2.83E-02 <u>after</u> the first hour of no seal cooling (i.e., there is no failure during the first hour) which gradually increases over time without seal cooling. However, even if there were no failure of the seal assembly, the seals would continue to provide a leak path from the RCS at a rate of 21 gpm per pump until cooling is restored. Westinghouse estimates that core uncovery would occur at approximately 20 hours for a 2-loop plant (see Figure 8-5 of Ref. 22) under these conditions (i.e., continuous 21 gpm leak per pump).

In addition to the Westinghouse analysis presented in WCAP-10451, an assessment of RCP seal failures is presented in Appendix C.14 of NUREG-1150 [Ref. 23]. In this analysis, an expert solicitation process (including a Westinghouse representative) was utilized to predict RCP seal leakage rates for various possible seal failure combinations. However, the report states that "prior to 90 minutes, there is no risk of seal failure." Following this 90 minutes, the RCP seal leakage rates and seal failure combinations are generally more conservative than in the Westinghouse analysis.

Based on the above information, the Ginna Station PSA will assume the following with respect to a seal LOCA.

a. Following the loss of all seal cooling (i.e., CVCS and CCW), operators must trip the running RCPs within 2 minutes or a seal LOCA of 480 gpm per pump will result.

b. Following the loss of all seal cooling (and trip of the RCPs), a leakage rate of 3 gpm per pump will be assumed for the first 30 minutes. This is equivalent to 180 gallons (or 20 ft^3) which is only 10% of the water volume in the pressurizer at hot zero power. As such, if seal cooling is restored within 30 minutes so that the leakage rate remains at 3 gpm, no further RCS inventory makeup is required. Recovery of seal cooling may be in the form of either CCW to the thermal barrier or a total of 6 gpm from CVCS to the seal assembly (plus availability of seal return). Since one CVCS pump at its lowest speed setting is equivalent to approximately 15 gpm, one of three CVCS pump is considered successful for seal injection.

c. Following 30 minutes of no seal cooling, the leakage rate is assumed to increase to 21 gpm per pump which remains constant until seal cooling is restored or until the seal assembly has failed. Seal failure can only be prevented by restoration of seal cooling which may be in the form of either CCW to the thermal barrier or a total of 42 gpm from CVCS to the seal assembly (plus seal return). Since 42 gpm is above the low speed setting of one CVCS pump, but within the design flowrate of 45 gpm, either one CVCS pump at its full speed setting or two of three CVCS pumps at their low speed setting is acceptable (the fact that two pumps at their low speed setting is only 30 gpm total is considered sufficient to provide the necessary cooling to restore leakage back to 3 gpm). If CCW is used to provide seal cooling, then some form of RCS makeup is also required which will be assumed to be the same requirements as that for the smallest sized LOCA. To simplify the model, RCS makeup will only be assumed to be required after 60 minutes (see item d below). A total of 30 minutes of 3 gpm leakage and 30 minutes of 21 gpm leakage amounts to only 1400 gallons (193 ft^3) which is equivalent to the pressurizer volume at hot zero power.

d. Following 30 minutes of no seal cooling, the seal assembly failure probability is dependent on several factors including seal type and whether or not operators have successfully depressurized the RCS. However, for both the Westinghouse and NUREG-1150 analyses, seal failure is not postulated until after at least 60 minutes. After this 60 minutes, the seal failure probability increases with time. As discussed above in item c, it is assumed that after 60 minutes, some form of primary system makeup is required to mitigate a 21 gpm per pump seal leakoff rate with no corresponding seal failure. A seal failure results in at most 480 gpm per pump which is the same LOCA size category as the 21 gpm per pump leak per Section 3.2.2.3.3. Therefore, the only difference between a seal LOCA and maintaining seal integrity after 60 minutes is the length of time which is available prior to core damage. The evaluation of time available prior to core damage is presented in Appendix B.

e. The only form of seal cooling recovery which will be considered is restoration of offsite power. All other equipment related failures of CVCS and CCW will be assumed to be unrecoverable.

The specific success criteria for a RCP seal LOCA is provided in Section 3.2.2.3.3.

4.2.2.3.3 Pipe Breaks

Figure 6.3-4 of the Ginna Station UFSAR [Ref. 2] presents a bar graph in which LOCA sizes are compared against the emergency core cooling system (ECCS) components. Essentially three category of LOCAs are presented as described below:

1.	Small LOCAs	< 3"	2/3 SI pumps (note - 1/3 CVCS pumps is stated as being capable of mitigating ≤ 3/8" break) and 1/2 RHR pumps for recirculation only
2.	Medium LOCAs	3" to 10"	2/3 SI pumps and 1/2 RHR pumps (note - the graph also suggests that this category could be as small as 3" to 6")
3.	Large LOCAs	> 10"	1/2 RHR pumps and 1/2 accumulators (note - the graph also suggests that large LOCAs could be as small as 6")

The accident analyses presented in Chapter 15 of the UFSAR only analyze "small" LOCAs (i.e., 3" to 6") and the large design basis guillotine break. That is, the small and medium LOCAs are essentially combined for ease of analysis. This is an overly conservative assumption; as such, MAAP runs were performed to better define the LOCA break sizes which correspond to UFSAR Figure 6.3-4. The SGTR event is analyzed separately from the small LOCAs in the UFSAR.

Multiple MAAP runs were made by varying LOCA size and the available equipment (see Table 4-2). As a result of these runs, the LOCA break sizes for the Ginna Station PSA partition into four general categories as described below:

1.	Small-Small LOCA (SSLOCA)	< 1"	Cannot depressurize to SI setpoint on break size alone; therefore, need AFW. Require high pressure recirculation since cannot reach RHR conditions before depletion of RWST. RCS inventory loss is small enough to allow rapid RCS depressurization to the RHR setpoint using AFW and SGs if one accumulator is available.
2.	Small LOCA (SLOCA)	1" to 2"	Slowly depressurizes to SI setpoint on break size alone. Require high pressure recirculation since cannot reach RHR condition before depletion of RWST. RCS inventory loss is small enough that to allow rapid RCS depressurization to the RHR setpoint using AFW and SGs if one accumulator is available.

3.	Medium LOCA (MLOCA)	2" to 5"	Slowly depressurizes to RHR setpoint on break size alone, but SI is needed initially to avoid core melt.
4.	Large LOCA (LLOCA)	≥ 5"	Depressurizes to RHR setpoint essentially immediately.
5.	SGTR	0.664"	Same as SSLOCA except for numerous operator actions.

The details concerning these LOCA categories are provided below. Table 4-4 summarizes the associated success criteria while Table 4-5 discusses the significant differences from the accident analyses.

<u>Small-Small LOCA</u>. MAAP runs S0ABCDE, SLOCA32, and S11BCDE-2 were performed to confirm this category of LOCA size. Essentially, runs S11BCDE-2 (1" LOCA) and SLOCA32 (3/4" LOCA) demonstrate that one of three SI pumps is sufficient for inventory makeup, but not for core cooling for break sizes up to 1". That is, with the same initial conditions (one of three SI pumps and no CVCS, RHR, AFW pumps and accumulators), the core temperature for a 3/4" LOCA exceeded 1800°F while it did not for a 1" LOCA. Therefore, AFW is assumed to be required for LOCA sizes less than 1" to provide the necessary core cooling. Also, only one of three AFW pumps is required consistent with the accident analyses; however, 45 minutes will be allowed to initiate AFW versus 10 minutes based on SG dryout conditions (see Section 4.2.2.4).

Additional MAAP runs were also made assuming that 2/3 SI pumps were available (SLOCA32B and S12BCDE-2). For the 3/4" LOCA, there was no discernible improvement since the RCS does not depressurize fast enough to use the additional SI. For the 1" LOCA, the additional SI pump only maintains RCS at a slightly higher pressure, thus delaying entry into the RHR mode of cooling. Therefore, 1/3 SI pumps will be considered as success. In addition, high pressure recirculation will be required using the RHR system consistent with UFSAR Figure 6.3-4 since the MAAP runs do not demonstrate the capability to reach RHR before the RWST is depleted.

Since MAAP is not as detailed as other NRC accepted T/H codes used for the accident analyses, the above success criteria was considered qualitatively as follows:

a. UFSAR Figure 6.3-4 shows that two of three SI pumps is sufficient for LOCAs < 3" in diameter which is one additional SI pump than shown by MAAP as being required. There is also no discussion of the need for AFW in the figure. However, a 3" LOCA has a larger flow area than a 1" LOCA by a factor of 9. This difference impacts both the amount of energy being released by the break and the rate of RCS depressurization which in turn impacts the required number of SI pumps and the need for AFW.

b. The SGTR analysis (0.664" LOCA) shows that a reactor trip on Overtemperature ΔT occurs at 49 seconds while an SI signal on low pressurizer pressure does not occur until 296 seconds. In addition, it is not until approximately 500 seconds that RCS is sufficiently depressurized to 1400 psig that the SI pumps can begin to inject. This depressurization includes the use of AFW to one SG and the MSSVs. Therefore, given the long time to depressurize the RCS assuming that AFW is available for a SGTR event, it is reasonable to conclude that the MAAP defined success criteria for number of SI (1/3) and AFW (1/3) pumps is appropriate for breaks < 1".

Note that for small enough LOCAs (approximately a 3/8" break), 2 CVCS pumps are sufficient to provide the inventory control role in place of SI (see run S0ABCDE); however, this was not considered since the charging pumps are shed following an SI signal. Also, somewhere in the 1/4" size range, the break should be small enough to remain within the capacity of one CVCS pump and could therefore be classified as a transient rather than a LOCA. However, this distinction has not been made for the Ginna Station PSA project to simplify the modeling process (i.e., any LOCA > 0" will essentially require inventory control by the ECCS).

In addition to the above discussion, MAAP runs SLOCA21, SLOCA22, SLOCA23, SLOCA24, SLOCA25, SLOCA 26, SLOCA26B, and SLOCA27 were performed to confirm the viability of rapid RCS cooldown using the SGs and accumulators to the RHR setpoint. These runs were designed based on the EOPs which provide this option in event there is a complete SI system failure during small-small LOCAs (see procedures FR-C.2 [Ref. 24] and FR-C.1 [Ref. 25] based on inadequate core cooling). Essentially, with 1 RHR pump, 1 accumulator, and 1 AFW pump, and varying the break discharge coefficient and time so that operators begin the cooldown from 45 to 60 minutes following the event, MAAP demonstrates that core damage is prevented. Since cooldown is not initiated until at least 45 to 60 minutes, use of AFW, SAFW, or MFW is successful.

Finally, since a RCP seal LOCA can range anywhere from a 42 gpm leak (21 gpm per pump) to a 960 gpm rupture (1.08" LOCA), the seal LOCA will be considered within this category of LOCA.

Small LOCA. This category of LOCA completes the small LOCA bar shown on UFSAR Figure 6.3-4. MAAP run S11BCDE-2 confirms that one of three SI pumps is sufficient for RCS inventory makeup and core cooling; thus, AFW is not required for break sizes greater than 1" equivalent diameter. The upper range of this category of LOCA is based the runs made for the Medium LOCA whereby there is sufficient RWST inventory and SI core cooling to reach RHR conditions prior to requiring high pressure recirculation. Again, credit for rapid cooldown of the RCS using AFW and the ARVs will be credited as an option in the event that SI is failed.

In summary, the small LOCA success criteria will be the same as for small-small LOCA except that AFW is not required. Once again, one of three SI pumps will be used in place of the two pumps assumed in the accident analysis.

Finally, based on MAAP runs FB12A, FB12D, FB12E, FB12G, and FB12H, a single PORV is enough to depressurize the RCS to the SI setpoint without the aid of AFW. Hence, a PORV LOCA is classified as a small LOCA. This is also consistent with Reference 21.

Medium LOCA. MAAP runs S21BC2E, S31BCDE, S41BC2E, and S51BC2E demonstrate that one of three SI pumps is sufficient for injection in 2" to 5" LOCAs in order to reach RHR conditions prior to depletion of the RWST. Meanwhile, runs S3AB12E and S4AB12E indicate that the break is not large enough for RHR alone to prevent core damage. Runs S21BCD2 and S21BC2E also indicate that the gain from accumulators for a 2 inch LOCA is minimal enough to ignore the accumulators in the MLOCA success criteria. However, even though the MAAP runs show that RHR is not required in the injection phase, RHR would be required in the injection phase in order to empty the RWST to the switchover setpoint (i.e., 15% RWST level). UFSAR Figure 6.3-4 also shows that RHR would be required. Therefore, the Ginna Station PSA will assume the same.

A run was also performed to evaluate if AFW alone is sufficient to reduce RCS pressure to the RHR setpoint. MAAP run S2A2C2E demonstrates that AFW will reduce RCS pressure but not prior to the onset of core damage. Since runs S21BC2E, S31BCDE, and S41BC2E demonstrate that one of three SI pumps is sufficient for core cooling without AFW, the availability of AFW is of no consequence. Therefore, the medium LOCA success criteria will be one of three SI and one of two RHR pumps for injection and one of two RHR pumps for recirculation.

Once again, the MAAP runs demonstrate that one of three SI pumps is sufficient to provide core cooling versus the two of three pumps used in the accident analysis. The above MAAP runs were also performed assuming two of three pumps to evaluate the differences. Essentially, requiring two SI pumps results in a more rapid depletion of the RWST with little or no improvement in the core temperature.

Large LOCA. MAAP runs S5AB12E, S6AB12E, and S8AB12E show that adequate core cooling is achieved using one of two RHR pumps for injection for LOCAs as small as a 5 inch equivalent break. Note that MAAP run S51BC2E indicates that a 5 inch LOCA can also be mitigated using one of three SI pumps (i.e., no injection from the RHR pumps). Rather than create a special category of LOCAs which can be mitigated using either one of three SI pumps or one of two RHR pumps, it was arbitrarily (but conservatively) assumed that large LOCAs encompassed any break greater than 5 inches.

It should also be noted that the MAAP runs show that the unavailability of the accumulators does not prevent the RHR system from providing the necessary core cooling. However, this will be ignored in the Ginna Station PSA which will assume that one of two accumulators is required consistent with the accident analyses.

SGTR. The typical SGTR which is modeled both in PSAs and accident analyses is the guillotine break of one SG tube. Failure of multiple tubes is not modeled due to the low probability of more than one tube failing at the same time. Also, industry events have typically been due to large leaks (versus a guillotine rupture); therefore, assuming a design basis guillotine break should encompass all potential scenarios. Since a SG tube has an inner diameter of 0.664 inch, a SGTR falls within the SSLOCA category of LOCAs. However, a SGTR is a much more complex scenario with significant operator action required. Therefore, the SGTR event is evaluated separately.

The SGTR event is modeled in the accident analysis for two cases. The first case is to demonstrate that SG overfill as a result of the tube rupture does not occur since it could lead to water relief through the MSSVs and thus, the high probability for a stuck open safety valve with an impact on offsite doses. The second case evaluates a tube rupture specifically for offsite dose consequences assuming that the ARV on the ruptured SG is stuck open. The Ginna Station PSA will use the timing and operator actions from both these cases for the purpose of determining success criteria.

Similar to a SSLOCA, the reactivity control function is provided by the RTS. However, the RCS pressure and inventory control functions are complicated by the fact that this type of LOCA bypasses the containment. As such, the break flow from the RCS must be terminated by equalizing RCS and the ruptured SG pressure. This is accomplished through isolation of the ruptured SG (e.g., closure of its MSIV) and depressurization of the RCS to the ARV setpoint of 1050 psig, thus equalizing pressure between the primary and secondary sides. There are essentially four major operator actions following a SGTR as described below:

a. *Identify and Isolate the Ruptured SG* - Once a tube rupture has been identified through various station alarms and indications (reactor trip is assumed to be on Overtemperature ΔT), operators must isolate all feedwater flow to, and steam flow from, the affected SG. Since the SGTR is assumed to result in an SI actuation due to low pressurizer pressure, MFW will be automatically isolated such that only AFW must be stopped. Because this requires operator action, the accident analysis assumes that it takes the operator 10 minutes following the event to isolate AFW and close the MSIV on the affected SG.

b. *Cooldown the RCS to Establish Subcooling Margin* - Following isolation of the ruptured SG, operators attempt to rapidly cool the RCS. This is accomplished by using at least one ARV (preferably on the intact SG due to dose consequences). The accident analysis requires that the RCS be cooled down until RCS subcooling at the ruptured SG pressure is 35°F. This subcooling margin ensures that adequate subcooling will be available in the RCS following depressurization of the RCS to the ruptured SG pressure. The accident analysis assumes that the ARV is opened within 20 minutes following isolation of the ruptured SG and takes approximately an additional 20 minutes to cooldown the RCS.

c. *Depressurize RCS to Restore Inventory* - Following cooldown of the RCS, operators must depressurize the RCS using at least one pressurizer PORV. Depressurization must continue until one of the following is met: (1) RCS pressure is less than the ruptured SG pressure and pressurizer level is > 5%, (2) pressurizer level is > 75%, or (3) RCS subcooling is 0°F. The time required to reach any of these three conditions is dependent upon plant conditions and equipment availability. However, the accident analysis assumes that depressurization is initiated within 2 minutes following RCS cooldown and complete within an additional 32 seconds.

d. *Terminate SI to Stop Primary to Secondary Leakage* - Once the RCS is sufficiently depressurized, the SI pumps must be isolated (CVCS is assumed to be tripped on SI) to terminate the break flow. SI can be terminated if all of the following conditions are met: (1) RCS subcooling is ≥ 0°F, (2) one of three AFW pumps is available or intact SG level is in the narrow range, (3) RCS pressure is stable or increasing, and (4) pressurizer level is > 5%. As can be seen, three of the four conditions for terminating SI are equivalent to or bounded by the termination of the RCS depressurization step. As such, the accident analysis assumes that SI is terminated within 1 minute of completing RCS depressurization.

The failure of operators to perform the above actions have various consequences. However, the real consequence is that the time available for operators to stop the break flow from the RCS is significantly reduced. This is due to the fact that the RWST inventory will continue to deplete without the availability of containment sump recirculation and the SG will continue to fill creating the potential for overfill conditions. In the event the RWST is depleted prior to leak termination, the only alternative is a rapid cooldown to RHR conditions using the intact SG ARV (see procedures FR-C.2 [Ref. 24] and FR-C.1 [Ref. 25] based on inadequate core cooling). Once the RHR setpoint is reached, RHR cooling can be started to reduce the RCS pressure to atmospheric pressure, thereby terminating the loss of RCS inventory. During the rapid RCS cooldown, RCS inventory is maintained via reverse flow from the ruptured steam generator; thus, unlike the similar situation for SSLOCAs, the accumulators are not needed.

Since the time frames for the operator actions are very important, several MAAP runs were performed. The results of these MAAP runs are summarized below:

a. MAAP runs RUH2A, RUH2B, and RUH2C show that with rapid RCS depressurization and cooldown to RHR conditions initiated within 45 minutes, high core tempertures are averted (i.e., core damage does not occur) assuming no SI is available. In addition, the time to reach RHR conditions is based on whether or not the accumulators are blocked. Therefore, the Ginna Station PSA will assume that operators must initiate rapid cooldown to RHR conditions within 45 minutes if SI is not available.

b. MAAP runs RUH2D, RUH2E, RUH2F, RUH2G, RUH2H, and RUH2I were performed to determine the consequences with no SI available, with a stuck open relief valve on the ruptured SG. The runs include various assumptions for the timing of the stuck open relief valve and the relief valve flow resistance. Essentially, the runs show that without isolation of the ruptured SG and with no SI, rapid cooldown of the RCS within 45 minutes to RHR conditions is successful. Therefore, the Ginna Station PSA will assume that isolation of the ruptured SG must occur within 45 minutes or rapid cooldown to RHR conditions initiated.

In addition, it is also noted that for the operator times used in the accident analysis, the NRC required that 80% of the shift operating crews be tested to ensure the times could be met, which they were.

4.2.2.4 RCS Heat Removal Success Criteria

As discussed above, heat removal from the RCS is an important parameter and can be achieved in one of two ways: (1) SG cooling or (2) energy release via a break in the primary system. Each option is discussed below.

<u>SG Cooling</u>. SG cooling is the preferred RCS heat removal scheme for transients (i.e., non-LOCA initiating events) as well as small LOCAs and SGTR sequences. Since each SG can remove 50% of the rated thermal power, one SG can easily remove the entire decay heat load of the reactor following a plant trip. In order to use the SGs to remove decay heat, there must be an adequate source of feedwater (AFW, SAFW, or MFW) and a steam vent path (atmosphere or condenser).

Based on a review of the feedwater requirements for SG cooling per the UFSAR [Ref. 2] and the technical specifications [Ref. 6], the following is the success criteria which will be used:

a. For MFW and main steam line breaks, the worst case scenario is a high energy line break in the Intermediate Building. In this case, the UFSAR assumes that all three preferred AFW pumps are failed such that only one SAFW pump is available within 10 minutes (with an additional single failure). Therefore, one of three AFW or one of two SAFW pump is success for these events.

b. For loss of MFW events and small LOCAs, one AFW pump is assumed to be available within 10 minutes in the accident analysis. This is due to the analysis requirement to prevent a pressurizer PORV from releasing liquid (versus steam) for a loss of MFW event and the need to depressurize the RCS to the SI pump shutoff head for a small LOCA. Therefore, one of three AFW or one of two SAFW pumps is success for these events.

c. For all other transients and the SGTR event, the accident analysis requirements for AFW are not critical due to the nature of the transient. Therefore, one of three AFW or one of two SAFW pumps will be considered as success for these events similar to the loss of MFW and main steam line breaks. However, it should be noted that a large steamline or feedwater line break may fail the TDAFW as a source of heat removal (i.e., fails driving source). Also, one AFW pump within 45 minutes (versus the 10 minute accident analysis assumption) will be used based on the time available before SG tube uncovery (see MAAP run FW01X). A delay until 45 minutes was also verified on simulator runs.

d. For all cases in which SAFW is considered an acceptable means of providing SG cooling, the recovery of one of two MFW pumps will also be considered success since a MFW pump is capable of providing necessary core cooling up to at least 50% power. It should be noted that the condensate pumps can also be used to pump "through" the MFW pumps under emergency conditions; however, this will not be assumed for the PSA.

e. Following a station blackout event, the TDAFW pump is the only source of feedwater which would be available. Per the UFSAR [Ref. 2], it has been demonstrated that the TDAFW pump is AC power independent. However, the TDAFW pump cannot operate indefinitely due to the limited DC power source (i.e., batteries). In accordance with 10 CFR 50.63, Ginna Station has been evaluated with respect to a station blackout event lasting up to 4 hours. This evaluation concluded that the battery capacity was sufficient to allow the TDAFW pump to operate for at least 4 hours during the event. Further engineering analysis indicates that the TDAFW pump can actually survive up to 6 hours. It was also noted that the capability to cross-tie the Technical Support Center (TSC) batteries and diesel generator to the normal Ginna Station sources exist; however, this option will be treated as a potential recovery only. If the TDAFW pump were inoperable, the SGs are not expected to dry out until > 45 minutes based on simulator and MAAP runs (note - this time increases if the RCS is depressurized). Given that core damage will not occur until some time after SG dryout, the Ginna Station PSA will assume the following for a station blackout event:

1. The TDAFW pump can operate for up to 6 hours on DC power only. If the TDAFW pump fails at 6 hours, operators must restore offsite power within 4 additional hours for transients (see Appendix B). However for LOCAs, DC power must be restored within 2.25 hours of the SBO (5 hours for SGTRs) due to inventory loss concerns.

2. If the TDAFW pump fails at time zero, core damage will occur 1 hour later. Therefore, offsite power must be restored within this 1 hour period. However, if the RCS is depressurized, the time to core damage and the time period to restore offsite power is extended (see Appendix B).

In addition to the feedwater supply, each SG must also have a steam vent path. This can be provided by the steam dump system, the ARVs, or by the MSSVs. Any single valve in each of these three systems is considered success based on its energy removal capability [Ref. 2].

Energy Release From Primary System Pipe Break. Primary bleed and feed cooling is an alternate method of decay heat removal for transients and small LOCAs in the event that SG cooling is lost. This method of cooling uses a path to "bleed" off RCS inventory while also "feeding" the RCS with cooling water which eventually cools and depressurizes the RCS. The Ginna EOPs [Ref. 26], require operators to "Check SI pumps - AT LEAST ONE RUNNING", indicating that the success criteria for the "feed" portion of bleed and feed as one of three SI pumps. Later steps of FR-H.1 require the opening of both PORVs, thus suggesting the success criteria for the "bleed" portion of bleed and feed to be 2/2 PORVs. However, MAAP runs FB12A, FB12D, and FB12H indicate that one of two PORVs is sufficient. Since these options are not provided in the EOPs, the one of three SI pumps and two of two PORVs is identified as the success criteria for the Ginna Station PSA. Based on the Reference 27, feed and bleed must be initiated prior or shortly after SG dryout. MAAP run FB12H shows that operator cues will be reached as soon as 23 minutes given the above success criteria while MAAP run FW01X shows SG dryout occurs as early as 45 minutes.

RCS heat removal is generally achieved for medium and large LOCAs if the RCS inventory control function is achieved. These types of LOCAs are similar to bleed and feed operations in that the SI pumps and RHR pumps supply cooling water to the reactor (the "feed" function) while the break itself removes hot water from the RCS (the "bleed" function). Initially, cooling water is supplied by the refueling water storage tank (RWST). Later, water is recirculated from the containment sump and cooled via the RHR heat exchangers.

It should be noted that containment heat removal may be required to support the recirculation function since for larger size breaks, failure of containment heat removal could lead to containment failure due to overpressurization and, thus, loss of the containment sump inventory and the recirculation function. Containment heat removal is also important for NPSH concerns. Failure of the containment heat removal systems (containment fan coolers and containment spray) is analogous to the failure of other support systems (e.g., CCW, electric power, etc.) with respect to the Level 1 analysis, and therefore is not explicitly stated in the RCS heat removal success criteria. However, the status of containment heat removal is of primary importance to the Level 2 analysis, and the Level 1 event trees directly address the operability of the containment heat removal systems for medium and large LOCAs to aid in the determination of plant damage states. Therefore, the success criteria for the containment heat removal will be defined in Section 10.

4.3 Final Success Criteria Summary

A final listing of the success criteria is presented in Table 4-4 with all significant differences from the accident analysis discussed in Table 4-5. In addition, Table 4-8 provides a list of significant differences from the success criteria used by the other 2-loop Westinghouse plants. These differences are discussed below along with how specific initiators and inter-system dependencies affect the safety functions previously described.

4.3.1 Differences From Similar Westinghouse Plants

Table 4-8 was generated to describe the significant differences between the success criteria used in the PSAs submitted to the NRC in response to GL 88-20 for the other 2-loop Westinghouse plants [Ref. 3] [Ref. 4] [Ref. 5] and what will be used in the Ginna Station PSA. Justification for these differences are provided below.

4.3.1.1 Transients

For transients, there are only two significant differences from the other plants which are summarized below:

a. The other plants have separate event trees for main steam line breaks and loss of MFW, SW, CCW, IA, MFW and loss of offsite power events while the Ginna Station PSA has combined them into one event tree. This difference is mainly attributable to the method of analysis and not to any success criteria issues.

b. Point Beach considers the potential for a main steam line break induced SG tube rupture. However, the supporting text states that this is due to "older" tubes. Since the Ginna Station SGs were replaced in 1996, this is not expected to be of concern.

c. The other plants require SI for steam line breaks while the Ginna Station PSA does not based on re-analysis of the Chapter 15 accident.

4.3.1.2 Station Blackout

For a SBO event, the only significant success criteria differences relate to the assumed time for core uncovery following loss of AFW. The times used in the Ginna Station PSA are provided in Appendix B.

4.3.1.3 LOCAs

For small break LOCAs, there are three major differences from the other plants which are summarized below:

a. The other plants do not differentiate that AFW may not be required for a certain class of small break LOCAs while the Ginna Station PSA has used MAAP runs and evaluations of accident analysis runs for SGTR and small LOCAs to justify this assumption.

b. The other plants provide an option for feed and bleed cooling for small break LOCAs which can be used as a recovery action if necessary (note - Ginna Station has two extra AFW pumps).

c. Kewaunee and Point Beach require operators to cooldown to low pressure recirculation conditions while the Ginna Station PSA assumes that stabilizing the RCS using SI (on recirculation) and AFW is acceptable. While achieving RHR conditions is the ultimate goal, it is assumed that significant time exists for the operators to reach this when needed.

For medium break LOCAs, there are three major differences from the other plants which are summarized below:

a. Kewaunee and Point Beach require SI for recirculation and not just injection as the Ginna Station PSA has assumed. Various MAAP runs show that only utilizing SI during injection for this break size is sufficient. In addition, WCAP-14426 [Ref. 27] shows that for 3" LOCAs, the RCS depressurizes to 400 psia within 1000 seconds with a continuing depressurizing trend such that it can be expected that RHR entry conditions (150 psia) would be reached significantly prior to RWST depletion.

b. Kewaunee and Point Beach provide an option for rapid depressurization to RHR conditions using AFW and the accumulators in the event SI fails which can be used as a recovery action if necessary.

c. Kewaunee and Point Beach do not require RHR for injection. Various MAAP runs show that RHR is not required for core cooling; however RHR injection conditions are reached within a few hours. Since the RWST must empty prior to changing to recirculation conditions and UFSAR Figure 6.3-4 shows that RHR is required, the Ginna Station PSA included this requirement.

d. Prairie Island assumes that either SI or RHR is sufficient during the injection phase of the accident. The Ginna Station PSA conservatively ignores this part of the break spectrum and assumes that SI is required early.

There are no real differences with respect to the large break LOCA category or SGTRs.

4.3.1.4 ATWS

For ATWS events, the Ginna Station PSA event tree is much more detailed than the other 2-loop plants to eliminate potential non-conservative assumptions. These issues are discussed in detail in Section 4.2.2.1 above. Since the Ginna Station PSA event tree is more conservative, and provides additional requirements consistent with necessary plant system response, the differences are considered acceptable.

4.3.2 Initiators and Inter-System Dependencies

The success of the systems that provide the four safety functions of Section 4.1 can be directly affected by the initiator or subsequent failures of other systems. Most of these dependencies will be identified in the system and model development efforts where the system interactions are easier to understand. However, some initial dependencies were identified as guidance to the event tree development or as peripheral information from the task. This information is summarized in Table 4-9, which indicates how the various initiators used in the PSA model impact some of the systems associated with the safety functions.

An initiator dependency may either be a challenge (i.e., it causes an automatic demand for a safety system and hence is an opportunity for its subsequent failure) or a system fault (i.e., is a direct source of the inoperability of the system). The reactivity, RCS pressure control, and inventory control functions are affected by initiator dependencies via challenges (with the exception of seal cooling failures) while the heat removal function is affected by initiator dependencies through either challenges or faults. Several examples are listed below:

a. The ECCS is challenged by both LOCAs (which result in a drop in pressurizer pressure and higher containment pressure) and transients (e.g., steamline breaks which lower pressurizer level because of shrinkage due to overcooling).

b. A loss of SW will lead to a manual reactor trip and a direct loss of CCW which fails one of two forms of RCP seal cooling, potentially challenging seal integrity.

c. A steamline or main feedline break in the Intermediate Building produces a steam environment that is assumed to fail all of the preferred AFW pumps. Finally, a steamline or feedline break in the Turbine Building is assumed to fail the MFW pumps, IA system, and the preferred AFW pumps (due to the block wall which exists between the Turbine and Intermediate Buildings).

These dependencies are all shown in Table 4-9.

In addition to Table 4-9, Figure 4-1 shows a "bubble chart" indicating the system-level dependencies among frontline and support systems. The chart is self-explanatory. "Connections" are by way of heat exchangers (e.g., service water to component cooling water), direct air cooling (e.g., the SAFW Building heating, ventilation and air conditioning of the SAFW pump rooms), and direct water injection (e.g., SI into the RCS). Note that timing enters some of the connections between bubbles (e.g., the CCW/SW heat exchange may begin immediately but is not typically required until during the recirculation phase while the HVAC interaction is a long-duration evolution, potentially many hours).

Finally, as discussed in Section 4.2.1 each of the initiator and inter-system dependencies is modeled at the most appropriate gate(s) in the logic model. Initiators amount to another kind of basic event and connections between systems are indicated by transfer gates in the models. Therefore, the consequences of each initiator are specifically included within the fault tree model to make sure it is appropriately addressed.

4.4 Summary

The success criteria to be used in the Ginna Station PSA are summarized in Table 4-4. The operator actions required to support the identified success criteria are summarized in Table 4-10. This information will serve as the basis for generation of the event trees provided in Section 5.

Table 4-1
Evaluation of Initiators with Respect to Sequence and System Level Success Criteria

Initiator Type	*Impact on Core Performance Functions*				*Impact on Plant System Performance*	*Level 2 Analysis Considerations*
	Reactivity Control	*RCS Pressure Control*	*RCS Inventory Control*	*RCS Heat Removal*		
Transients	None; transients followed by reactor trip system (RTS) failure are grouped under the ATWS category.	Major impact depending on the specific initiator involved (e.g., loss of offsite power).	None; transient-induced LOCAs (e.g., RCP seal LOCAs and PORV LOCAs) are grouped under the LOCA category.	Major impact, depending on the specific initiator involved (e.g., loss of MFW).	Major impact, depending on the specific initiator involved. Note that initiators are defined, in part, due to their impact on post-trip plant system operation.	No specific effects; note that initiators which fail plant systems designed to prevent core damage may also fail containment systems (e.g., CS, CI System).
LOCAs	None; LOCAs followed by RTS failure are grouped under the ATWS category. However, reactivity control for large LOCAs is accomplished by rapid boron injection (see reactivity control).	None; the LOCA will depressurize the RCS eliminating potential to exceed upper RCS design pressure limit. RCS inventory control response will provide necessary lower limit pressure control.	Major impact; LOCA break size dictates the amount of RCS makeup required to ensure that the reactor core is covered.	Major impact, depending on the LOCA break size and the occurrence of transient-induced LOCAs. For medium and large LOCAs, the systems used to provide RCS inventory control are also used to ensure RCS heat removal.	Major impact, depending on the location of the LOCA. LOCAs in SI or RHR injection piping will partially fail these systems. ISLOCAs may fail plant systems due to dynamic effects (e.g., pipe whip) or steam flooding.	LOCAs are subdivided according to their ability to bypass the containment: • No bypass • Bypass - ISLOCAs - SGTRs
ATWS	Major impact; ATWS represents failure of the RTS.	Major impact since primary system pressure must be maintained ≤ 3200 psig.	Major impact if the peak pressure exceeds the RCS limiting pressure of 3200 psig.	Major impact, depending on the specific initiator involved.	No specific effects; plant system performance impacts related to transients and LOCAs also apply to ATWS.	No specific effects; Level 2 considerations for transients and LOCAs also apply to ATWS.

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
RUH2A	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	2	1	0	• isolate ruptured SG at time = 0 • AFW to intact SG only • C/D on intact SG at time = 45 m • accumulators blocked at 300 psia	no	Reach RHR shutoff head at time = 6.4 h
RUH2B	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	1	1	0	• isolate ruptured SG at time = 0 • AFW to intact SG only • C/D on intact SG at time = 45 m • accumulators blocked at 300 psia	no	Reach RHR shutoff head at time = 5.7 h
RUH2C	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• isolate ruptured SG at time = 0 • AFW to intact SG only • C/D on intact SG at time = 45 m	no	Reach RHR shutoff head at time = 4.8 h
RUH2D	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2C with ruptured MSSV failed open when it first lifts	no	No core melt, but RCS voiding
RUH2E	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2C with ruptured MSSV valve failed open at 20 min	no	Response almost identical with RUH2D
RUH2F	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2D with VFSEP = 0.3	no	Better cooldown/ depressurization than RUH2D
RUH2G	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2D with VFSEP = 0.7	yes	Core melt occurs, not enough depressurization to reach RHR shutoff head
RUH2H	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2G with intact SG ARV fully opened at 30 min	no	

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
RUH2I	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg • 0.50 ft above tube sheet	0	0	1	0	1	0	• RUH2G with intact ARV fully opened at 45 min	no	• Run suggests that rapid cooldown may be delayed for up to 45 min
RUH2J	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg • 0.50 ft above tube sheet	0	0	0	2	1	0	• same as RUH2I except ARV is not opened and credit is taken for accummulators	yes	• fuel reaches 1800 F at 5.5 hours
SLOCA21	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 45 m • accumulators blocked at 300 psia	no	• reach RHR shutoff at time 3.5 hr • PORV lift - MAAP model issue
SLOCA22	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • Force C/D at 100 F/hr • (SLOCA21 with RCP LOCA, delayed depressurization and rapid cooldown)	no	• no change from SLOCA21 • PORV lift - MAAP model issue
SLOCA23	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • Force C/D at 100 F/hr • (SLOCA21 with RCP LOCA, delayed depressurization and rapid cooldown)	no	no change from SLOCA21
SLOCA24	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • Force C/D at 100 F/hr • VFSEP = 0.3 • (SLOCA21 with VFSEP = 0.3)	no	• compatible to SLOCA22 • PORV lift - MAAP model issue
SLOCA25	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • Force C/D at 100 F/hr • VFSEP = 0.3 • (SLOCA21 with VFSEP = 0.3)	no	• Slight TCRHOT increase, but RHR turns around • PORV lift - MAAP model issue

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
SLOCA26	LOCA	• 5.9E-3 ft² (1.04 inch) • cold leg (RCP node)	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • force C/D at 100 F/hr • VFSEP = 0.7 • FCDBRK = 1.0 • (SLOCA25 with FCDBRK = 1.0)	yes	• core uncovers and heats up to 2000 F even with accum
SLOCA26B	LOCA	• 5.9E-3 ft² (1.04 inch) • cold leg (RCP node)	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 60 m • accumulators blocked at 300 psia • force C/D at 100 F/hr • VFSEP = 0.7 • FCDBRK = 1.0 • (SLOCA26 using both ARVs)	yes	• core uncovers and heats up to 2000 F even with accum
SLOCA27	LOCA	• 5.9E-3 ft² (1.04 inch) • cold leg (RCP node)	0	0	1	1	1	0	• isolate one SG at time = 0 • C/D on other SG at time = 45 m • accumulators blocked at 300 psia • force C/D at 100 F/hr • VFSEP = 0.7 • FCDBRK = 1.0 • (SLOCA26 with earlier cooldown)	no	• core uncovers but only heats up to 1000 F
FB12A	LMFW	N/A	0	1	2	2	0	1	•no MFW or SAFW	yes	• core temp reaches 2500 F but does not melt • BAF cue time = 1385.7 sec
FB12D	LMFW	N/A	1	1	2	2	0	1	• FB12A except that 1 CVCS pump is initially operating (turned off during feed and bleed)	yes	• core temp reaches 1800 F but does not melt • BAF cue time = 846.8 sec
FB12G	LVMW	N/A	1	1	2	2	0	2	• FB12A with 2 PORVs	no	• brief core uncovery • BAF cue time = 13.5 hr

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pump	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
FB12H	LMFW	N/A	1	2	2	2	0	1	• FB12A with 1 PORV and 2 SI pumps	no	• BAF cue at time = 1385.7 sec • Recirc at time = 24104.8 sec
FB13E	LMFW	N/A	0	3	2	2	0	0	• no MFW or SAFW • delay start of BAF until 0.5 hr after cue recieved	no	• SG level reaches 3 ft at time = 0.4 hr • BAF initiated at time = 1 hr
S0ABCDE	LOCA	• 7.7E-4 ft^2 (3/8 inch) • hot leg	2	0	0	0	0	0	• no MFW or SAFW	no	• 2 CVCS pumps can provide core cooling for very small LOCAs • PORV lift - MAAP model issue
SLOCA32	LOCA	• 3.1E-2ft^3 (.75 inch) • cold leg	0	1	0	0	0	0	• no MFW or SAFW	yes	• fuel reaches 1800 F at 2.5 hours
SLOCA32B	LOCA	• 3.1E-3 ft^2 (.75 inch) • cold leg	0	2	0	0	0	0	• SLOCA32 with 2 SI pumps	yes	• no real impact of # of SI pumps
S11BCDE-2	LOCA	• 2.2E-3 ft^2 (2 inch) • hot leg	0	1	0	0	0	0	• no MFW or SAFW	no	• confirms SG cooling needed for SSLOCAs • RWST depleted at time = 13.5 hr
S12BCDE-2	LOCA	• 2.2E-3 ft^2 (2 inch) • hot leg	0	2	0	0	0	0	• S11BCDE-2 with 2 SI pumps	no	• additional SI pump slightly delays depressurization to RHR
S21BCD2	LOCA	• 2.2E-3 ft^2 (2 inch) • hot leg	0	1	0	2	0	0	• no MFW or SAFW	no	• RWST depleted at time = 10.9 hr
S21BC2E	LOCA	• 2.2E-3 ft^2 (2 inch) • hot leg	0	1	0	0	0	0	• no MFW or SAFW	no	• cofirms MLOCA success criteria • RWST depleted at time = 11 hr

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pump	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
S2A2C2E	LOCA	• 2.2E-2 ft² (2 inch) • hot leg	0	0	0	0	1	0		yes	• fuel heatup starts at time = 0.52 hr • fuel reaches 1800 F at time = 0.72 hr • RCP pressure < RHR shutoff head during fuel heatup
S31BCDE	LOCA	• 4.9E-2 ft² (3 inch) • hot leg	0	1	0	0	0	0	• no MFW or SAFW	no	• RWST depleted at time = 11 hr • RCW pressure < RHR shutoff head at time of recirc switchover
S3AB12E	LOCA	• 4.9E-2 ft² (3 inch) • hot leg	0	0	1	2	0	0	• no MFW or SAFW	yes	• confirms SI required as RCS will not dep to RHR shutoff head prior to core damage
S41BC2E	LOCA	• 8.7E-2 ft² (4 inch) • hot leg	0	1	0	0	0	0	• no MFW or SAFW	no	• RWST depleted at time = 10.2 hr
S4AB12E	LOCA	• 8.7E-3 ft² (4 inch) • hot leg	0	0	1	0	0	0	• no MFW or SAFW	yes	• confirms SI required as RCS will not dep to RHR shutoff head prior to core damage
S5AB12E	LOCA	• 1.4E-1 ft² (5 inch) • hot leg	0	0	1	0	0	0	• no MFW or SAFW	no	• RWST depleted at time = 2 hr
S51BC2E	LOCA	• 1.4E-1 ft² (5 inch) • hot leg	0	1	0	0	0	0	• no MFW or SAFW	no	• RWST depleted at time = 10 hr
S6AB12E	LOCA	• 2.0E-1 ft² (6 inch) • hot leg	0	0	1	0	0	0	• no MFW or SAFW		• RWST depleted at time = 2 hr
S8AB12E	LOCA	• 3.5E-1 ft² (8 inch) • hot leg	0	0	1	0	0	0	• no MFW or SAFW	no	• RWST depleted at time = 2 hr

Table 4-2
Summary of MAAP Runs to Support Success Criteria

Case	Init Event	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accum	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
FW01T	LMFW	N/A	0	0	0	0	1	0	• 1 AFW pump at 1 min • MSIVs open • Letdown isolated	no	• PORV lifts
FW01U	LMFW	N/A	0	0	0	0	1	0	• 1 AFW pump at 1 min • MSIVs open	no	• PORV lifts
FW01V	LMFW	N/A	0	0	0	0	2	0	• 2 AFW pumps at 1 min • MSIVs open	no	• PORV lifts
FW01X	LMFW	N/A	0	0	0	0	0	0	• No AFW available	yes	• SG dryout at 45 minutes • fuel reaches 1800 F at 2.3 hrs
FW01Z	LMFW	N/A	0	0	0	0	1	0	• AFW available for 6 hrs only	yes	• SG dryout at 8.5 hrs • fuel reaches 1800 F at 10.8 hrs
FW01AA	LMFW	N/A	0	0	0	0	1	0	• AFW available for 4 hrs only • ARV opened at 3 hrs	yes	• SG dryout at 6.5 hrs • fuel reaches 1800 F at 9 hrs
SLB01D	MSLB	N/A	0	0	0	0	0	0		no	• RCS pressure goes to 500 psig but levels off
SLB01E	MSLB	N/A	0	1	0	0	0	0	• Same as SLB01D but with 1 SI pump	no	• RCS pressure goes to 500 psig and rapidly rises
SLB01F	MSLB	N/A	0	2	0	0	0	0	• Same as SLB01D but with 2 SI pumps	no	• RCS pressure goes to 500 psig and rapidly rises
SLOCA33	SBO	• 5.93E-3 ft^2	0	0	0	2	1	0	• TDAFW available for 6 hrs only	yes	• fuel reaches 1800F at 2.25 hrs
SLOCA34	SBO	• 3.47E-3 ft^2	0	0	0	2	1	0	• TDAFW available for 6 hrs only	yes	• fuel reaches 1800F at 2.75 hrs

Table 4-3
CVCS Emergency Boration Rate

The boration requirements of the CVCS to achieve subcriticality within 1 hour following an ATWS can be estimated as follows:

(1) To achieve subcriticality, the RCS boron concentation must be increased from full power beginning of life (BOL) equilibrium xenon conditions to 1% shutdown, xenon free conditions with all rods out. Per the Ginna Station reactor engineer, these values are 1333 ppm and 1871 ppm, respectively, for Cycle 26. The delta ppm between these cases is 538 ppm.

(2) The CVCS emergency boration path per Ginna Station EOPs is via the boric acid storage tanks (BASTs). The Ginna Station TRM allows the boron concentration within these tanks to range from 4700 ppm up to 23,000 ppm based on the volume available. Per the Ginna Station reactor engineer, the BASTs are normally maintained at approximately 13,000 ppm. Therefore, assuming the CVCS is injecting fluid of this boron concentration, 1606 gallons of water from the BASTS must be injected.

(3) The CVCS pumps normally operate at approximately 45 gpm but are limited to 15 gpm at their low speed setting. Evaluating both conditions yields the following:

a. 1606 gal / 45 gpm = 36 min < 1 hour

b. 1606 gal / 15 gpm = 107 min / 2 pumps = 53.5 min < 1 hour

The above calculation is very conservative since after 1 hour, xenon levels would be high enough such that the 1871 ppm value listed in (1) is very high. It is expected that only 150 ppm (vs. 558) would be needed due to power defects to achieve subcriticality within 1 hour. Using 150 ppm as the requirement, then 2 CVCS pumps at their low speed setting would only require a BAST concentration of 7500 ppm in order to achieve subcriticality within 1 hour.

Table 4-4
Sequence-Level and System-Level Success Criteria

Initiator Group	*Reactivity Control*	*RCS Pressure Control*	*RCS Inventory Control*	*RCS Heat Removal*
Transients	RTS	**Locked Rotor:** SG Relief: 8/8 MSSVs or 7/8 MSSVs and 1/2 ARVs or 6/8 MSSVs and 2/2 ARVs and PZR Relief: 2/2 PZR safeties or 1/2 PZR safeties and 2/2 PORVs and PZR Spray **Loss of Electrical Load/ Loss of MFW Events:** 1/2 PZR safeties or 2/2 PORVs (and PZR spray for Loss of Load only) and SG Relief: 8/8 MSSVs or 7/8 MSSVs and 1/2 ARVs or 6/8 MSSVs and 2/2 ARVs **SLB Inside Containment / Intermediate Bldg:** 1/2 MSIVs or Non-Return Check Valve Closure on Affected SG or 1/3 SI pumps **SLB Turbine Building:** 1/2 MSIVs or 1/3 SI pumps	**RCP seal integrity:** Seal injection (1/2 CVCS) or Thermal barrier cooling (1/2 CCW) or Trip running RCPs within 2 minutes and within 60 min: Restore seal injection (2/3 CVCS pumps @ low speed) or Restore seal injection (1/3 CVCS pumps @ full speed) or Restore thermal barrier cooling (1/2 CCW) **Loss of Electrical Load:** 2/2 PORVs reclose/isoated and 2/2 safeties reclose (if SG reliefs fail or 2/2 PORVs fail) **Locked Rotor:** 2/2 PORVs reclose/isolated and 2/2 safeties reclose **Loss of MFW Events:** 2/2 PORV reclose/isolated and 2/2 safeties reclose (if SG reliefs fail and 2/2 PORVs fail) **MFW Line Breaks:** 2/2 PORVs close/isolated **Steam Line Breaks:** 2/2 PORVs reclose/isolated (if PZR spray fails) and 2/2 safeties reclose (if PZR spray and PORVs fail)	**1/2 Steam Generators:** 1/3 AFWPs or 1/2 MFWPs or 1/2 SAFWPS and 1/8 steam dump valves or 1/2 ARVs or 1/10 S/G SVs or **Bleed and Feed:** 1/2 PORVs and 1/3 SI pumps and 1/2 RHR pumps and 1/2 RHR heat exchangers **Loss of MFW / Locked Rotor / Loss of Load:** 8/8 MSSVs close and 2/2 ARVs close **SBO** TDAFW pump runs 6 hrs without AC power **Long-Term Loss of Offsite Power:** Restore RCPs within 6 hours or Provide 100 kW of PZR heaters or Control Rod Shroud Fans or Bleed and Feed (see above)

Table 4-4
Sequence-Level and System-Level Success Criteria

Initiator Group	*Reactivity Control*	*RCS Pressure Control*	*RCS Inventory Control*	*RCS Heat Removal*
SSLOCAs (< 1")	RTS	See RCS Heat Removal	HPI and HPR: Successful RCS heat removal (1/3 AFW only) to depressurize to SI pump shutoff head <u>and</u> 1/3 SI pumps (injection and recirculation) <u>and</u> 1/2 RHR pumps (recirculation) <u>or</u> LPI and LPR: Successful RCS heat removal to depressurize to RHR pump shutoff (rapid cooldown initiated within 60 minutes) <u>and</u> 1/2 accumulators <u>and</u> 1/2 RHR pumps (injection and recirculation)	1/2 Steam Generators: 1/3 AFWPs <u>or</u> 1/2 MFWPs <u>or</u> 1/2 SAFWPS <u>and</u> 1/8 steam dump valves <u>or</u> 1/2 ARVs <u>or</u> 1/10 S/G SVs <u>and</u> HPI and HPR: 1/3 SI pumps <u>and</u> 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers <u>or</u> Rapid Cooldown: 2/2 PORVs <u>and</u> 1/2 ARVs <u>and</u> 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers
SLOCAs (1"- 2")	RTS	Not Required	HPI and HPR: 1/3 SI pumps (injection and recirculation) <u>and</u> 1/2 RHR pumps (recirculation) <u>or</u> LPI and LPR: Successful RCS heat removal to depressurize to RHR pump shutoff (rapid cooldown initiated within 60 minutes) <u>and</u> 1/2 accumulators <u>and</u> 1/2 RHR pumps (injection and recirculation)	HPI and HPR: 1/3 SI pumps <u>and</u> 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers <u>or</u> Rapid Cooldown: 2/2 PORVs <u>and</u> 1/2 ARVs <u>and</u> 1/2 RHR pumps <u>and</u> 1/2 RHR hxs <u>and</u> 1/2 Steam Generators: 1/3 AFWPs <u>or</u> 1/2 MFWPs <u>or</u> 1/2 SAFWPS <u>and</u> 1/8 steam dump valves <u>or</u> 1/2 ARVs <u>or</u> 1/10 S/G SVs
MLOCAs (2"-5")	RTS	Not Required	HPI: 1/3 SI pumps <u>and</u> LPI and LPR: 1/2 RHR pumps	HPI: 1/3 SI pumps <u>and</u> LPR: 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers
LLOCAs (> 5")	Not Required	Not Required	LPI and LPR: 1/2 RHR pumps <u>and</u> Short-Term Core Flood: 1/2 accumulators	LPI and LPR: 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers

Table 4-4
Sequence-Level and System-Level Success Criteria

Initiator Group	*Reactivity Control*	*RCS Pressure Control*	*RCS Inventory Control*	*RCS Heat Removal*
SGTRs	RTS	See RCS Inventory Control	Terminate Break Flow: 1/3 SI pumps <u>and</u> SG isolation <u>and</u> equalization of RCS and SG pressures below the ARV setpoint using PORVs <u>or</u> LPI and LPR: Rapid cooldown to RHR conditions (1/2 ARVs and 2/2 PORVs) initiated within 45 minutes <u>and</u> 1/2 RHR pumps (injection and recirculation)	1/2 Steam Generators: 1/3 AFWPs <u>or</u> 1/2 MFWPs <u>or</u> 1/2 SAFWPS <u>and</u> 1/8 steam dump valves <u>or</u> 1/2 ARVs <u>or</u> 1/10 S/G SVs

Table 4-4
Sequence-Level and System-Level Success Criteria

Initiator Group	*Reactivity Control*	*RCS Pressure Control*	*RCS Inventory Control*	*RCS Heat Removal*
ATWS	**Initiate Action Within 10 Minutes toAchieve Subcriticality:** manual rod insertion or emergency boration using 2/3 CVCS pumps (low speed stop) or emergency boration using 1/3 CVCS pumps (full speed) or trip rod MG sets	**Provide Feedwater:** MFW or AMSAC or Auto Turbine Trip and AFW Initiation **Maintain RCS Pressure < 3200 psig:** MFW or 2/2 PRZR SVs and manual rod insertion and 100% AFW and > 76 days into fuel cycle or < 76 days into fuel cycle and 1/2 PORVS or 50% AFW and > 83 days into fuel cycle or 19 to 83 days in fuel cycle and 1/2 PORVS or < 19 days into fuel cycle and 2/2 PORVs or no manual rod insertion and 100% AFW and > 193 days into fuel cycle or 139 to 193 days into fuel cycle and 1/2 PORVS or 82 to 139 days into fuel cycle and 2/2 PORVs or 50% AFW and > 209 days into fuel cycle or 155 to 209 days into fuel cycle	See RCS Pressure Control	**1/2 Steam Generators:** MFW or AFW per RCS Pressure Control and 8/8 steam dump valves or 8/8 MSSVs or 7/8 MSSVs and 1/2 ARVs or 6/8 MSSVs and 2/2 ARVs

Table 4-5
Significant Differences From UFSAR Accident Analyses

Initiator	Item	UFSAR Assumption	PSA Assumption	Justification
All	1	Only rod of highest worth remains withdrawn from the core following reactor trip.	At least one rod bank must be fully inserted into core for reactivity control (i.e., up to 24 rods may be withdrawn).	If at least one rod bank does not fully insert, then are into an ATWS event. Special consideration of transient reactivity events in ATWS tree will be included (e.g., steam line break). Also, ATWS is not a DNB concern for Condition I and II events per Reference 14.
	2	The accident analysis generally does not credit the use of the ARVs in place of the MSSVs.	Assume one ARV is equivalent to one MSSV.	UFSAR Table 5.4-7.
	3	The accident analysis assumes 1 AFW pump is available within 10 minutes.	Assume one AFW pump is required within 45 minutes.	MAAP run FW01X which shows SG dryout at 45 minutes for worst case transient.
TIIALOSS TI000SWA TI000SWB TI000CCW TI000DCA TI000DCB	1	The UFSAR does not specifically analize these events (loss of IA, SW, CCW, and DC power) since they are considered bounded by more limiting transients.	These events will be treated similarly to loss of MFW events since they are all expected to result in a loss of MFW as a minimum. The specific effects of these transients (e.g., loss of RCP seal cooling) will be specifically addressed within fault trees.	Conservative assumption.
TIFWLOSS	1	The accident analysis assumes that the PORVs will lift in order to maximize the potential for them to release liquid and stick open. However, there is no discussion of whether the PZR safeties will be challenged if the PORVs fail to lift.	The PZR safeties will not lift upon failure of the PORVs provided that sufficient SG pressure relief is available.	MAAP runs FW01T, FW01U, and FW01V. Also simulator runs.

Table 4-5
Significant Differences From UFSAR Accident Analyses

Initiator	Item	UFSAR Assumption	PSA Assumption	Justification
ATWS	1	Long-term shutdown must be initiated within 10 minutes with CVCS as one option; however, no success criteria are provided.	2/3 CVCS pumps at low speed setting or 1/3 CVCS pumps at full speed. Both require supply from 13,000 ppm BAST.	See Table 4-3.
	2	Only Condition I and II events are considered.	All Condition III and IV events will be considered with same success criteria as Condition I and II events except that steam line breaks and locked rotor events will be assumed to result in direct core damange. Large LOCA does not require evaluation consistent with accident analysis.	UFSAR does not consider Condition III and IV events due to low probability. With the two exceptions, these events are similar to, or bounded by, the evaluated Condition I and II events.
	3	Accident analysis does not address need for SG and pressurizer relief valves to reclose.	Failure to reclose will result in core damage (can transfer to LOCA trees if needed for recovery actions).	Conservative assumption to address post ATWS event requirements.
	4	Accident analysis ssumes that all control systems and components are operable. As such, only loss of MFW events actually requires use of AMSAC.	All ATWS events will require use of AMSAC without crediting use of control systems.	Conservative assumption that allows simplification of model.
TIFWLOSS TIRXTRIP	1	The accident analysis does not address the effects of MSSVs failing to open.	If more than one MSSV fails to open, then both PORVs or one PZR safety valve must open.	Conservative estimate based on PORV and PZR safety valve relief capability versus MSSVs.
TIRXTRIP	1	The accident analysis separates this event into several evaluations (e.g., loss of electrical load, rod ejection).	Assume worst case transient for each functional requirement.	Conservative assumption.
TIRCPROT	1	The UFSAR does not take any credit for the PORVs for RCS pressure relief since automatic PORV controlled is never assumed unless it makes the accident worse (for DNB considerations).	Two PORVs will be considered equivalvent to one PZR safety.	UFSAR Table 5.4-7.

Table 4-5
Significant Differences From UFSAR Accident Analyses

Initiator	Item	UFSAR Assumption	PSA Assumption	Justification
LI0SGTRA LI0SGTRB	1	Specific times are used for operator actions for mitigating the SGTR. However, these times are not "maximums", only "achievable."	Operator actions were evaluated using MAAP to provide upper time limits.	MAAP runs RUH*. Approach and times are consistent with other 2-loop plants.
TIFLBACT TIFLBBCT TIFLB0TB TIFLBAIB TIFLBBIB TIFLBSGB	1	The MFW line break is isolated within 1 minute to prevent the potential for containment overpressurization (> 60 psig).	MFW isolation is not required.	Containment is not expected to be breached until > 100 psig which provides ample margin. Also, there are multiple methods of isolating MFW including opening pump breakers, etc.
LISSLOCA LISBLOCA LIMBLOCA	1	2/3 AFW pumps are required to depressurize the RCS to SI pump shutoff head.	1/3 AFW pumps are required to depressurize the RCS to SI pump shutoff head for SSLOCA only.	MAAP runs S0ABCDE, SLOCA32, and S11BCDE-2. Also, sensitivity runs for the accident analysis show that the amount of AFW is not a limiting factor. (see ITS bases for LCO 3.7.5)
	2	2/3 SI pumps is required to mitigate the event since each pump is 50% capacity.	1/3 SI pumps is required to mitigate the event.	Accident analysis focuses on larger LOCAs (3"-6") which have different core cooling requirements. Also, depressurization rate is slow enough that additional SI is not likely to be able to inject into the RCS. For LOCAs > 1", a sensitivity study to evaluate impact of this assumption in the PSA models will be made.

Table 4-5
Significant Differences From UFSAR Accident Analyses

Initiator	Item	UFSAR Assumption	PSA Assumption	Justification
LI0SGTRA LI0SGTRB	1	Specific times are used for operator actions for mitigating the SGTR. However, these times are not "maximums", only "achievable."	Operator actions were evaluated using MAAP to provide upper time limits.	MAAP runs RUH*. Approach and times are consistent with other 2-loop plants.
TI0SLBSD TISLBSVA TISLBACT TISLBBCT TISLB0TB TISLBAIB TISLBBIB TISLBSGB	1	2/3 SI pumps is required to mitigate the event since each pump is 50% capacity.	No SI pumps are required to mitigate the event.	SI is only required for boron injection to limit the return to criticality. MAAP runs show that no SI is required for cooling. New accident analysis evaluations confirm this.

Table 4-6
Seal LOCA Support Calculations

1. *Standard formula:*

$Q = \dot{m} v$ where:

Q	is the volumetric flow rate (gpm, ft^3/sec)
v	is the specific volume (ρ^{-1}, $ft^3/lb\text{-}m$)
$\dot{m}$	is the mass flow rate (lb-m/s)

2. *MAAP formula:*

$\dot{m} = A_b G C_d$ where:

A_b	is the area of the break (in^2)
G	is the mass flux ($lb\text{-}m/ft^2\text{-}sec$)
C_d	is break discharge coefficient (0.75 per [13])

3. *Determination of equivalent break size:*

$Q = A_b G C_d v$

where A_b can be defined as:

$$A_b = \frac{\pi}{4} (d)^2 \ (ft^2)$$

$= 0.7854\ d^2$ where d is the diameter of the break (ft)

Per ASME steam tables, v at 550°F 2250 psig (hot shutdown) is 0.021335 ($ft^3/lb\text{-}m$)

Per Table 4-7, G = 22,767 ($lb\text{-}m/ft^2\text{-}sec$)

This results in:

$Q = 0.7854 \cdot d^2\ (ft^2) \cdot 22{,}767\ (lb\text{-}m/ft^2\text{-}sec) \cdot 0.75 \cdot 0.021335\ (ft^3/lb\text{-}m) \cdot 7.48\ (gal/ft^3) \cdot 60\ (sec/min)$

or $Q = 128{,}411 \cdot d^2$

With Q = 960 gpm, d = 7.48E-03 ft or 1.08 in

Table 4-7
Mass Flux Calculation
(Supports Table 4-6)

MAAP formula [13]:

$$G = \sqrt{\frac{2p_u(1-r)}{v}}$$

where		
	G	is the mass flux ($lb\text{-}m/ft^2\text{-}s$)
	p_u	is the upstream pressure (psi)
	r	is max (η_{crit}, p_d/p_u)
	v	is specific volume ($ft^3/lb\text{-}m$)
	p_d	is the downstream pressure (psi)
	η_{crit}	is min (η, p_{sat}/p_u)
	η	is 0.83 - (0.15/0.22) x
	x	is water quality ($\leq$ 0.2)

Data:

$P_u = 2250\ (lb/in^2)$

$p_{sat} = 1050\ (lb/in^2)$

$p_d = 14.7\ (lb/in^2)$

For LOCAs x = 0; hence, $\eta = 0.83$.

$\eta_{crit} = \min\ (0.83,\ 1050/2250) = 0.47$

$r = \max\ (0.47,\ 14.7/2250) = 0.47$

This results in:

$$G^2 = \{\ 2 \cdot 2250\ (lb/in^2) \cdot 144\ (in^2/ft^2) \cdot 32.2\ (lb\text{-}m\text{-}ft/lb\text{-}sec^2) \cdot (1 - 0.47)\} \div 0.021335\ (ft^3/lb\text{-}m)$$

or $G^2 = 518{,}339{,}254.7\ (lb\text{-}m^2/ft^4\text{-}s^2)$

or $G = 22{,}767\ (lb\text{-}m/ft^2\text{-}s)$

Table 4-8
Significant Success Criteria Differences From Other 2-Loop Plants

Event Tree	*Point Beach*	*Prairie Island*	*Kewaunee*
SSLOCA SLOCA	1. SG Cooling (AFW) is required for all small LOCAs (not just SSLOCA). 2. Requires cooldown to LPR conditions. 3. Provides option for feed and bleed cooling.	1. SG Cooling (AFW) is required for all small LOCAs (not just SSLOCA). 2. Requires containment heat removal for for all small LOCAs (versus crediting RHR HXs). 3. Provides option for feed and bleed cooling.	1. SG Cooling (AFW) is required for all small LOCAs (not just SSLOCA). 2. Requires cooldown to LPR conditions or use of CVCS in place of SI. 3. Provides option for feed and bleed cooling.
MLOCA	1. Provides the option to rapidly cooldown to RHR conditions using AFW and accumulators if SI is failed. 2. Requires accumulators. 3. Does not require containment cooling. 4. Requires high head recirculation. 5. Does not require RHR for injection.	1. Assumes either SI or RHR is success for injection phase.	1. Provides the option to rapidly cooldown to RHR conditions using AFW and accumulators if SI is failed. 2. Does not require containment cooling. 3. Requires high head recirculation. 4. Does not require RHR for injection.
LLOCA	1. Does not require containment cooling.	None.	1. Does not require containment cooling.
ATWS	1. Assumes all initiators can be mitigated by AMSAC. 2. Very simplified event tree with no breakdown of AFW vs. RCS pressure relief.	1. Assumes all initiators can be mitigated by AMSAC. 2. Requires containment heat removal following PZR relief valve lift.	1. Assumes all initiators can be mitigated by AMSAC.
SBO	1. Provides option for feed and bleed cooling. 2. Assumes 7 hours for core uncovery if cooldown is successful, 5 hours if not.	1. Assumes 2 hours for core uncovery following loss of AFW. 2. Requires containment heat removal following PZR relief valve lift. 3. Assumes 5 hours for core uncovery if cooldown is successful, 4 hours if not.	1. Assumes 2 hours for core uncovery following loss of AFW. 2. Assumes 11 hours for core uncovery if cooldown is successful, 9 hours if not.

Table 4-8
Significant Success Criteria Differences From Other 2-Loop Plants

Event Tree	*Point Beach*	*Prairie Island*	*Kewaunee*
Transients	1. Separates transients based on MFW availability, MSLB, MFLB, LOOP, CCW, DC power, IA, and SW; otherwise, success criteria is essentially equivalent. 2. Addresses potential for MSLB induced tube rupture (due to old tubes). 3. Requires SI for steam line breaks.	1. Separates MSLBs, FWLBs, and LOOP out from other transients; otherwise, success criteria is essentially equivalent. 2. Requires SI for steam line breaks.	1. Separates transients based on MFW availability, MSLB, MFLB, LOOP, CCW, DC power, IA, and SW; otherwise, success criteria is essentially equivalent. 2. Requires SI for steam line breaks.
SGTR	None.	None.	None.

Table 4-9
Matrix of Initiating Event Function Effects

	Reactivity Control	*Pressure and Inventory Control*				*Heat Removal*	
	RT	*ECCS*	*PV*	*SV*	*SE*	*MF*	*AF*
TIRXTRIP	x		x(1)				
TIGRLOSP	x		x			x	
TISWLOSP	x		x			x	
TI48LOSP	m				x		
TIFWLOSS	x		x			x	
TIFLBACT	x	x	x			x	
TIFLBBCT	x	x	x			x	
TIFLB0TB	x	x	x			x	x
TIFLBAIB	x	x	x			x	x
TIFLBBIB	x	x	x			x	x
TIFLBSGB	x	x	x			x	
TISLBACT	x	x	x			x	
TISLBBCT	x	x	x			x	
TISLB0TB	x	x	x			x	x
TISLBAIB	x	x	x			x	x
TISLBBIB	x	x	x			x	x
TI0SLBSD	x	x				x	
TISLBSVA	x	x				x	
TISLBSGB	x	x	x			x	
TIIALOSS	m		x			x	
TIRCPROT	x		x	x			
LIRVRUPT	x	x				x	
LISSLOCA	x	x				x	
LISBLOCA	x	x				x	
LIMBLOCA	x	x				x	
LILBLOCA	x	x				x	
LI0SGTRA	x	x				x	
LI0SGTRB	x	x				x	
LIISLOCA	x	x				x	
TI000SWn	m		x			x	x(2)
TI000CCW	m		x				
TI000DCA	x		x			x	
TI000DCB	x		x			x	

Legend:

1	loss of electrical load only	2	long term suction only
RT	automatic reactor trip results (except for "m" - manual trip by procedure)	SE	a loss of all RCP seal cooling (thermal barrier and injection) results
ECCS	a condition for automatic SI actuation results	SV	direct challenge to PZR safeties results
PV	direct challenge to PORVs results	AF	failure of preferred AFW results
MF	loss of all MFW directly results		

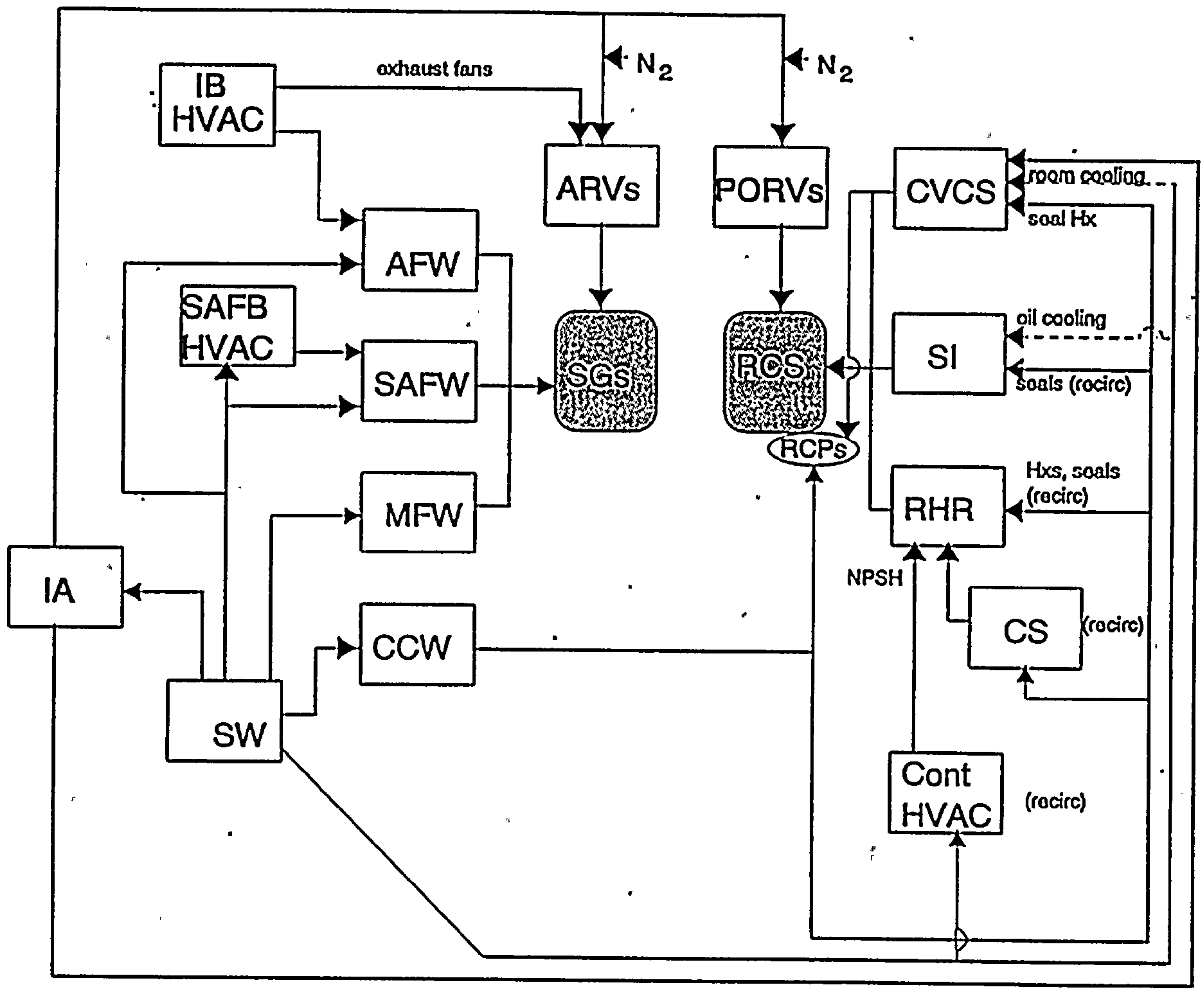
Table 4-10
Listing of Success Criteria Defined Operator Actions

Event Name	*Initiator*	*Description*
MSHFDISOLR	SGTR	Operators Fail to Isolate Ruptured SG
MFHFDMF100	SGTR TRANS SSLOCA SLOCA	Operators Fail to Re-establish MFW Flow Post Trip
RCHFDCDDPR	SGTR	Operators Fail to Cooldown and Depressurize RCS Given SI Operation to Prevent SG Overfill
RCHFDCDTR2	SGTR	Operators Fail to Cooldown to RHR After SI Fails
RCHFDCOOLD	SGTR	Operators Fail to Cooldown to RHR After ARV Sticks Open
RCHFDCDOVR	SGTR	Operators Fail to Cooldown to RHR Following SG Overfill
ACAADLOSP1	SBO	Failure to Restore Offsite Power Within 1 Hour
ACAADLOSP2	SBO	Failure to Restore Offsite Power Within 2.5 Hours (LOCAs)
ACAADLOSP5	SBO	Failure to Restore Offsite Power Within 5 Hours (SGTRs)
ACAALOSP10	TRANS	Failure to Restore Offsite Power Within 10 Hours
RCHFDPLOCA	TRANS	Operators Fail to Close PORV Block Valve (515/516) To Terminate LOCA Within 3 Minutes
RCHFD00RCP	TRANS SGTR SLOCA SSLOCA	Operators Fail to Trip RCPs Within 2 Minutes Following Loss of Support Systems
RCHFD01RCP	TRANS SGTR SLOCA SSLOCA	Operators Fail to Restore RCP Seal Cooling Within 1 Hour
RCHFD01BAF	TRANS	Operators Fail to Implement Feed and Bleed
RCHFDCD0SS	SSLOCA SLOCA	Operator Fails to Cooldown to RHR After SI Fails
RCHFDSCRAM	ATWS	Operators Fail to Trip Rod Drive MG Sets During ATWS
RCHFD00MRI	ATWS	Operators Fail to Manually Insert Rods

Table 4-10
Listing of Success Criteria Defined Operator Actions

Event Name	*Initiator*	*Description*
RRHFDRECRC	SSLOCA SLOCA MLOCA LLOCA	Operators Fail to Switch to Low-Head Recirculation
SRHFDRECRC	SSLOCA SLOCA	Operators Fail to Switch to High Head Recirculation
RCHFDMGSET	ATWS	Operators Fail to Trip Motor-Generator Sets
CVHFDBORAT	ATWS	Operators Fail to Implement Emergency Boration

Figure 4-1
Plant System Dependices



A ——▶ B Indicates that system A supports, e.g., supplies water or air to system B
A - - - ▶ B Indicates that system A supports system B but not included in PSA as documented in Section 6.

5.0 EVENT TREES

Once the success criteria have been developed, they must be translated into a logical definition of the accident progression. That is, given a specific initiating event, all of the successes and failures of the four functions discussed in Section 4.1 must be evaluated so as to determine the accident end state (e.g., core damage). Since there are multiple means of achieving each of the four core protection functions, this can be a complicated task. As such, event trees are developed for each of the initiating event groups identified in Table 4-4 (note that station blackout events (SBO) were broken out separately for reasons described below). Very large LOCAs (initiator LIRVRUPT) by definition lead to core damage since they result in break flow rates which exceed the capability of the emergency core cooling system (ECCS); consequently, no event tree was developed. Also, intersystem LOCAs are evaluated separately in Section 8.2.

An event tree represents the accident progression in a logical manner such that each success or failure state can be readily identified. Essentially, the event tree is developed based on the four core protection functions. These functions are placed on the top or header of the event tree. Since there may be several means of successfully performing the function, there is typically more than four headers. A system may also perform multiple functions (e.g., safety injection (SI) may provide both RCS inventory control and RCS pressure control following a loss-of-coolant (LOCA) accident); therefore, the number of headers may also be reduced.

The event trees developed for the Ginna Station PSA are shown in Figures 5-1 through 5-8. Using Figure 5-1 as an example, the tree begins at the left side under "TI." It is then read by moving to the right along the line until a "branch" is reached. The branch defines whether the represented header event is successful or failed (i.e., up versus down, respectively). A branch is typically found under each event tree header; however, this may not always be true since a previous branch may have already defined the success or failed state for later points in the event tree. The event tree branches are followed all the way to the right of the figure where the end state is either:

a. *OK* - Enough functions have been performed successfully to prevent core damage;

b. *CD* - One or more functions have failed such that core damage will occur; or

c. *Transfer* - The accident progression has resulted in a transfer into a second event tree which will define additional success requirements (e.g., a transient which results in a stuck open PORV will transfer to a LOCA tree).

In addition to providing a simple pictorial display of the accident progress, the event trees also serve to identify what systems must be modeled. For example, in Figure 5-1, header "B1" is titled "SG Cooling (AFW)." This header refers to the ability of auxiliary feedwater (AFW) to provide necessary SG cooling. As seen from Table 4-4, one of three AFW pumps is successful for the RCS Heat Removal function. Therefore, this portion of the event tree defines whether one of three AFW pumps either succeeds or fails. To evaluate this success or failure state, a fault tree model of the AFW system must be created. These system models are described in Section 6.0.

The following sections describe the eight event trees, including each end state.

5.1 Transient Event Tree

Figure 5-1 shows the transient event tree. The event tree is entered for every transient initiator (i.e., those initiating events which begin with TI*). The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is defined by heading, "K, Reactor Scram" which requires RCCA insertion upon a reactor trip signal. If at least one RCCA bank does not insert, the sequence transfers to the anticipated transient without scream (ATWS) event tree.

b. *RCS Pressure Control* - Success of this function is defined by "PC, RCS Pressure Control" which requires the pressurizer PORVs and/or safety valves to lift in order to maintain primary system pressure within accepted limits. Failure to achieve this would most likely result in a LOCA; however the Ginna Station PSA will conservatively assume that it directly results in core damage. Also included within event PC is failure to provide pressurizer heaters during long-term loss of reactor coolant pump events.

c. *RCS Inventory Control* - Success of this function is defined by three headings: (1) "Q1, At Least 2 PORVs/SVs Reseat," (2) "Q2, All PORVs/SVs Reseat," and (3) "Q4, RCP Seal Cooling." The first two headings refer to the number of PORVs and pressurizer safety valves which successfully reseat following their opening. If more than one PORV or safety valve sticks open (Q1), then a transfer to the medium LOCA tree occurs. If only one PORV or safety valve fails to reseat (Q2), the sequence transfers to the small LOCA tree. The last heading (Q4) addresses those transients which result in a seal LOCA due to loss of support cooling to the reactor coolant pump (RCP) seals.

d. *RCS Heat Removal* - Success of this function is defined by six headings: (1) "SG, No Steam Line Break (SG Reliefs Reseat)," (2) "MS, Main Steam Isolated," (3) "B1, SG Cooling (AFW)," (4) "L2, SG Cooling Restored (SAFW/MFW)," (5) "UH1, High Pressure Injection (Feed)," and (6) "P1, Bleed via PORVs (Bleed)." Heading SG refers to main steam line breaks and for all other transients, the successful reclosure of the steam generator (SG) relief valves. Heading MS addresses the ability to isolate the affected SG via the main steam isolation valves (MSIVs) and non-return check valves for main steam line breaks. The third and fourth headings (B1 and L2) refer to the successful injection of water into one of two SGs via either the AFW, Standby AFW (SAFW), or main feedwater (MFW) systems. The last two headings (UH1 and P1) refer to the ability to perform feed and bleed operations using SI (UH1) and the pressurizer PORVs (P1) given that AFW, SAFW, and MFW have all failed.

In addition to the above four functions, a heading related to SBO was added to the transient event tree to ensure that all SBO sequences other than those which transfer to the medium LOCA event tree (see Section 5.2) were transferred to the SBO event tree. This was done due to the unique timing issues following a SBO (e.g., battery depletion times).

The following sections discuss each of the 11 end states for the transient event tree which result in either core damage or a transfer to another event tree.

5.1.1 Sequence TI,B1,L2,P1

This accident sequence is one in which a transient occurs (TI) with a subsequent failure of all AFW (B1), SAFW, and MFW (L2). Given this scenario, operators would attempt to perform feed and bleed operations. SI is successfully performed (UH1); however, both PORVs fail to open to provide the necessary "bleed" function (P1) resulting in core damage. It should be noted that this sequence assumes that RCS pressure control (PC) and RCP seal cooling (Q4) is successful, all PORVs and safety valves (Q1 and Q2) and the SG relief valves (SG) reseat, and that no SBO (SB) has occurred. This sequence also assumes that no steam line break (SG) has occurred.

5.1.2 Sequence TI,B1,L2,UH1

This accident sequence is similar to TI,B1,L2,P1 except that the "feed" portion fails during feed and bleed. That is, a transient occurs (TI) with a subsequent failure of all AFW (B1), SAFW, and MFW (L2). Given this scenario, operators would attempt to perform feed and bleed operations; however, SI fails to provide injection (UH1) resulting in core damage. It should be noted that this sequence assumes that RCS pressure control (PC) and RCP seal cooling (Q4) is successful, all PORVs and safety valves (Q1 and Q2) and the SG relief valves (SG) reseat, and that no SBO (SB) has occurred. This sequence also assumes that no steam line break (SG) has occurred.

5.1.3 Sequence TI,SG,B1,L2,P1

This accident sequence is similar to TI,B1,L2,P1 except that the a steam line break has occured. That is, a steam line break occurs (TI) or the SG relief valves otherwise fail to reseat (SG) with a subsequent failure of all AFW (B1), SAFW, and MFW (L2). Given this scenario, operators would attempt to perform feed and bleed operations; however, the PORVs fail to open (P1) resulting in core damage. It should be noted that this sequence assumes that RCS pressure control (PC) and RCP seal cooling (Q4) is successful, all PORVs and safety valves (Q1 and Q2) reseat, safety injection (UH1) is successful in the "feed" phase, steam line isolation has occured (MS), and that no SBO (SB) has occurred.

5.1.4 Sequence TI,SG,B1,L2,UH1

This accident sequence is similar to TI,B1,L2,P1 except that the a steam line break has occured. That is, a setam line break occurs (TI) or the SG relief valves otherwise fail to reseat (SG) with a subsequent failure of all AFW (B1), SAFW, and MFW (L2). Given this scenario, operators would attempt to perform feed and bleed operations; however, SI fails to provide injection (UH1) resulting in core damage. It should be noted that this sequence assumes that RCS pressure control (PC) and RCP seal cooling (Q4) is successful, all PORVs and safety valves (Q1 and Q2) reseat, steam line isolation has occured, and that no SBO (SB) has occurred.

5.1.5 Sequence TI,SG,MS,UH1

This accident sequence is one in which a main steam line break occurs (TI and SG). Following this event, the affected SG must be isolated to prevent a uncontrolled cooldown event (MS). However, the affected SG is not isolated requiring SI in order to maintain RCS pressure and inventory which subsequently results in core damage. This sequence assumes that RCS pressure control (PC) and RCP seal cooling (Q4) is successful, all PORVs and safety valves (Q1 and Q2) reseat, and that no SBO (SB) has occurred.

5.1.6 Sequence TI,PC,UH1

This accident sequence is one in which a transient occurs (TI) and the minimum necessary primary system relief valves (i.e., PORVs and safety valves) fail to open to relieve overpressure conditions (PC). While this scenario would most likely result in a LOCA, it is unknown as to the size or location of the LOCA. Therefore, this sequence is conservatively assumed to directly result in core damage. This assumption can be reassessed if the sequence is shown to be of significance. This sequence assumes that RCP seal cooling (Q4) is successful, all open PORVs and safety valves reseat (Q1 and Q2) and no SBO (SB) has occurred.

5.1.7 Sequence TI,Q4

This accident sequence is a transient event (TI) in which RCP seal cooling is lost (Q4). This results in a seal LOCA which transfers to the small-small LOCA event tree. A seal LOCA can result from the operators failing to trip the RCPs within 2 minutes given that all support cooling is lost, or the failure to restore RCP seal cooling within 1 hour after the RCPs have been tripped to prevent long-term degradation of the seals. This sequence assumes that all PORVs and safety valves (Q1 and Q2) reseat, and that no SBO (SB) has occurred.

5.1.8 Sequence TI,Q2

This accident sequence is a transient event (TI) in which a single PORV or safety valve fails to reclose upon being challenged. This creates a PORV or safety valve LOCA which transfers to the small LOCA tree. This sequence assumes that only one PORV is stuck open (Q1).

5.1.9 Sequence TI,SB

This accident sequence refers to a transient (TI) in which a SBO has occurred (i.e., all power is lost to the 480 V safeguards buses). This sequence transfers to the SBO event tree which specifically addresses the timing issues related to restoring offsite power. The location of the SB heading was chosen based on the fact that none of the preceding headings can be recovered for a SBO event. Since all of the headings which follow the SB heading rely on the safeguards buses and/or do not transfer to the medium and large LOCA event trees, the SBO related sequences must be transferred outside of the transient event tree for further evaluation.

5.1.10 Sequence TI,Q1

This accident sequence is a transient event (TI) in which any combination of two or more PORV or safety valves fail to reclose upon being challenged and transfers to the medium LOCA tree.

5.1.11 Sequence TI,K

This accident sequence is one in which a transient occurs (TI) and the reactor trip system fails to insert at least one RCCA bank (K). This sequence then transfers to the ATWS event tree.

5.2 Station Blackout Event Tree

Figure 5-2 shows the SBO event tree. The event tree is entered for every transient, small-small and small LOCA, and steam generator tube rupture (SGTR) initiator in which all power is lost to the 480 V safeguards buses. Transfers from the medium and large LOCAs were not considered due to their low frequencies and the low likelihood of restoring offsite power within the short time frame necessary for success. The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Since the SBO tree begins from transfers from other event trees, reactivity control requirements are not specified in the SBO tree. Instead, these are specified in the transient, small-small and small LOCA, and SGTR event trees.

b. *RCS Pressure Control* - Since the SBO tree begins from transfers from other event trees, RCS pressure control requirements are not specified in the SBO tree. Instead, these are specified in the transient, small-small and small LOCA, and SGTR event trees.

c. *RCS Inventory Control* - Since the SBO tree begins from transfers from other event trees, RCS inventory control requirements are not specified in the SBO tree. Instead, these are specified in the transient, small-small and small LOCA, and SGTR event trees. However, it should be noted that RCS inventory is a consideration with respect to timing for offsite power restoration since a loss of inventory reduces the time available.

d. *RCS Heat Removal* - Success of this function is defined by all seven headings of the SBO event tree: (1) "B2, TDAFW Pump Starts and Runs," (2) "HR1, Restore Offsite Power - 1 Hr," (3), "LOCA, LOCA Event?" (4) "HRX, Restore Offsite Power - X Hrs," (5) "B3, SG Cooling (AFW)," (6) "L3, SG Cooling Restored (SAFW/MFW)," and (7) "RH3, Rapid RCS Depressurization to RHR." Heading "B2" refers to successful operation of the TDAFW pump for SG cooling. If the TDAFW pump fails, offsite power must be restored in one hour (HR1) before core damage occurs. If the TDAFW pump is successful, then offsite power must be restored within 2.25 hours for LOCA events (5 hrs for SGTRs) or 10 hours for non-LOCA events to prevent core damage. For all cases, rapid cooldown to RHR conditions or long-term (RH3) is required following recovery of offsite power.

The following sections discuss each of the 9 end states for the SBO event tree which result in core damage.

5.2.1 Sequence SBO,RH3

This accident sequence is one in which a SBO event has occurred where the TDAFW pump was initially successful (B2) and offsite power was restored within 1 hour (HR1). However, rapid depressurization to RHR conditions (RH3) fails leading to core damage. This sequence assumes that cooldown to RHR is required due to the lost RCS inventory.

5.2.2 Sequence SBO,HR1,RH3

This accident sequence is one in which a LOCA related SBO event has occurred (LOCA) where the TDAFW pump was initially successful (B2) and offsite power was not initially restored (HR1). For this sequence, offsite power is restored within 2.25 hours (HR_02); however, rapid cooldown and depressurization to RHR conditions (RH3) fails leading to core damage. Since this sequence will not generate "minimal" cutsets with respect to the overall SBO event tree (i.e., additional failures beyond those presented in SBO,RH3 would have to occur), it is typically not evaluated.

5.2.3 Sequence SBO,HR1,HR_02

This accident sequence is one in which a LOCA related SBO event has occurred (LOCA) where the TDAFW pump was initially successful (B2) and offsite power was not initially restored (HR1). For LOCA related sequences, offsite power must be restored within 2.25 hours (HR_02)(5 hours for SGTRs) to prevent core damage due to the lost RCS inventory and the expected failure of the TDAFW pump from battery depletion. For this sequence, offsite power is not restored within 4 hours leading to core damage.

5.2.4 Sequence SBO,HR1,LOCA,RH3

This accident sequence similar to SBO,HR1,RH3 except that the SBO is not LOCA related. That is, a SBO event has occurred where the TDAFW pump was initially successful (B2) and offsite power was not initially restored (HR1). For this sequence, offsite power is restored within 10 hours (HR_10); however, rapid cooldown and depressurization to RHR conditions (RH3) fails leading to core damage. Since this sequence will not generate "minimal" cutsets with respect to the overall SBO event tree (i.e., additional failures beyond those presented in SBO,RH3 would have to occur), it is typically not evaluated.

5.2.5 Sequence SBO,HR1,LOCA,HR_10

This accident sequence is similar to SBO,HR1,HR_02 except that the SBO is not LOCA related. That is, a SBO event has occurred where the TDAFW pump was initially successful (B2) and offsite power was not initially restored (HR1). For non-LOCA related sequences, offsite power must be restored within 10 hours (HR_10) to prevent core damage due to the lost RCS inventory via the degraded RCP seals and the expected failure of the TDAFW pump from battery depletion. For this sequence, offsite power is not restored within 10 hours leading to core damage.

5.2.6 Sequence SBO,B2,RH3

This sequence is similar to SBO,RH3 except that the TDAFW pump fails (B2) but offsite power is restored within 1 hour (HR1). Since this sequence will not generate "minimal" cutsets with respect to the overall SBO event tree (i.e., additional failures beyond those presented in SBO,RH3 would have to occur), it is typically not evaluated.

5.2.7 Sequence SBO,B2,B3,RH3

This sequence similar to SBO,RH3 except that: (1) AFW fails (B3) with SAFW or MFW successfully providing the necessary SG cooling function (L3), and (2) the TDAFW pump fails (B2) but offsite power is restored within 1 hour (HR1). Since this sequence will not generate "minimal" cutsets with respect to the overall SBO event tree (i.e., additional failures beyond those presented in SBO,RH3 would have to occur), it is typically not evaluated.

5.2.8 Sequence SBO,B2,B3,L3

This sequence is one in which a SBO occurs where the TDAFW pump fails to run (B2), offsite power is restored within 1 hour (HR1) but the remaining AFW (B3), SAFW and MFW (L3) pumps fail. This leads to core damage since no SG cooling is available leading to core uncovery.

5.2.9 Sequence SBO,B2,HR1

This sequence is one in which a SBO occurs where the TDAFW pump fails to run (B2) and offsite power is not restored within 1 hour (HR1). This leads to core damage since no SG cooling is available leading to core uncovery.

5.3 Small-Small LOCA Event Tree

Figure 5-3 shows the small-small LOCA event tree. This event tree is entered for every LOCA smaller than 1" and for transient initiators which result in a similar sized LOCA (i.e., RCP seal LOCA). The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is defined by heading, "K, Reactor Scram" which requires RCCA insertion upon a reactor trip signal. If at least one RCCA bank does not insert, the sequence transfers to the ATWS event tree.

b. *RCS Pressure Control* - Success of this function is really a subset of the RCS Heat Removal Function since a small-small LOCA does not require any form of RCS pressure relief other than that provided by the break. Consequently, as long as decay heat removal is successful, there is no further requirements of the RCS Pressure Control function.

c. *RCS Inventory Control* - Success of this function is defined by two headings: "UH2, High Pressure Injection (SI)" and "XH, High Pressure Recirculation (SI and RHR)." The first heading (UH2) refers to the ability of one of three SI pumps to provide injection into the RCS. The second heading (XH) requires the capability to perform high-head recirculation once the refueling water storage tank (RWST) has been depleted using the residual heat removal (RHR) and SI systems.

d. *RCS Heat Removal* - Success of this function is defined by three headings: (1) "B1, SG Cooling (AFW)," (2) "L1, SG Cooling Restored (SAFW/MFW)," and (3) "RH1, Rapid RCS Depressurization to RHR." Headings B1 and L1 refer to the successful injection of water into one of two SGs via either the AFW, SAFW, or MFW systems. This is required for both decay heat removal and to potentially support depressurization of the RCS to the shutoff head of the SI pumps. The last heading (RH1) refers to the ability to perform a rapid cooldown to RHR conditions given that AFW, SAFW, and MFW have all failed.

In addition to the above four functions, a heading related to SBO was added to the small-small event tree to ensure that these sequences were transferred to the SBO event tree. This is done due to the unique timing issues following a SBO (e.g., battery depletion times).

The following sections discuss each of the 7 end states for the small-small LOCA event tree which result in either core damage or a transfer to another event tree.

5.3.1 Sequence SS,XH,RH1

This accident sequence is one in which a small-small LOCA occurs (SS) and high-head recirculation fails (XH) given that SI was initially successful (UH2). Following the failure of high-head recirculation, a failure to reach RHR conditions by rapidly cooling down the RCS occurs (RH1) resulting in core damage. This sequence assumes that no SBO (SB) has occurred, and that AFW (B1) is successful.

5.3.2 Sequence SS,UH2,RH1

This accident sequence is similar to SS,XH,RH1 except that SI fails (UH2) prior to reaching high-head recirculation conditions. That is, a small-small LOCA occurs (SS) with a subsequent failure of SI. This is followed by a failure to reach RHR conditions by rapidly cooling down the RCS (RH1) resulting in core damage. This sequence assumes that no SBO (SB) has occurred, and that AFW (B1) is successful.

5.3.3 Sequence SS,B1,XH,RH1

This accident sequence is identical to SS,XH,RH1 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall small-small LOCA event tree (i.e., additional failures beyond those presented in SS,XH,RH1 would have to occur), it is typically not evaluated.

5.3.4 Sequence SS,B1,UH2,RH1

This accident sequence is identical to SS,UH2,RH1 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall small-small LOCA event tree (i.e., additional failures beyond those presented in SS,UH2,RH1 would have to occur), it is typically not evaluated.

5.3.5 Sequence SS,B1,L1

This accident sequence is one in which a small-small LOCA occurs (SS) with a subsequent failure of AFW (B1), SAFW and MFW (L1) resulting in core damage. Given this scenario, operators could potentially open the PORVs in order to create a larger LOCA and thus cool down to RHR conditions; however, this was considered a highly unlikely success path and was ignored. This sequence assumes that no SBO (SB) has occurred.

5.3.6 Sequence SS,SB

This accident sequence refers to a small-small LOCA (S) in which a SBO has occurred (i.e., all power is lost to the 480 V safeguards buses). This sequence transfers to the SBO event tree which specifically addresses the timing issues related to restoring offsite power. The location of the SB heading was chosen based on the fact that all of the subsequent headings require the 480 V safeguards buses such that the SBO related sequences must be transferred outside of the small-small LOCA event tree prior to evaluating these functions.

5.3.7 Sequence SS,K

This accident sequence is one in which a small-small LOCA occurs (SS) and the reactor trip system fails to insert at least one RCCA bank (K). This sequence then transfers to the ATWS event tree.

5.4 Small LOCA Event Tree

Figure 5-4 shows the small LOCA event tree. This event tree is entered for every break size between 1" and 2" and for transient initiators which result in a similar sized LOCA (i.e., PORV or pressurizer safety valve LOCA). The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is defined by heading, "K, Reactor Scram" which requires RCCA insertion upon a reactor trip signal. If at least one RCCA bank does not insert, the sequence transfers to the ATWS event tree.

b. *RCS Pressure Control* - Success of this function is assured by the break size which is equivalent to a pressurizer PORV or safety valve. Consequently, there are no further requirements of the RCS Pressure Control function.

c. *RCS Inventory Control* - Success of this function is defined by two headings: "UH2, High Pressure Injection (SI)" and "XH, High Pressure Recirculation (SI and RHR)." The first heading (UH2) refers to the ability of one of three SI pumps to provide injection into the RCS. The second heading (XH) requires the capability to perform high-head recirculation once the refueling water storage tank (RWST) has been depleted using the residual heat removal (RHR) and SI systems. However, if either of the two preferred means fail, cooldown to RHR conditions using AFW is a successful alternative. This alternative is defined by three headings: (1) "B1, SG Cooling (AFW)," (2) "L1, SG Cooling Restored (SAFW/MFW)," and (3) "RH1, Rapid RCS Depressurization to RHR."

d. *RCS Heat Removal* - Success of this function is really a subset of the RCS Inventory Function in that SI and high-head recirculation provide the necessary core cooling. In the event that these systems fail, then cooldown to RHR conditions using AFW is a successful alternative.

In addition to the above four functions, a heading related to SBO was added to the small event tree to ensure that these sequences were transferred to the SBO event tree. This is due to the unique timing issues following a SBO (e.g., battery depletion times).

The following sections discuss each of the 8 end states for the small LOCA event tree which result in either core damage or a transfer to another event tree.

5.4.1 Sequence S,XH,RH1

This accident sequence is one in which a small LOCA occurs (S) and high-head recirculation fails (XH) given that SI was initially successful (UH2). Following the failure of high-head recirculation, a failure to reach RHR conditions by rapidly cooling down the RCS occurs (RH1) resulting in core damage. This sequence assumes that AFW is successful (B1), and no SBO (SB) has occurred.

5.4.2 Sequence S,XH,B1,RH1

This accident sequence is identical to S,XH,RH1 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall small LOCA event tree (i.e., additional failures beyond those presented in S,XH,RH1 would have to occur), it is typically not evaluated.

5.4.3 Sequence S,XH,B1,L1

This accident sequence is one in which a small LOCA occurs (S) and high-head recirculation fails (XH) given that SI was initially successful (UH2). Following the failure of high-head recirculation, an attempt to cooldown to RHR conditions is unsuccessful due to a failure of AFW (B1) and SAFW and MFW (L1), resulting in core damage. This sequence assumes that no SBO (SB) has occurred.

5.4.4 Sequence S,UH2,RH1

This accident sequence is one in which a small LOCA occurs (S) and SI subsequently fails (UH2). Following the failure of SI, an attempt to cooldown to RHR conditions fails (RH1), resulting in core damage. This sequence assumes that no SBO (SB) has occurred and that AFW (B1) is successful.

5.4.5 Sequence S,UH2,B1,RH1

This accident sequence is identical to S,UH2,RH1 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall small LOCA event tree (i.e., additional failures beyond those presented in S,UH2,RH1 would have to occur), it is typically not evaluated.

5.4.6 Sequence S,UH2,B1,L1

This accident sequence is one in which a small LOCA occurs (S) and SI subsequently fails (UH2). Following the failure of SI, an attempt to cooldown to RHR conditions is unsuccessful due to a failure of AFW (B1) and SAFW and MFW (L1); resulting in core damage. This sequence assumes that no SBO (SB) has occurred.

5.4.7 Sequence S,SB

This accident sequence refers to a small LOCA (S) in which a SBO has occurred (i.e., all power is lost to the 480 V safeguards buses). This sequence transfers to the SBO event tree which specifically addresses the timing issues related to restoring offsite power. The location of the SB heading was chosen based on the fact that all of the subsequent headings require the 480 V safeguards buses such that the SBO related sequences must be transferred outside of the small LOCA event tree prior to evaluating these functions.

5.4.8 Sequence S,K

This accident sequence is one in which a small LOCA occurs (S) and the reactor trip system fails to insert at least one RCCA bank (K). This sequence then transfers to the ATWS event tree.

5.5 Medium LOCA Event Tree

Figure 5-5 shows the medium LOCA event tree. This event tree is entered for every break size between 2" and 5" and for transient initiators which result in a similar sized LOCA (i.e., multiple PORV or pressurizer safety valve LOCA). The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is defined by heading, "K, Reactor Scram" which requires RCCA insertion upon a reactor trip signal. If at least one RCCA bank does not insert, the sequence transfers to the ATWS event tree.

b. *RCS Pressure Control* - Success of this function is assured by the break size which is greater than that of a single pressurizer PORV or safety valve. Consequently, there are no further requirements of the RCS Pressure Control function.

c. *RCS Inventory Control* - Success of this function is defined by five headings: (1) "UH2, High Pressure Injection (SI)," (2) "UL, Low Pressure Injection (RHR)," (3) "XL, Low Pressure Recirculation (RHR)," (4) "FC, Containment Fan Coolers," and (5) "UCS, Containment Spray." The first two headings refers to the ability of one of three SI pumps (UH2) and one of two RHR pumps (UL) to provide injection into the RCS. The third heading (XL) requires the capability to perform low pressure recirculation once the RWST has been depleted using the RHR system. The fourth and fifth headings refer to maintaining containment cooling using either the containment recirculation fan coolers (FC) or containment spray system (UCS) since the failure of these systems could lead to a containment failure which directly affects SI and RHR.

d. *RCS Heat Removal* - Success of this function is really a subset of the RCS Inventory Function in that SI, RHR, and low pressure recirculation provide the necessary core cooling.

The following sections discuss each of the 5 end states for the medium LOCA event tree which result in either core damage or a transfer to another event tree.

5.5.1 Sequence M,FC,UCS

This accident sequence is one in which a medium LOCA occurs (M) and all forms of containment cooling fail (FC and UCS). This scenario is assumed to eventually result in containment failure which could fail RHR and/or SI piping inside containment or fail RHR NPSH requirements resulting in core damage. This sequence assumes that SI (UH2), RHR (UL) and low pressure recirculation (XL) are successful.

5.5.2 Sequence M,XL

This accident sequence is one in which a medium LOCA occurs (M) and low pressure recirculation (XL) subsequently fails resulting in core damage. This sequence assumes that SI (UH2) and RHR (UL) are successful.

5.5.3 Sequence M,UL

This accident sequence is one in which a medium LOCA occurs (M) and low pressure injection (UL) subsequently fails resulting in core damage. This sequence assumes that SI (UH2) is successful.

5.5.4 Sequence M,UH2

This accident sequence is one in which a medium LOCA occurs (M) and SI (UH2) subsequently fails resulting in core damage.

5.5.5 Sequence M,K

This accident sequence is one in which a medium LOCA occurs (M) and the reactor trip system fails to insert at least one RCCA bank (K). This sequence then transfers to the ATWS event tree.

5.6 Large LOCA Event Tree

Figure 5-6 shows the large LOCA event tree. This event tree is entered for every break size > 5". The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is provided by RCS Inventory Control which injects enough borated water to render the reactor core subcritical. Consequently, there are no further requirements of the Reactivity Control function.

b. *RCS Pressure Control* - Success of this function is assured by the break size which is greater than that of a single pressurizer PORV or safety valve. Consequently, there are no further requirements of the RCS Pressure Control function.

c. *RCS Inventory Control* - Success of this function is defined by five headings: (1) "UA, Accumulators", (2) "UL, Low Pressure Injection (RHR)," (3) "XL, Low Pressure Recirculation (RHR)," (4) "FC, Containment Fan Coolers," and (5) "UCS, Containment Spray." The first two headings refers to the ability of one of two accumulators (UA) and one of two RHR pumps (UL) to provide injection into the RCS. The third heading (XL) requires the capability to perform low pressure recirculation once the RWST has been depleted using the RHR system. The fourth and fifth headings refer to maintaining containment cooling using either the containment recirculation fan coolers (FC) or containment spray system (UCS) since the failure of these systems could lead to a containment failure which directly affects SI and RHR.

d. *RCS Heat Removal* - Success of this function is really a subset of the RCS Inventory Function in that the accumulators, RHR, and low pressure recirculation provide the necessary core cooling.

The following sections discuss each of the 4 end states for the large LOCA event tree which result in either core damage or a transfer to another event tree.

5.6.1 Sequence A,FC,UCS

This accident sequence is one in which a large LOCA occurs (A) and all forms of containment cooling fail (FC and UCS). This scenario is assumed to eventually result in containment failure which could fail RHR piping inside containment or fail RHR NPSH requirements resulting in core damage. This sequence assumes that the accumulators (UA), RHR (UL), and low pressure recirculation (XL) are successful.

5.6.2 Sequence A,XL

This accident sequence is one in which a large LOCA occurs (A) and low pressure recirculation (XL) subsequently fails resulting in core damage. This sequence assumes that the accumulators (UA) and RHR (UL) are successful.

5.6.3 Sequence A,UL

This accident sequence is one in which a large LOCA occurs (A) and low pressure injection (UL) subsequently fails resulting in core damage. This sequence assumes that the accumulators (UA) successful.

5.6.4 Sequence A,UA

This accident sequence is one in which a large LOCA occurs (A) and the accumulators subsequently fail resulting in core damage.

5.7 Steam Generator Tube Rupture Event Tree

Figure 5-7 shows the steam generator tube rupture (SGTR) event tree. This event tree is entered for all LOCAs which occur in the SGs. The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Success of this function is defined by heading, "K, Reactor Scram" which requires RCCA insertion upon a reactor trip signal. If at least one RCCA bank does not insert, the sequence transfers to the ATWS event tree.

b. *RCS Pressure Control* - Success of this function is really a subset of the RCS Inventory Control since the primary response to a SGTR is to equalize pressure between the secondary and primary systems in order to terminate the break flow prior to depletion of the RWST. Consequently as long as RCS Inventory Control is successful, there is no further requirements of the RCS Pressure Control function.

c. *RCS Inventory Control* - Success of this function is defined by six headings: (1) "I1, Ruptured SG Isolated," (2) "UH2, Safety Injection," (3) "D1, RCS Cooldown and Depressurization," (4) "I2, Ruptured SG ARV Closure," (5) "P3, Rapid Depressurization Using SGs," and (6) "RH2, Long-Term Cooling (RHR) Achieved." The first heading (I1) identifies whether the operators have successfully isolated the ruptured SG since failure to accomplish this requires cooldown to RHR conditions prior to RWST depletion. The second heading (UH2) refers to the ability of one of three SI pumps to provide injection into the RCS. The third heading (D1) addresses the ability of the operators to open the ARVs and PORVs in order to cooldown and depressurize the RCS to terminate the break flow by equalizing pressure between the primary and secondary systems. The fourth heading (I2) is similar to (I1) in that the ruptured SG ARV sticks open (after the intact SG ARV fails to open) requiring a rapid cooldown to RHR conditions prior to RWST depletion. The last two headings (P3 and RH2) address the capability to rapidly cooldown to RHR conditions given that the ruptured SG cannot be isolated or SI is not available.

d. *RCS Heat Removal* - Success of this function is defined by two headings: (1) "B1, SG Cooling (AFW)," and (2) "L1, SG Cooling Restored (SAFW/MFW)." These headings refer to the successful injection of water into one of two SGs via either the AFW, SAFW, or MFW systems. This is required for both decay heat removal and to potentially support depressurization of the RCS to the shutoff head of the SI pumps.

In addition to the above four functions, a heading related to SBO was added to the SGTR event tree to ensure that these sequences were transferred to the SBO event tree. This is due to the unique timing issues following a SBO (e.g., battery depletion times).

The following sections discuss each of the 15 end states for the small-small LOCA event tree which result in either core damage or a transfer to another event tree.

5.7.1 Sequence R,I2,RH2_01

This accident sequence is one in which a SGTR occurs (R) and the ARV on ruptured SG must be opened (due to failure of the other ARV) which then fails to close (I2). Subsequently, long-term cooling via RHR fails (RH2) leading to core damage. This sequence assumes that the ruptured SG is initially isolated (I1), SI (UH2) and AFW (B1) is successful, and the ARV and PORV are successfully used to initially equalize primary and secondary system pressures.

5.7.2 Sequence R,D1,RH2_01

This accident sequence is one in which a SGTR occurs (R) and the ARV and/or PORV fail to open (D1) such that the break flow into the ruptured SG cannot be stopped prior to SG overfill. This leads to a stuck open SG relief valve, but long-term cooling via RHR fails (RH2) leading to core damage. This sequence assumes that the ruptured SG is initially isolated (I1), and that SI (UH2) and AFW (B1) is successful.

5.7.3 Sequence R,B1,I2,RH2_01

This accident sequence is identical to R,I2,RH2_01 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,I2,RH2_01 would have to occur), it is typically not evaluated.

5.7.4 Sequence R,B1,D1,RH2_01

This accident sequence is identical to R,D1,RH2_01 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,D1,RH2_01 would have to occur), it is typically not evaluated.

5.7.5 Sequence R,B1,L1

This accident sequence is one in which a SGTR occurs (R) and AFW (B1) and SAFW/MFW (L1) all fail. The break flow is insufficient to cool down the RCS to RHR conditions on its own such that core damage occurs. This sequence assumes that the ruptured SG is initially isolated (I1) and that SI (UH2) is successful.

5.7.6 Sequence R,UH2,RH2_02

This accident sequence is one in which a SGTR occurs (R) and SI fails (UH2). The operators must now attempt to achieve RHR cooling prior to depletion of the RWST which fails (RH2) leading to core damage. This sequence assumes that the ruptured SG is initially isolated (I1) and AFW (B1) is successful.

5.7.7 Sequence R,UH2,P302

This accident sequence is one in which a SGTR occurs (R) and SI fails (UH2). The operators must now attempt to achieve RHR cooling prior to depletion of the RWST, but the ARVs fail to open to provide cooldown capability (P302). If this sequence proves to be a significant contributer, utilizing the condenser can be considered as an alternative. This sequence assumes that the ruptured SG is initially isolated (I1) and AFW (B1) is successful.

5.7.8 Sequence R,UH2,B1,RH2_02

This accident sequence is identical to R,UH2,RH2_02 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,UH2,RH2_02 would have to occur), it is typically not evaluated.

5.7.9 Sequence R,UH2,B1,P302

This accident sequence is identical to R,UH2,P302 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,UH2,P302 would have to occur), it is typically not evaluated.

5.7.10 Sequence R,UH2,B1,L1

This accident sequence is identical to R,B1,L1 except that SI also fails (UH2). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,B1,L1 would have to occur), it is typically not evaluated.

5.7.11 Sequence R,I1,RH2_02

This accident sequence is one in which a SGTR occurs (R) and the ruptured SG is not isolated (I1). Operators must now attempt to achieve RHR cooling prior to depletion of the RWST which fails (RH2), leading to core damage. This sequence assumes that AFW (B1) is successful.

5.7.12 Sequence R,I1,B1,RH2_02

This accident sequence is identical to R,I1,RH2_02 except that AFW fails (B1) with SAFW or MFW successfully providing the necessary SG cooling function (L1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,I1,RH2_02 would have to occur), it is typically not evaluated.

5.7.13 Sequence R,I1,B1,L1

This accident sequence is identical to R,B1,L1 except that the ruptured SG is not isolated (I1). Since this sequence will not generate "minimal" cutsets with respect to the overall SGTR event tree (i.e., additional failures beyond those presented in R,I1,L1 would have to occur), it is typically not evaluated.

5.7.14 Sequence R,SB

This accident sequence refers to a SGTR (R) in which a SBO has occurred (i.e., all power is lost to the 480 V safeguards buses). This sequence transfers to the SBO event tree which specifically addresses the timing issues related to restoring offsite power. The location of the SB heading was chosen based on the fact that all of the subsequent headings require the 480 V safeguards buses such that the SBO related sequences must be transferred outside of the SGTR event tree prior to evaluating these functions.

5.7.15 Sequence R,K

This accident sequence is one in which a SGTR occurs (R) and the reactor trip system fails to insert at least one RCCA bank (K). This sequence then transfers to the ATWS event tree.

5.8 ATWS Event Tree

Figure 5-8 shows the ATWS event tree. This event tree is entered for every transient in which at least one RCCA bank did not insert and render the reactor core subcritical. The relationship of the event tree headings and the four core protection functions described in Table 4-4 is as follows:

a. *Reactivity Control* - Failure of this function is attributed to either an electrical or mechanical failure of the reactor protection system (RPS). These failures are addressed by headings "KE, Electrical Scram" and "KM, Mechanical Scram," respectively. Given that a failure of the RPS has occurred, success of the reactor control function is defined by three headings: (1) "RI, Manual Rod Insertion," (2) "KI, Initiator Can Be Mitigated," and (3) "LT, Reactivity Control." The first header (RI) refers to the operators manually inserting the RCCAs given that there is an electrical failure of the RPS. The second header (KI) identifies whether the event can be mitigated since large steam line breaks and RCP locked rotor events are assumed to directly result in core damage (see Section 4.2.2.1). The final heading (LT) refers to the need for operators to initiate emergency boration within 10 minutes using the Charging system.

b. *RCS Pressure Control* - Success of this function is defined by four headings: (1) "MF, MFW Available," (2) "TT, Turbine Trip/AFW Initiation," (3) "AM, AMSAC Initiation," and (4) "PR, Primary Pressure Relief." The first heading (MF) refers to the fact that if MFW is available, then enough cooling water is being provided to the SGs to mitigate the event. However, if MFW is unavailable, then a turbine trip and AFW initiation must occur from either the installed systems (TT) or via AMSAC (AM). Given that some form of feedwater is being provided to the steam generators, then the PORVs and pressurizer safeties must be available to provide for RCS pressure relief (PR) to maintain the RCS below 3200 psig. Note that the required amount of RCS pressure relief is dependent upon the number of AFW pumps available (see RCS Heat Removal). Consequently, there are actually four events contained within PR (i.e., PR01, PR02, PR03, and PR04).

c. *RCS Inventory Control* - Since the RCS is at greater than full power conditions with no primary system breaks, there is no requirement for this function.

d. *RCS Heat Removal* - Success of this function is defined by three headings: (1) "MF, MFW Available," (2) "FF, 100% AFW Flow," and (3) "PF, 50% AFW Flow." These headings define the three conditions of where MFW is available, and where 100% and 50% of AFW is available, respectively. The amount of MFW and AFW defines both the RCS heat removal capability and the success requirements for the PORVs and pressurizer safety valves (see RCS pressure control).

The following sections discuss each of the 25 end states for the ATWS event tree which result in core damage.

5.8.1 Sequence IE,KE,MF,PR01

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) where MFW is unavailable (MF). AFW is successfully initiated by AMSAC (AM), but the associated RCS pressure relief requirements are not successful (PR01) which leads to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the operators successfully insert the rods (RI). Also, AMSAC is assumed to initiate 100% of AFW.

5.8.2 Sequence IE,KE,MF,FF,PR02

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) where MFW is unavailable (MF). AFW is successfully initiated by AMSAC (AM), but the associated RCS pressure relief requirements are not successful (PR02) which leads to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the operators successfully insert the rods (RI). Also, AMSAC is assumed to initiate only 50% of the available AFW (i.e., failure of event FF with success of event

PF).

5.8.3 Sequence IE,KE,MF,FF,PF

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) where MFW is unavailable (MF). AFW is successfully initiated by AMSAC (AM), but the AFW system subsequently fails (FF and PF) leading to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the operators successfully insert the rods (RI).

5.8.4 Sequence IE,KE,MF,AM

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) where MFW is unavailable (MF). AMSAC fails to actuate AFW (AM) which leads to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the operators successfully insert the rods (RI).

5.8.5 Sequence IE,KE,RI,LT

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with a subsequent failure of the operators to insert the rods (RI) and achieve long-term boration (LT) which leads to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM), MFW is available (MF), and that the initiator can be mitigated (KI).

5.8.6 Sequence IE,KE,RI,MF,LT

This accident sequence is identical to IE,KE,RI,LT except that MFW is assumed to be unavailable (MF). Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KE,RI,LT would have to occur), it is typically not evaluated.

5.8.7 Sequence IE,KE,RI,MF,PR03

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with no MFW available (MF) and a failure of the operators to insert the rods (RI). AFW is successfully initiated by AMSAC (AM), but the RCS pressure relief is unsuccessful leading to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the initiator can be mitigated (KI). Also, AMSAC is assumed to initiate 100% of AFW.

5.8.8 Sequence IE,KE,RI,MF,FF,LT

This accident sequence is identical to IE,KE,RI,LT except that MFW is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KE,RI,LT would have to occur), it is typically not evaluated.

5.8.9 Sequence IE,RI,MF,FF,PR04

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with no MFW available (MF) and a failure of the operators to insert the rods (RI). AFW is successfully initiated by AMSAC (AM), but RCS pressure relief is unsuccessful (PR04) leading to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the initiator can be mitigated (KI). Also, AMSAC is assumed to initiate only 50% of the available AFW (i.e., failure of event FF with success of event PF).

5.8.10 Sequence IE,KE,RI,MF,FF,PF

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with no MFW available (MF) and a failure of the operators to insert the rods (RI). AFW is successfully initiated by AMSAC (AM), but AFW subsequently fails (FF and PF) leading to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the initiator can be mitigated (KI).

5.8.11 Sequence IE,KE,RI,MF,AM

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with no MFW available (MF), and a failure of the operators to insert the rods (RI). AMSAC subsequently fails (AM) which leads to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM) and that the initiator can be mitigated (KI).

5.8.12 Sequence IE,KE,RI,KI

This accident sequence is an ATWS event (IE) caused by an electrical failure of the RPS (KE) with no MFW available (MF) and a failure of the operators to insert the rods (RI). Given these conditions, the subject initiating event cannot be mitigated (e.g., RCP locked rotor event) (KI) leading to a high pressure core damage scenario. This sequence assumes that the rods are capable of mechanically scramming (KM).

5.8.13 Sequence IE,KM,LT

This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) and a failure of long-term boration (LT) which fails leading to a high pressure core damage scenario. This sequence assumes that the initiator can be mitigated (KI) and that MFW is available (MF).

5.8.14 Sequence IE,KM,MF,LT

This accident sequence is identical to IE,KM,LT except that MFW is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,LT would have to occur), it is typically not evaluated.

5.8.15 Sequence IE,KM,MF,PR03

This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) with no MFW available (MF). AFW is successfully initiated by its installed start logic (TT) but RCS pressure relief is unsuccessful (PR03) leading to a high pressure core damage scenario. This sequence assumes that the initiator can be mitigated (KI) and that 100% of AFW is initiated.

5.8.16 Sequence IE,KM,MF,FF,LT

This accident sequence is identical to IE,KM,LT except that MFW is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,LT would have to occur), it is typically not evaluated.

5.8.17 Sequence IE,KM,MF,FF,PR04

This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) with no MFW available (MF). AFW is successfully initiated by its installed start logic (TT) but RCS pressure relief is unsuccessful (PR04) leading to a high pressure core damage scenario. This sequence assumes that the initiator can be mitigated (KI) and 50% of the available AFW is initiated (i.e., failure of event FF with success of event PF).

5.8.18 Sequence IE,KM,MF,FF,PF

This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) with no MFW available (MF). AFW is successfully initiated by its installed start logic (TT) but AFW subsequently fails (FF and PF) leading to a high pressure core damage scenario. This sequence assumes that the initiator can be mitigated (KI).

5.8.19 Sequence IE,KM,MF,TT,LT

This accident sequence is identical to IE,KM,LT except that MFW is assumed to be unavailable (MF). Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,LT would have to occur), it is typically not evaluated.

5.8.20 Sequence IE,KM,MF,TT,PR03

This accident sequence is identical to IE,KM,MF,PR03 except that the installed AFW start logic (TT) is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,MF,PR03 would have to occur), it is typically not evaluated.

5.8.21 Sequence IE,KM,MF,TT,FF,LT

This accident sequence is identical to IE,KM,MF,FF,LT except that the installed AFW start logic (TT) is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,MF,FF,LT would have to occur), it is typically not evaluated.

5.8.22 Sequence IE,KM,MF,TT,FF,PR04

This accident sequence is identical to IE,KM,MF,FF,PF04 except that the installed AFW start logic (TT) is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,MF,FF,PF04 would have to occur), it is typically not evaluated.

5.8.23 Sequence IE,KM,MF,TT,FF,PF

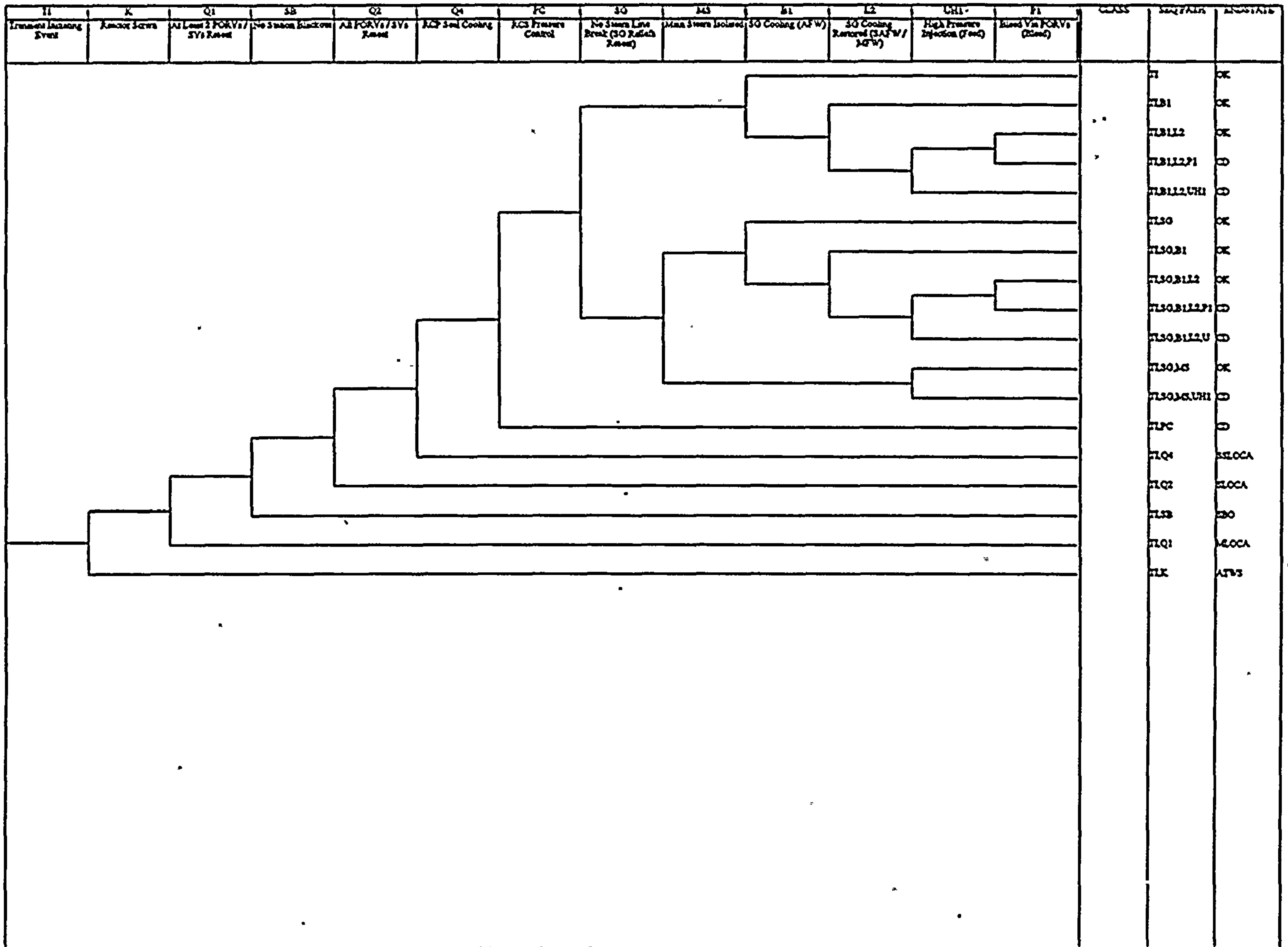
This accident sequence is identical to IE,KM,MF,FF,PF except that the installed AFW start logic (TT) is assumed to be unavailable. Since this sequence will not generate "minimal" cutsets with respect to the overall ATWS event tree (i.e., additional failures beyond those presented in IE,KM,MF,FF,PF would have to occur), it is typically not evaluated.

5.8.24 Sequence IE,KM,MF,TT,AM

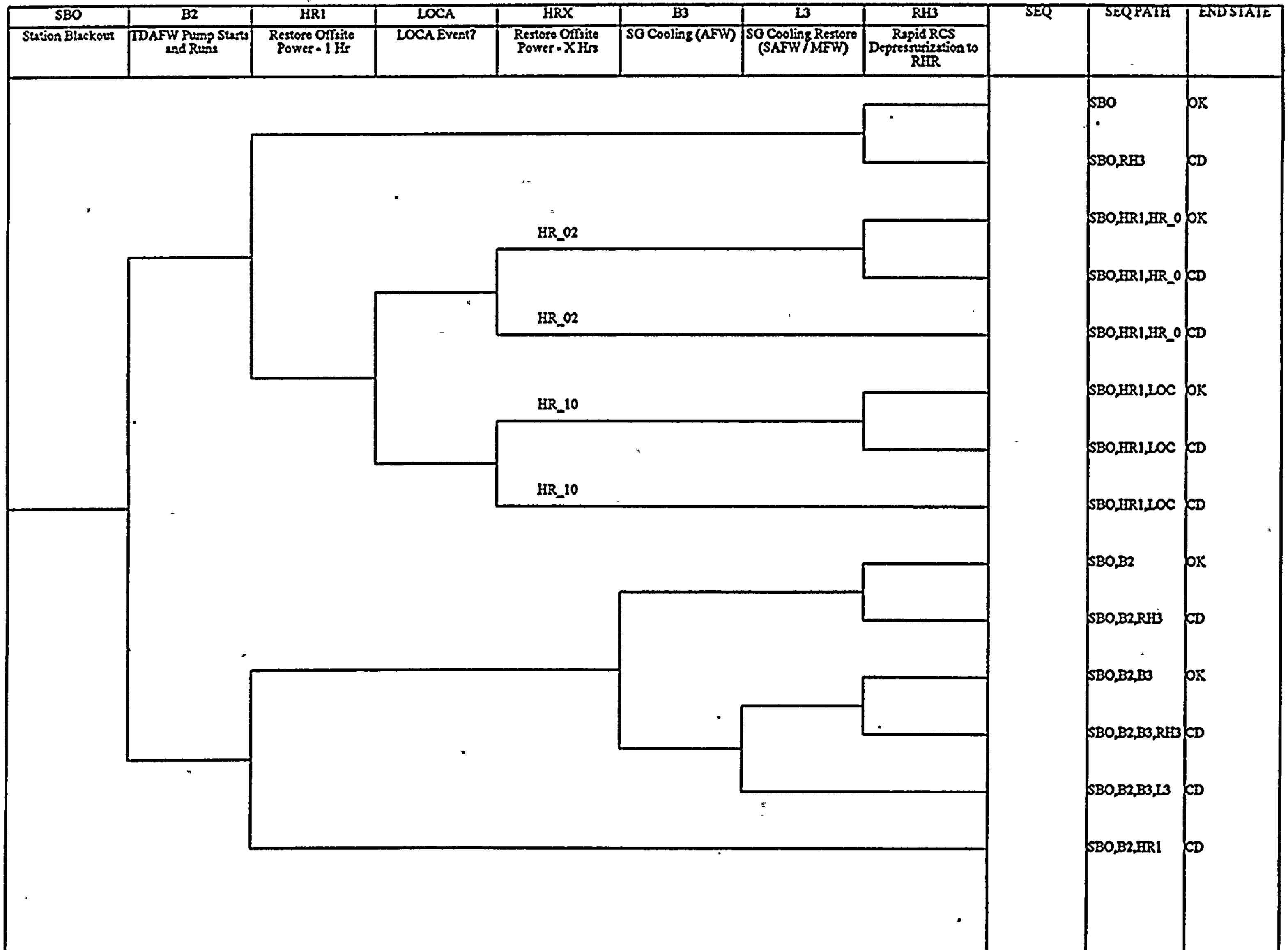
This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) with no MFW available (MF). However, AFW is not initiated due to failure of the installed system (TT) and AMSAC (AM) leading to a high pressure core damage scenario. This sequence assumes that the initiator can be mitigated (KI).

5.8.25 Sequence IE,KM,KI

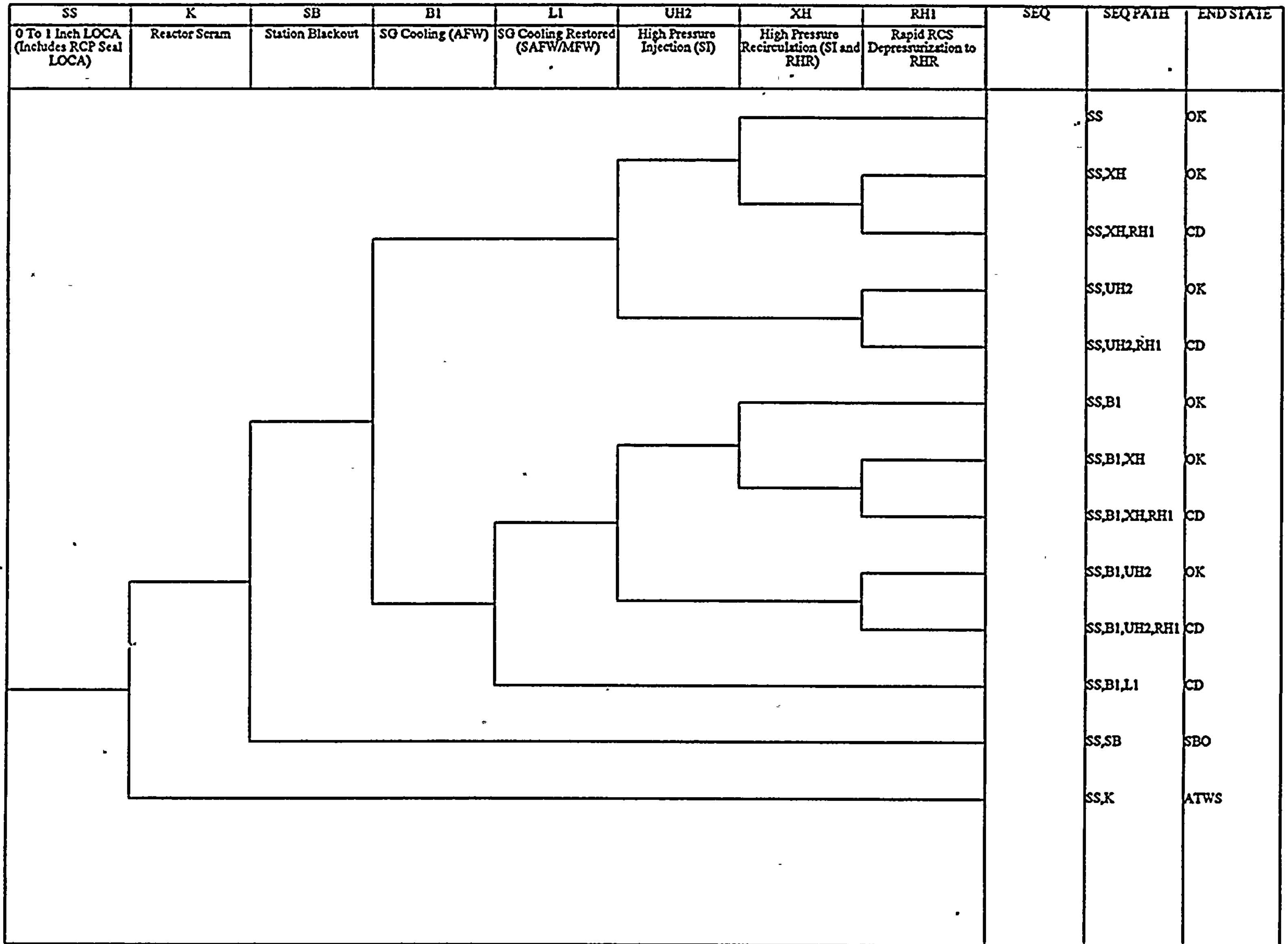
This accident sequence is an ATWS event (IE) caused by an mechanical failure of the RPS (KM) which cannot be mitigated due to the subject initiating event (e.g., RCP locked rotor) (KI) leading to a high pressure core damage scenario.



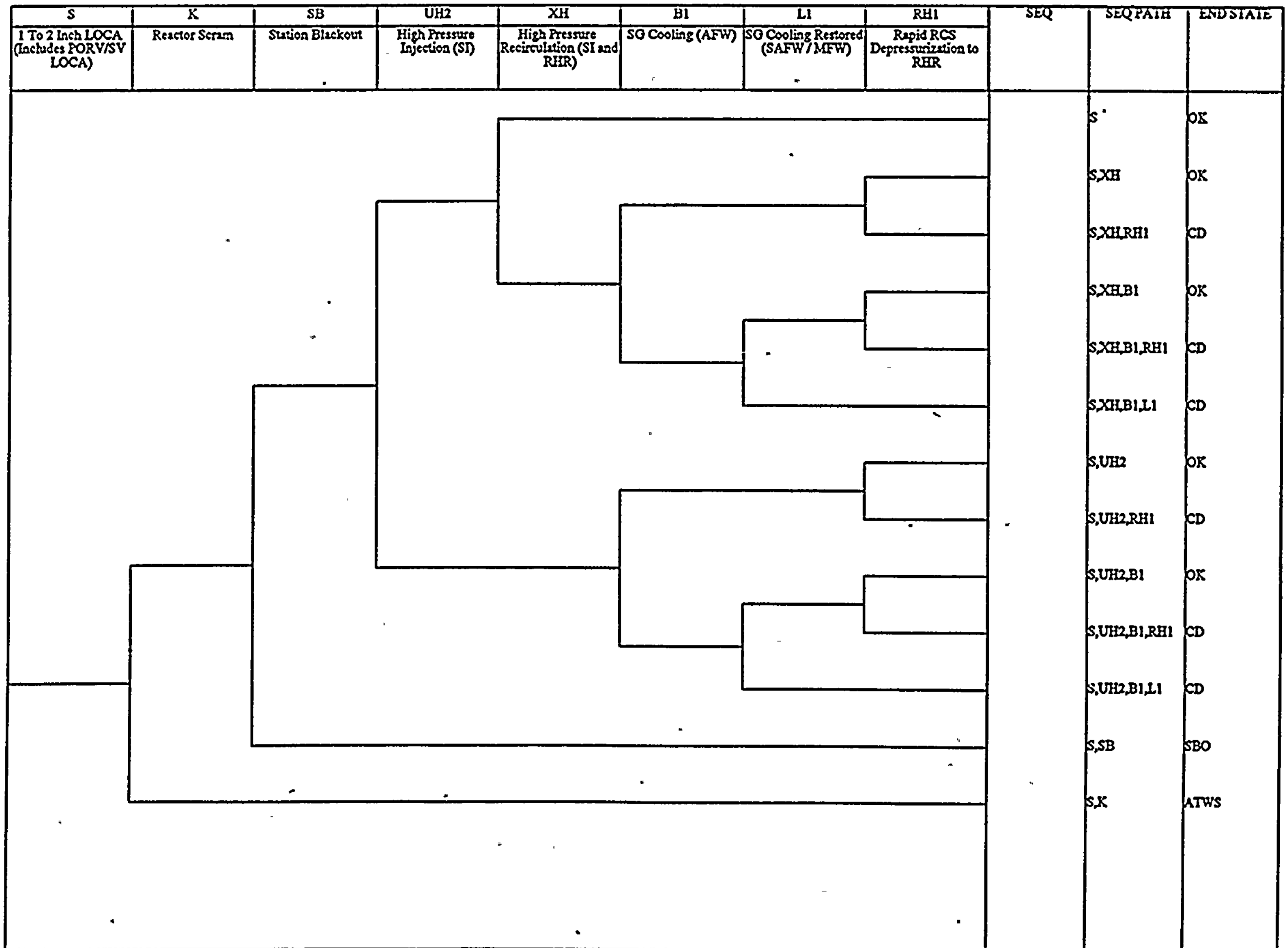
TRANSIENT EVENT TREE - FIGURE 5-1	C:\CAFTA-W\ETA\GINTRANS.ETA	1/5/97	Page 1



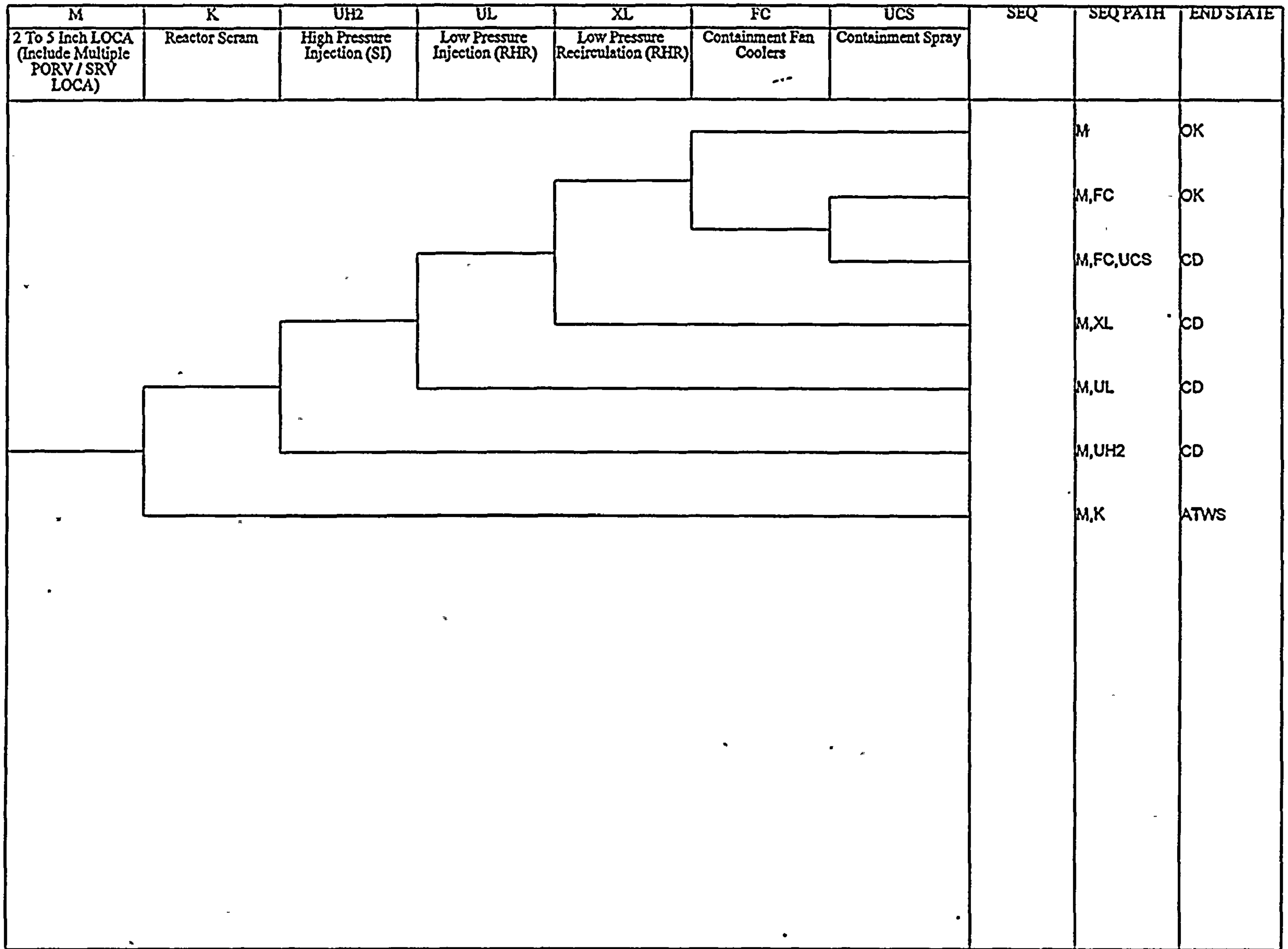
STATION BLACKOUT EVENT TREE - FIGURE 5-2	C:\CAFTA-W\ETA\GINSBO.ETA	1/5/97	Page 1



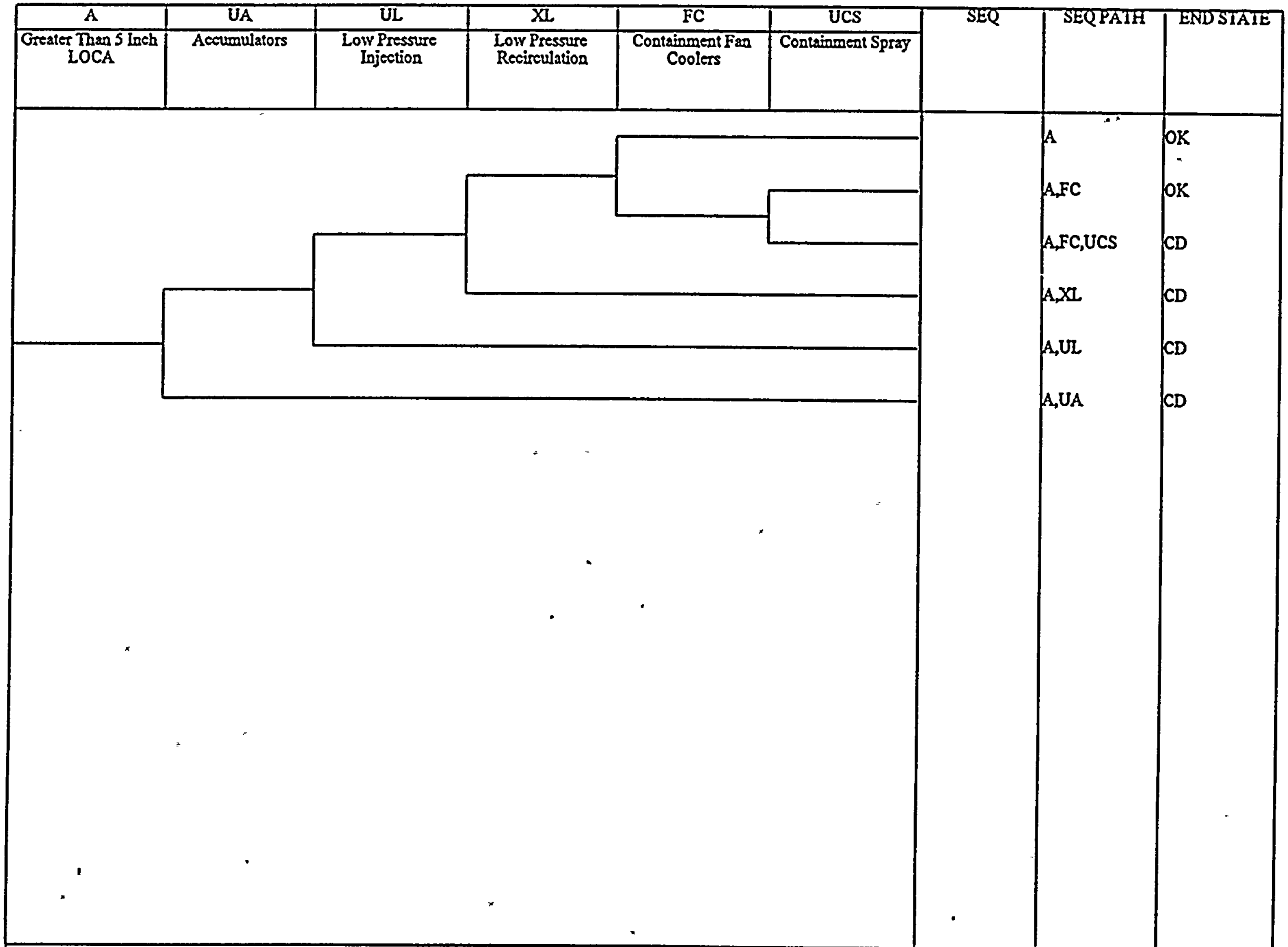
SMALL-SMALL LOCA EVENT TREE - FIGURE 5-3	C:\CAFTA-W\ETA\GINSSLOC.ETA	11/15/96	Page 1



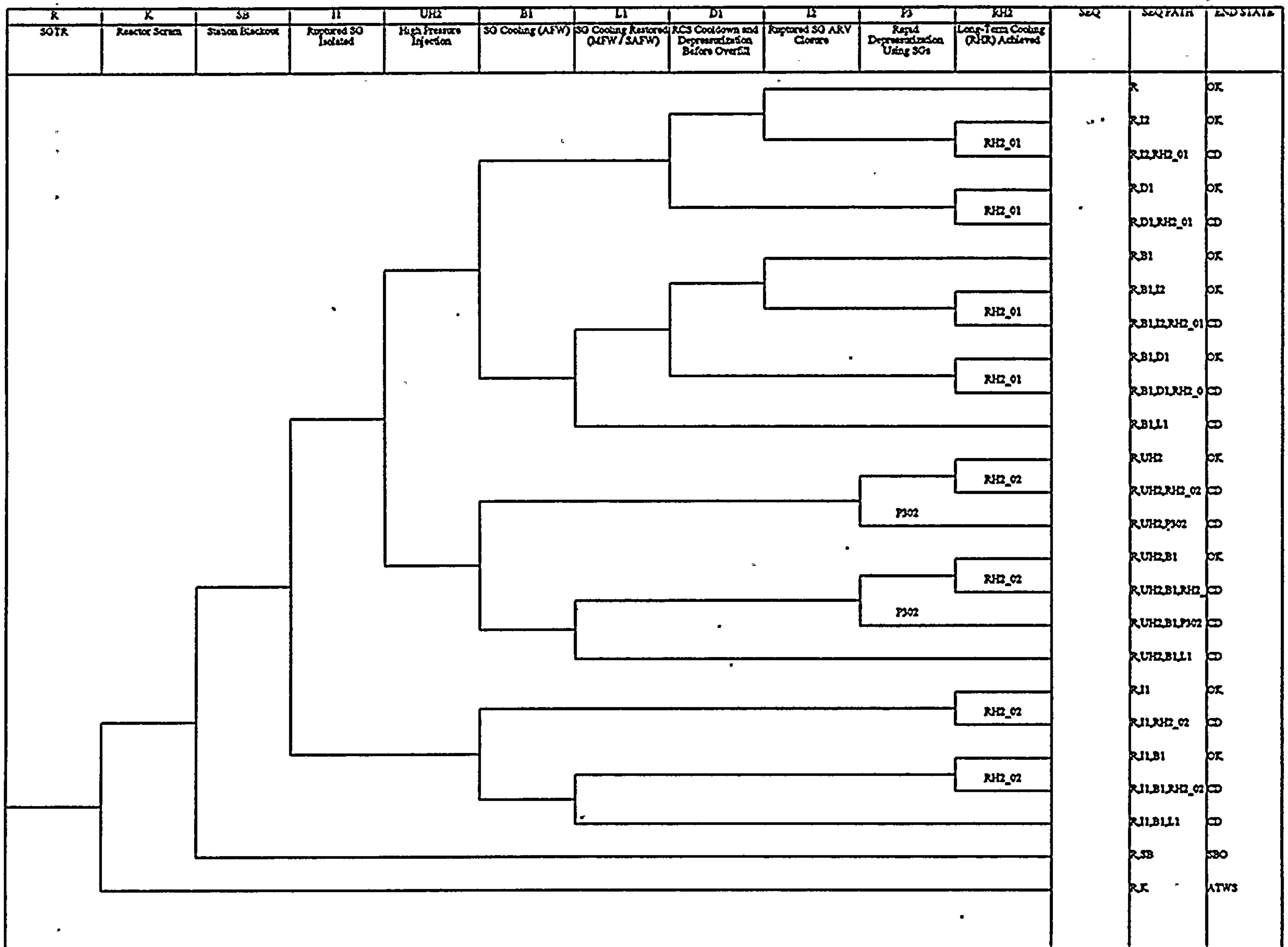
SMALL LOCA EVENT TREE - FIGURE 5-4 | C:\CAFTA-W\ETA\GINSLOCA.ETA | 11/15/96 | Page 1



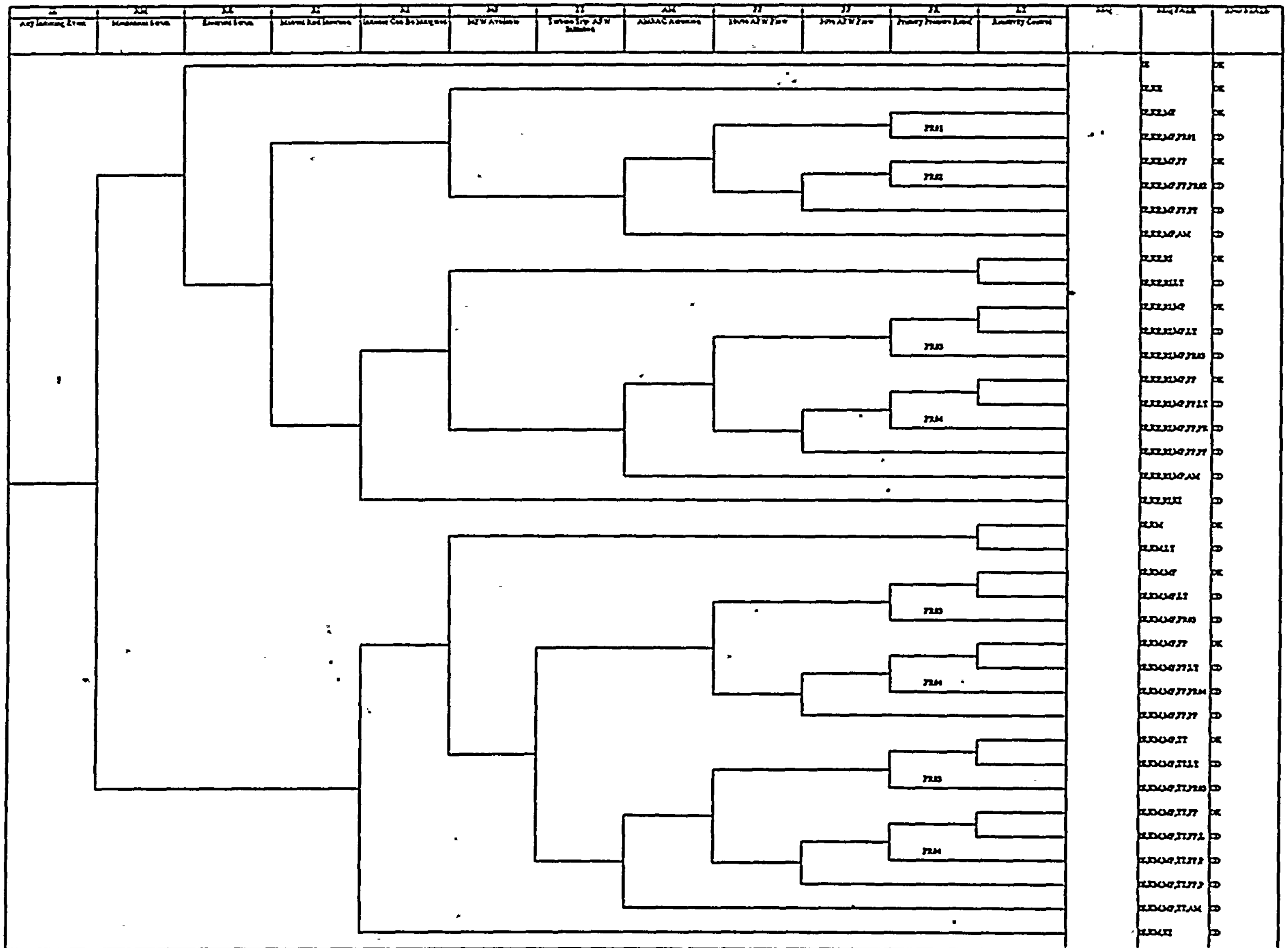
MEDIUM LOCA EVENT TREE - FIGURE 5-5	C:\CAFTA-W\ETA\GINMLOCA.ETA	11/15/96	Page 1



LARGE LOCA EVENT TREE - FIGURE 5-6 | C:\CAFTA-W\ETA\GINLLOCA.ETA | 11/15/96 | Page 1



STEAM GENERATOR TUBE RUPTURE - FIGURE 5-7	C:\CAFTA-W\ETA\GINSGTR.ETA	11/15/96	Page 1



ATWS EVENT TREE - FIGURE 5-8	C:\CAFTA-W\ETA\GINATWS.ETA	11/15/96	Page 1

6.0 SYSTEM ANALYSIS

The system analysis task consisted of developing fault tree models for each of the systems required in order to solve the event trees described in Section 5. This includes those front-line systems specifically described in the event trees (e.g., safety injection) and those support systems necessary for successful operation of the front-line systems (e.g., electric power). For each system which is modeled, the following is provided:

a. Identification of the system function with respect to the event trees (i.e., reactivity control, RCS inventory control, RCS pressure control, and decay heat removal);

b. General description of the system;

c. Description of the fault tree model; and

d. Major assumptions used in development of the fault tree model.

In addition to the details provided with respect to each modeled system, there were general "rules" which were used in the development of the fault tree models. These rules are provided below:

a. Modularization of the models (i.e., combining multiple independent basic events into one new basic event) was encouraged since it speeds the model solution and reduces the potential number of cutsets which have to be reviewed. However, the following items were not allowed to be modularized:

    1. human error events;
    2. non-independent events (i.e., events which appear in multiple locations);
    3. transfers to other fault tree models;
    4. test and maintenance events; and
    5. faults which cannot occur at the same time (this aids in the recovery process).

b. Fault tree models were developed to the level for which failure data exists (see Table 7-1). Since most components can be broken down to many "piece parts" (e.g., a valve can be broken down into its motor-operator and valve body) a standard set of component boundaries was used to ensure consistency across models and with respect to failure data [Ref. 28]. In addition, the following modeling guidelines were used:

    1. Manual valves were included to provide mechanisms to model potential recovery actions.

2. Pipe breaks were typically not included unless they resulted in either the initiating event (or were the result of the initiator) or complete loss of a system. Also, flow diversions from small lines were typically not modeled unless it could be demonstrated that they would lead to failure of the parent system.

3. All circuit breakers, relays, and fuses were modeled to support dependency analyses and for fire evaluations. However, these components are typically within the boundary of the parent component for data analysis purposes such that their failure probability is generally set to zero after an initial dependency search.

4. Minimum recirculation lines were only modeled if their failure resulted in failure of the associated pump over the modeled mission time.

5. Initiating events were added to a fault tree model if they directly impacted the success of the system.

6. Equipment unavailability due to testing and maintenance was added to each fault tree model as appropriate (see Table 7-4). Also, separate events for human failure to restore the system to operable status following maintenance and testing were added to the models as appropriate (see Table 7-13).

7. Human failure events following an accident were added to the models as necessary. Typically, human failures immediately following the accident were provided in the system models (e.g., failure to manually start standby auxiliary feedwater) while long-term failures to restore equipment were treated as a recovery event and added on a cutset-by-cutset basis (e.g., failure to stop a residual heat removal pump with a leaking seal during the recirculation phase of an accident). See Tables 7-13 and 8-5, respectively.

8. Common cause failures were added for each fault tree model on a system basis. Table 7-3 provides a listing of those events which were included within the fault trees.

c. The following naming scheme was used to ensure consistency across the system models:

1. Each basic event was labeled as SSCCMxxxxx where SS denotes the PSA system, CCM denotes the component type and failure mode (see Table 7-1), and xxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, SWMVP04616 refers to the failure of Service Water (SW) motor-operated valve (MV) 4616 (04616) to open (P).

2. Modularized events were labeled as SSMMxxxxxx where SS denotes the PSA system, MM denotes that the event is a module, and xxxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, SWMMMV4616 refers to multiple related failures (MM) of Service Water (SW) motor-operated valve 4616 (MV4616).

3. Test and maintenance events were labeled as SSTMxxxxxx where SS denotes the PSA system, TM denotes that the event is a test and maintenance event, and xxxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, SWTM4616MT refers to a maintenance event (TM) of Service Water (SW) motor-operated valve 4616 (4616MT).

4. Human failure events were labeled as SSHFMxxxxx where SS denotes the PSA system, HF denotes that the event is a human failure event, M denotes a timing designator ("L" for pre-accident events and "D" for post-accident events), and xxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, AFHFD1ATRIP refers to a post-accident human failure (HFD) to reopen Auxiliary Feedwater Water (AF) motor-operated valve 4007 after its associated pump trips (1ATRP).

5. Common cause failure events were labeled as SSCCxxxxxx where SS denotes the PSA system, CC denotes that the event is a test and maintenance event, and xxxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, SWCCPUMPSR refers to a common cause failure (CC) of the Service Water (SW) pumps to run (PUMPSR).

6. Logic flags used to re-configure the fault tree model were identified as SSAAxxxxxx where SS denotes the PSA system, AA denotes that the event is a logic flag, and xxxxxxx denotes the alphanumeric string that uniquely identifies the event (typically the EIN). For example, SWAASWP1AR refers to a logic flag (AA) in the Service Water (SW) system with respect to whether Pump A is running (SWP1AR).

Table 8-1 contains the final listing of basic events used in the models.

6.1 AC Power System

6.1.1 AC Power System Function

For the purpose of the Ginna Station PSA, the AC Power system includes the offsite power sources, the 4160 V buses, the 480 V buses, and their associated motor control centers (MCCs). The offsite power sources function to supply power to the 480 V safeguards buses, via 4160 V Buses 12A and 12B, during normal operation and after a reactor trip. The offsite power sources also supply the non-safeguards 480 V buses following a reactor trip by connecting Buses 12A and 12B to Buses 11A and 11B, respectively. The 480 V safeguards buses function to provide power to various loads throughout the plant which are required to operate during an accident. These loads are supplied either directly off the buses themselves, or off MCCs connected to the buses. The 480 V safeguards buses also provide power to the 120 V Instrument Bus system which supplies motive power to various loads and instrumentation, and to the DC Power system through the battery chargers. The 120 V Instrument Bus and DC Power systems are modeled separately. In addition, the 480 V safeguards buses can be supplied by their respective diesel generators (DGs) which provide an emergency backup source of power should the offsite power sources become unavailable. The DGs are also modeled separately.

As such, the AC Power system is a support system to essentially all event tree headings and to three of the four core protection functions (i.e., RCS pressure control, RCS inventory control, and decay heat removal). In addition, the loss of the AC Power system is specifically addressed in the station blackout event tree.

6.1.2 AC Power System Description

A simplified diagram of the AC Power system is provided in Figure 6-1. As shown in the figure, there are two 34.5 kV transmission lines connected to the onsite power system via the 34.5 kV/4160 V station auxiliary transformers (SATs) 12A and 12B and their associated circuit breakers. Circuit 751 supplies SAT 12A, which in turn is connected to Bus 12A through breaker 52/12AY and to Bus 12B through breaker 52/12AX. Circuit 767 supplies SAT 12B, which is connected to Bus 12A through breaker 52/12BY and to Bus 12B through breaker 52/12BX. The other two 4160 V buses, 11A and 11B, are both connected to the output of the main generator via a single 19 kV/4160 V unit transformer. Each bus has its own circuit breaker separating it from the transformer.

Buses 11A and 12A can be connected by a Bus Tie Breaker 52/BTA-A and Buses 11B and 12B can be connected by Bus Tie Breaker 52/BTB-B. For purposes of the PSA, this is only relevant in that Buses 11A and 11B lose their normal power source following a reactor trip and must switch to a different source if they are to remain energized. Certain non-safety loads which are included in the model are connected directly to the Buses 11A and 11B via a circuit breaker (e.g., main feedwater pumps).

The 4160 V buses are connected to the 480 V buses via 4160 V/480 V station service transformers (SSTs). Buses 11A and 11B feed non-safeguards Buses 13 and 15, respectively. Bus 12A feeds safeguards Buses 14 and 18, while Bus 12B feeds safeguards Buses 16 and 17. There is a 4160 V circuit breaker between the 4160 V bus and the SST, and a 480 V circuit breaker between the SST and the 480 V Bus. The safeguard loads are either connected to these buses through individual circuit breakers, or through one of the MCCs which are connected to the bus by a circuit breaker.

6.1.3 Description of AC Power System Fault Tree Model

The AC Power system fault tree has multiple top gates. Essentially, top gates exist for each of the following components (note that several components may actually be an input into another top gate; e.g., loss of power on Bus 14 is an input into MCC C):

a. Loss of power on MCCs A, B, C, D, E, F, G, H, J, K, L, and M; and
b. Loss of power on Buses 13, 14, 15, 16, 17, and 18.

In addition to the standard models, "circular logic" models were developed to specifically address the DG dependency on service water (SW) and the SW dependency on the DGs. These circular logic models are identical to the standard model except that for support of the DGs, all SW related electrical failures are removed while for support of the SW model, all DG failures caused by SW are removed.

The success criteria of the AC Power system model is to provide AC electrical power to necessary plant components within prescribed voltage limits such that the bus remains available for the entire mission time (i.e., the bus does not trip out on loss of voltage or undervoltage conditions).

A failure of power on the 480 V safeguards buses is modeled as either a local fault on the bus or the failure of both the normal supply from Bus 12A or 12B, and the failure of the associated DG. Since the DG may be in the standby mode, or may be running and tied to the bus due to monthly testing or technical specification requirements, the fault tree is separated into two branches. One branch assumes that the DG is running and tied to the bus, and the other assumes that it is not running and is in standby. There is conditional probability included in each branch to take into account the amount of time per reactor year that the plant is in the assumed configuration.

Failures of the Bus 12A and 12B supplies to the 480 V buses include failure of the 4160 V/480 V SSTs and their high and low side circuit breakers, a fault on the 4160 V bus itself, failure of the 34.5 kV/4160 V SATs and their high and low side circuit breakers, and failures of the offsite power circuits. The model is set up with four logic flags which represent each of the two offsite power circuits supplying each of the two 4160 V buses. This allows the model to be set up to represent all offsite power being supplied by either one circuit, or both offsite circuits supplying power in a 50/50 configuration. The latter configuration can be either offsite circuit supplying either 4160 V bus.

There are several human failure events associated with the AC Power system fault tree model (note that several of these events are identified as ACAA* instead of ACHFD* to allow appropriate recoveries):

a. *ACAADLOSP1 - Operators Fail to Restore Offsite Power Within 1 Hour.* This event describes the failure of operators to restore offsite power within 1 hour. This event applies following a station blackout (SBO) with coincident failure of the turbine-driven AFW pump. The probability of this event is provided in Appendix B.

b. *ACAADLOSP2 - Operators Fail to Restore Offsite Power Within 2.25 Hours.* This event describes the failure of operators to restore offsite power within 2.25 hours. This event applies following a SBO coincident with a LOCA where the turbine-driven AFW pump continues to operate; however, the loss of inventory causes core damage. The probability of this event is provided in Appendix B.

c. *ACAADLOSP5 - Operators Fail to Restore Offsite Power Within 5 Hours.* This event describes the failure of operators to restore offsite power within 5hours. This event applies following a SBO coincident with a SGTR where the turbine-driven AFW pump continues to operate; however, the loss of inventory causes core damage. The probability of this event is provided in Appendix B.

d. *ACAALOSP10 - Operators Fail to Restore Offsite Power Within 10 Hours.* This event describes the failure of operators to restore offsite power within 10 hours. This event applies following a SBO where LOCA conditions do not exist and the turbine-driven AFW pump fails following battery depletion at 6 hours. The probability of this event is provided in Appendix B.

e. *ACHFDCR751 - Operators Fail to Use Alternate Circuit 751.* This event describes the failure of operators to use alternate offsite power Circuit 751 when power is being supplied by Circuit 767 (0/100 mode) and the circuit fails.

f. *ACHFDCR767 - Operators Fail to Use Alternate Circuit 767.* This event describes the failure of operators to use alternate offsite power Circuit 767 when power is being supplied by Circuit 751 (100/0 mode) and the circuit fails.

The AC Power system model contains the following logic flags to support various plant configurations:

a. *ACAAMCCG18 - MCC G is Being Powered from Bus 18.* Since MCC G can be powered from either Bus 17 or 18, setting this flag to true indicates that it is being powered from Bus 18. Setting this flag to false indicates that it is being powered from Bus 17.

b. *ACAA50_50N - Offsite Power In 50/50 Mode (Normal).* Setting this flag to true identifies that Circuit 751 is supplying Bus 12A and Circuit 767 is supplying Bus 12B.

c. *ACAA50_50A - Offsite Power in 50/50 Mode (Alternate).* Setting this flag to true identifies that Circuit 767 is supplying Bus 12A and Circuit 751 is supplying Bus 12B.

d. *ACAA100_0X - Offsite Power in 100/0 Mode.* Setting this flag to true identifies that Circuit 767 is supplying both Bus 12A and Bus 12B.

e. *ACAA0_100X - Offsite Power in 0/100 Mode.* Setting this flag to true identifies that Circuit 751 is supplying both Bus 12A and Bus 12B.

Probability values for these flags when not being used as a true/false flag are provided in Appendix C.

6.1.4 AC Power System Fault Tree Model Assumptions

a. For the fault tree branch which assumes that the DG is initially running due to testing activities, the failure mechanisms which were modeled include failure of the DG to continue running combined with the normal supply breaker opening. The supply breaker opening could be caused by an SI signal or a failure of the Bus 12A or 12B supply. Failures of the DG to start, failure of the output breaker to close onto the bus, and failures of load shed devices are not included in this branch since the diesel is assumed to be running and tied to the bus. For the remaining branch where the DG is in the standby mode, the failure mechanisms include a failure of the Bus 12A or 12B combined with a failure of the DG to supply power. Since the DG is not tied to the bus, the failure to start, failure to run, failure of the normal Bus 12A or 12B supply breaker to open, and failure of the DG output breaker to close are included.

b. All portions of the AC Power system are in operation during normal plant operation, so that any failures to correctly align portions of the system after maintenance is performed would be immediately detected due to a failure of at least that portion of the system. Therefore, no latent human failure events were included. During accident conditions, all other required changes in system alignment are automatic. Although there is the potential to restore portions of the system after a failure occurs (e.g. using bus cross ties) these would be included during the quantification of the model as recovery events,

c. Buses 11A and 11B normally receive power from station unit transformer 11 during power operation; however, upon a reactor trip, Buses 11A and 11B are transferred to Buses 12A and 12B. Since the PSA assumes that all initiating events either directly result in a reactor trip, or the need for a manual reactor trip, it was assumed that the transfer to Buses 12A and 12B must be successful for power to be available.

c. Buses 11A and 11B normally receive power from station unit transformer 11 during power operation; however, upon a reactor trip, Buses 11A and 11B are transferred to Buses 12A and 12B. Since the PSA assumes that all initiating events either directly result in a reactor trip, or the need for a manual reactor trip, it was assumed that the transfer to Buses 12A and 12B must be successful for power to be available.

d. The probability that the DG will trip following an initiating event, given that it was already running and tied to its associated safeguards buses was conservatively assumed to be 1.0E-01 based on engineering judgement.

e. Following a reactor trip, the Bus 11A and 11B normal supply breakers will open and the buses will automatically tie to Buses 12A and 12B. Plant personnel then physically rack out the Bus 11A and 11B supply breakers to ensure they do not close onto the now de-energized station unit transformer 11. This evolution introduces a possible human failure if personnel inadvertently re-close either supply breaker. However, the fault trees are concerned only with plant trips related to accident conditions. It is therefore assumed that during accident conditions other activities would take precedence over the isolation of these breakers and this activity would not be performed, thus eliminating this human error possibility. Also, this human error is considered bounded by the potential to lose offsite power post-trip (probability of 0.01).

f. Events DG1ANOTRUN and DG1BNOTRUN represent the probability that the DGs A and B, respectively, are not running and tied to their two associated safeguards buses. This will be the case unless the DG is being paralleled to the bus for its monthly test, or because it is running due to the opposite DG being out of service due to maintenance. Each DG is tested monthly using procedure PT-12.1 or PT-12.2 [Ref. 29]. During the test, the DG is started and loaded onto both its associated safeguards buses for approximately 2 hrs. Therefore, the probability that it is running and tied to the bus due to monthly testing is:

2 hrs. * 12 / (8760 hrs. * .81) = 3.38E-03

Technical Specifications require that if one DG generator is out of service, the other DG must be started within 24 hours if it cannot be demonstrated that the first DG inoperability is not of a common mode failure potential. Plant-specific data indicates that the DGs have been under repair on 29 occasions over nine years of data collection. Further, none of the repair times exceeded 24 hours. This would indicate that the opposite DG would never have to be started. However, to be conservative, it was assumed that there was one more DG repair which lasted more than 24 hours, thus requiring the opposite DG to be started. Assuming that the operable DG was run for 1 hour, the probability that it is running for this reason is:

1 DG run/9 years * 1hr./DG run / (.81 * 8760 hrs) = 1.566E-05 / hr

Adding the two values together gives a total probability of 3.40E-03. Subtracting this value from 1.0 gives the probability that the DG is not running or 9.97E-01.

g. The potential for offsite power to be lost following the reactor trip due to transmission instabilities was also added to the models. This loss of offsite power could be a grid failure (ACLOPRTALL) or a failure of specific offsite power circuit (ACLOPRT751 and ACLOPRT767).

h. A high energy line break in the Turbine or Intermediate Building is assumed to fail MCCs A and B due to the steam environment.

6.2 Auxiliary Feedwater (AFW) System

6.2.1 AFW System Function

The main function of the AFW system is to maintain steam generator (SG) water inventory when the non-safety related Main Feedwater (MFW) system fails so that the decay heat removal function is available. The AFW system is actually comprised of two sub-systems, the preferred AFW system and the standby AFW (SAFW) system. The preferred AFW system is used during plant startup, cooldown, shutdown operations, and emergency situations. The SAFW system provides backup feedwater in the event that the preferred AFW system is unavailable due to a high-energy line break in the Intermediate Building or other similar common mode failure event. The SAFW system is placed into service by operator action in the control room.

6.2.2 AFW System Description

The preferred AFW system consists of two motor-driven (MDAFW) pumps and one turbine-driven (TDAFW) pump. Normally, each MDAFW pump supplies one SG, but the alignment can be altered to allow a MDAFW pump to supply either or both SGs. The TDAFW pump is normally aligned to supply feedwater to both SGs. Each MDAFW pump supplies the SGs through normally open, motor-operated discharge valves (4007 and 4008) while the TDAFW pump provides water through normally open, air-operated valves (4297 and 4298). Discharge AOVs (4480 and 4481) are provided to allow bypassing of the MDAFW pumps' discharge MOVs (4007 and 4008, respectively) during periods when low flow is required (e.g., startup). A manual cross-connection (manual valves 4359 and 4360 and MOVs 4000A or 4000B) between MDAFW Pumps A and B and the TDAFW pump is also provided for an alternate flowpath. This allows for continuous makeup to the SGs during extended hot shutdown conditions.

The two preferred MDAFW pumps are 480V, 3 phase, 300 hp, 3600 rpm motors, capable of supplying a minimum of 200 gpm at 1085 psig. Each pump contains an oil pump which will start when the AFW pump starts. The MDAFW pumps have splash-lubricated gears; the motors are of an open, drip-proof design powered from the safeguards buses. The TDAFW pump receives steam from either or both SGs and is capable of supplying a minimum of 400 gpm at 1085 psig. It has both AC and DC lube oil pumps with the AC lube oil pump normally running. The TDAFW pump will trip on overspeed, low bearing oil pressure of 3 psig, or low governor oil pressure of 25 psig sensed at the throttle trip valve. On any turbine trip, both the governor valve (9519E) and the trip throttle valve (3652) will shut and require reset before it can be used again.

All three preferred AFW pumps have recirculation lines back to the condensate storage tanks (CSTs). The air-operated recirculation valves for the MDAFW pumps (AOVs 4304 and 4310) open automatically on high discharge pressure of 1350 psig. The TDAFW pump's recirculation valve (AOV 4291) is normally open, but automatically opens on low flow of 100 gpm.

Water is supplied to the preferred AFW pumps by means of gravity feed from the two 30,000 gallon capacity CSTs. For reactor power operation, a minimum of 22,500 gallons in at least one tank is required with a single CST supplying enough water to remove decay heat for two hours after a reactor trip from full power. The SW system provides a backup water supply to the AFW system. An additional supply of feedwater can be provided through the yard fire hydrant system, the condenser hotwells, the outside condensate storage tank, and the city water system. SW also provides cooling water to all three preferred AFW lube oil systems.

The SAFW system consists of two motor-driven pumps located in the SAFW Pump Building separate from the main portion of the AFW system. SAFW is manually actuated and aligned so that each pump supplies one SG. The two motor-driven pumps are capable of supplying at least 200 gpm at 1085 psig and are powered from the safeguards buses. The pumps do not have an automatic actuation capability but are initiated and operated manually from the control room. In the event that the preferred AFW pumps fail to function properly after a high energy pipe break or fire in the Intermediate Building, or all means of feedwater are lost, the operators are alerted to the condition by control room indicators, alarms, and annunciators. The operators are instructed to manually remove the affected MDAFW pump from the bus and place the respective SAFW pump into operation on the associated bus. Flow to the SGs is controlled by throttling the associated SAFW pump discharge valve (MOVs 9704A and 9704B).

The safety related water source for SAFW is from the SW system through respective loops which can be cross-connected if necessary. However, the fire water system can be used if there is a total loss of SW by use of a fire hydrant located outside the SAFW Pump Building. A water source from the city water system is also available. Finally, a supply tank with a 10,000 gallon capacity is provided to store condensate quality water as a source of supply for periodic testing of the system. Nonetheless, SW is also required to supply the SAFW room coolers as discussed in Section 6.11.

A simplified diagram of the AFW and SAFW systems is provided in Figures 6-2.1, 6-2.2, and 6-2.3.

6.2.3 Description of AFW Fault Tree Model

The AFW fault tree model is organized based on providing flow to each SG with the event trees identifying the necessary number of AFW trains which must be successful. The fault tree is further segregated into the three pump trains of preferred AFW and the two pump trains of SAFW. Essentially, the model is broken down into the following areas: (1) the three AFW and two SAFW pump trains; (2) common suction sources; (3) the six injection lines to the SGs; and (4) the cross-ties between the pump trains. Additionally, failure of the SG blowdown AOVs (5737 and 5738) to close on a AFW pump start was assumed to fail flow to their associated SG since failure of AOV-5737 or AOV-5738 to close would result in the inability to maintain SG inventory due to the 100 gpm flow rate through each AOV. The top gate for each of these "modeling blocks" is provided below:

a.	AF510	Failure of MDAFW Pump Train A (PAF01A) to SG A Common Header
b.	AF610	Failure of MDAFW Pump Train B (PAF01B) to SG B Common Header
c.	AF410	Failure of TDAFW Pump Train (PAF03) to Common Header
d.	AF912	Failure of SAFW Pump Train C (PSF01A) to Common Header
e.	AF952	Failure of SAFW Pump Train D (PSF01B) to Common Header
f.	AF200	Failure of Hotwell Supply to CSTs for Long-Term Supply to AFW
g.	AF295	Failure of Condensate Storage Tanks (TCD02A and TCD02B)
h.	AF580	Failure of MDAFW Pump Injection Line to SG A
i.	AF680	Failure of MDAFW Pump Injection Line to SG B
j.	AF480	Failure of TDAFW Injection Line to SG A
k.	AF485	Failure of TDAFW Injection Line to SG B
l.	AF905	Failure of SAFW Pump Train C (PSF01A) Injection Line to SG A
m.	AF907	Failure of SAFW Pump Train D (PSF01B) Injection Line to SG B
n.	AF350	Failure of MDAFW Train A to Train B Cross-connect
o.	AF922	Failure of SAFW Train C to Train D Cross-connect

There are several human actions included in the AFW fault tree model which are described in detail below:

a. *AFHFDAFWAB - Operators Fail to Open Cross-Tie Valves Between MDAFW Trains.* This event describes the failure of operators to cross-connect the MDAFW trains when required. The actions necessary to cross-connect the trains are to open either MOV 4000A or 4000B.

b. *AFHFDSAFWX - Operators Fail to Correctly Align SAFW.* This event describes the failure of operators to start and correctly place into service SAFW pump C or D.

c. *AFHFDSUPPL - Operators Fail to Supply Alternate Sources of Water to AFW.* This event describes the failure of operators to manually transfer the suction of MDAFW Pumps A and B and the TDAFW pump from the CSTs to an alternate suction source (e.g., SW). Indication of the need to change suction sources is provided by level transmitters on each CST.

d. *AFHFDALTTD - Operators Fail to Provide Cooling to TDAFW Lube Oil From Diesel Fire Pump* - This event describes the failure of operators to align long-term cooling water for the TDAFW lube oil coolers to the diesel fire pump. The TDAFW pump has been shown to be able to survive for approximately 2 hours without lube oil cooling; however, cooling is required to survive up to 6 hours under station blackout conditions.

e. *AFHFDTDAFW - Operators Fail to Manually Start TDAFW Pump* - This event describes the failure of operators to manually start the TDAFW pump when the start signal fails during a SBO event.

Failure to restore equipment to service after test or maintenance is modeled at the train levels in all cases except for the TDAFW pump which is modeled at the pump level since it feeds both SGs.

There are no logic flags identified for the AFW logic model.

6.2.4 AFW Fault Tree Model Assumptions

a. Since the PSA is being modeled for 100% power conditions, the main turbine is latched. Consequently, the position of the AFW bypass switch for AOVs 4480 and 4481 is inconsequential to the model since the pumps will either start immediately or within 32 seconds (PSA success criteria requires actuation within 45 minutes).

b. Based on condensate requirement calculations, there are several cases where the CSTs provide enough water on their own for the RCS to reach 350°F (RHR setpoint). However, to cover all scenarios, it was assumed that the CSTs do not provide enough water; thus, alternate water sources are necessary for long-term cooldown requirements. Sources of water which were modeled include SW, city water, and fire water systems.

c. The motor-operated discharge valves (4007, 4008, 9704A and 9704B) for the MDAFW and SAFW pumps are normally positioned full open and throttle back to approximately 200 - 230 gpm. Failure to throttle flow is assumed to fail flow to the applicable SG since too little flow will provide inadequate SG cooling while too much flow could cause a pump trip on overspeed.

d. The TDAFW pump cannot be used if there is a large unisolable break in either the main steam or feedwater lines. This is due to the fact that the break causes the affected SG to rapidly depressurize. The TDAFW pump will then trip on overspeed as the SG depressurizes. As such, the model shows that any steam or feed line break inside the containment or the Intermediate Building fails the TDAFW pump.

e. Condensate AOV 4294 was not modeled since the valve is not required for successful operation of AFW. This valve is only used to maintain a higher pressure than the SW system at the suction of the AFW pumps, thus preventing leakage of SW into the AFW system and the SGs. Consequently, the failure of AOV 4294 has no impact on the ability of AFW to provide water to the SGs.

f. It was assumed that the AFW pump train selector switches were in "AUTO" in the control room which is their normal position while at power.

g. The failure (i.e., transfers closed) of manual isolation valves for the SG level transmitters and the SW differential pressure switches was assumed to be within the component boundary of the transmitter or indicator. Consequently, they are not modeled. In addition, the condensing pots for SG level transmitters were considered to be within the transmitter component boundary.

h. Each CST has its own level transmitter. Consequently, it was assumed that if the level transmitters for the CSTs were providing very different readings, operators would investigate. Therefore, both level transmitters would have to fail before operators would miss the opportunity to transfer suction sources.

i. Diversion of flow through the AFW and SAFW pump suction relief valves (4020, 4021, 9709A and 9709B) was not modeled since the relief valves are less than one-third the diameter of the suction line and previous history has not demonstrated a problem with their lifting.

j. The model assumes that if AFW is needed, then both the MFW and condensate pumps are lost. Consequently, the condensate transfer pump must be used to transfer water from the hotwell to CSTs. As such, the flowpath from Condensate Pumps A and B to the CSTs via reject valve 4317 was not modeled even though this is the first option presented in ER-AFW.1 [Ref. 30].

k. The two MDAFW pumps receive various automatic start signals including the tripping of both MFW pumps. That is, the MFW pump breakers (Bus11A/07 and Bus11B/25) must fail to open to prevent the start signal. However, only initiating events which do not result in a MFW pump trip were included for failure to generate a start signal. If the MFW pumps failed to trip (i.e., continued to run during the event), then AFW would most likely not be required.

l. The bypass AOVs (4480 and 4481) around the MDAFW pump isolation MOVs (4007 and 4008, respectively), were not modeled for several reasons. First, these valves are only used for long-term cooldown which the model does not specifically address. That is, SG level is difficult to maintain in low flow conditions using MOVs 4007 and 4008 such that AOVs 4480 and 4481 were added to provide finer control at low steam rates. Second, the valves are maintained closed, verified closed each shift, and receive a close signal upon MDAFW pump actuation above 5% power. Finally, 4480 and 4481 were not considered as successful alternatives to 4007 and 4008 since they are only half the size.

m. The failure of the TDAFW quench tank was not assumed to result in a failure of the TDAFW pump lube oil cooling system or the steam exhaust path from the turbine. In both cases, water and steam would still be able to perform their primary function. That is, SW could still provide cooling to the lube oil cooler by flowing out of the break, while a rupture of the tank would result in a pressure difference across the turbine (i.e., atmospheric vs. SG pressure) allowing steam to drive the turbine.

n. The TDAFW outlet AOVs to SGs A and B (4297 and 4298) fail open on loss of instrument air. Since the valves are normally open, this failure mode is of no consequence to the model except when the flowpath to a faulted SG must be isolated.

o. A high energy line break in the Intermediate Buildings was assumed to fail the three preferred AFW pumps since they are not protected (i.e., in their own room). A similar break in the Turbine Building was also assumed to fail the three AFW pumps since the block wall between the Turbine and Intermediate Buildings is not designed for these loads. These scenarios were much of the basis for adding the SAFW system.

p. The TDAFW flow control valves (4297 and 4298) are manually operated from the control room. These valves are not interlocked with any flow transmitters like those for the MDAFW pumps. The flow transmitters in each line are only used by operations to ensure that at least 200 gpm is available to each SG. However, there would have to be a failure of the flow transmitter and SG level indications before operations would incorrectly adjust TDAFW flow (i.e., multiple independent failures). Consequently, this failure mode was not modeled.

q. The TDAFW pump AC and DC lube oil pumps are considered to be within the boundary of the TDAFW pump. Consequently, only the power sources for the lube oil pumps are modeled. In addition, if both lube oil pumps failed, operators were assumed to have two hours to recover cooling [Ref. 2, Section 10.5.4.2].

r. The TDAFW pump governor (9519E) and trip throttle valve (3652) were assumed to be within the component boundary of the pump. In addition, all of the miscellaneous steam relief and drain lines were assumed to be within the pump boundary.

s. The cross-connect between the TDAFW pump train and the MDAFW pumps was not modeled since it was not assumed to be required given the number of installed AFW pump trains. However, this line can be considered for recovery purposes if necessary. In addition, this line was not included as a diversion path since it includes two normally closed manual valves.

t. The event trees allow the use of the faulted SG during a SGTR if the other SG is not available. Consequently, a SGTR was only assumed to fail the affected SG if operators isolated it per FR-H.1 [Ref. 26]. In addition, it was assumed that a SG was always unavailable during a steamline or feedline break, regardless of whether or not operators isolated it. This is due to NPSH concerns with the pumps.

u. It was assumed that if it was necessary to cross-connect the MDAFW pumps, then the pump associated with the SG that is being provided AFW flow had tripped. Consequently, it was necessary to reopen the isolation MOV (4007 or 4008) in all instances.

v. NUREG/CR-5764 [Ref. 31] identifies three major contributors to AFW system failures that have occurred throughout the industry. According to the report, valve mispositionings were the most common contributors to AFW system failures. AFW valve lineups for valves outside containment are checked once per month per technical specification requirements. Also, failures to restore equipment to service after test or maintenance have been included in the model. Another significant finding in the report is a failure of multiple pumps due to steam binding as a result of leaking hot feedwater past check valves. Pump casings and pipes are checked for temperature every shift per Procedure O-6; consequently, this failure mode has not been addressed due to the limited time available for this failure mechanism to occur. The report also identified that a loss of power to a vital bus could fail the TDAFW and one MDAFW pump. This failure mode is not applicable to Ginna Station.

w. The model assumes that all three preferred AFW pumps will receive an automatic start signal on any reactor trip due to low SG level since MFW is either lost at the time of the initiator or isolated procedurally by operators.

6.3 Chemical Volume and Control System (CVCS)

6.3.1 CVCS System Function

The CVCS functions which are directly related to the event trees are:

a. Providing seal injection water to the reactor coolant pump (RCP) shaft seals;

b. Providing a source of borated water to the RCS for emergency boration in the case of an ATWS event; and

c. Providing an auxiliary source of pressurizer spray water.

The CVCS also accomplishes the normal charging function to maintain inventory in the RCS which is provided within the fault tree.

With respect to the first function, the RCPs are motor-driven pumps and the motor shafts penetrate the RCP casings to drive the pump impellers. The points at which the shafts penetrate the casings are sealed to prevent the escape of reactor coolant. Each seal assembly requires a supply of injection water from the CVCS. Some of this water, injected into the seal at a pressure slightly above that of the RCS, flows along the shaft into the pump. A portion also flows along the shaft away from the RCP and is collected and recovered. The supply of cool, clean water into the RCP seal keeps out debris and prevents the seal from being damaged by the high-temperature reactor coolant. A failure of the seal injection water, combined with a failure of component cooling water (CCW) to the thermal barrier heat exchanger, could cause a failure of the seal, leading to an RCP seal LOCA, which is a special case of a small break LOCA.

If an anticipated transient without scram (ATWS) occurs, operators are directed by emergency operating procedures to begin emergency boration via the CVCS. In this case, boric acid solution from the boric acid storage tank (BAST) is supplied by the boric acid transfer pumps directly to the suction of the charging pumps which inject the solution into the RCS.

During cooldown and depressurization following a SG tube rupture (SGTR) event, auxiliary pressurizer spray may be used to depressurize the RCS, if the normal pressurizer spray and pressurizer power operated relief valves (PORV) are unavailable. In this case, the output of the charging pumps is directed through AOV 296 directly to the pressurizer spray nozzles.

Therefore, CVCS supports the reactivity control, RCS pressure control, and RCS inventory control functions.

6.3.2 CVCS System Description

The CVCS can be divided into two basic functional portions: letdown and charging. During normal operation, the letdown flow out of the RCS is recycled back to the volume control tank (VCT) and back into the RCS, with limited makeup required from other sources. However, for the purposes of the fault tree models, it has been assumed that all letdown flow is isolated (e.g., loss of instrument air, containment isolation). Therefore, the letdown portion of the CVCS is not addressed in the CVCS models. However, the isolation of letdown flow to the VCT adds the additional requirement of a new suction source for the charging system.

Three positive-displacement charging pumps provide flow through the CVCS. Each pump has a maximum output of 60 gpm at 2385 psig; however, the normal operating maximum flow is approximately 45 gpm. The pumps are driven by 480 VAC, 100 Hp motor connected to their shaft by a hydraulic type speed control system. The speed control system takes a current signal, either from a pressurizer level indicator or from the manual controller, and converts it to an pneumatic signal using instrument air (IA). The IA then positions the vari-drive speed control mechanism to produce the desired pump output. Upon a loss of IA, the vari-drive mechanism fails to the slowest speed which corresponds to approximately 15 gpm. Each pump has a relief valve on its discharge line to prevent over pressurization.

As stated earlier, the normal suction supply to the pumps is from the VCT. With letdown isolated, when the VCT level drops below 20%, the BA transfer pumps and RMW pumps start and AOVs 110A; 110B, and 111 open to supply flow to the suction of the charging pumps. When the level in the VCT drops below approximately 13%, the suction supply automatically switches over to the refueling water storage tank (RWST) by closing the valve to the VCT and opening the valve to the RWST. In addition, the charging pumps can be manually supplied from the BASTs or the reactor makeup water system via the boric acid blender.

The charging pumps discharge to a common pulsation dampener and from there flow is directed either to the RCP seal injection sub-system or to the RCS. Approximately 30 gpm of the CVCS flow is directed from the pulsation dampener, through a control valve (AOV 142), through 3 regenerative heat exchangers in series and through the normal charging path to cold leg loop B. The regenerative heat exchangers warm the water being supplied to the RCS by removing heat from RCS letdown flow. If the normal charging path is unavailable, the alternate path contains an AOV which acts as both an isolation valve and a relief valve. When a differential pressure of 250 psid exists across the valve, it opens allowing charging flow into the Loop B hot leg. Flow from the regenerative heat exchangers can also be used to supply auxiliary pressurizer spray through a normally closed AOV in parallel with the normal and alternate charging supply lines.

The seal injection water supply is routed through a common 5-micron filter before separating into two parallel paths leading to the seal assemblies of the two RCPs. Approximately 8 gpm of the injection supply is delivered to each RCP, with 3 gpm flowing upwards through the seal assembly and returning to the VCT through the seal water heat exchanger and the balance flowing downward and entering the RCS.

The boric acid (BA) system and the reactor makeup water (RMW) system are included within the CVCS fault tree. The two boric acid transfer pumps take suction from the BASTs and supply relatively concentrated boric acid solution to the emergency boration valve (MOV-350) which is normally closed, and also through a flow control valve (AOV-110A) to the boric acid blender. Flow through the emergency boration valve goes directly to the suction header of the charging pumps. The two RMW pumps supply pure water from the RMW tank through a flow control valve (AOV-111) to the boric acid blender. The flow from the BA system and the RMW system is combined in the boric acid blender which supplies the output to the suction header of the charging pumps. The flow control valves for both BA and RMW are adjusted to maintain the required BA concentration in the RCS

A simplified diagram of the CVCS is provided in Figure 6-3.

6.3.3 Description of CVCS Fault Tree Model

The CVCS fault tree is organized under five top gates as follows:

a.	CV100	Failure of Charging Flow to RCS
b.	CV400	No Flow From Charging to Auxiliary Spray
c.	CV500	No Boron From Charging (Emergency Boration)
d.	CV998	Loss of Seal Injection or Return to RCP A
e.	CV999	Loss of Seal Injection or Return to RCP B

Since there are three charging pumps, the success criteria for the last three top gates are as follows:

CV500: One of three charging pumps running at maximum speed or two of three pumps running at minimum speed, a suction supply from the BAST, and a flow path to the RCS through either the normal or alternate charging lines.

CV998: One of three charging pumps running at minimum speed, a suction supply from the RWST or from the RMW control system, a flow path from the pulsation dampener to the RCP seal, and a flow path from the RCP seal to the VCT or to the PRT through the relief valve.

CV999: One of three charging pumps running at minimum speed, a suction supply from the RWST or from the RMW control system, a flow path from the pulsation dampener to the RCP seal, and a flow path from the RCP seal to the VCT or to the PRT through the relief valve.

Top gates CV100, CV400, and CV500 are organized into two major subsections: (1) failure of charging flow, and (2) failure of the flow paths into the RCS. Failure of charging flow is further divided into branches representing failure of the suction source to the charging pumps (e.g., flow from the BAST), and failure of the charging pumps themselves. Since the success criteria for the emergency boration function is 1 of 3 pumps at full speed, or 2 of 3 pumps at minimum speed, the fault tree for failure of adequate flow from the charging pumps includes failure of all three pumps to run, or failure of two pumps to run and failure of the third pump to run at maximum speed. The fault tree section for failure of a charging pump to run at maximum speed is the same as the failure of the pump to run with the addition of the failure of IA to the pump speed controller. However, since the other failure mechanisms are included in the gate for the failure of all 3 pumps to run at all, only the failure of IA to the speed controller is included.

Failure of flow paths to the RCS includes failure of the manual valves, check valves and AOVs in the line from the pulsation dampener to the charging isolation valves, and failure of the normal and alternate charging path isolation valves themselves. Failure of the normal charging path isolation valve (AOV-294) includes failure of the valve itself, failure of the IA supply to the valve, and failure of DC power to the solenoid valve supplying air to the AOV. Since AOV-294 fails closed on loss of IA or loss of DC power to the solenoid, either failure is a failure of the valve to remain open. Failure of the alternate path (valve 392A) is modeled as a failure of the valve or its downstream check valves to open.

Top gates CV998 and CV999 are identical in structure. The gates are divided into four basic sections: (1) failure of valves in line from the seal injection filter to the RCP seal, (2) failure of valves in line from the RCP seal to common leakoff header, (3) failure of flow from the seal injection filter, and (4) failure of normal and alternate seal water return paths from the common leakoff header. The first two sections are straightforward while the last two sections are described in detail below.

Failure of flow from the seal injection filter includes failures of the filter itself, and failure of charging flow from the pulsation dampener to the filter. Failure of charging flow consists of two branches, one representing failure of the charging pumps and the other representing failure of the suction source. Failure of the charging pumps is simply the failure of all three pumps to run at any speed (i.e. no IA dependency), while failure of the suction source is more involved. This branch is divided into two further branches, representing failure of the suction supply from the RWST and failure of the suction supply from the RMW system. Since either of these sources is adequate to supply seal cooling flow, these branches are combined using "AND" logic. Failure of suction from the RWST includes failure of the normal supply valve from the VCT (AOV-112C) to close, failure of the supply valve from the RWST (AOV-112B) to open, or failure of the signals to these valves to operate. Failure of the suction source from the RMW control system includes failure of the RMW pumps to operate, failure of the two AOVs in the line to the charging pump suction header (110B and 111), or failure of the signal for those components to operate.

Failure of the normal and alternate seal water return paths from the common leakoff header include both the failure of the normal flow path and failure of the relief valve to the PRT (314). Failure of the normal flow path includes physical failures of the components in the line to remain open, or actual or spurious containment isolation signals which close containment isolation MOV 313. Failure of the relief valve is simply the mechanical failure of the valve to open on demand.

The CVCS model contains the following human interaction events:

a. *CVHFDBORAT - Operators Fail to Implement Emergency Boration.* This event describes the failure of operators to implement emergency boration during an ATWS event. This event covers the entire sequence of actions which must be taken by operators to successfully complete emergency boration.

b. *CCHFDPMPST - Operators Fail to Manually Load Charging Pump.* This event represents the failure of the operators to start a charging pump for RCP seal injection, given that the pump has tripped on and SI signal or undervoltage. If seal cooling were needed, operators are instructed by procedures to start a charging pump.

c. *CVHFD00313 - Operators Fail to Isolate MOV 313 to Prevent a LOCA Outside CNMT.* This event describes the failure of operators to isolate the containment penetration containing MOV 313 (seal return isolation) if the valve fails to close following a seal LOCA. In this instance, a LOCA outside containment would be created that could eventually fail the RHR system.

d. *CVHFD00371 - Operators Fail to Isolate AOV 371 to Prevent a LOCA Outside CNMT.* This event describes the failure of operators to isolate the containment penetration containing AOV 371 (Letdown isolation) if the valve fails to close. In this instance a LOCA outside containment would be created during the recirculation phase of an accident that could eventually fail the RHR system.

e. *CVHFDSUCTN - Operators Fail to Manually Open Suction Line to CVCS Pumps.* This event describes the failure of operators to manually re-align suction from the VCT to the RWST upon failure of the normal suction valves.

The model contains the following three logic flags:

a. *CVAACHPMPA - Charging Pump A Running* - Setting this flag to true identifies that Pump A is running. Two of three charging pumps are normally operating.

b. *CVAACHPMPB - Charging Pump B Running* - Setting this flag to true identifies that Pump B is running. Two of three charging pumps are normally operating.

c. *CVAACHPMPC - Charging Pump A Running* - Setting this flag to true identifies that Pump C is running. Two of three charging pumps are normally operating.

6.3.4 CVCS Fault Tree Model Assumptions

a. A loss of power to level transmitters LT-112 and LT-139 causes the transmitter to give a low level signal. Since the desired function of these transmitters is to give a low level signal, a loss of power to the transmitters is not modeled as a failure.

b. The RMW Mode Selector Switch is generally operated in the "AUTO" position per step 4.3 of procedure S-3.1, "Boron Concentration Control" [Ref. 32]. However, per operations personnel, the RMW mode selector switch is routinely operated manually for dilutions (approximately every 2 hours). For ease of modeling, it has been assumed that valves 110B, and 111 are closed. This is conservative since these valves need to be open to perform their function, and the failure rate for the valves failing to open is higher than the failure rate for the valves transferring closed.

c. The success criteria for charging to the RCP seals is flow from one charging pump running at 15 gpm. During normal system operation with the RMW mode selector switch in the "AUTO" position, flow would be initiated from both the BAST using the BA transfer pumps and from the RMW tank using the RMW pumps. Supply flow from the RMW pumps and flow from the BA transfer pumps is combined in the BA blender with the amount of flow from each source adjusted to maintain the correct boron concentration in the RCS. Thus, depending on the alignment of the system flow could be required from either the RMW pumps, the BA transfer pumps, or both. Since the actual alignment varies throughout the operating cycle, failure of flow from the RMW pumps was arbitrarily used to model failure of all flow. This is appropriate since the BA transfer system and the RMW system are very similar in design and thus have similar failure mechanisms (i.e. both fail on loss of IA, both sets of pumps have the same power supplies, etc.).

d. For the emergency boration function, in which charging pump speed is relevant to success criteria, it was assumed that the charging pump LOCAL\REMOTE selector switches for all three pumps are in the REMOTE position. This places the control of the pumps at the main control board, and is the normal operating configuration. It is also assumed that the main control board speed controller is in the MANUAL mode. Therefore, IA to the local speed control cabinet is not required, and the signal from pressurizer level transmitter LT-428 is disconnected. As such, failure of IA to the local speed control cabinet, and failure high of the level transmitter are not modeled.

e. It is assumed that the AOV-112C from the VCT to the charging pump suction header does not need to close in order to successfully complete emergency boration. This is due to the fact that the flow from the VCT is driven by gravity plus 20 to 30 psig from the Hydrogen blanket while the flow from the BAST is driven by the 2 BA transfer pumps at 60 to 70 psig normal operating pressure. Therefore, the common suction header would be pressurized to some degree and prevent cavitation of the charging pumps due to air entrainment when the VCT emptied completely. This assumption is supported by the fact that there is no mention of closing AOV-112C in the EOP's for and ATWS event.

f. It is assumed that letdown will be isolated at the time of the reactor trip. As such, the VCT only has a finite source of water for suction to the charging pumps. Under these conditions, there is estimated to be at most 30 minutes of water available to the charging pumps (assuming they are at their low speed setting). Since the RCP seals require cooling for at least 24 hours to prevent long-term degradation from resulting in a seal LOCA, it is assumed that the VCT is unavailable and that charging pump suction must be provided from the BA blender or the RWST.

g. During normal plant operation, the RMW control system (RMW system and BA transfer system) operates to supply flow to the RCS when the VCT level drops to 20% and stops when level reaches 30%. Per the system engineer, normal RCS leakage rate is approximately .25 gpm. Per Operations personnel, 12 gallons is roughly equal to 1%, so that 10% would equal 120 gallons. Therefore, at a leakage rate of .25 gpm, this would take 480 minutes, or 8 hours. Therefore, it is conservatively assumed that the time between demands for components in these systems is 12 hours. It should be noted that the RMW system is typically used every 2 to 3 hours for dilutions, etc. However, this has not be accounted for in the model.

h. Failure event CVPPPBASYS represents plugging of the piping between MOV-350 and the charging pump suction header. The failure rate for this line was taken from Ginna Station plant specific data for plugging of boric acid system piping. However, since that data was collected, the concentration of boric acid in the BAST's has been reduced from 12 weight % to approximately 4 weight %. This reduces the minimum temperature to preclude boric acid precipitation from approximately 140°F, to 65°F. Since the heat tracing maintains the boric acid system piping above 150°F, the probability of precipitation and plugging are greatly reduced. Therefore, the failure rate for this event has been reduced by a factor of 10. Failure event CVPPPFCH02 represents plugging of the boric acid filter and the common boric acid system piping between the pumps and MOV-350. This event has also been reduced by a factor of 10. Finally, the plant specific data for plugging of the piping included all the piping from the boric acid storage tanks to the suction of the SI pumps. Since event CVPPPBASYS represents plugging of only a very small fraction of the total piping length considered in the failure data, the failure rate has been further reduced by a factor of 10.

i. Event CVHFTHTRAC represents failure of the heat tracing in the BA system. Since the time that the plant specific failure data was collected, the concentration of boric acid has been reduced from 12 weight % to approximately 4 weight %. At that concentration, per the Technical Requirements Manual (TRM), the minimum line temperature required to preclude precipitation is 70°F. It is assumed that the temperature in the auxiliary building is less that 70°F 50% of the time. Therefore, heat tracing is only required 50% of the time. As such, the exposure time for this event was reduced by 50%.

6.4 Component Cooling Water (CCW) System

6.4.1 CCW System Function

The CCW system functions to remove heat from the following standby safety equipment and transfers the heat to the SW system:

a. Safety Injection (SI) Pumps - each SI pump has two seal heat exchangers (one for each mechanical seal) supplied with cooling flow by CCW. The total flow through all six heat exchangers is approximately 75 gpm. Cooling capability is only required during the recirculation phase of an accident, since during the injection phase the flow through the pumps is from the RWST which provides adequate cooling.

b. Containment Spray (CS) Pumps - each CS pump has one seal heat exchanger to cool the mechanical seals, supplied with approximately 15 gpm of cooling flow from CCW. Cooling capability is only required during the recirculation phase of an accident, since during the injection phase the flow through the pumps is from the RWST which provides adequate cooling.

c. Residual Heat Removal (RHR) Heat Exchangers - each heat exchanger receives approximately 2400 gpm of cooling flow from CCW which is only required during the recirculation phase of an accident. This is based on the fact that during the injection phase, flow through the heat exchangers will be from the RWST which will be Auxiliary Building room temperature (i.e., < 100°F).

d. RHR Pumps - each RHR pump has one seal heat exchanger to cool the mechanical seals, and two bearing water jackets, supplied with a total of approximately 20 gpm of cooling flow from CCW. Cooling capability is only required during the recirculation phase of an accident, since during the injection phase (if RHR is required for low pressure injection) the flow through the pumps is from the RWST which provides adequate cooling.

e. RCPs - each RCP has a thermal barrier heat exchanger which is used to cool RCS primary water flowing upwards over the RCP shaft. Cooling capability is only required if normal seal water injection (i.e., CVCS) fails.

Additionally, during normal plant operation, the CCW system operates to provide cooling to the excess letdown heat exchanger, non-regenerative heat exchanger, RCP seal water heat exchangers, boric acid recycle evaporator (when in service), sample heat exchangers (5), post accident sample coolers (4), waste evaporator condenser, waste gas compressors, and the reactor support cooling pads. However, cooling to these components is not addressed in the fault tree model. As such, CCW supports three of the four core protection functions (i.e., control of RCS pressure, control of RCS inventory, and decay heat removal) and most of the event tree headings.

The CCW system also serves as an intermediate system between the RCS and the SW system and insures that any leakage of radioactive fluid from the RCS related components being cooled is contained within the plant.

6.4.2 CCW System Description

The CCW system is a closed loop system consisting of two parallel pump trains each containing a suction block valve (722A and 722B), a 150 hp horizontal centrifugal pump which can supply 2980 gpm at a pressure of 78 psid, a discharge check valve (723A and 723B), and a discharge isolation valve (724A and 724B). The two trains discharge into a single header which then splits to supply flow to the shell side of two parallel CCW-to-SW heat exchangers. Each heat exchanger has an inlet isolation valve (733A and 733B) and an outlet isolation valve (734A and 734B). Leaving the CCW-to-SW heat exchangers, the water returns to a single header which supplies water to the equipment listed in Section 6.4.1, which are arranged in parallel. After cooling the equipment, the CCW enters a single header which then supplies flow to the suction of the CCW pumps. A 2000 gallon carbon steel surge tank, which is normally vented to atmosphere, is connected to this suction header and provided with a locked open manual isolation valve (728). The surge tank functions to provide NPSH for the pumps, as well as to accommodate minor changes in CCW volume and provide a continuous source of CCW for a short period should a leak occur somewhere in the system.

Normally, one CCW pump is in service with the other pump in standby. System temperature control is accomplished by manually throttling SW isolation valves 4619 and 4620 on the outlet of the shell side of CCW Heat Exchangers A and B, respectively. Temperature of CCW supplied to various components is normally kept below 100°F, however a maximum temperature of 120°F is allowable when the RHR system is in service for plant cooldown.

Makeup water can be taken from the primary water treatment plant and delivered to the surge tank. The normal source of water is provided from the reactor makeup water transfer pumps through MOV 823. The CCW makeup systems are capable of coping with normal system leakage in post-accident operation. Additionally, leak off from the CCW pump seals is collected in the CCW pump seal drain tank (TACO1) and can be manually pumped, using the CCW pump seal drain tank pump, to the surge tank.

The CCW system penetrates the containment at seven locations (penetrations 124, 125, 126, 127, 128, 130, and 131) with process lines providing cooling water to and from the RCP A and B bearings and thermal barrier coolers, the excess letdown heat exchanger, and the reactor support coolers. The inlet and outlet lines to the excess letdown heat exchangers both use the same penetration (124). Only the isolation valves to and from the reactor support coolers receive an automatic containment isolation signal. The CCW lines for the two RCP thermal barrier heat exchangers have inlet (749A and 749B) and outlet (759A and 759B) motor-operated isolation valves which can be used to isolate these lines if necessary. The supply lines also contain a check valve (750A and 750B) immediately downstream of the containment penetration. Automatic isolation of these lines by the MOVs is not provided due to the potential for damaging the RCPs following a spurious containment isolation signal.

CCW flow to the SI pump mechanical seal heat exchangers is provided by six 3/4" lines that originate from a common 2" header. Each line has an inlet and outlet manual isolation valve (777E-H, J-N, P, R, and S) for the heat exchanger. The six lines outlet to another common 2" header which is provided with flow indication (FE-650) and a manual isolation valve (764C) downstream of this flow element.

CCW flow to the two containment spray pump mechanical seal heat exchangers is provided by two 3/4" lines that originate from a common 2" header. These lines are reduced to 1/2" prior to entering the heat exchanger and increase back to 3/4" downstream of the heat exchanger. The heat exchangers each have a manual inlet (777B and 777C) and outlet (777A and 777D) isolation valve. The two lines outlet to a common 2" header which is provided with flow indication (FE-649) and a manual isolation valve (764D) downstream of the flow element.

CCW flow to each of the two RHR heat exchangers is provided by a 10" line supplied directly from the main CCW heat exchanger outlet header. Each heat exchanger has a motor operated inlet valve (738A and 738B) which is closed during normal plant operation. Downstream of the heat exchanger is a throttle valve (780A and 780B) used to control flow, and thus temperature, and a manual isolation valve (741A and 741B). The lines from the two heat exchangers discharge to a common 14" header.

CCW flow to the mechanical seals and jacket water coolers for each of the two RHR pumps is provided by a 2" line with a manual isolation valve (707A and 707B) which splits into three 3/4" lines, one to the seal cooler and two to the jacket water coolers. These lines return to a 2" line with another isolation valve (708A and 708B). Total flow to the two pumps is measured by flow element (FE-651).

A simplified diagram of the CCW system and CCW to the reactor coolant pumps is provided in Figures 6-4.1 and 6-4.2, respectively.

6.4.3 Description of CCW Fault Tree Model

The fault tree is organized under eleven top gates that model failure of the CCW system to provide cooling water to various components as follows:

a.	CC010	CCW Not Available to RCP A Pump Seal
b.	CC020	CCW Not Available to RCP B Pump Seal
c.	CC030	Insufficient CCW Cooling to RHR Heat Exchanger A (EAC02A)
d.	CC040	Insufficient CCW Cooling to RHR Heat Exchanger B (EAC02B)
e.	CC050	Loss of CCW to Containment Spray Pump B (PSI02B)
f.	CC060	Loss of CCW to Containment Spray Pump B (PSI02B)
g.	CC070	Insufficient CCW Cooling to RHR Pump A (PAC01A)
h.	CC080	Insufficient CCW Cooling to RHR Pump B (PAC01B)

i. CC090 Failure to Provide Cooling Water to SI Pump C (PSI01C)
j. CC100 Failure to Provide Cooling Water to SI Pump B (PSI01B)
k. CC110 Failure to Provide Cooling Water to SI Pump A (PSI01A)

With the exception of items a. and b. above, each top gate includes gate CC000 which models the failure of the CCW system to provide cooled water to the outlet heat exchanger during the recirculation phase of a LOCA. This comprises the majority of the CCW fault tree and contains failures of the pumps, heat exchangers, and associated piping and valves in the CCW supply up to, and including, the 14" header downstream of valves 734A and 734B. This gate does not contain any specific operator actions (e.g., starting pumps) because failrue of these actions is addressed by failure of operators to correctly transfer to sump recirculation. Items a. and b. above contain gate CC000A which is essentially the same as CC000 except that it does include operator failures to start pumps on coincident SI/UV conditions, or on failure of the auto-start feature of the standby pump.

Each top gate then combines gate CC000 (or CC000A) with failures of the specific components, downstream of the header, which supply flow to and from the particular component requiring cooling. The success criteria for the CCW fault tree is one CCW pump and one CCW heat exchanger providing flow to a specified system load.

The following are the two human failure events included within the CCW fault tree model:

a. *CCHFDCCWAB - Operators Fail to Start Standby CCW Pump If Automatic Signal Fails.* This event describes the failure of the operators to start the standby CCW pump given that the pump auto start feature fails (e.g., PIC 617 fails to start standby pump).

b. *CCHFDSTART - Operators Fail to Start a CCW Pump Following LOOP and SI.* This event describes the failure of operators to start a CCW pump following an SI signal coincident with a loss of offsite power which automatically sheds the CCW pumps. This event includes loading the CCW pump onto the DGs and only applies to non-recirculation events (e.g., for restoration of RCP seal cooling). Placing the CCW pumps back into service during the recirculation phase of an accident is addressed by the RRHFDRECRC event in the RHR system.

The CCW model contains the following logic flags:

a. *CCAACCPMPA - CCW Pump A is Aligned to Run.* Setting this flag to true indicates that CCW Pump A is in service.

b. *CCAACCPMPB - CCW Pump B is Aligned to Run.* Setting this flag to true indicates that CCW Pump B is in service.

6.4.4 CCW Fault Tree Model Assumptions

a. The CCW lines inside containment are not missile protected, thus, following medium and large LOCAs, it is conceivable that the CCW lines could be damaged and require manual isolation. However, the configuration has been analyzed and it has been determined that a medium or large LOCA would not damage the CCW lines inside containment using licensing criteria for pipe whips, etc. Therefore, the failure of the piping inside containment due to a LOCA has been added to the fault tree but its probability of occurring has been set to zero.

b. The fault tree is drawn under the assumption that a CCW-to-SW heat exchanger tube failure will cause leakage from the CCW system (normal operating pressure ~80 psig) to the SW system (operating pressure at CCW heat exchangers 50 to 60 psig), and thus failure of the CCW system due to loss of water inventory (i.e., the pressure of the CCW system is greater than the pressure of the SW system). This assumption was verified during the system walkdown and discussions with plant personnel.

c. The CCW surge tank provides NPSH to the suction header of the CCW pumps. It is assumed that if the manual isolation valve (728) in the line from the surge tank to the suction header closed, or if the tank ruptured, the pumps would have inadequate NPSH and the system would fail.

d. Pressure indicating controller PIC-617 senses the discharge pressure of the CCW pumps and sends a signal to auxiliary relay PIC-617-X in the relay room which starts the standby pump on low pressure. Even though the circuit between the PIC and the relay room passes through the Intermediate Building, it is located sufficiently far away from the block walls and piping that a high energy line break (HELB) in the Intermediate or Turbine Building is not expected to fail the circuit and thus fail the start of the standby pump.

e. Due to the fact that the water in the CCW system is highly treated and therefore extremely clean, a failure due to the plugging of any of the common piping has not been included in the fault tree.

f. Although not all the valves in the lines which supply CCW to the RCP bearing coolers and seal coolers are in series, it is assumed that a failure of any one of those valves fails the top events CC010 or CC020 for ease of modeling.

g. The failure of the SI pump, RHR pump, and CS pump mechanical shaft seal water heat exchangers are included in the failure data for the pump failing to run. For this reason the heat exchangers have not been modeled separately.

h. It is assumed that if CCW flow to the RHR pump seal water heat exchangers was restricted due to valve failure it would be noticed in a flow reduction on the indicator on the common outlet header (FE-651) which is recorded once per shift. However, the log sheets containing this value are only reviewed once per day, therefore the time between verifications is assumed to be 24 hours.

i. It is assumed that if CCW flow to SI pump seal water heat exchangers was restricted due to valve failure, it would not be noticed in a flow reduction on the indicator on the common outlet header (FE-650). A failure of one line is assumed to fail the pump. It is assumed that a failure of 2 or more of these isolation valves would be noted in a reduced flow on the common indicator if it occurred at power when flow is reviewed once per day.

j. It is assumed that if CCW flow to the CS pump seal water heat exchangers was restricted due to valve failure it would be noticed in a flow reduction on the indicator on the common outlet header (FE-649) which is reviewed once per day.

6.5 Compressed Air Systems

6.5.1 Compressed Air System Function

The Compressed Air system is actually comprised of two sub-systems: (1) Instrument Air (IA) and (2) Service Air (SA). For the purposes of the Ginna Station PSA, only IA is specifically addressed although SA is modeled as a potential backup to the IA system. The function of the IA System is to supply compressed air to the pneumatic instruments and apparatus of various systems through IA headers. Since the IA system is non-safety related, it is not required to mitigate any accidents (and therefore, it is not required to operate for any event tree heading or core protection function). However, the failure of the IA system directly affects many safety related systems since it will reconfigure valves and pumps to their "fail-safe" position. Therefore, the availability of the IA system affects three of the four core protection functions (i.e., control of RCS pressure, control of RCS inventory, and decay heat removal) and most of the event tree headings.

6.5.2 Compressed Air System Description

The IA system produces 120 to 125 psig dry, filtered air used as the motive power for valve actuation; it consists of three air compressors with each compressor having an aftercooler (IA Compressor C only has an intercooler) and air reservoir. Air from the receivers is supplied to the IA header through filters and an air dryer. The IA header delivers air to the Turbine Building header which then distributes compressed air to headers in the:

a. Intermediate Building;
b. Containment;

c. Service Building;
d. Auxiliary Building; and
e. All-Volatile Treatment Building.

The SA system produces 115 to 125 psig unfiltered air used in the maintenance air connections throughout Ginna Station, and for fire water storage tank pressurization. The SA system consists of one air compressor with an associated aftercooler and air receiver. Cross-connections between SA and IA allow the SA system to supply the IA header if IA pressure drops below 90 psig. The cross-connect occurs prior to the IA filters. Therefore, air being supplied to the IA header will always pass through the filters and dryer.

IA Compressors A and B and the SA Compressor are vertical, canned, non-lubricated, single stage, double acting, reciprocating compressors each capable of supply 300 cfm of compressed air. Each compressor can be placed in constant run, off, or in auto standby (this provides automatic backup to the operating compressor). IA Compressor C is an Atlas Copco 2-stage, oil free, rotary screw compressor capable of supplying 456 cfm. The compressor is either in run or stop. Based on the capabilities of each compressor, either IA Compressor C or any combination (i.e., two compressors) of IA Compressors A, B, and the SA Compressor can handle the entire system load during normal and emergency operations.

The air receivers located downstream of the compressors and aftercoolers provide a storage volume of compressed air. Each receiver is provided with a safety valve, moisture drain trap, air line to a control cavity, and pressure indications. The three IA receivers then supply a common air header to the filters and air dryers. When IA Compressor C is in service, IA Dryer C is also placed into operation to remove moisture from the IA system. IA Dryer C utilizes a rotating drum made of moisture absorbing material to remove moisture from the air. When IA Compressors A and B are in constant run, two heaterless air dryer trains are normally in operation to reduce the dew point of the air to -70°F at atmospheric pressure. Each of the two dryer train contain two desiccant-filled absorption towers (Train A contains towers TIA05A and TIA05B, and Train B contains towers TIA05C and TIA05D) and operates with a cycle time of 10 minutes.

The prefilter before each dryer removes entrained moisture and oil to prevent fouling of the dehydration towers. The after filter of each dryer removes any desiccant dust which may be present in the air.

Simplified diagrams of the IA system are provided in Figures 6-5.1 through 6-5.3.

6.5.3 Description of Compressed Air Fault Tree Model

The top events for the IA System are the supply of clean, dry air to various components identified in other fault tree models. The central event in the IA fault tree is defined at gate IA000, which represents the compressed air output from the compressors and dryers. The only active component downstream of this gate, and within the IA system boundary, is containment isolation valve 5392. Gate IA000 is an OR with inputs representing the possible failure paths of the IA system dependent on compressor operation and air dryer alignment. The failure path is determined by logic flag conditions which are discussed at the end of this section. IA Compressor C or any other two compressors are capable of supplying adequate air flow. Thus, IA Compressor C and two of the three other air supply sources must fail in order to fail the model. Additionally, both the SA compressor and backup air compressors (containment breathing and diesel) must fail to fail the SA path. Failures of the cooling water and electric power sources are modeled for each compressor.

The model contains the following human failure events:

a. *IAHFDSCA03 - Operators Fail to Place CNMT Breathing Air Compressor Into Service.* This event describes the failure of operators fail to place the containment breathing compressor in service as a backup for the SA compressor.

b. *IAHFDCSA04 - Operators Fail to Place the Diesel Air Compressor Into Service.* This event describes the failure of operators fail to place the diesel air compressor in service as a backup for the SA compressor.

Logic flags are included in the model to describe the initial configuration of running IA compressors as follows:

a. *IAAIAC02A - IA Compressor A (CIA02A) Running.* Setting this flag to true identifies that IA Compressor A is running. If this is true, then IAAAIAC02B is also most likely true due to the needs of the IA system at power.

b. *IAAAIAC02B - IA Compressor B (CIA02B) Running.* Setting this flag to true identifies that IA Compressor B is running. If this is true, then IAAAIAC02A is also most likely true due to the needs of the IA system at power.

c. *IAAAIAC02C - IA Compressor C (CIA02C) Running.* Setting this flag to true identifies that IA Compressor C is running.

6.5.4 Compressed Air Fault Tree Model Assumptions

a. The system of orifices and temperature control valves that control SW flow within the each compressor is considered part of the compressor for modeling and failure data purposes.

b. Failure of the valves in the sensing line from IA to valve 5251 (the valve that allows the SA System to back-up the IA System) is more likely to cause an unnecessary transfer than an unavailability of the SA System to backup IA. Therefore, these valves are not included in the IA system failure model.

c. It was assumed that IA Dryer C is running anytime the IA Compressor C is running. It is possible to run IA Compressor C with the C dryer bypassed; however, this is not a normal occurrence and therefore not included in the model.

d. Poor air quality due to moisture content and other containments is not specifically addressed in the model. Failure of the dryers and filters is assumed to include impediments to air flow, not how well moisture and particulate is removed from the air.

e. The IA compressors are assumed to be failed for any high-energy line break in the Intermediate (fails piping and AOV 5392) or Turbine Buildings (fails IA compressors).

6.6 Containment Isolation System

6.6.1 Containment Isolation System Function

[LATER]

6.6.2 Containment Isolation System Description

[LATER]

6.6.3 Description of Containment Isolation Fault Tree Model

[LATER]

6.6.4 Containment Isolation Fault Tree Model Assumptions

[LATER]

6.7 Containment Spray (CS) System

6.7.1 CS System Function

The CS System, in conjunction with the containment recirculating fan coolers (CRFCs) and the emergency core cooling system (ECCS), is designed to remove heat from containment during accident situations to control containment pressure within required limits. The CS system is also capable of removing airborne iodine and particulate fission product inventories from the containment atmosphere following a postulated accident minimizing fission product leakage to the environment. With respect to the Level 1 PSA, the CS system is only used for medium and large break LOCAs to prevent overpressurization of containment beyond the Level 2 PSA calculation of containment failure and for RHR NPSH concerns (see Section 10). If overpressurization of containment were to occur, then it cannot be assured that ECCS piping and components within containment would remain capable of performing their function. Therefore, the CS system supports the RCS inventory control and decay heat removal core protection functions.

With respect to the Level 2 PSA, the CS system is credited with respect to removing airborne iodine and particulate fission product inventories from the containment. This aspect is addressed in Section 10.

6.7.2 CS System Description

The CS system delivers borated water, initially drawn from the RWST and blended with sodium hydroxide (NaOH) from the spray additive tank, to the spray nozzles located in the dome of containment. When a low level is reached in the RWST and CS spray is still required, the CS pump suction is fed from the discharge of the RHR pumps. The CS system consists of the RWST, two pumps, two liquid jet eductors, a spray additive tank, two spray headers, spray nozzles, and the necessary piping, valves, instrumentation and controls.

Automatic initiation of the CS system occurs when sensors monitoring containment pressure detect a hi-hi containment pressure of 28 psig. Actuation signals generated in the Engineered Safety Features Actuation System (ESFAS) start the CS pumps and open the spray additive valves and the discharge valves to the CS headers. The CS system can also be manually initiated and controlled from the control room.

The CS system utilizes two 200 hp Ingersoll-Rand horizontal centrifugal pumps with a design flow rate of 1615 gpm and a minimum flow rate of 1200 gpm. The system incorporates a liquid jet eductor in each train to entrain the NaOH solution and mix it with the borated water from the RWST. Once the caustic solution leaves the CS pump discharge, it passes through motor operated discharge valves (MOVs 860A, 860B, 860C, and 860D), into containment, through two 6" spray headers and into two spray rings, each with a 1200 gpm capacity. The spray rings have 89 and 90 nozzles, respectively. The nozzles are at varying angle orientations and relative header positions to insure a minimum of 90% area coverage and uniform heat and fission product removal within containment.

A simplified flow diagram of the CS system is provided in Figure 6-7.

6.7.3 Description of CS Fault Tree Model

The CS fault tree model has the following top gates:

a. CS300 Failure to Provide Flow From CS During Injection
b. CR400 Failure to Provide Flow From CS During Recirculation

The logical structure of the fault tree beneath these gates generally follows the physical layout of the CS system. The injection mode includes failures of the CS pumps to start and run, and failures of the CS motor-operated isolation valves (860A, 860B, 860C, and 860D) to open, and passive failures of the RWST, piping, and spray ring headers. The recirculation mode includes failures of 896A and 896B to close (isolation of the RWST from sump fluid), no flow from RHR, and the CS system failures as described for the injection mode.

In addition to the two top gates, there are several gates which directly support other fault tree models. Gate CS110 (No flow available at TSI01 (RWST) discharge header to SI and CS) supports the SI fault tree and contains failures of MOVs 896A and 896B, piping and tank ruptures that could drain the RWST, and failure to respond of the RWST level transmitters (LT-920 and LT-921). Gate CR401 (MOVs 896A and 896B fail to close) supports the SI recirculation model and contains failures to close of MOVs 896A and 896B. Gate CS411 (RWST level transmitters fail to respond - no cue to switch to recirculation) supports the RHR fault tree and contains failures to respond of the RWST level transmitters. Gate CS410 (Failure of RWST to maintain inventory available to all systems) supports the SI fault tree and contains piping and tank ruptures which could drain the RWST and failure to respond of the RWST level transmitters.

For the Level 1 PSA, operation of one CS pump or one CRFC is considered success with respect to maintaining containment pressure within acceptable limits (see Section 10).

There are no human failure events or logic flags used in the CS fault tree model.

6.7.4 CS Fault Tree Model Assumptions

a. The 3/4" lines to valves 864A, 864B, 869A, 869B, 2821, 2822, 2823, 2824, 2825, 2826, 2829, 2830, 2839, 2861, 2862, 2863, 2864 and to test connection inside containment have not been modeled due to the small size (the delivery line is a 6" line) and the unrelated nature of the lines (unlikely to have common cause failure).

b. The 2" lines between MOVs 860A & 860B and check valve 862A and between MOVs 860C & 860D and check valve 862B have not been modeled due to there being welded caps on the end of each line.

c. Ventilation support of the CS pumps is not required during post-accident conditions [Ref. 2, Section 3.11.3.2].

d. Minimum recirculation flow for the CS pumps has not been modeled due to the design of the system. The CS pumps actuate at a pressure of 28 psig in containment. This pressure is not high enough to require the pumps to go to minimum recirculation. The pump discharge valves would have to fail closed, operators would have to fail to open them, and a manual valve in the eductor flowpath would have to transfer closed in order for the CS pumps to fail to have minimum recirculation. This combination of events was considered to be a remote possibility and was therefore not modeled.

e. The CS pump mechanical shaft seals are cooled by water taken from the discharge of the CS pumps and cooled by the CCW system. During the injection phase, this water is drawn from the RWST and will provide sufficient seal cooling.

f. The diversion of flow to the charcoal filters is assumed to fail CS.

g. Only the failure of both RWST level transmitters has been modeled because if one transmitter fails, giving the operators significantly different level indications, the operators would visually determine the level or attach a gauge to the tank to measure the head of water.

h. The failure to isolate the test return line to the RWST has not been modeled as a diversion flow path due to the fact that there are three normally closed manual valves in sequence for each train (two of the valves are common to both trains). Testing procedures have separate steps with separate mark-offs for each step with independent verification checks for each of these valves. Therefore, the likelihood of leaving the three valves in sequence open was considered negligible.

i. Per conversations with operations, the manway on top of the RWST is normally left open so that operators can check the water level with a flashlight. Therefore, the need for the vacuum breakers (2850 and 2851) on the RWST were not modeled.

j. Tank leakage has not been modeled since tank rupture was included. Tank leakage would have to be ANDed with the failure of operators to detect the leakage over a significantly large period of time (i.e., days). Tanks considered in the CS fault tree are monitored for level at least once every eight hours with auxiliary operators also performing their rounds. In addition annunciators would alarm on low level conditions.

k. For data purposes, MOVs are assumed to act like manual valves if the power is removed from the operators.

l. Root valves for instrumentation were not modeled since these valve failures were assumed to be part of the instrumentation boundary for data analysis purposes.

6.8 DC Power System

6.8.1 DC Power System Function

For the purposes of the Ginna Station PSA, the DC Power system is the 125 VDC electrical network which is comprised of the station batteries, battery chargers, and various distribution panels. The DC Power system provides control and motive power to the following systems and components:

a. The normal and emergency supply breakers related to the AC Power system (i.e., the 4160 V and 480 V buses).

b. The DG control panels and output breakers, such that on a loss of the normal power supply to the 480 V safeguards buses, the normal supply breakers will open, the DGs will start, and the DG output breakers will close onto the affected buses.

c. The circuit breakers connecting loads to the safeguards buses (and loads on the MCCs) so that the required breakers will open and shed the loads when an undervoltage condition on the bus occurs.

d. The undervoltage system so that on a loss of AC power to any of the buses, the appropriate undervoltage signals are sent.

e. The ESFAS so that SI signals are generated when required by accident conditions (i.e., the master relays require DC power in order to energize and generate a signal).

f. The DC Power system is the normal power supply to the 120 VAC Instrument Buses which in turn provides instrumentation and controls for reactor protection and safeguards cabinets.

g. Control and/or motive power to operate various motor operated pumps, fans, valves, and other miscellaneous loads which are required during accident conditions.

As such, the DC Power system is a support system to essentially all event tree headings and all four core protection functions.

6.8.2 DC Power System Description

The 125 VDC power system consists of two independent trains. The power supply to each train consists of a battery (which feeds through the main battery disconnect switch), and two battery chargers. The battery and the chargers supply a main fuse cabinet. The main fuse cabinet then supplies the main DC distribution panel, and other distribution panels in the DG room, the main control board, the Auxiliary Building, and the Screenhouse. Train B also supplies a distribution panel in the turbine building.

The station batteries are 60-cell, lead-acid, station-type batteries rated at 150 amps for 8 hours (1200 amp-hr). The normal output voltage is 130 VDC. The station batteries are designed to provide a minimum of 4 hours of service following a SBO; however, they are assumed to provide up to 6 hours for the TDAFW pump per Appendix B.

There are two battery chargers for each train, each supplied with 480 VAC, 3 phase, 60 Hz input. Battery Chargers 1A and 1A1 are supplied from MCC C, while Chargers 1B and 1B1 are supplied from MCC D. Chargers 1A and 1B output 130 VDC at 150 amps, while Chargers 1A1 and 1B1 output 125 VDC at 200 amps. A single battery charger is designed to provide the necessary DC power system for each train.

Heating and cooling to the battery rooms is provided via the HVAC unit located in the air handling room adjacent to Battery Room A. A thermostat in each of the battery rooms send signals to the controller which provides heat to the rooms if the temperature drops below 71°F, and provides cooling if the temperature goes above 77°F. An exhaust fan in each battery room helps move air out of the rooms. A constant air flow of 1000 cfm is maintained for each room to maintain hydrogen concentrations below required levels.

A simplified diagram of the DC power system is provided in Figure 6-8.

6.8.3 Description of DC Power System Fault Tree Model

The DC Power system fault tree has multiple top gates. Essentially, top gates exist for each of the following distribution panels (note that several components may actually be an input into another top gate; e.g., loss of power on Main DC Distribution Panel A fails power to Auxiliary Building DC Distribution Panel A):

a. Battery A and B Main Fuse Cabinets
b. Main DC Distribution Panels A and B
c. Auxiliary Building Distribution Panels A and B
d. Auxiliary Building Distribution Panels A1 and B1
e. DG DC Distribution Panels A and B
f. Screen House DC Distribution Panels A and B
g. Main Control Board DC Distribution Panels A and B
h. Turbine Building DC Distribution Panel

Except for those loads supplied directly from Main DC Distribution Panels A or B, the logic for component requiring DC power starts with the failure of the associated distribution panel and works its way back through the Main DC Distribution Panel, through the battery main fuse cabinet, and back to the battery and AC power supplies.

The fault trees for the failures of the distribution panels and the main fuse cabinets include failures of the fuses and the disconnect switch for the circuit supplying the load in question. The failure of the power supplies to the main DC fuse cabinets is modeled for three different cases: (1) long-term, (2) long-term circular logic clip, and (3) short-term, depending upon the DC load that is ultimately being supplied. These definitions are somewhat misleading, however, because they are distinguished more by the power supplies that are available, than by the time frame in which they are required. In fact, the only time dependency included in the model is an hourly failure event for the batteries, for 24 hours, which is included in the long-term and long-term circular logic clip fault trees, as well as the demand failure event. For the short-term trees, only the demand failure is included.

The long-term logic assumes that the batteries and both battery chargers are available to supply power. This is the normal alignment and is used in the other fault tree models for most of the DC loads. This assumes that AC power is potentially available to Buses 14 and 16, and therefore, must fail in order to fail power to the battery chargers. The circular logic clip for the long-term DC power eliminates the dependency on the DGs. This logic is used for gates which depend on the DGs or supply power to circuitry for certain DG auxiliary loads which are only required once the DG has started. This logic includes both demand and hourly failure of the battery. The short-term logic assumes that AC power to the battery chargers is unavailable such that the batteries are the only source of DC power. This logic is used for gates which assume that AC power has been lost, such as the Bus 14 and 16 undervoltage system, and the DG starting circuitry. This logic includes only a demand failure of the battery. The short term logic also does not include failrues of the batteries due to low temperatures in the battery rooms (see Section 6.8.4.c) because failure is not expected to occur within 2 hours.

The success criteria of the DC Power system model is to provide DC electrical power to necessary distribution panels within prescribed voltage limits such that the panels remain available for the entire mission time (i.e., does not trip out on loss of voltage or undervoltage conditions).

There are no human failures or logic flags used in the DC Power system fault tree model.

6.8.4 DC Power System Fault Tree Model Assumptions

a. Although shown as switches on the electrical drawings, the automatic throwover for Buses 13 through 18 are actually controlled by relays, and are modeled as such.

b. Failures of equipment in the battery rooms due to hydrogen buildup was not modeled in the fault tree. If the normal ventilation to the rooms failed, it would cause main control board annunciator C-13 to light. Operators would be dispatched to start the emergency DC fan to the rooms. If this fan failed to start, operators could still open the doors to the battery room to allow air flow, thus reducing the hydrogen concentration. Calculations have shown that the operators would have over 4 hours to take appropriate action, with the batteries on an equalizing charge and no air flow in or out of the rooms, before reaching the combustible limit of 4% by volume. Since the battery rooms are not air tight, some air flow would be expected, thus increasing the amount of time available to take action.

c. Failure of the batteries due to cold air being blown into the battery rooms was assumed to be a concern only when the control room HVAC unit is operating in the recirculation mode and outside air temperature is below 40°F. If the control room HVAC unit is not in recirculation, the warm air from the control room exhausts to the air handling room and is blown into the battery rooms, with no outside air used. If the control room HVAC unit is in recirculation, it does not exhaust any air to the air handling room and approximately 400 cfm of outside air would be blown into the battery rooms. If the heating unit were to fail, the air would enter the battery rooms at ambient temperature. It is assumed for the model that the control room is in recirculation mode during testing, maintenance, or during a LOCA. It is conservatively assumed that the electrolyte solution in the batteries would take at least 2 hours to drop below the 55°F limit, since the initial minimum temperature of the electrolyte would be approximately 71°F. Loss of IA to the battery room HVAC control unit, and failure of the main HVAC unit fan were not considered failures which would cause cold temperatures in the battery rooms, even though they would both cause the heater to turn off. This is because those failures would also cause the normal supply fan and the two exhaust fans to stop and would not start the emergency DC powered fan. Therefore, while there would be no heating capability, there would also be no air flow to the rooms and thus no cold air would be forced in.

d. The control room HVAC unit is operated in the recirculation mode during performance of the calibration of the control room chlorine monitor, ammonia monitor, gas radiation monitor, particulate radiation monitor, and iodine radiation monitor. Per discussion with plant personnel, these calibration procedures are performed with the plant on line, and the total time in recirculation for calibration of the 3 radiation monitors is about 2 days, while the time in recirculation mode for calibration of the chlorine and ammonia monitors is about 5 to 7 hours each. Further, it was stated that there is often significant corrective maintenance required on these systems which can last a week or more. Therefore, it was conservatively assumed that the control room HVAC system is in recirculation mode due to testing or maintenance for two weeks out of each year.

e. Failures of equipment in the battery rooms due to high temperatures was also considered. A design analysis evaluated the temperature rise in the battery rooms due to heat loads in those rooms, with a loss of all ventilation and a loss of all offsite power. The results of that analysis showed that the temperature rise in Battery Room B was 8.84°F after 5 hours and that the rate of increase had leveled off at approximately 1.15°F/hr. Thus at 24 hours, the room temperature would be 107.68°F, well below the 120°F operability limit specified by NUMARC 87-00 [Ref. 33]. Battery Room A was shown to be at 102.44°F at 5 hours and rising at a rate of approximately 2.8°F/hr. This would indicate that temperature at 24 hours would be 155.62°F. However, the analysis is extremely conservative for the following reasons:

1. It assumed that a loss of offsite power had occurred, thus putting greater loads on the equipment in the battery room, and increasing the heat load.

2. The heat capacity of the steel reinforcement in the walls, the lead in the batteries, the battery cell containers, the structural members in the room and the interior wall and ceiling masonry was not included in the analysis.

3. It was assumed that no heat transferred out of the room through the walls or floor, even though the room is below ground and two of the walls and the floor are in direct contact with the soil which is assumed to have a maximum summer temperature of 60°F.

Assuming that the actual heatup rate would be 50% of that calculated in the analysis, the temperature would be 89.6°F at 5 hours and 116.2°F at 24 hours. Therefore, failures due to loss of ventilation have not been included in the model. However, it is possible that the temperature control could fail in a way such that the heating unit is on when it should not be. This heater is an 18 kW unit which would increase the heat load in each room (7.92 kW for room A and 5.76 kW for room B) by a factor about 2 for room A and 3 for room B. It cannot, therefore be assumed that the room temperature would stay below 120°F, so this scenario was included in the model. It should be noted, that high temperature is not a concern for the operability of the batteries themselves, since an increase in electrolyte temperature actually improves battery performance in the short term. The only equipment that is assumed to be adversely affected by high temperature is the battery chargers (and the inverters, which are included in a separate model).

f. It was assumed that failure of fuses or disconnect switches in DC power circuits to any loads which do not have automatic throwover to an emergency DC circuit would be immediately detected. Due to the amount of effort required to verify this for each individual load, this verification was not performed.

6.9 Diesel Generator (DG) System

6.9.1 DG System Function

The DG system functions to supply 480 VAC power to safeguards Buses 14, 16, 17, and 18, in the event that the normal power supply to those buses is unavailable. DG A supplies Buses 14 and 18, while DG B supplies Buses 16 and 17. When an undervoltage condition occurs on a bus, the associated DG receives a start signal. When the DG comes up to speed and attains the required voltage and frequency, the output breaker(s) from the DG to the bus(es) with undervoltage will close, thus providing power to those buses. Since the DGs provide an emergency backup to the offsite power sources, they support the same functions as the AC Power system (see Section 6.1.1).

6.9.2 DG System Description

The DG system consists of two DG sets and their associated fuel supply, air start motors, starting circuitry, output breakers, lube oil system, cooling water, and ventilation.

Each DG set consists of an Alco, V type, 16 cylinder, turbocharged, 4 cycle diesel engine, and a Westinghouse 3-phase, 60 Hz, 480 VAC generator. The two DGs are housed in the DG building which is capable of withstanding seismic and extreme snow loads, and can protect the DGs from external flooding and tornado winds and missiles. A new reinforced-concrete slab roof with a reinforced-concrete parapet was recently constructed covering the entire DG building.

Fuel oil is supplied to the engines from independent 350 gallon fuel oil day tanks, through a filter, by the associated fuel oil booster pump. The fuel oil transfer pump (when in automatic mode) pumps fuel from the common fuel oil storage tank to the individual fuel oil day tanks. There is a check valve and a foot valve in the supply line for the transfer pump to maintain prime.

The diesel engines are started by an air start motor which is supplied with compressed air from two air receivers. There are two solenoid valves in parallel which open to allow air to the air start motor which starts the engine. The two air receivers for each engine are supplied with compressed air by a 480 VAC air compressor. The compressors automatically start when receiver pressure drops to 220 psig and stops when pressure reaches 250 psig. In order to start the engine, the solenoid valves receive an open signal from the control circuitry.

The control circuitry for the DG sets has two basic functions: to start the engine, and to close the generator output breaker on to the appropriate bus(es). The starting circuitry consists of open relay contacts in a 125 VDC circuit. When the contacts close, the solenoids for the air start motors open, opening the valves and starting the engine. The contacts in the circuit for DG A will close under the following conditions:

a. Undervoltage on 480 VAC Bus 14 (relays 27X1/14 and 27BX1/14);
b. Undervoltage on 480 VAC Bus 18 (relays 27X1/18 and 27BX1/18);
c. SI signal (relay SI-18X); and
d. Manual start (local or from MCB).

The contacts in the circuit for DG B will close under the following conditions:

a. Undervoltage on 480 VAC Bus 16 (relays 27X1/16 and 27BX1/16);
b. Undervoltage on 480 VAC Bus 18 (relays 27X1/17 and 27BX1/17);
c. SI signal (relay SI-28X); and
d. Manual start (local or from MCB).

The control circuitry for the generator output breaker will cause the breaker to close on to the associated bus when the DG has attained required voltage and frequency, if the normal supply breaker to the bus is open. Normal DC power to the control circuit for DG A is supplied by DC Train A, while emergency DC power is supplied by DC Train B. Normal DC power to the control circuit for DG B is supplied by DC Train B, while emergency DC power is supplied by DC Train A. Automatic transfer to the emergency DC power supply on loss of the normal power supply is provide for both DGs.

During standby conditions, lubrication of the engines is provided by an electric rotary prelube pump. When the engine is operating, lubrication is provided by a rotary pump attached to the shaft of the engine. In both cases, oil is drawn from the oil sump under the engine, passes through a filter and is routed to the supply header either directly, or through the lube oil cooler, depending on the oil temperature. The lube oil cooler is supplied with cooling water by the SW system.

The jacket water cooling system removes the heat of combustion from the diesel cylinders and heads. It also provides cooling to the turbocharger. The jacket water is circulated through a closed system by a pump attached to the engine shaft, and an expansion tank provides surge and makeup capability. The jacket water is passed through a heat exchanger which is cooled by SW.

Each DG is housed in its own room with separation ventilation systems to prevent excessive heat from causing a failure of the DG. Each room has two ventilation supply fans. One fan cools the room itself, while the other is dedicated to cooling the control panel. The fans start when the jacket water pressure increases above 11 psig (i.e. when the diesel has successfully started) and the room temperature is above 90 degrees. Each fan has an associated air-operated damper which opens when the fan starts to allow air flow into the room and closes when the fan stops. Each room has two sets of passive dampers which open to allow air to exhaust to the outside.

The DGs are shown on Figure 6-1.

6.9.3 Description of DG Fault Tree Model

The DG fault tree is organized under four top gate as follows:

a.	DG400	Failure of DG A Supply Power to Bus 14
b.	DG800	Failure of DG A Supply Power to Bus 18
c.	DG600	Failure of DG B Supply Power to Bus 16
d.	DG800	Failure of DG B Supply Power to Bus 17

Each top gate is divided into two logical sections: the failure of the DG to supply power, and the failure of the DG output breaker to close onto the bus.

The success criteria for the DG supplying power is that the DG must start and run for 24 hours following an undervoltage condition. The failure of the DGs to supply power is organized into the failure of the DG to start and the failure of the DG to run, either of which will fail the DG. The branch for failure to start includes only the components or systems which are required to operate immediately upon an undervoltage condition to start the DG. The branch for failure to run includes those systems which are required to operate soon after the DG starts and remain operable for the entire 24 hour period. This was done so that the failure to run gate could be used independent of the failure to start gate in cases where the DG is running at the start of an event.

The branch for the failure of the DG to start includes the basic events for the DG fails to start and the DG being unavailable due to test and maintenance, the common cause event for the DG fails to start, and gates for the failure of air to the air start motor and the failure of Bus 14 or Bus 18 loads to be shed. Failure of air to the air start motor includes the manual valves in the line from the air receivers to the solenoid valves, failure of the solenoid valves to receive an open signal, and failure of the solenoid valves to open. It should be noted that the model assumes that the DG will have to close onto both safeguards buses and therefore loads must be shed from both. However, when the entire plant model is quantified it is possible that there could be cutsets which include a loss of power to only one safeguards bus (i.e. failure the feeder breaker, or local fault). In that case, the model would indicate that any failure of loads to shed from the other safeguards bus would fail the DG. Since this would not really be the case, any cutsets of this type could be deleted. This branch also includes the failure of the SI load sequencer to properly time the starting of loads onto the DG.

The branch for the failure of the DG to run includes the following:

a. *Failure of the DG to run for the required 24 hour mission time once started*: This branch includes the basic event of the DG fails to run, the common cause event for DG failing to run, and the DG tripping after an initiating event given that it was running initially due to the opposite DG being out of service.

b. *Failure of the fuel oil supply to the day tank*: This branch includes failures of the fuel oil storage tank and valves in the line to the transfer pump, failure of the transfer pump (including loss of prime), failure of valves in the line to the recirculation/fill solenoid valves, failure of the solenoid valves that would prevent filling of the day tank or overflow the day tank, and common cause events.

c. *Failure of service water cooling to the DG*: This is a direct transfer to the SW model.

d. *Failure of the DG room ventilation system*: This branch includes failure of air flow to the rooms, failure of the ceiling and void area exhaust dampers, and freezing of the jacket water sensing lines due to the ventilation system operating in cold weather when it should not.

As stated above, the second major logical branch of this model represents the failure of the DG output breaker to close onto the bus. The success criteria for the output breaker closing is that the breaker must close onto the bus when the diesel has achieved minimum rated voltage and frequency. This branch of each top gate is divided into the following two logical sections, either of which will fail the DG.

a. *Failure of the DG output breaker to receive a signal to close*: This branch includes failure of the normal supply breaker to receive an open signal, failure of the normal supply breaker to open upon receiving a signal, failure of the relay to send a signal that the breaker is open, and failure of the relay indicating the DG is up to voltage and frequency to send a signal.

b. *Failure of the DG output breaker to close upon receiving a signal*: This includes the basic events for the failure of the breaker to close and the failure of the breaker to remain closed, as well as a direct transfer to the 125 VDC model gate for loss of DC control power to the breaker.

There are no human actions modeled in this fault tree.

The only logic flags used in this model define whether or not certain equipment powered off the 480 VAC safeguards buses are operating at the time of an undervoltage on the bus. If they are, then they must be shed from the bus prior to closing the DG output breaker onto that bus. These logic flags are defined by the affected system (i.e., CCW, HVAC, AC Power, and CVCS).

6.9.4 DG Fault Tree Model Assumptions

a. Failure of any of the loads on the 480 VAC safeguards buses to shed when required on undervoltage would not prevent the DG output breaker from closing onto the bus, but it is assumed that the DG would fail when the output breaker closed due to the excessive load on the bus. This assumption is conservative since the DG is designed to close with some load on the bus if no SI signal is present (i.e., CCW pump). Also, different plant conditions will result in different loadings on the DGs (e.g., a large break LOCA will have a different voltage drop on the safeguards bus than a small break LOCA due to the RCS pressure effect on the pumps). Since it has not been determined how much load could be picked up by the DG for every possible scenario, it was assumed that a failure of a single breaker to open would fail the DG (i.e., the failure probability of a DG due to failure of load shedding is based on the probability of a single breaker failing to open on each of the two buses the DG supplies).

b. A failure of the level indicating transmitters in the DG fuel oil day tanks could cause the fuel oil transfer pumps to fail to start, and the recirculation/fill SOVs (5907, 5907A, 5908, and 5908A) to fail, either overfilling the day tank and depleting the fuel oil supply, or failing to refill the day tank. In this event, the operators have the ability to operate both the pumps and the SOVs manually from the DG room to maintain proper level in the day tanks. This operator action has not been included in the model but can addressed by a recovery event if required.

c. It is assumed that the control switches for the DG room cooling fans are in the AUTO position, and the relay contacts from the jacket water pressure switch and the temperature switches (for the A1 and B1 fans) have not failed closed. If the fans were in the run position, or the relay contacts had closed, the fans would be running continuously even when the DG was not in operation, and this would be quickly discovered during auxiliary operator walkdowns.

d. Since the air operated solenoid valves which open the supply fan dampers fail so that the dampers are open, no events were included for loss of air to the SOVs. Also, the DG room exhaust dampers are passive devices so they have not control circuitry or motive power.

e. It is assumed that one out of two trains of DG room cooling is sufficient to keep the DG operational [Ref. 6, LCO 3.8.1].

f. It is assumed that a loss of DC control power to the DG control panel which occurs after the diesel has started will not cause the diesel to fail. All of the trip functions for the diesel require power to the control panel to actuate. Therefore, if there is no control power, there will be no trip. This was confirmed with Electrical Engineering personnel. However, a loss of normal DC control power to the DG control panel will cause the oil pressure time delay relays OPT1 and OPT2 to de-energize, failing the room cooling fans. This failure was included in the logic for failure of the ventilation for the DGs.

g. There is an overflow line from the DG day tanks to the fuel oil storage tank. However, it is assumed that if the fill solenoid valves controlling flow to the day tanks (5907 or 5908) failed to close when the tank filled, some of the fuel oil would flow out of the breather pipe into the DG room. This could deplete the inventory in the storage tank or cause a fire or explosion in the DG room. Thus, failure of this valve to close is assumed to fail the DG with a probability of 0.1.

h. If the recirculation valve in the line to the DG day tanks (5907A or 5908A) failed to close when the fill valve (5907 or 5908) opened, the flow through the two lines would be roughly proportional to the cross-sectional area of the lines. The fill line to the day tank is a 1" line while the recirculation line is 0.75" line. Thus, 64% of the flow from the pump would go to the day tank. Since the minimum flow from the pump is 15 gpm, the flow to the tank would be approximately 9 gpm, which is well above the required 3 gpm. Therefore, it is assumed that the recirculation valve failing open will not by itself fail the DG. The ability to provide adequate flow to the day tank with the recirculation valve open was demonstrated by performance of PT-12.6 with the leads removed from valve 5907 on February 2, 1996.

i. If the fill solenoid valve in the line to the DG day tanks (5907 or 5908) failed to open when required while the DG is running, the level in the day tank would decrease to the low level alarm setpoint, and if nothing was done, it would continue to decrease to the low-low level alarm setpoint. Upon receipt of either of these alarms, annunciator J-24 (DG A) or J-32 (DG B) would light. Procedure AR-J-32 [Ref. 34] instructs the operators to go the DG control panel to check which alarm is lit. Upon finding that the low (or low-low) level alarm is lit, the operators are instructed to open the manual bypass valve (5937 or 5938) to allow flow around the closed solenoid valve and into the day tank. This has not been modeled in the fault tree but can be used as a recovery event.

j. When an undervoltage condition exists coincident with an SI signal, the SI load sequencer is prevented from sending signals to the time delay relays (which start the required loads on the safeguards buses), by contacts in undervoltage relays which open when the relay energizes. If the contacts for the train A sequencer failed to open, the time delay relays will receive signals immediately upon the SI signal being present. Assuming that it will take 10 seconds for the DG to achieve required voltage and frequency (per the accident analysis), when the output breakers from DG A close onto Buses 14 and 18, SI Pumps A and C would already be loaded onto the bus. This is assumed to overload the DG resulting in its failure. Similarly, if the contacts for the train B sequencer failed to open, SI Pump C would be loaded onto the bus when DG B output breakers close, and 2 seconds later RHR Pump B would start. Again, this is assumed to fail the diesel.

k. The SOVs in the supply lines from the fuel oil storage tank to the fuel oil day tanks (5970, 5907A, 5908, and 5908A) open and close repeatedly while the diesel is running to direct flow either to the day tank or back to the storage tank when the day tank is above a certain level. The failure of these valves to open or close is modeled as a standby failure using an interval representing the time between starting the DGs. However, this does not take into account the fact that they would have to change position approximately 32 times in a 24 hour mission. Since plant-specific failure data collected against these SOVs did not indicate an significant number of failures (i.e., 1 failure in 9 years), the failure rate was not adjusted to account for the potential number of valve position changes.

l. Relays AR-93 and AR-94 energize to position the fill/recirculation solenoid valves in the fill alignment. These relays are assumed to be included within the component boundary for the solenoid valves and have a failure probability of 0.0.

m. No consideration was given to freezing events in the DG rooms for the following reasons:

1. The only freezing concern identified is the jacket water pressure sensing lines, which are only required to be operable to start the DG. Since the fans do not start until the DG has started, there is no concern that the pressure sensing lines would freeze prior to starting the DG.

2. Analysis has shown that with one fan operating and the outside temperature at its design low temperature of 2°F, the temperature inside the DG room would not go below freezing.

n. Following performance of the monthly DG test procedure, the DG is tripped and requires resetting in order to be available for automatic start and load on an undervoltage signal. The failure of the operator to reset the DG at the end of the test was not modeled because this failure would result in main control board annunciator J-24 (DG 1A) or J-32 (DG 1B) being illuminated and it is assumed that the operators would quickly correct the situation.

o. No events were included in the DG fails to run logic to account for the failure of the diesel to run given that it was running at the start of the event (either due to its own monthly testing, or the opposite DG being unavailable which requires the DG to be run within 24 hours), and subsequently trips due to the initiating event. The AC power model for failure of power to the four safeguards buses divides the failure of power on each bus into two distinct branches. One is for when the diesel is running and tied to that bus, and the other is for when the diesel is idle. Therefore, the tripping of the diesel which is already running is only applicable to the branch which assumes it is running. Thus, this situation is handled explicitly in the AC Power model and not in the DG model.

p. The logic for the failure of the air start solenoid valves assumes that there is an undervoltage on both buses supplied by the diesel in question, and thus, both start signals would have to fail in order for the solenoid to receive no start signal. This assumption is legitimate for situations in the overall plant model when all offsite power is lost. There are situations in the overall model in which only power to one of the two buses would be lost (i.e. loss of the 4160/480 V transformer to a single bus or failure of the circuit breakers to that bus). In this case, only an undervoltage signal from that bus will be generated, and the model is not conservative. However, given that there are two air start solenoids for each diesel, each of which receives its start signal from different undervoltage relays, and the fact that even if the diesel failed to start, there would still be power available on the other safeguards bus in that train, and on the other train, this non-conservatism is not expected to have an impact on the overall model.

qs. The logic in the model that fails the diesel upon failure of the loads to shed from the safeguards buses assumes that an undervoltage has occurred on both buses supplied by the diesel. As discussed in p. above, there are situations in the overall model where this is not the case. In these situations, the model is overly conservative. However, the cutsets which result from this can be readily identified since they will contain a failure in the AC power system specific to one bus and a failure of a load to shed from the other bus, and thus they can be eliminated if desired.

6.10 Engineered Safety Features Actuation System (ESFAS)

6.10.1 ESFAS System Function

The ESFAS automatically initiates various engineered safeguards, or safety features, to limit the consequences of accidents. When the ESFAS logic senses a condition requiring safety features actuation, it sends an appropriate signal to activate the master relays; the master relays, in turn, activate auxiliary or slave relays that operate the motor controllers or breakers of the safeguards devices. The ESFAS model addresses only the sensing and actuation features of the ESFAS while the remaining fault tree models address the failures of the component which receives the ESFAS signal. ESFAS is comprised of the following sub-systems:

a. SI actuation;
b. Containment isolation;
c. containment ventilation isolation (CVI);
d. MS isolation;
e. CS actuation;
f. MFW isolation;
e. DG actuation; and
f. AFW pump actuation.

As such, ESFAS supports all four core protection functions (i.e., reactivity control, RCS pressure control, RCS inventory control, and decay heat removal).

6.10.2 ESFAS System Description

The ESFAS actuates appropriate safety related components whenever RCS, containment, or secondary systems deviate from the specified safe operating region. To achieve this, nuclear and process instrumentation is monitored using analog monitoring loops. Each loop consists of a transmitter, power supply, and bistable, plus associated test components. Loops may contain other digital and analog devices. In addition, some loops (e.g., T_{avg}) contain two analog detector strings.

The bistable in each instrument loop controls safeguards logic relays. The contacts of these logic relays are wired together in logic matrices in such a way that, when a required combination of parameters deviate from their acceptable operating region, a master relay is actuated. This master relay then actuates a number of auxiliary relays which control individual safety-related components.

There are two digital actuation trains (logic matrices, master relays and auxiliary relays) and up to four analog instrumentation channels associated with the ESFAS. A minimum of two-out-of-three (2/3) logic is used for most functions with two-of-four (2/4) logic used in the remaining functions. Each channel and each train is physically and electronically independent. Components of different channels are physically separated, penetrate the containment at different locations, and are supplied by independent electrical power supplies.

There are four cabinets for each train located in the Relay Room. Each cabinet receives signals from the bistables in the protection cabinets. All of the cabinets are divided into two sections by a metal divider plate. The logic relays are located in the front section, and master and auxiliary relays are located in the rear section. Except for CS actuation, the bistable in each analog circuit is de-energized when the measured parameter is in an acceptable region. This design feature is used so that loss of power to the bistable will cause it to transfer to its tripped (or safe) position. CS bistables are normally de-energized and become energized when the measured parameter enters an unacceptable region. This is different from the other functions due to the undesirable consequences of an inadvertant CS actuation from loss of power to the circuit.

Once the bistable is tripped, safeguards logic auxiliary relays (one for train A and one for train B) de-energize (energize for CS), shut their contacts. When the required number of logic auxiliary relay contacts within the logic matrix close, the master relay(s) energizes, closing its contacts and activating the ESFAS signal auxiliary relay(s). As the auxiliary relay contacts close, some safety-related components start or operate to mitigate the detected unsafe condition. Other components are actuated via a time delay slave relay in cases where normal power has been lost to the vital bus(es). The analog channels are actually powered by separate power supplies mounted in the protection racks. These are fed from various "MQ-" distribution panels off the 120 VAC Instrument Buses.

The master and slave relays are powered from 125 VDC. Each analog channel is fed from a different 120 VAC Instrument Bus. Two of these Instrument Buses (A and C) are normally supplied by interveters and two (B and D) are supplied by constant voltage transformers.

Manual reset of the SI actuation relay may be accomplished at any time following their operation. CS, containment isolation, and CVI can reset after the initiating signal clears while MS isolation and MFW line isolation do not have reset functional capability. Once reset action is taken, the SI signal master relay(s) is reset and its operation blocked until the ESF initiating signal clears, at which time it is automatically unblocked and restored to service.

When 480 V Buses 14 and 16 remain energized, closure of the master SI relay(s) contact initiates the safeguards sequencing circuit by energizing one control relay and eight timing relays. The control relay in each train starts an SI pump. The remaining loads are started when the Agastat time delay relays time out and shut the breakers. On a loss of normal power to Bus 14 and 16, the sequence would be triggered by the closure of the 27X6/14 or 27BX6/14 (or /16) relays following bus re-energization.

6.10.3 Description of ESFAS Fault Tree Model

Since each fault tree identifies the specific slave or master relay which actuates the associated component, the ESFAS fault tree is organized based on the slave relays. As such, a top event is provided for each slave and master relay for the functions listed in Section 6.10.1. Failure at each top is the failure of the auxiliary or master relay to actuate. The fault tree proceeds from the top events through the logic circuitry of the ESFAS and down to the individual sensors. The condition of sensed parameters (e.g., pressure, temperature) occurs in response to initiating events. Spurious actuations include a spurious signal as well as spurious failures of equipment.

A summary of the input channels to each ESFAS system is contained in the Technical Specifications [Ref. 6, LCO 3.3.2].

There are no human failure events or logic flags in the ESFAS fault tree. However, it is noted that initiating events are specifically identified in the fault tree as to whether they are expected to directly result in reaching an ESFAS parameter (e.g., a large break LOCA will result in actuation of CS on high containment pressure).

6.10.4 ESFAS Fault Tree Model Assumptions

a. Failures to restore the sensing equipment channels to service after test or maintenance would be immediately noticed on annunciator alarms in the control room or in a system actuation if sufficient channels were tripped. These failures have been included, even though they are not really expected.

b. The impact of loss of power to various bistables, sensors, and instrument loops, is based on a failure analysis of ESFAS bistable power sources.

6.11 Heating, Ventilation, and Air Conditioning (HVAC) Systems

6.11.1 HVAC System Function

Fault tree models were developed for the following HVAC systems:

a. Containment Recirculation Fan Coolers (CRFCs)
b. Charging Pump Room Coolers
c. Control Room Ventilation System
d. Relay Room Coolers
e. SAFW Pump Building Ventilation System
f. Intermediate Building Ventilation System
g. Control Rod Shroud Fans
h. Diesel Generator Building Ventilation System (note - this is included in the DG fault tree)

Essentially, each HVAC system functions to control room temperature and humidity during normal operations and following accidents and transients. Only the CRFCs, SAFW Pump Building ventilation system, Intermediate Building ventilation system, and DG Building ventilation system have direct impact on the event trees and core protection functions. That is, the CRFCs supports the RCS inventory control and decay heat removal core protection functions, the SAFW Pump Building and Intermediate Building ventilation system affect the decay heat removal function, and the DG Building ventilation system supports all core protection functions expect for reactivity control. The Control Rod Shroud Fans were modeled as a potential recovery for the pressurizer heaters for long-term support of natural recirculation. All remaining HVAC systems are not specifically used in the overall plant model.

6.11.2 HVAC System Descriptions

A description of each HVAC system is provided below.

CRFCs

The CRFCs consists of four air handling units, each containing a motor, fan, cooling coils, moisture separators and high efficiency particulate air filters, duct distribution system, and instrumentation and controls. Two of the four air handling units (A and C) are equipped with activated charcoal filter units, normally isolated from the main air recirculation flow path, which serve to remove volatile iodine following an accident. The filter units are located on a platform above the operating floor within containment. The fans are direct-driven, centrifugal type, and the coils are plate fin-tube type. Air-operated, tight-closing, 125-lb USAS butterfly valves isolate any inactive air handling system from the duct distribution system. The CRFCs function during normal operation is accomplished using all four air handling units (potentially less during the winter) with common header discharge ducting to ensure adequate distribution of filtered and cooled air throughout the containment. During normal operation, the flow sequence through the air handling units is as follows: cooling coils, moisture eliminator, high efficiency particulate air filters, fan, and discharge header.

The CRFCs are supplied by individual lines from the SW system. Each inlet line is provided with a shutoff valve and drain valve. Similarly, each discharge line from the cooler is provided with a shutoff valve and drain valve. This allows each cooler to be isolated for draining or maintenance.

During normal plant operation, SW flow through the units is throttled for containment temperature control purposes by a valve on the common discharge header from the cooling units (4561). An independent full-flow valve (4562) opens automatically in the event of a SI signal to bypass the control valve. Both valves fail in the open position upon loss of air pressure and either valve is capable of passing the full flow required for all four fan cooler units. Each of the fan cooler units is in continuous or intermittent operation. Collection and measurement of condensate from the cooling coils is one method used to determine leakage from fluid systems within the containment. Any leakage occurring in a cooling coil would result in leakage of SW into the containment. Individual flow and temperature indicators are located on the discharge from each cooler unit which alarm on the control board in order to provide additional means of detecting a leak in a fan cooler unit.

A simplified diagram of the CRFCs is provided in Figures 6-11.1 and 6-11.2.

Charging Pump Room Coolers

The charging pump room is cooled by redundant cooling units using SW as the cooling medium. Electrical power for the fan motors is provided from safeguards MCCs C and D. The capacity of each unit is sufficient to maintain acceptable room-ambient temperatures when the minimum number of pumps required for system operation are in service. Hence, one cooler is normally operating. However, engineering analyses have demonstrated that the room coolers are not required for continued operation of the charging pumps under accident conditions [Ref. 35]. Therefore, this system does not directly support any fault trees.

A simplified diagram of the Charging Pump Room Coolers is provided in Figure 6-11.3.

Control Room Ventilation System

The Control Room ventilation system is comprised on a single air handling unit supply fan and return fan which are powered from safeguards MCC K. A single filtration train which includes its own supply fan can also be placed into service during radiological, chemical, or fire events. The Control Room ventilation system is designed to maintain the control room between 50°F and104°F following design basis accidents. Typically, 2000 cfm of fresh air is continuously provided into the control room unless the system is isolated due to radiation, toxic gas, fire or smoke. It is unknown as to what affect (if any), the loss of this system would have on plant equipment post-accident. Since the Control Room ventilation system cannot be directly tied to any specific function or system, it was not included in the event trees.

A simplified diagram of the Control Room ventilation system is provided in Figure 6-11.4.

Relay Room Coolers

The relay room is cooled by two non-safety related SW cooled air conditioning units. Each consists of a fan, compressor and condenser, filter and dampers. It is unknown as to what affect (if any), the loss of this system would have on plant equipment post-accident. Since the Relay Room ventilation system cannot be directly tied to any specific function or system, it was not included in the event trees.

A simplified diagram of the Relay Room coolers is provided in Figure 6-11.5.

SAFW Pump Building Ventilation System

The SAFW Pump Building ventilation system provides cooling and heating as required to maintain the pump room temperature within the design temperature range of 60°F to 120°F. There are two room coolers, each unit is automatically started whenever its associated SAFW pump is started. The cooling units can also be manually started from a local control panel, using a control switch that has RUN-AUTO-OFF positions. SW flow to the room coolers is controlled by a two-way valve in the discharge line from the coil.

The SAFW room electrical heating system operates whenever the temperature in the pump room falls below the thermostat setting of 60°F to 65°F. The heating system is not safety related nor powered from a safety-related bus since it is not required during operation. If the heating system fails, portable heating equipment can be used or the pumps can be started and run in the recirculation mode. Auxiliary operators perform walkdowns of the SAFW Pump Building on at least a shift basis.

A simplified diagram of the SAFW Pump Building ventilation system is provided in Figure 6-11.6.

Intermediate Building Ventilation System

The AFW pumps and the ARVs are located in the north sector of the Intermediate Building, which is divided into north and south sectors by a fire wall. The Intermediate Building has no tempered air supply system; instead, it relies on outside air being drawn into the building by exhaust and roof fans. Air is drawn into the Intermediate Building (north) through dampers located in the east Intermediate Building wall, and from the Turbine Building basement through fire door F36. Air is exhausted from the Intermediate Building (north) by propeller driven exhaust fans. Air is also exhausted from the Intermediate Building (north) to the Auxiliary Building exhaust fans by redundant Intermediate Building Exhaust Fans A and B. Additionally, Intermediate Building Exhaust Fan C takes suction from the area in vicinity of the AFW pumps and exhaust the air to the general area of the Intermediate Building (south).

Because of a minor (from an ability to achieve safe shutdown standpoint) freezing incident, many of these intake dampers are closed off in the winter with plywood. With this increased awareness by the plant staff, a serious freezing incident is not considered to be credible.

A simplified diagram of Intermediate Building ventilation system is provided in Figure 6-11.7.

Control Rod Shroud Fans

The Control Rod Shroud Fans act to remove the heat generated by the control rod drive mechanism coils. The two fans are rated at 60 hp and 14,000 cfm each, and take suction from the shroud and discharge to the containment atmosphere. Air-operated dampers at the suction of the fans are locked open while backdraft dampers are installed to prevent reverse flow through the fans. The fans are considered as a potential backup to the pressurizer heaters for preventing a steam bubble from forming in the reactor vessel head during long-term natural circulation (i.e., operation without the RCPs).

A simplified drawing of the Control Rod Shroud Fans is provided in Figure 6-11.8.

6.11.3 Description of HVAC Fault Tree Model

The fault tree is organized into separate fault trees for each top event (i.e., each ventilation system). Each tree starts at the outlet for cooled air and works backwards to the air inlet. Transfer gates to cooling, motive power, actuation power and signals are shown. The following is a description of each top gate and its respective success criteria.

a. *HV800 - FAILURE OF CONTAINMENT HVAC SYSTEM*: This top event is defined as the failure of four of four CRFCs in containment. This success criteria (one of four are successful) is discussed in Section 10. A separate top event is provided for each CRFC so that other system success criteria can be included in the Level 1 or Level 2 analysis without re-modeling the system. The operating state of the equipment is controlled by logic flags (e.g., normally operating).

b. *HV200 - CHARGING PUMP ROOM COOLING FAILURES*: This top event describes failure of adequate charging pump room cooling. One train is considered adequate to cool the charging pump room.

c. *HV300 - VENTILATION SYSTEM FAILURE IN THE CONTROL ROOM*: This top event models the failure of the Control Room ventilation system, which is a single train system.

d. HV500 - VENTILATION SYSTEM FAILURE IN THE RELAY ROOM: This top event models the failure of two of two trains of air conditioning to the relay room.

e. *HV600 - STANDBY AUXILIARY FEEDWATER HVAC FAILURES*: The SAFW cooling units are automatically started when the respective pump is started. Either train can cool either SAFW pump for success.

f. *HV700 - INTERMEDIATE BUILDING VENTILATION FAILURE*: This top event includes the failure of the mechanical and natural convection air flow in the Intermediate Building such that necessary cooling to the AFW fails. Failure is defined by loss of natural convection cooling within the Intermediate Building and loss of the Intermediate Building exhaust fans.

g. *HV834 - FAILURE OF CONTROL ROD SHROUD FAN A TO START*: This top event models the failure of Control Rod Shroud Fan A to start and run.

h. *HV838 - FAILURE OF CONTROL ROD SHROUD FAN B TO START*: This top event models the failure of Control Rod Shroud Fan B to start and run.

The following are the human errors included in the HVAC fault trees:

a. *HVHFDABVLP - Operators Fail to Restart Auxiliary Building Exhaust Ventilation Following LOOP*. This event describes the failure of operators to restart the Auxiliary Building ventilation system following a loss of offsite power since the units must be manually restarted under these conditions.

b. *HVHFD_HS88 - Operators Fail to Place HS-88 in Fire Position*. The event describes the failure of operators to place control room isolation switch HS-88 in the "Fire" position in order to isolate the control room.

c. *HVHFDCRTRM - Operators Fail to Restart CR HVAC Following LOOP*. This event describes the failure of operator fails to restart control room ventilation system following a loss of offsite power since they must be manually started under these conditions.

d. *HVHFDIBVEN - Operators Fail to Re-Start IB Exhaust Fans Following LOOP*. This event describes the failure of operators to restart Intermediate Building ventilation system following a loss of offsite power since they must be manually started under these conditions..

e. *HVHFDRELRM - Operators Fail to Start HVAC in Relay Room Following LOOP*. This event describes the failure of operators to start the relay room coolers following a loss of offsite power since they must be manually started under these conditions.

f. *HVHFD_CTMT - Operators Fail to Re-Start Containment Cooling*. This event describes the failure of operator to the CRFCs following a loss of offsite power without a SI signal present since they must be manually started under these conditions..

g. *HVHFDACF5A - Operators Fail to Start Control Rod Shroud Fans.* This event describes the failure of operators to restart the Control Rod Shroud Fans following a loss of offsite power since they must be manually started under these conditions.

h. *HVHFD_DOOR - Operators Fail to Open SAFW Building Door Following Loss of HVAC.* This event describes the failure of operators to open the SAFW Pump Building door following loss of building ventilation to providing necessary cooling.

The following logic flags have been identified for the HVAC systems as follows:

a. *HVAAHVCT_A - CRFC Unit A Running.* Setting this flag to true identifies that CRFC unit A is running and in service. Normally three of four CRFCs are in service.

b. *HVAAHVCT_B - CRFC Unit B Running.* Setting this flag to true identifies that CRFC unit B is running and in service. Normally three of four CRFCs are in service.

c. *HVAAHVCT_C - CRFC Unit C Running.* Setting this flag to true identifies that CRFC unit C is running and in service. Normally three of four CRFCs are in service.

d. *HVAAHVCT_D - CRFC Unit D Running.* Setting this flag to true identifies that CRFC unit D is running and in service. Normally three of four CRFCs are in service.

e. *HVAAHVCWPA - Chilled Water Pump Loop A is Running.* Setting this flag to true identifies that Chilled Water Train A is in service for supporting the Control Room ventilation system.

f. *HVAAHVCWPB - Chilled Water Pump Loop B is Running.* Setting this flag to true identifies that Chilled Water Train B is in service for supporting the Control Room ventilation system.

g. *HVAAHV0301 - Control Room Radiation Monitor R-1 Senses High Radiation.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

h. *HVAAHV0426 - Control Room Radiation Monitor R-37 Senses High Particulates.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

i. *HVAAHV0427 - Control Room Radiation Monitor R-38 Senses High Iodine.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

j. *HVAAHV0428 - Control Room Radiation Monitor R-36 Senses High Noble Gas.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

k. *HVAAHV0429 - Control Room Chlorine Monitor Senses High Chlorine Level.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

l. *HVAAHV0430 - Control Room Ammonia Monitor R-36 Senses High Ammonia Level.* Setting this flag to true causes the control room isolation logic to assume that it must isolate.

m. *HVAA<30DEG - Minimum Outside Air Temperature is Below 30 Degrees.* Setting this flag to true identifies that the outside air temperature is < 30°F.

n. *HVAA<40DEG - Average Temperature is ≤ 40 Degrees.* Setting this flag to true identifies that the outside air temperature is ≤ 40°F.

o. *HVAA<45DEG - Outside Air Temperature is Below 45 Degrees.* Setting this flag to true identifies that the outside air temperature is < 45°F.

p. *HVAA>64DEG - Outside Air Temperature is > 64 Degrees.* Setting this flag to true identifies that the outside air temperature is > 64°F.

q. *HVAA>80DEG - Outside Air Temperature is ≥ 80 Degrees.* Setting this flag to true identifies that the outside air temperature is ≥ 80°F.

6.11.4 HVAC Fault Tree Model Assumptions

a. The Control Room ventilation system fault tree model assumes that the loss of IA will fail the cooling function due to the isolation of the chilled water sources.

b. It is assumed that the ARVs will function in the expected environment without ventilation, but the temperatures are too hot to operate the valves locally.

c. The AFW pumps will all fail if the TDAFW pump is operating without ventilation because most of the heat within the area is from the steam piping to the turbine.

d. Natural circulation of air is sufficient to cool the AFW and ARV areas in the Intermediate Building (North). This is assumed to be true as long as fire door F36 is open and a flow path through the Intermediate Building roof fans exist. The roof fans do not have to be running.

e. The model of the CRFC SW discharge flow path assumes that failure of 4561 to fully open fails the flow path through the valve. Flow due to modulated positioning of 4561 is assumed inadequate since the SW success criteria only requires one pump.

f. Failure of the CRFC motor coolers is not explicitly modeled. This is because there are only two basic failure mechanisms for the motor coolers: (1) loss of SW flow to the motor coolers, and (2) failure of the cooling coils themselves. Since the SW supply to the motor coolers is the same as the supply to the air cooling coils, this is already addressed. It is assumed that failure of the coils themselves is included in the event for the motor to run.

6.12 Instrument Bus System

6.12.1 Instrument Bus System Function

The 120 VAC Instrument Bus system functions to provide power to instrumentation and controls for reactor protection and safeguards cabinets These racks provide power to various transmitters, instrument loops and relays in the reactor protection and safeguards actuation system. As such, the 120 VAC Instrument Bus system supports all four core protection functions (i.e., reactivity control, RCS pressure control, RCS inventory control, and decay heat removal).

6.12.2 Instrument Bus System Description

The 120 VAC Instrument Bus system consists of four distribution buses, Instrument Buses A, B, C, and D. These instrument buses then supply seven distribution panels (A through G) via Twinco voltage regulators. Only Distribution Panels A, B, C, D, and E have been included in the fault tree due to modeling needs. Power is supplied to the various instrument racks from either the instrument buses directly or from the distribution buses.

Power to Instrument Bus A is normally supplied through an auto static transfer switch from Inverter A which converts DC power to 120 VAC. The inverter receives its power from DC Train A through Main DC Distribution Panel A. Power is also supplied to the auto static transfer switch from a 480/120 VAC constant voltage transformer (CVT) fed from 480 VAC MCC C. During normal operation, the transfer switch feeds power from the inverter to the instrument bus. Upon a failure of the inverter or a loss of power from the inverter, the transfer switch automatically aligns the power supply from the CVT to the instrument bus within 1/4 cycle. This provides an essentially uninterrupted power supply to the instrument bus should the normal DC power supply fail. Power to Instrument Bus C is supplied in a similar fashion from a second auto static switch which receives power from Inverter B (from DC Train B through Main DC Distribution Panel B), and from a second CVT fed from MCC D.

Power to Instrument Bus B is supplied from a 480/120 VAC CVT fed from MCC C. Since this bus has no DC power backup, power on the bus will be lost during a loss of offsite power event until the DGs start and re-energize Bus 14. Power to Instrument Bus D is supplied from a 480/120 VAC CVT fed from MCC B. MCC B is a non safeguards bus which is fed directly from offsite power such that on a loss of offsite power, Instrument Bus D will be lost.

Inverter MQ-483 also supplies power to one of the instrument racks (Y2). This inverter is supplied directly from Main Control Board DC Distribution Panel A.

6.12.3 Description of Instrument Bus Fault Tree Model

The Instrument Bus system model has multiple top gates. Essentially, top gates exist for each of the following components (note that several components may actually be an input to another top gate; e.g. loss of power on Instrument Bus A is an input to loss of power on Distribution Panels A and E):

a. Loss of power on Instrument Buses A, B, C, and D;
b. Loss of power on Distribution Panels A, B, C, D, E, and F; and
c. Loss of power from Inverter MQ-483.

In addition to the standard model (referred to as long term gates), for certain of the events listed above, there are also top gates representing the short term failure and/or a "circular logic" gate. The short term gate for Instrument Buses A and C include only the DC power feed from the inverter, and use the short term DC power gates to the inverter (i.e. the battery chargers are excluded). These gates are used in the model to supply instrumentation which is used when offsite power is lost (i.e. turbine auto stop relays, etc.). The circular logic gates eliminate the tie between the AC Power system and certain of the ESFAS gates. This is done because a SI signal caused by the ESFAS impacts the operation of the AC Power system (i.e. opening of normal supply breakers, starting of the DGs, etc.).

The long-term loss of power on Instrument Buses A and C include local faults on the bus itself, opening of the normal supply breaker, or failure of the power supply from the auto static transfer switch. Failure of the power supply from the auto static transfer switch includes failure of power from the inverter and failure of power from the CVT, combined in "AND" logic. Failure of power from the inverter includes failure of the inverter itself, including input and output circuit breakers, or failure of the DC power supply to the inverter. It should be noted that the failure of the auto static transfer switch is included as a failure of power from the inverter because on a failure of the switch, the power supply automatically transfers over to the CVT. Failure of power from the CVT includes failures of the CVT, including input and output circuit breakers, or failure of the power supply from the MCC supplying the CVT.

Since Instrument Buses B and D do not have a power feed from the DC power system, the models for these buses only include failure of power from the CVT feeding the bus.

The top gates for failure of power on the distribution panels include the top gate for failure of power on the associated instrument bus and failures of the voltage regulator and circuit breakers which feed power from the instrument bus to the distribution panel.

There are no human actions or logic flags associated with the Instrument Bus fault tree model.

6.12.4 Instrument Bus Fault Tree Model Assumptions

a. It is assumed that there is no failure of the auto static transfer switch which will fail the power supply from both the inverter and the CVT. The design is such that upon a failure of the switch, power from the CVT will be provided to the instrument bus.

b. The DC supply breakers and the DC fault protection breakers to the inverters are actually DC components; however, they are more appropriately included in the instrument bus model.

c. The circuits and circuit breakers from the instrument buses and distribution panels to the instrument racks have been included in the models for which the instrument rack supplies power. This was done to avoid having an extremely large number of top gates in the Instrument Bus model (i.e. one top gate for every circuit).

6.13 Main Steam (MS) System

6.13.1 MS System Function

For the Ginna Station PSA, the MS system is comprised of only the following components:

a. Atmospheric Relief Valves (ARVs)
b. Main Steam Safety Valves (MSSVs)
c. Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves

The ARVs and MSSVs provide support of the RCS pressure control function by lifting at their prescribed setpoints to remove steam (i.e., energy) from the secondary system. Separately, the ARV also supports the RCS pressure control function during a steam generator tube rupture (SGTR) event by cooling down the RCS in order to equalize primary and secondary system pressures and stop the flow out the break. In addition, the ARVs support the decay heat removal function by cooling down the RCS in order to use the RHR system under certain conditions (e.g., failure of all SI during a small-break LOCA).

The MSIVs and non-return check valves serve to isolate a ruptured SG during a SGTR, feedwater or main steam line break. This prevents an unnecessary primary system cooldown and serves to protect the RCS pressure control function.

6.13.2 MS System Description

There are four MSSVs and one ARV provided on each MS line. One MSSV is set to lift at 1085 psig while the remaining are set at 1140 psig. The ARV is set to lift at 1050 psig. The MSSVs are designed to provide relief for the full steam load while the ARVs (3410 and 3411) are air-operated valves with 329,000 lbm/hr normal and 890,000 lbm/hr maximum relief capacities.

The ARVs can be operated remotely or locally using the valve manual operator, and can be isolated by a manual valve located upstream of the valves. The pneumatic supply to the valves is provided by the IA system, and backup supply is provided by the nitrogen supply systems. Twelve nitrogen bottles (6 for ARV 3411 and 6 for ARV 3410) are located in the Turbine Building outside the door to the control room.

During remote operation, the ARV positioner controls the air pressure. In the automatic mode the valve is normally set to lift at 1050 psig. In event the automatic mode controller fails, is set wrong, or the controller is in manual operation, a pressure switch will trip causing a solenoid valve to energize causing the ARV to open at 1060 psig. When pressure decreases to 1005 psig, the solenoid will de-energize causing the valve to close. The valves can also be manually operated with a handwheel mounted on each valve.

The MSIVs are air-operated swing check valves which fail closed on loss of air and are designed to close within 5 seconds under no-flow conditions. The non-return check valves are swing check valves which close against reverse flow. The MSIVs and non-return check valves work in series to ensure that at least one SG is available for decay heat removal.

A simplified diagram of the MS system is provided in Figures 6-13.1, 6-13.2, and 6-13.3.

6.13.3 Description of MS Fault Tree Model

The following are the top gates for the MS fault tree model:

a. MS315A Failure to Isolate SG A Main Steam Line
b. MS345A Failure to Isolate SG B Main Steam Line
c. MS600 Failure of MSSVs and ARVs to Provide Pressure Relief

The success criteria for these top events is provided in Section 4. The following are the human failure events included in the MS fault tree model:

a. *MSHFDISOLR - Operators Fail to Isolate a Ruptured SG* - This event describes the failure of operators to isolate a ruptured SG following a SGTR. The failure to perform this action is assumed to result in SG overfill.

b. *MSHFDLARVA - Operators Fail to Manually Operate ARV 3411* - This event describes the failure of operators to manually operate ARV 3411 to depressurize the SG.

c. *MSHFDLARVB - Operators Fail to Manually Operate ARV 3410* - This event describes the failure of operators to manually operate ARV 3410 to depressurize the SG.

d. *MSHFDISOLA - Operators Fail to Isolate a SG Using Secondary Valves.* This event describes the failure of operators to isolate a ruptured SG using secondary valves after the primary automatic valves fail to close.

e. *MSHFDMSIVX - Operators Fail to Manually Close an Open MISV.* This event describes the failure of operators to manually closed the MSIVs if the signal to the valves fails.

There are no logic flags for the MS fault tree model.

6.13.4 MS Fault Tree Model Assumptions

a. Failure of any nitrogen bottle to supply compressed gas (e.g., bottle or valve failure) will prevent the operation of the associated ARV with nitrogen as a motive force. This assumption is based on information provided in EWR-1024.

b. A high energy line break in either the Turbine or Intermediate Buildings is assumed to fail the automatic opening capability of the ARV due to block wall interactions. However, the MSIV is protected such that it would only fail closed in this scenario.

6.14 Miscellaneous Systems

6.14.1 Miscellaneous Systems Function

In addition to the detailed fault tree models, simplified models were also developed for several systems to address their potential failure. These systems were either used for recovery purposes only or were treated in detail in the event trees. The systems included within the miscellaneous category are:

a. MFW system; and
b. Reactor Trip System (RTS).

The MFW system was used as a potential recovery for loss of all AFW and therefore supports decay heat removal. Upon failure, the RTS generates a reactor trip signal except for failures related to the reactor trip breakers. The failure of the reactor trip breakers or trip logic is specifically addressed in the ATWS event tree. Therefore, the RTS supports the reactivity control function.

6.14.2 Miscellaneous Systems Description

The MFW system at Ginna Station is comprised of two single-stage centrifugal motor-driven pumps with a capacity of 7400 gpm. Each pump has its own lubrication system including two AC driven pumps, one DC auxiliary pump, oil reservoir, oil coolers, and filters. The MFW pumps are provided with high-pressure gland seal-water from the discharge header of the condensate booster pumps.

The MFW pumps take suction from the Condensate system which in turn takes suction from the main condenser. The MFW pumps operate in parallel; however, their respective discharge lines combine to form a common line through the feedwater heaters. The line then splits to provide flow to each SG. The SG injection lines each have an air-operated feedwater regulating valve (4269 and 4270) along with bypass valves for low-flow conditions. The regulating valves, their bypass valves, and the MFW pumps all fail close or trip on a SI signal.

The RTS is actually two independent trains, each comprised of signal process control equipment and reactor trip switchgear. The RTS begins at instrument loops which have field instruments that send signals to bistables which in turn control reactor trip logic relays. The contacts of these logic relays are wired together in logic matrices in such a way that, when a required combination of parameters deviate from their acceptable operating region, a reactor trip signal is generated. Depending on which trip was generated, the reactor trip breakers shunt and/or UV trip mechanisms are actuated, opening the breakers and de-energizing the control rod drive mechanisms (CRDMs). The reactor trips for Ginna Station are listed in Table 3-1.

Simplified diagrams of the MFW and RTS systems are provided in Figures 6-14 and 3-3, respectively.

6.14.3 Description of Miscellaneous Fault Tree Model

The MFW system fault tree is comprised of a single top gate (MF100). Failure of MFW is attributed to failure of the operators to place MFW into service post-accident, the loss of MFW as an initiating event, failure of support systems (Buses 11A and 11B, IA, and SW), and high energy line breaks in the Turbine Building (i.e., MFW and MS line breaks). Given the high value for failure of operators to place MFW into service post-accident, no failures of the MFW pumps or valves were included.

The RTS is essentially modeled in the ATWS event tree which considers failures of the reactor trip breakers and the RTS logic. The ATWS event tree is organized into actions required following a mechanical failure of the breakers to open and a failure of the RTS signal to reach the breakers.

The human failure events for the MFW system and RTS fault tree models are as follows:

a. *MFHFDMF100 - Operators Fail to Re-establish MFW.* This event describes the failure of operators to re-establish MFW following a reactor trip. Separate values are provided for SI and non-SI events due to the different operator responses.

b. *RCHFD00MRI - Operators Fail to Manually Insert Rods.* This event describes the failure of operators to manually insert the rods after an electrical failure of the RTS.

c. *RCHFDSCRAM - Operators Fail to Trip MG Sets During ATWS* - This event describes the failure of operators to trip the MG sets in the field to generate a reactor trip after an ATWS event.

There are no logic flags in either MFW or RTS model.

6.14.4 Miscellaneous Model Assumptions

a. MFW is assumed to be lost at the time of the initiating event due to either a direct result of the trip or as a result of operator procedural actions to isolate MFW since the AFW system is used under low flow conditions. Therefore, operators must always re-establish MFW post trip for use in the PSA models.

6.15 Reactor Coolant System (RCS)

6.15.1 RCS System Function

For the Ginna Station PSA, the RCS is comprised of only the following components:

a. Power operated relief valves (PORVs);
b. Pressurizer safety valves;
c. Pressurizer spray;
d. Pressurizer heaters; and
e. Reactor coolant pumps (RCPs).

The PORVs, safety valves, and pressurizer spray support the RCS pressure control function by maintaining the RCS below its design limit (i.e., 2485 psig) following transients which increase RCS pressure. The PORVs also support the decay heat removal function in the event that all AFW and SAFW is lost by creating a "bleed" path from the primary system to allow SI to provide necessary core cooling. Finally, the PORVs support the RCS pressure control function during a SGTR event by depressuizing the RCS to equalize primary and secondary system pressures. The pressurizer heaters support the RCS pressure control function by increasing pressure in the RCS to ensure that a subcooling margin is maintained for natural circulation cooldown situations. The RCPs support pressurizer spray with respect to RCS pressure control. Failure of seal cooling to the RCPs also leads to a potential small break LOCA.

6.15.2 RCS System Description

The pressurizer safety valves are spring loaded, self-actuated valves set to open at 2485 psig, and have a steam relief capacity of 288,000 lb/hr each. These are the only RCS pressure relieving devices credited in the accident analysis for maintaining RCS below its design limit.

The PORVs are power operated valves with a steam release capacity of 179,000 lb/hr each. The valves can be supplied with IA or nitrogen as the motive force for opening the valve. During PORV operation, a 3-way solenoid valve isolates the nitrogen supply to the PORVs while aligning the IA supply path. The IA supply is normally isolated from the 3-way valve during power operation by a solenoid valve. The solenoid is operated by contacts from pressurizer pressure instrumentation within its control circuitry. On a high pressure signal (2335 psig) from two pressure transmitters, the solenoid opens, allowing IA to open the PORV. When the reactor coolant system is below 330°F, the 3-way valve is manually re-aligned to isolate IA and align the nitrogen supply to the PORVs. The nitrogen supply is isolated from the 3-way valve by a solenoid valve which opens on a high pressure signal (i.e., 410 psig) from 2 of 3 pressure channels, allowing nitrogen to the PORV causing it to open. The nitrogen system can also be placed into service at power in the event that IA is lost for recovery of a SGTR event.

The pressurizer heaters and pressurizer spray valves combine to maintain RCS pressure within acceptable limits during steady state or transient conditions. The pressurizer heaters are separated into the proportional group and the backup group. Each of these groups has an AC circuit breaker feeding two separate power distribution panels, each of which feeds a heater group. The proportional group is controlled by a silicon controlled rectifier (SCR) which receives a signal from a pressurizer pressure instrument loop. The output of the heaters is maintained inversely proportional to the pressurizer pressure. At normal RCS pressure of 2235 psig, the heaters are on at 50% capacity. If pressure decreases, the output of the heaters increases such that they are at their maximum output of 400 kW when pressure drops to 2220 psig. The backup group of heaters also have a maximum output of 400 kW and are either fully on or fully off. The backup heaters turn fully on at or below 2210 psig or with a 5% increase in pressurizer level.

Normal pressurizer spray functions to limit pressure increases in the RCS by spraying relatively cool reactor coolant into the steam void of the pressurizer to condense steam, thus reducing pressure. Flow to a single pressurizer spray nozzle is provided by two 3" lines connected to the Loop A and Loop B cold legs. The driving force for the spray flow is provided by the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force. Pressure sensors (PT-429 and PT-449) in the pressurize feed signals to the air operated spray valves (431A and 431B). The spray valves begin to open at approximately 2260 psig and are fully open at 2310 psig. Full flow from pressurizer spray is 200 gpm per valve for a total flow into the pressurize of 400 gpm.

Ginna Station has two RCPs, each one a 6,000 hp pump capable of pumping 90,000 gpm. The RCPs are motor-driven pumps and the motor shafts penetrate the RCP casings to drive the pump impellers. The points at which the shafts penetrate the casings are sealed to prevent the escape of reactor coolant. Each seal assembly requires a supply of injection water from the CVCS. Some of this water, injected into the seal at a pressure slightly above that of the RCS, flows along the shaft into the pump. A portion also flows along the shaft away from the RCP and is collected and recovered. The supply of cool, clean water into the RCP seal keeps out debris and prevents the seal from being damaged by the high-temperature reactor coolant. A failure of the seal injection water, combined with a failure of component cooling water (CCW) to the thermal barrier heat exchanger, could cause a failure of the seal, leading to an RCP seal LOCA, which is a special case of a small break LOCA.

Simplified diagrams of the RCS are provided in Figures 6-15.1, 6-15.2, and 6-15.3.

6.15.3 Description of RCS Fault Tree Model

The RCS fault tree is organized under several top gates as follows:

a.	RC111	Failure of Both RCPs to Continue Running
b.	RC150	Failure of Pressurizer Spray in Automatic Mode
c.	RC200	Failure of Both Pressurizer PORVs to Open in Automatic Mode
d.	RC250	Failure of Either Pressurizer PORV to Open in Automatic Mode
e.	RC300	Failure of Either Pressurizer PORV to Open in Manual Mode
f.	RC300A	Failure of Both Pressurizer PORVs to Open in Manual Mode
g.	RC500	Failure to Achieve 100 kW of Pressurizer Heater Capacity
h.	RC600	Failure of PORV Block Valve 515 to Close on Demand
i.	RC700	Failure of PORV Block Valve 516 to Close on Demand

The success criteria for each of these top events is essentially defined by the event definition itself.

The fault tree for failure of both RCPs to continue running includes failure of the pumps themselves, failure of seal cooling, and all conditions which fail power to 4160 V Buses 11A and 11B.

The fault tree for failure of pressurizer spray in automatic mode includes branches for the failure of flow from both spray valves, common cause failure of the spray valves to open, failure of IA, failure of DC power to the solenoid valves for the spray valves, and failure of the signals from the pressurizer pressure instrumentation. The failure of flow from both spray valves branch includes failure of each spray valve to open and failure of the RCPs to continue operating. Failure of an RCP to run fails the flow to its corresponding spray valve.

Top gates RC200 and RC250 describe the failure of PORV 430 and 431C to open automatically, combined in "AND" logic and "OR" logic, respectively. The failure of the PORVs to open consists of the event for failure of the PORV to open, the common cause failure of the PORVs to open, the block valve transferring closed, the block valve being closed due to excessive PORV leakage, and the failure of IA to the PORV. The gate for failure of IA includes not only failures of IA itself, but failure of the solenoid valve to open, failure of DC power to the solenoid, and failure of the solenoid to receive a signal to open from the pressurize pressure instrumentation. This logic is identical for the two PORVs.

Top gates RC300 and RC300A describe the failure of PORV 430 and 431C to open manually, combined in "AND" logic and "OR" logic, respectively. As stated above, the manual mode of operation of the PORVs allows for the use of nitrogen as a motive force, if IA is unavailable. The fault tree for failure of the PORV in manual control addresses the failure of the PORV to open, the common cause failure of the PORVs to open, failure of the block valve to open given that it is closed due to excessive PORV leakage and failure of IA and nitrogen to the PORV. Failure of IA to the PORV includes failure of the IA supply to the solenoid valve, failure of the solenoid valve to open, failure of the DC power supply to the solenoid and failure of the hand switch. Note that there is no pressure sensing instrumentation involved since the valve would be operated by the hand switch which bypasses the pressure signals. The branch for failure of the nitrogen supply includes failures in the nitrogen path to the 3-way valve, failure of the solenoid valve upstream of the 3-way valve to open, failure of the 3-way valve to change position, and failure of DC power to the solenoid valves. Failure of the 3-way valve to change position includes both failures of the valve and failures of the signal from the pressure instrumentation. Although the valve would be operated by a hand switch, high pressure signals from the pressurizer pressure instrumentation must still be present in order to open the valve.

The fault tree for failure to achieve 100 kW of pressurizer heaters is divided into two basic branches. One branch represents failure of the proportional heaters while the other branch represents failure of the backup heaters. These two branches are combined using "AND" logic since either set of heaters is sufficient to achieve 100 kW of capacity. Failure of the proportional heaters includes failures of the heaters to operate, loss of all power on Bus 14, or an SI or UV signal on Bus 14 (which sheds the heaters) combined with an operator failure to restore the heaters within 6 hours. Failure of the heaters to operate includes failure of the two heater groups, failure of the two distribution panels, failure of the circuit breaker feeding the two distribution panels, failure of the signal to the heaters, or failure of the pressurizer level control signal which will trip the heaters. The fault tree for the backup heaters is similar with the exception that the backup heaters are powered from Bus 16, and failure of the level control signal is combined with the event of the operators failure to load the heaters because the manual pushbutton start of the backup heaters bypasses all other control signals.

The following are the human events contained in the RCS fault tree model.

a. *RCHFD000RCP - Operators Fail to Trip RCPs After Loss of Support Systems.* This event describes the failure of operators to trip the RCPs within 2 minutes following loss of CVCS and CCW to prevent a possible seal LOCA.

b. *RCHFD001RCP - Operators Fail to Restore RCP Seal Cooling Within One Hour.* This event describes the failure of operators to restore RCP seal cooling within one upon trip of the pumps. Cooling to the seals is still required with the RCS at elevated temperatures and pressures to prevent degradation and possible failure of the seals.

c. *RCHFDHEATR - Operators Fail to Implement Feed and Bleed.* This event describes the failure of operators to implement feed and bleed using SI and the PORVs upon loss of all cooling to the SGs.

d. *RCHFDHEATR - Operators Fail to Load Pressurizer Heaters Following LOOP or SI.* This event describes the failure of operators to load the pressurizer heaters onto Buses 14 and 16 following loss of offsite power or a SI signal to support continued natural circulation.

e. *RCHFDPLOCA - Operators Fail to Close PORV Block Valves (515/516) to Terminate LOCA.* This event describes the failure of operators to terminate a PORV LOCA by closing the associated PORV block valve.

There are no logic flags in the RCS fault tree model.

6.15.4 RCS Fault Tree Model Assumptions

a. It is assumed that for both automatic and manual pressurizer spray to operate, at least one RCP must be operating. Per Operations staff, if only one RCP is in operation, only the spray line that is associated with that loop will operate. Further, if the spray valve for the opposite loop (with no RCP running) opens on a high pressure signal, and is not reclosed, spray flow from the running loop will bypass the pressurizer and flow through the open valve back into the RCS. Operators are trained on this evolution and are aware of the need to close the open valve. Therefore, it was assumed that failure of a RCP fails the associated spray path.

b. Operators are directed by emergency operating procedures to trip the RCP(s) upon a loss of CCW flow to the thermal barriers. Therefore, it is assumed in the model for failure of the RCPs to continue running that a failure of CCW fails the affected RCP(s). However, failure to trip the RCPs upon loss of CCW only results in a seal LOCA if CVCS is also failed.

c. During a SGTR event, emergency operating procedures dictate the use of auxiliary pressurizer spray to depressurize the RCS if normal pressurizer spray is unavailable and neither pressurizer PORV. is available. However, during a SGTR event, letdown flow would be isolated and as such, the auxiliary spray flow from CVCS would not be heated by the regenerative heat exchanger. It is uncertain whether the pressurizer spray nozzles would survive the introduction of the unheated RWST water from the charging system due to the large temperature differential between the spray nozzle and the charging flow. Therefore, although auxiliary pressurizer spray has been modeled, it is not credited in the overall plant model.

d. It is likely that most failures of the IA system would not affect the automatic operation of the PORVs since automatic operation of the PORVs is only required immediately after the reactor trip and most IA failures would be longer term failures which would still allow for opening of the PORVs in the short term. Therefore, it was assumed that only initiators which directly fail IA will constitute a failure of the PORVs in automatic mode.

e. For modeling the manual operation of the PORVs, both nitrogen and IA were considered as motive sources. It was assumed that if IA failed and nitrogen was to be used, RCS pressure would be above the LTOP setpoint of 410 psig, and as such, when the N2 arming switch is placed in the "ARM" position, overpressure condition would be sensed by the LTOP pressure transmitters, and the solenoid valves allowing nitrogen to the PORVs would open. Failures of the pressure instrumentation are explicitly modeled.

6.16 Residual Heat Removal (RHR) System

6.16.1 RHR System Function

The RHR system performs the following functions:

a. Refloods the RCS using the RWST inventory if RCS pressure is below pump shutoff head of 140 psig.

b. Recirculates the containment sump B inventory through heat exchangers and back to the RCS via the RHR pumps if RCS pressure is below the RHR pump shutoff head of 140 psig.

c. Recirculates the containment sump B inventory through heat exchangers and back to the RCS via the SI pumps, if RCS pressure is greater than 140 psig but less than the SI pump shutoff head of approximately 1500 psig.

Therefore, the RHR system supports the RCS inventory control and decay heat removal functions.

6.16.2 RHR System Description

The RHR System consists of two pumps, two heat exchangers, and associated piping, valves, and instrumentation. Suction paths exist from the RCS Loop A hot leg, the RWST, and containment sump B. Discharge paths are to the RCS Loop B cold leg, the reactor vessel, the RWST supply line to SI, and to SI Pump C.

RHR suction supply to the pumps is from the RWST via a 10-inch line containing a normally open MOV (856), and a check valve (854). When the system is operating to provide residual heat removal, suction is via a 10-inch line from the RCS Loop A hot leg, containing two motor-operated isolation valves (700 and 701). Recirculation supply post-LOCA is from containment sump B via parallel trains of 8-inch piping, each containing two motor-operated valves (850A/B and 851A/B). Suction crosstie capability exists via a 10-inch line containing two normally-open MOVs (704A/B). The two pumps are horizontally-mounted centrifugal type, each capable of delivering 1560 gpm at 140 psid.

Downstream of the discharge of each pump is a check valve (710A/B) and a manual discharge isolation valve (709A/B). The pump discharge lines are then crosstied via an 8-inch line containing two normally-closed manual isolation valves (709C/D). There is a heat exchanger in each train, each with a manual isolation valve on the inlet and a check valve on the outlet. A 3-inch orificed minimum flow line branches off just after each heat exchanger and returns flow to the RWST suction line.

There is also a 6-inch bypass line around heat exchanger EAC02A to the segment of the injection line common to both trains. This line contains an air-operated butterfly valve (626) with manual isolation valves on either side. Flow can be diverted around the heat exchanger using this line, in order to control RCS temperature during shutdown.

Two 6-inch lines connect the RHR system to the SI system for high pressure recirculation. The connection to Train A is immediately downstream of the heat exchanger and to Train B after the heat exchanger outlet check valve. Two MOVs (857A/C) in this line isolate the A train from a common supply to SI. One MOV (857B) isolates Train B from this line. On the Train A side of the isolation valves, a 4-inch line branches off through two normally closed manual isolation valves (1816A/B) to supply SI Pump C.

Downstream of the heat exchanger outlet check valves are air-operated butterfly flow control valves and manual isolation valves. These are used, in conjunction with AOV 626, to regulate RHR flow through the heat exchangers in order to control RCS temperature during shutdown. Downstream of the manual isolation valves, the two trains combine into a common injection line. This line penetrates the containment and divides into three lines. Two of these lines, each containing a motor-operated valve (852A/B) and a check valve (853A/B), penetrate the reactor vessel and are used for injection and recirculation. The third line routes return flow from the common line past two motor-operated isolation valves (720 and 721) to RCS Loop B cold leg and is used during normal RHR conditions.

CCW is provided to the RHR pump seal heat exchangers and to the RHR heat exchangers. CCW supply to either set of heat exchangers is not required for the injection mode of pump operation; however, CCW supply to both sets of heat exchangers is required for recirculation and RHR operation.

Normal at-power system alignment is for injection operation. Pump suction is aligned to the RWST and discharge is aligned through the heat exchangers to the reactor vessel. The pump discharge crosstie and heat exchanger bypass valves are closed. A closed MOV (852A/B) and a check valve (853A/B) in each of two injection lines isolate the system from the RCS. CCW to the heat exchangers is not required for injection operation and is not valved in during normal operation. Pump minimum flow protection is provided by a small line just downstream of each heat exchanger which can recirculate approximately 200 gpm each back to the suction supply line.

If injection is demanded by a SI signal, the pumps are automatically started and the injection valves are opened. When RCS pressure falls below pump shutoff head, the pumps begin to deliver flow to the reactor.

Interlocks exist to protect the low-pressure portions of the system from RCS pressure and to ensure that RCS inventory is not misdirected. MOV 700 (RHR suction isolation from the RCS) cannot be opened unless RCS pressure is below 410 psig and sump suction MOVs 850A and 850B are closed. The other RHR suction valve, MOV 701, is operated with a key switch and cannot be opened unless sump isolation valves 850A and 850B are closed. MOV 721 (RHR return isolation) may not be opened unless RCS pressure is below 410 psig and MOV 720, the other return isolation, requires a key switch. Additional overpressure protection is provided by the CVCS relief valve, RV-203, which is connected to the RHR system by a locked-open manual valve.

A simplified diagram of the RHR system is provided in Figure 6-16.

6.16.3 Description of RHR Fault Tree Model

The RCS fault tree is organized under several top gates as follows:

a. RH200 Failure to Provide Flow From RHR in Injection Phase
b. RR100 Failure of RHR Sump Recirculation
c. RR500 Failure of RHR to Provide Long-Term Cooling

For the injection mode, provision of flow from the RWST to one injection line by one RHR pump is considered system success. For recirculation and long-term cooling, success is the provision of cooled flow by one pump to one injection line (or to one SI supply line). For recirculation, suction must be from containment sump B while for long-term cooling, suction is from the RCS. Since cooling is required for both cases, the heat exchanger corresponding to the operating pump must be operable, CCW cooling water must be supplied, and a CCW return path must exist.

The following human failures were included in the RHR fault tree model.

a. *RRHFDRECRC - Operators Fail to Correctly Shift the RHR System Recirculation.* This event describes the failure of operators to correctly shift the RHR system to the recirculation mode. The event includes the failure to align the CCW and SW systems as required in order to support recirculation.

b. *RRHFDTHROT - Operators Fail to Throttle RHR When Required.* This event describes the failure of operators to throttle RHR flow as necessary to prevent loss of NPSH during recirculation. Failure to throttle RHR flow to less than or equal to 1500 gpm per pump with one containment sump B suction MOV closed would result in failure of both RHR pumps due to loss of NPSH.

c. *RRHFDSEALX - Operators Fail to Trip RHR Pumps Following Seal Failure.* This event describes the failure of operators to trip a RHR pump during the recirculation phase upon loss of the pump seals. The failure to trip the pump could result in the flooding of both RHR pump motors.

The following flag was used in the RHR fault tree model.

a. *RRAASEALOC - Seal LOCA Requiring MOV 313 to Close to Prevent ISLOCA.* Setting this flag to true identifies that the sequence being solved is a seal LOCA where MOV 313 (seal return line) must close in order to prevent a LOCA outside containment.

6.16.4 RHR Fault Tree Model Assumptions

a. Operation of the RHR pumps for an extended period without minimum flow protection could result in their failure. This concern is considered applicable for all cases except for large break LOCAs.

b. It was assumed that RHR room coolers are not necessary for system success [Ref. 2, Section 3.11.3.2], so the coolers were not included in the model.

c. It is assumed that CCW must be supplied for pump seal cooling during long-term cooling and recirculation.

d. It is assumed that temperature control is not required for recirculation to succeed (i.e., flow control via AOVs 625 and 624 is not required for the initial 24 hours following a LOCA).

e. NPSH to the RHR pumps can be lost during recirculation if MOVs 852A and 852B are both open, AOVs 624 and 625 are not throttled, one containment suction line is closed (MOVs 850 or 850B), and containment is saturated. This has been conservatively modeled as requiring throttling anytime there is a failure of a suction path. If these failures become significant, the pump train components for the associated AOV can be deleted from the cutsets.

f. When the station is in the RHR mode of operation, manual valves 712A and 712B are opened and FCV 626 is used for flow/temperature control. It is possible that human failures could result in leaving 712A and 712B open during subsequent operations. It is assumed, however, that 626 would be closed and that this pathway will still be isolated. The position of valve 626 can be determined from the control room and is verified daily by control operators. Therefore, flow diversions around the heat exchangers were not included in the recirculation or long-term cooling models.

g. The injection mode is initiated by ESFAS. It was assumed that the failure of the actuation system to provide a SI signal results in failure to provide low pressure injection. Operator action to manually initiate injection is addressed in the ESFAS model.

h. Opening of MOV 857B is assumed to create a flow diversion path from the system in modes other than SI augmentation. This diversion can affect both trains. Opening of MOV 857A and 857C can similarly affect Train A. It is assumed that this second flow diversion path is not relevant to Train B as check valve 697A would have to open as well.

i. Performance of the quarterly safeguards valve surveillance may render a train of the RHR system inoperable for a few minutes. This period of unavailability has been included in the model.

j. No events have been included in the model for the failure of MOV's 1813A or 1813B to remain closed. If either of these valves were to fail to remain closed, the driving head for flow through the path would be the difference in elevation between containment sump "B" and the inlet to the CVCS holdup tank, plus any pressure in containment. The top of the sump is at elevation 235-8", while the best estimate of the pressure in containment at the earliest start of RHR recirculation is 23.3 psi (38 psia - 14.7), which equates to 53-9" of head. Therefore the total driving head for flow through this path would be 289-5". The inlet valve to the CVCS holdup tank is located on the top of the tank at an elevation of 265-9". Therefore, the net head available to provide flow to the tank is 23-8". It should be noted that there is a significant length of piping between the sump and the holdup tanks which would provide flow resistance. The reactor coolant drain tank pumps are also in the path and would not be operating, thus providing flow resistance. Therefore, although these flow resistances have not been quantified, it is assumed that they would most likely increase the required driving head beyond that which is available such that no flow would occur. If all flow resistances are conservatively ignored, given the available driving head, some water would be diverted from the suction of the RHR pump and flow through this path into the CVCS holdup tank. Eventually, the tank would fill and challenge the relief valve. The relief valve setting is 15 psi which equates to 34-8" of pressure. Since there is only 23-8" of driving head, there would not be enough head to cause the relief valve to open. The volume of the holdup tank is approximately 33,000 gallons. Assuming that the tank was 50% full at the start of the event, approximately 15,500 gallons would be diverted from the suction of the RHR pump and fill the CVCS holdup tank, at which point flow would stop. Due to the relatively small volume of water diverted, this is would not considered to constitute a failure of the RHR system.

k. Motor-operated valves which are locked in position and which are not required to re-orient during accident sequences were modeled as manual valves.

l. CCW lines from the RHR heat exchangers are 10" in diameter. A 1" relief valve can bypass flow around the isolation valves in this line, to protect the low-pressure CCW piping. It was assumed that any flow through this relief path would be irrelevant to the modeling of CCW cooling of the RHR heat exchangers.

m. A concern has been identified that a Turbine Building high energy line break could cause failure of a block wall separating the Turbine Building and the Intermediate Building. Subsequently, components located in the Intermediate Building or whose electrical cabling passes through the Intermediate Building could fail. As cabling for MOV 852A and MOV 857B pass through the Intermediate Building, they are subject to this failure mode.

n. If AOV 371 fails to isolate, RHR letdown to CVCS will continue and fill up the VCT which will overflow to the CVCS holdup tanks which overflow to the Waste Holdup tank which overflows to the Auxiliary Building Sump tank which overflows to the Auxiliary Building Sump which would flood out the RHR pumps. This is a long, slow, arduous path and there is the potential that operators would fail to notice the alarms along the way if a real accident were occurring since these are not normally high priority issues. This failure mechanism was included within the model. A similar failure mechanism exists if MOV 313 fails to close on the seal return line following a seal LOCA.

6.17 Safety Injection (SI) System

6.17.1 SI System Function

The SI system, part of the Emergency Core Cooling System (ECCS), consists of active (e.g., SI pumps) and passive (i.e., accumulators) components which function to provide borated water to cool the core in the case of a LOCA. The SI system serves the following functions:

a. Provides inventory control and core cooling (i.e., decay heat removal) for small break LOCAs where RCS pressure does not rapidly drop to the RHR pump shutoff head. This includes long-term protection via high-head recirculation.

b. Provides core cooling for large break LOCAs via the accumulators until the RHR system is providing necessary injection.

c. Provides reactivity control for large break LOCAs by rapidly injecting borated water into the reactor vessel.

Therefore, the SI system supports the reactivity control, RCS inventory control, and decay heat removal functions.

6.17.2 SI System Description

The active function of the SI system is to deliver borated water, drawn from the RWST to the cold legs of the RCS. The SI system initially draws borated water from the RWST until it reaches a low level. If continued injection is required, the system is reconfigured to take suction from the discharge of the RHR pumps. The passive function of the SI system delivers borated water with a minimum boron concentration of 2100 ppm from the accumulators to the cold legs of the RCS. The two train system consists of three pumps (one of which can be aligned to either train), two accumulators and the necessary piping, valves, instrumentation and controls.

SI Pump C can be aligned to provide cooling water to one or both RCS cold leg injection lines. This is accomplished by normally open MOVs on the discharge of the pump (871A and 871B) which close based on SI Pumps A and B breaker status. This ensures that two SI pumps are always available for injection.

The accumulators are designed to discharge their contents into the RCS with no dependance on power sources or actuation signals. The only moving parts in the accumulator injection trains are the two check valves in series separating the RCS from each accumulator. The path of the check valves is exposed to fluid of relatively low boric acid concentration contained within the RCS loop. Even if boron deposits accumulated, the differential pressure following a LOCA would be sufficient to allow fluid to be injected. Whenever the RCS pressure falls below the accumulator pressure, the check valves open, forcing borated water into the RCS.

Automatic initiation of the active function of the SI System occurs from an ESFAS signal when pressurizer pressure drops to 1750 psig or lower, SG pressure drops to 514 psig or lower, or sensors in containment sense containment pressure of 4 psig or greater.

The SI system utilizes three 350 hp Worthington horizontal centrifugal pumps with a design flow rate of 300 gpm, a maximum flow rate of 625 gpm and a maximum shutoff head of 3400 ft. A 1.5" minimum flow bypass line is provided on each pump discharge to recirculate flow to the RWST whenever the associated main SI flow path is passing little or no flow. The three bypass lines discharge to a 2" common header and are isolated from the RWST during recirculation.

A simplified flow diagram of the SI system is provided in Figure 6-17.

6.17.3 Description of SI Fault Tree Model

The fault tree is organized according to the functions of injection and recirculation. The following are the top gates:

a. SI100 Failure to Deliver Flow From 1 of 3 SI Pumps to the RCS During Injection

b. SR500 Failure to Deliver Flow From 1 of 3 SI Pumps to the RCS During Recirc

The logical structure of the fault tree beneath these gates generally follows the physical layout of the SI system. That is, SI Pump A can only provide flow to RCS Loop B Cold Leg, SI Pump B can only provide flow to RCS Loop A Cold Leg, while SI Pump C can provide flow to either RCS cold leg. A LOCA in either RCS cold leg is assumed to fail the ability of all SI via that cold leg. Failure of pumps to start and check valves to open are modeled for each pump train. In addition, common cause failures of all three pump trains is included.

The recirculation model includes both failures that occur during injection such as a pump failure to start or valve fails to open, and failures during recirculation. Failures affecting automatic actuations during injection are not considered to fail recirculation because the SI system is manually placed into service during recirculation. Common cause failures or any other failures that are common to all trains in injection are not considered to fail recirculation because the top logic indicates that the SI system is only used for recirculation after it has been used for injection (i.e., a failure of both trains during injection would result in core damage and the recirculation model would not be used). The standby times for recirculation are assumed to be the same as for injection since one train could fail and still have system success so that in recirculation it could not be determined whether or not a component has actuated. Total system failures in injection will be taken out of the recirculation results so as not to double count those failures.

The recirculation mode of the SI system as described in Procedure ES-1.3 [Ref. 36] requires operator action to align and initiate actuation of the system. This information has been modeled in the RHR fault tree model with the exception of the steps only applicable to aligning SI to the recirculation mode (e.g., opening MOVs 857A, 857B, and 857C). As such, there is only one human failure event in the SI fault trees:

a. *SRHFDRECRC - Operators Fails to Transfer SI System to Recirculation.* This event describes the failure of operators to correctly place the SI system in the recirculation mode after the RWST reaches 15% level.

b. *SIHFDSTRTP - Operators Fail to Start SI Pump on ESFAS Signal Failure.* This event describes the failure of operators to start the SI pumps after a failure in the ESFAS.

There are no logic flags used in the SI fault trees.

6.17.4 SI Fault Tree Model Assumptions

a. The 3/4" lines to valves 872A, 872B, 885A, 885B, 1817, 1826, 2801, 2802, 2803, 2804, 2805, 2806, 2807, 2808, 2809, 2810, 2811, 2812, 2813, 2814, 2815, 2816, 2817, 2833, 2834, 2835, 2842, 2843, 2844, 2849, and AOVs 839A, 839B, 839C, and 839D have not been modeled due to the small size (the delivery line is a minimum of 3") and the unrelated nature of the lines (unlikely to have a potential common cause failure).

b. The 2" line to AOVs 835A and 835B has not been modeled due to the small size (the delivery line is a 4" line) of the line.

c. The 2" lines to valves 892A and 892B have not been modeled due to the small size (the delivery line is a 10" line) of the lines.

d. The unavailability of SW cooling to the pump bearing coolers is assumed to fail the ability of the pump to perform its function during recirculation only since the RWST provides sufficiently cooled water during injection. Similarly, CCW cooling to the SI pumps' mechanical shaft seals is only required during recirculation.

e. MOV 871A only closes when breaker Bus16/12A for SI Pump B fails to close and breaker Bus14/20A for SI Pump A closes after the 3 second time delay. Otherwise, for all scenarios, this valve remains open. Since MOV 871A is powered from MCC C (Bus 14) and SI Pump A is powered from Bus 14, a failure of power on Bus 14 would by default fail the ability of MOV 871A to close. Also, MOV 871A and SI Pump A get ESFAS signals from train A; consequently, a failure of the ESFAS signal on train A would also by default fail the ability of MOV 871A to close. Finally, MOV 871A and SI Pump A are powered from Auxiliary Building DC Distribution Panel 1A (DCPDPAB01A); consequently, a failure of DC power on Auxiliary Building DC Distribution Panel 1A would by default fail the ability of MOV 871A to close. Therefore, the probability of MOV 871A receiving a signal to close does not include AC or DC power failure or the loss of the ESFAS signal. The same applies for MOV 871B and SI Pump B.

f. For modeling purposes, MOV 871A gets a signal to close when SI Pump B fails to start and SI Pump A starts. If SI Pump A starts and delivers flow to the SI train A injection line, the system is successful; however, if manual valve 888A transfers closed or check valve 889A fails to open, SI Pump A will continue to run recirculating back to the RWST. In this case, flow will be failed from SI Pump A due to the 889A or 888A failure, and flow will be failed from Pump C if MOV 871A closes (if SI Pump B fails to start). The same type of scenario exists in the case of MOV 871B.

g. The unavailability of a discharge flowpath for SW cooling to the SI pumps is assumed to fail the SI pumps during recirculation only. Since the probability of the discharge valve transferring closed is a very small probability and recovery would require discovery of the event and successful opening of an alternate discharge flowpath, the model has been simplified by assuming that the discharge valve transferring closed would fail SW cooling to the pumps.

h. Failure to inhibit backflow to the accumulators due to a check valve transferring open is assumed to fail SI because if the check valve transfers open, SI flow will enter the accumulators and discharge through the relief valve or, if the relief valve fails, will burst the tank. The relief valves lift at 790 psig and the design pressure of the tanks is 800 psig. This diversion of flow away from the RCS is assumed to fail the ability to provide core cooling.

i. The potential for injection through the normally locked closed RCS hot leg does not constitute SI system success due to PTS concerns.

j. Testing of SI Pump C is assumed to disable SI Train A or Train B (depending on which line the pump is discharging to).

k. There is HVAC cooling duct work above the SI pumps. Small amounts of water have been noted at various times dripping from this duct work onto the pumps; however, this has not been observed to cause failures of the pump and has therefore not been modeled.

l. Valves transferring closed is generally not modeled where valve fails to open is modeled because the failure to open is a much larger probability. Also, valves transferring open is not modeled where valve fails to close is modeled because the failure to close is a much larger probability.

m. For data purposes, MOVs are assumed to act like manual valves if the power is removed from the operators.

n. Check valve 870A transfers open has not been modeled as a flow diversion path for SI Pump A because it would have to occur in conjunction with Train B pressure being lower than Train A pressure (i.e.: if there were a LOCA in Train B) and with SI Pump C not pressurizing the line between 870A and 870B. Three such low probability events AND-ed together were not considered to contribute significantly to the failure of the system.

o. For events that require a pump breaker to be closed, a failure of the pump to start is assumed to result in an open breaker.

p. A nitrogen bubble in the SI line caused by failure of the accumulator check valves has not been modeled because this type of event has not occurred at Ginna Station.

q. Root valves for instrumentation were not modeled since these valve failures were assumed to be part of the instrumentation boundary for data analysis purposes.

r. A pipe break is assumed to occur in only one leg of the RCS. Also, a small, medium or large LOCA will fail the SI train that the LOCA is in and will create a flow diversion for SI Pump C even if the associated discharge MOV to that line fails to close.

s. SI Pump C failing to start on Bus 16 can occur if 2/SIP1C2 (the Agastat time delay relay to start SI Pump C on Bus 14) operates but breaker Bus14\19A (the breaker for SI Pump C on Bus 14) does not close and Agastat 2/1C2X fails to operate. This has been modeled as a logic circuit failure in order to simplify the model.

6.18 Service Water (SW) System

6.18.1 SW System Function

The SW System functions to remove heat from critical and non-critical loads during normal operation, and critical loads during accident conditions, and transfer the heat to Lake Ontario. The following loads receive SW flow during accident conditions:

a. containment recirculating fan coolers (CRFC);
b. DGs;
c. CCW heat exchangers;
d. RHR pump and charging pump area coolers (not required for the PSA purposes);
e. SI pump bearing oil coolers;
f. Suction for AFW and SAFW pumps; and
g. SAFW room coolers.

As such, the SW system supports three of the four core protection functions (i.e., RCS pressure control, RCS inventory control, and decay heat removal).

6.18.2 SW System Description

The SW system is an open loop system consisting of 4 Worthington 480 VAC vertical, two-stage, centrifugal pumps with Westinghouse motors arranged in two supply trains. The pumps are rated at 5300 gpm each, 1750 rpm, 308 BHP, 75 psig discharge pressure or a head of 198 feet, and 80°F design temperature. Pumps A and D are rated at 350 hp while Pumps C and D are rated at 300 hp. They each require a minimum flow of 160 gpm. Pumps B and D are powered from Bus 17 while Pumps A and C are powered from Bus 18. Water for the suction of the pumps flows from Lake Ontario through the intake structure, the inlet plenum, and the traveling screens and into the SW inlet bay in the Screenhouse. The pumps discharge through an expansion joint, a discharge check valve (4601 through 4604) and a manual isolation valve (4605 through 4608). Pumps A and B discharge into one 20" header (Train A) while pumps C and D discharge into a second 20" header (Train B).

At least one pump on each electrical bus must be operable at all times per the technical specifications. A pump can either be running, in standby, or out of service. Either the running pump or its alternate on the same electrical train must be selected to start on an UV or SI signal.

The two 20" supply headers supply SW to the various loads listed in Section 6.18.1. Six pairs of motor operated valves (4780 & 4609, 4670 & 4613, 4616 & 4735, 4615 & 4734, 4664 & 4614, and 4663 & 4733) automatically isolate the supply headers from the non-critical loads (with the exception of the reactor compartment coolers and containment penetration coolers) when conditions warrant. Each pair contains a butterfly valve in series with a gate valve (with the exception of valves 4609 and 4780 which are two butterfly valves).

The two supply headers are cross-connected in the following four places:

a. In the Screenhouse, there is a 4" line connecting the discharge of SW Pumps B and C just downstream of their discharge isolation valves (4606 and 4607). The cross-connect valves in this line (4611 and 4612) are normally closed.

b. In DG Room B, there is a 4" line connecting the 14" line from Train A which supplies DG A and the inner 10" non-safety loop, to the 4" line from Train B which supplies the DG B. The cross-connect valves in this line (4669 and 4760) are normally open to provide balanced flow and to allow one train of SW to supply both DGs if necessary.

c. In the Auxiliary Building basement there is a 16" line connecting the 20" line from Train A (to CCW Heat Exchanger A, the SFP Heat Exchanger A and the Standby SFP Heat Exchanger) to the 20" line from Train B (to CCW Heat Exchanger B and the SFP Heat Exchanger B). The cross-connect valves in this line (4610 and 4779) are normally closed.

d. In the Intermediate Building basement there is a 14" line connecting the 14" line from train A to CRFC's A and B, to the 16" line from train B to CRFC's C and D. The cross-connect valves in this line (4639 and 4756) are normally open to provide balanced flow and to allow one train of SW to supply all CRFC's if necessary.

There are a total of four separate SW return lines. One serves the DGs and various turbine plant loads and discharges to the plant discharge canal. A second serves the CRFCs and motor coolers, the reactor compartment coolers, and the air conditioning chillers, and discharges to the plant discharge canal. The other two SW return lines serve the SI pump coolers, the RHR and charging pump area coolers, the CCW heat exchangers, and the SFP heat exchangers. One SW header is the normal return and discharges into the discharge canal. The alternate SW discharge header is normally isolated and would only be used should the normal header be damaged. The alternate header discharges via an open concrete discharge structure into Deer Creek.

A simplified diagram of the SW System is provided in Figure 6-18.1 and 6-18.2.

6.18.3 Description of SW Fault Tree Model

The fault tree is organized under multiple top gates, each representing the failure to supply adequate SW flow to a particular component. The fault tree for each top gate is divided into two logical branches, one representing the failure of all SW flow to the component, and the second representing the failure of 3 of the 4 SW pumps and failure of the isolation of non-safety loads. This translates to success criteria of one pump operating with isolation, or two pumps operating without isolation.

The branch of the tree which models failure of 3 of 4 pumps and isolation includes failure of isolation, and failure of 3 of 4 pumps to operate. Due to the fact that only two SW pumps can be in the standby mode, there will always be two pumps which do not receive a start signal. Thus, there will always be at least one pump which can be manually started by the operators. The exception to this is common cause failures of the running pumps (which would affect all the pumps), and loss of all AC power (which is covered under the SBO scenario). For this reason, the branch of failure of 3 of 4 pumps is combined in an AND gate with a branch which models the failure of operators to recover a pump which did not receive a start signal. This branch includes the failure of operators to start a second pump and mechanical failures of pumps which would prevent starting of second pump (i.e. common cause failures). Failure of 3 of 4 pumps is modeled as all combinations of 3 pumps failing due to pump start or run failures, discharge check valves failing to open, or support system failures (AC power, DC power, etc.).

The branch of the tree modelling failure of isolation contains a branch representing conditions which do not cause an SI signal (i.e. the valves do not receive a signal to close) and a branch representing failure of the valves to close given that an SI signal exists. This branch includes failure of the power supply to the valves (i.e. Dgs), failure of the DC control power to the valves, and the failure of the signal to the valve (SI or UV).

The branch modeling failure of all 4 pumps to supply flow includes pump failures as described above, as well as valve failures such that even if adequate pumps were running, no flow path to the component would exist.

The following human failure is modeled in the SW fault tree:

a. *SWHFDSTART - Operators Fail to Start Redundant SW Pump or Isolate System.* This event describes the failure of operators to start a second SW pump or isolate the non-critical system loads after one of two operating SW pumps fail to run.

The following logic flags are provided in the SW fault tree:

a. *SWAASWP1AR - Service Water Pump PSW01A Is in Operation.* Setting this flag to true identifies SW Pump A as being in operation.

b. *SWAASWP1BR - Service Water Pump PSW01B Is in Operation.* Setting this flag to true identifies SW Pump B as being in operation.

c. *SWAASWP1CR - Service Water Pump PSW01C Is in Operation.* Setting this flag to true identifies SW Pump C as being in operation.

d. *SWAASWP1DR - Service Water Pump PSW01D Is in Operation.* Setting this flag to true identifies SW Pump D as being in operation.

e. *SWAASWP1AS - Service Water Pump PSW01A Is Selected In Standby.* Setting this flag to true identifies that SW Pump A is in standby. Note that a standby pump does not have to be the running pump. Setting this flag to true means that SW Pump C cannot be in standby.

f. *SWAASWP1BS - Service Water Pump PSW01B Is Selected In Standby.* Setting this flag to true identifies that SW Pump B is in standby. Note that a standby pump does not have to be the running pump. Setting this flag to true means that SW Pump D cannot be in standby.

g. *SWAASWP1CS - Service Water Pump PSW01C Is Selected In Standby.* Setting this flag to true identifies that SW Pump C is in standby. Note that a standby pump does not have to be the running pump. Setting this flag to true means that SW Pump A cannot be in standby.

h. *SWAASWP1DS - Service Water Pump PSW01D Is Selected In Standby.* Setting this flag to true identifies that SW Pump D is in standby. Note that a standby pump does not have to be the running pump. Setting this flag to true means that SW Pump B cannot be in standby.

i. *SWAARUN263 - Logic Flag (Evaluate Complete SW During Run).* Setting this flag to true identifies that the failure of the SW pumps will be evaluated by solving the as-designed SW fault tree model. Setting the flag to false identifies that the SW pump fault tree model solved to the lowest truncation limit (i.e., cutsets are generated) and re-converted to a fault tree will be used. This technique was required due to the number of potential SW configurations and computer limitations.

In addition to the SW logic flags, there are two other flags which have a direct impact on the SW system: IAAAIAC02A and IAAAIAC02C which indicate whether or not IA compressors A and C are in service, respectively. A logical true indicate they are in service, while a logical false indicates they are not in service. These flags are used in the logic for isolation MOVs 4613 and 4670 being unavailable (closed) for test or maintenance. If the flags are set to TRUE, then the valves cannot be out for test or maintenance, since there would be no SW flow to the compressors. Logic flag AAAAIAC02B indicates whether or not IA compressor B is in service. This flag is used in the logic for isolation MOVs 4614 and 4664 being unavailable for test or maintenance.

6.18.4 SW Fault Tree Model Assumptions

a. Failure of the discharge check valve of one of the pumps on a header to close is assumed to be a failure of the other pump to run, since flow could go back out through the open check valve into the SW bay. However, this can only occur if the pump with the failed check valve was running and tripped on a UV signal, and was not selected in standby. If the pump was not running, it can be assumed that the check valve is closed since an open check valve would be indicated by low SW header pressure and presumably corrected prior to the start of the accident. If the pump is running but does not trip, there is no need for the check valve to close. Finally, if the pump was running, tripped, but was selected in standby, it would start up again, and thus the check valve would not need to be closed.

b. It is assumed that failure of any two valves in a pair of SW isolation MOV's constitutes a failure of isolation for the entire SW system.

c. Under the logic for failure of flow from all 4 pumps to a component, it is assumed that if the normal flow path to the component is unavailable, an alternate path through the 14" SW cross-connect to the CRFCs can supply adequate flow.

d. There is no alternate flow path from SW Train A to the non-critical header isolation MOV 4670 which supplies IA Compressors A and C, Relay Room AC Units A and B, and MFW Pump A lube oil cooler. This path would be through the CRFC cross-connect valves and back through the DG cross-connect valves. Since the normal flow path is through a 14" line and the DG cross-connect valves are only 4" valves, it is assumed that there would not be adequate flow. The same reasoning applies to the flow path from SW Train B through the DG cross-connect valves to valve 4670.

e. No failures of the SW discharge path have been modeled. There are no valves, strainers, etc, involved, and the discharge piping is of sufficiently large diameter to make pipe blockage an extremely unlikely failure mode.

f. For the SW pump flags, the model has set Pumps A and D as normally running with all four pumps having an equal probability of being in standby. This was done to reduce the potential number of combinations or pumps operating / in standby due to computer limitations. The decision to use Pumps A and D (versus B and C) was arbitrary after a detailed review of the start logic and support systems for the four pumps.

g. High energy line breaks in the Turbine or Intermediate Buildings were assumed to fail MOVs 4613, 4614, 4664, 4663, and 4733 due to block wall interactions with the valve operators and their cabling.

6.19 Undervoltage (UV) Protection System

6.19.1 UV System Function

The UV system functions to sense the voltage present on the four safeguards 480 volt buses (14, 16, 17, and 18). Upon sensing a complete loss of voltage or a degraded voltage condition, the system energizes a series of auxiliary relays which opens or closes contacts in various other circuits. Although modeled under other systems (mainly the DG system), the main functions of the UV contacts are to open the normal feeder breaker to the affected bus, start the DG, and shed loads from the bus as required. The UV system also senses the voltage on non-safeguards Buses 13 and 15, as well as 4160 V Buses 11A and 11B. The Bus 13 and 15 UV system does not have any functions related to the accident sequence quantification task. The Bus 11A and 11B UV system sends a signal to the TDAFW pump to start upon loss of voltage on both buses which has been modeled and generates a reactor trip signal. Therefore, the UV system provides the same functions as the DG and AC Power systems (see Sections 6.1.9 and 6.1.1, respectively).

6.19.2 UV System Description

The design of the UV system for each of the safeguards buses is the same with the exception that Buses 14 and 16 have 12 output auxiliary relays while Buses 17 and 18 only have 8. This section will describe only one bus undervoltage scheme, with double asterisks (**) representing the number of the respective bus.

There are four undervoltage relays which sense voltage on a given bus. Two of the relays sense loss of voltage (27/** and 27B/**) while the other two relays (27D/** and 27D/B/**) sense degraded voltage. For the purposes of this model, no distinction has been made between the loss of voltage and the degraded voltage, since the event sequences which rely on the undervoltage relays assume that a complete loss of power has occurred on the bus. The undervoltage relays are connected to the bus through closed contacts in normally de-energized test relays 29-A, 29-B, 29-C, and 29-D. The undervoltage relays are arranged such that one loss of voltage and one degraded voltage relay are paired together with two pairs provided per bus. Tripping of either relay generates a trip of that relay pair with both pairs being tripped before an UV signal is generated.

The undervoltage relays are connected to 12 undervoltage auxiliary relays (27X1/** through 27X6/** and 27BX1/** through 27BX6/**) through two separate trains of solid state circuit cards which provide electrical isolation and testing capability. The solid state portion of the system consists of a control logic board, a decoder logic board, a solid state switch board, and a heat sink assembly.

Power to the undervoltage relays themselves is provided directly from the 480 volt bus being monitored. Power to the control cabinet is supplied by the 125 VDC power system through contacts in the throwover relay (83DC/**). Power is then fed from the control cabinet to the relay cabinet and to a 12 VDC power supply. The components on the control logic boards, decoder logic boards, solid state switches and the auxiliary relays receive power from either the control cabinet, the relay cabinet and/or the 12VDC power supply. There is also an emergency DC power supply which can supply the control cabinet, again, through contacts in the throwover relay.

The Bus 11A and 11B UV system is simpler, and does not have any solid state components. There are four undervoltage relays for each bus (27-1/11A through 27-4/11A, and 27-1/11B through 27-4/11B) which are directly connected to four auxiliary relays (27X1/11A through 27X4/11A, and 27X1/11B through 27X4/11B). The undervoltage relays are powered directly from Buses 11A and 11B while the auxiliary relays receive 125 VDC power from the main control board DC distribution panels.

6.19.3 Description of UV Fault Tree Model

The fault tree is organized into two logical sections, each of which has multiple top gates. One section has top gates representing the failure of the undervoltage auxiliary relays to energize during undervoltage conditions, while the other section has top gates which represent the undervoltage auxiliary relays energizing when no undervoltage condition exists. There is a top gate for each of the six auxiliary and backup auxiliary relays for Buses 14 and 16, and each of the four auxiliary and backup auxiliary relays for Buses 17 and 18, failing to generate a signal and generating a spurious signal. There is also a top gate (UV900) which models the failure of the Bus 11A and 11B UV system to send a signal to the TDAFW pump starting circuit upon loss of Buses 11A or 11B.

The fault trees for the top events which model the failure of the auxiliary relays to energize are composed of two major branches, one for failure of DC power to the components in the system, and another for the failure of the components themselves.

The failure of DC power branch includes failure of the normal DC power supply which is a direct transfer to the DC power model, and failure of the emergency DC power supply (again, a transfer to the DC power model) including the throwover relay. Other failures in this branch are fuse failures and the failure of the 12 V power supply output.

The component failure branch includes failures of the relays in the system to change state, and any failures of the solid state circuit cards. For failure modeling purposes, the solid state circuitry has been divided into four different components. These include the control logic board, the decoder logic board, the solid state switch, and the heat sink assembly. This was done because each of these boards are physically separate from each other and the failure data available is for a given logic card. The exception to this is the heat sink assembly which is physically located on the solid state switch card, but is a separate sub-assembly.

The fault trees for the top events which model the auxiliary relays energizing when no undervoltage exists consist of only the branch for component failure. This is because a loss of DC power to the system will not energize the auxiliary relays. The component failure branch is similar to that described above with the failures being in the opposite mode (i.e. failures which generate a signal as opposed to failures which prevent generating a signal). There is also an added failure mode for the test relays (29-A through 29-D) transferring to energized which would give a false signal, which is not present for the failure to give a signal top gates.

The following human failure event is included with the UV fault tree model:

a. *UVHFDBREAK - Operators Fail to Close DG Breaker on Failure of UV System.* This event describes the failure of operators to manually start and close the DG onto a bus when the UV system fails.

There are no logic flags associated with the UV system.

6.19.4 UV Fault Tree Model Assumptions

a. Since the DC power to all components comes from the same source through the control cabinet, it was assumed that any DC power failure that would cause a logic card to generate a spurious signal would also cause the other cards to fail to pass on the signal or would cause the auxiliary relays to fail to energize. Therefore, no failures of the DC power supply to the UV system were modeled as causing a spurious signal.

b. The top gates of the model representing the failure of the auxiliary relays for the safeguards buses to energize assume that a complete loss of power has occurred on the given bus. The top gates representing a spurious energizing of the auxiliary relays assume that no undervoltage condition exists. The fault tree for the failure of a Bus 11A and 11B undervoltage signal to the TDAFW pump includes the logic for the loss of power on Buses 11A and 11B so that no assumptions are required.

c. The decoder logic board essentially passes a signal from the control logic board to the solid state switch card without any components having to actuate or change state. Its function is only for indication purposes. There is, however, a fuse through which the current signal must pass which could fail open. Therefore, the failure of the decoder logic board was modeled as a fuse failure as opposed to a logic circuit failure.

d. Because the undervoltage relays are only placed in the trip position momentarily (less than 1 minute, per R&T personnel) no event has been included in the fault trees for spurious signal for this condition.

Figure 6-1
AC Power System

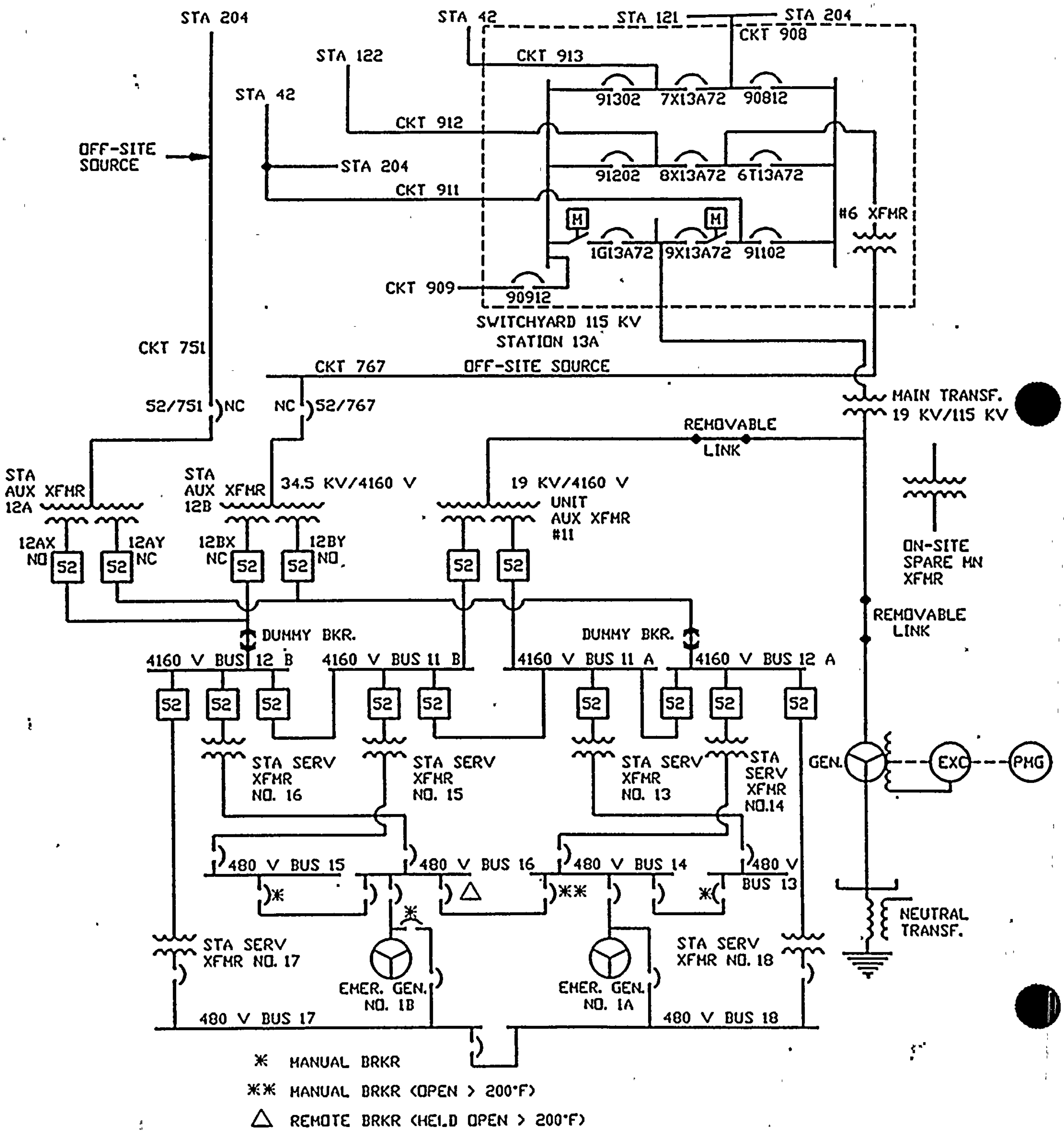


Figure 6-2.1
AFW System

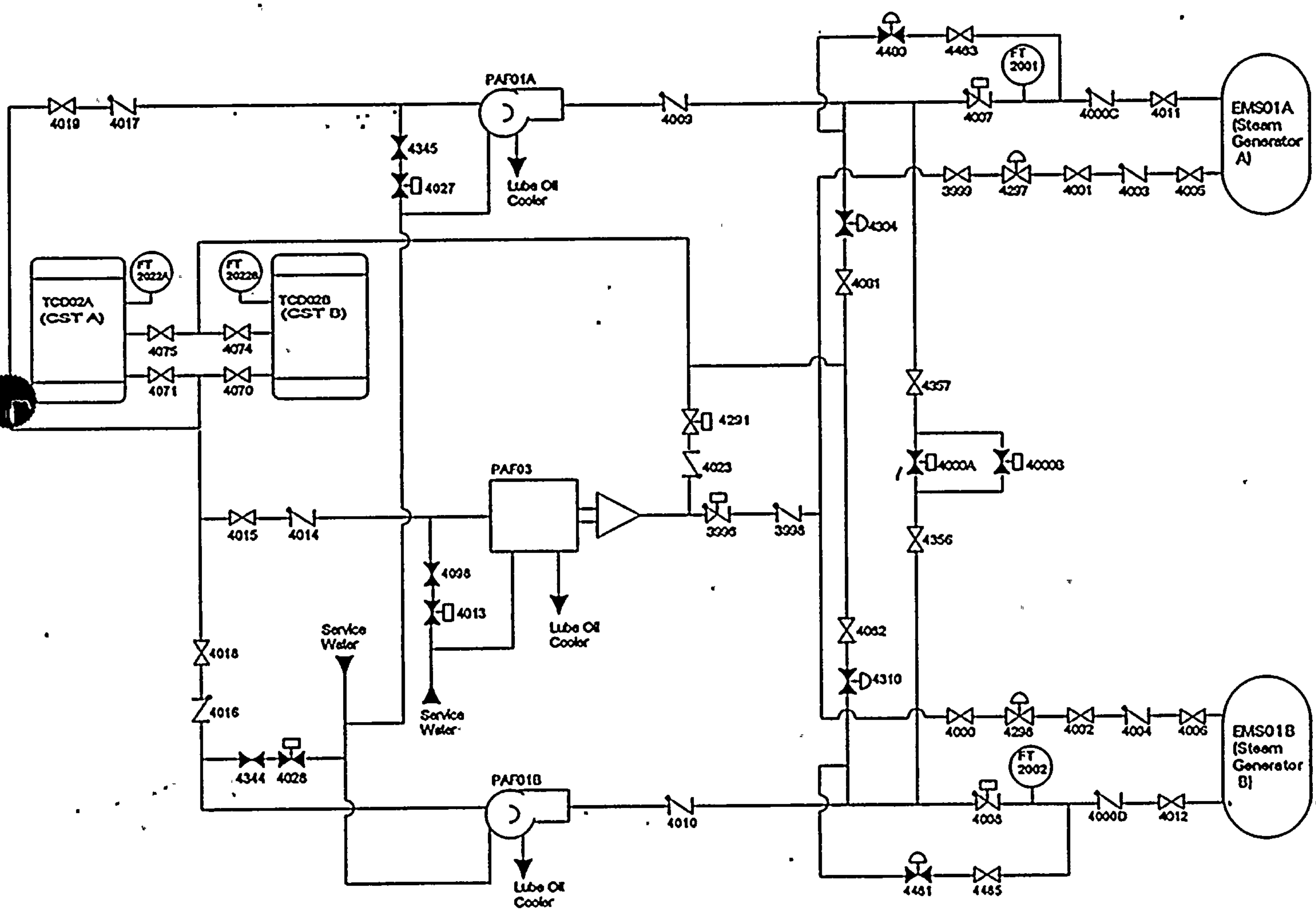


Figure 6-2.2
SAFW System

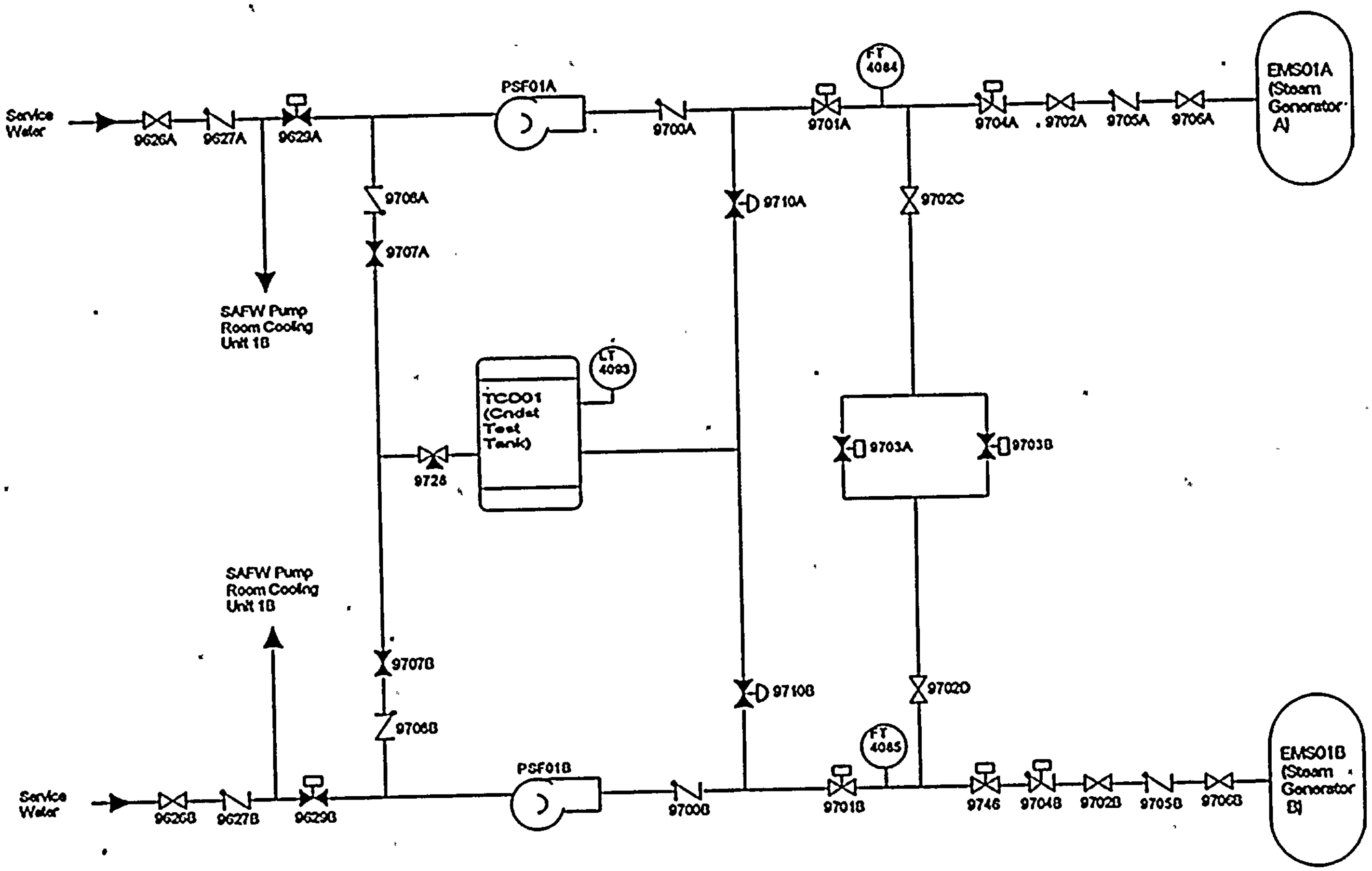


Figure 6-2.3
TDAFW Pump

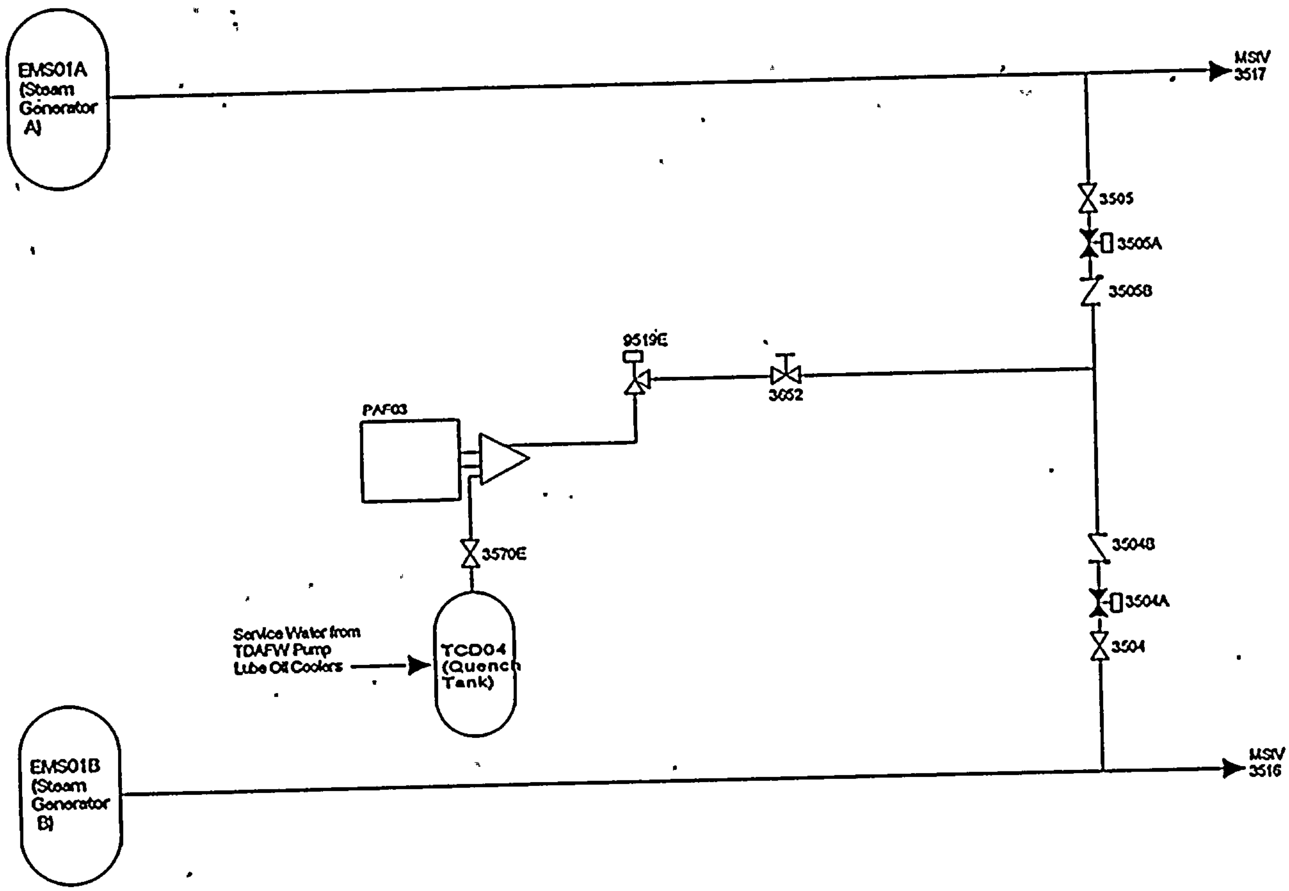


Figure 6-3
CVCS

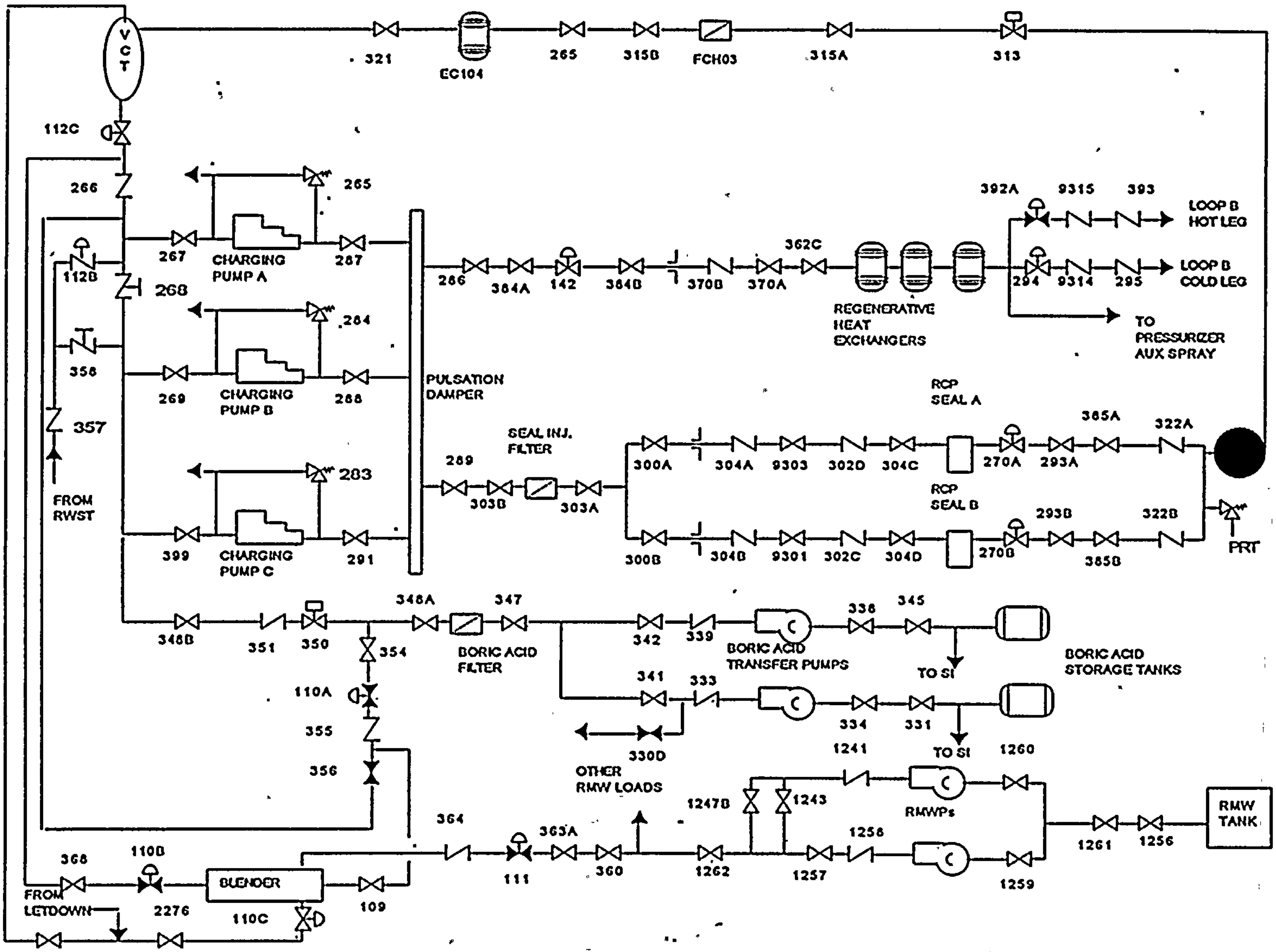


Figure 6-4.1
CCW System

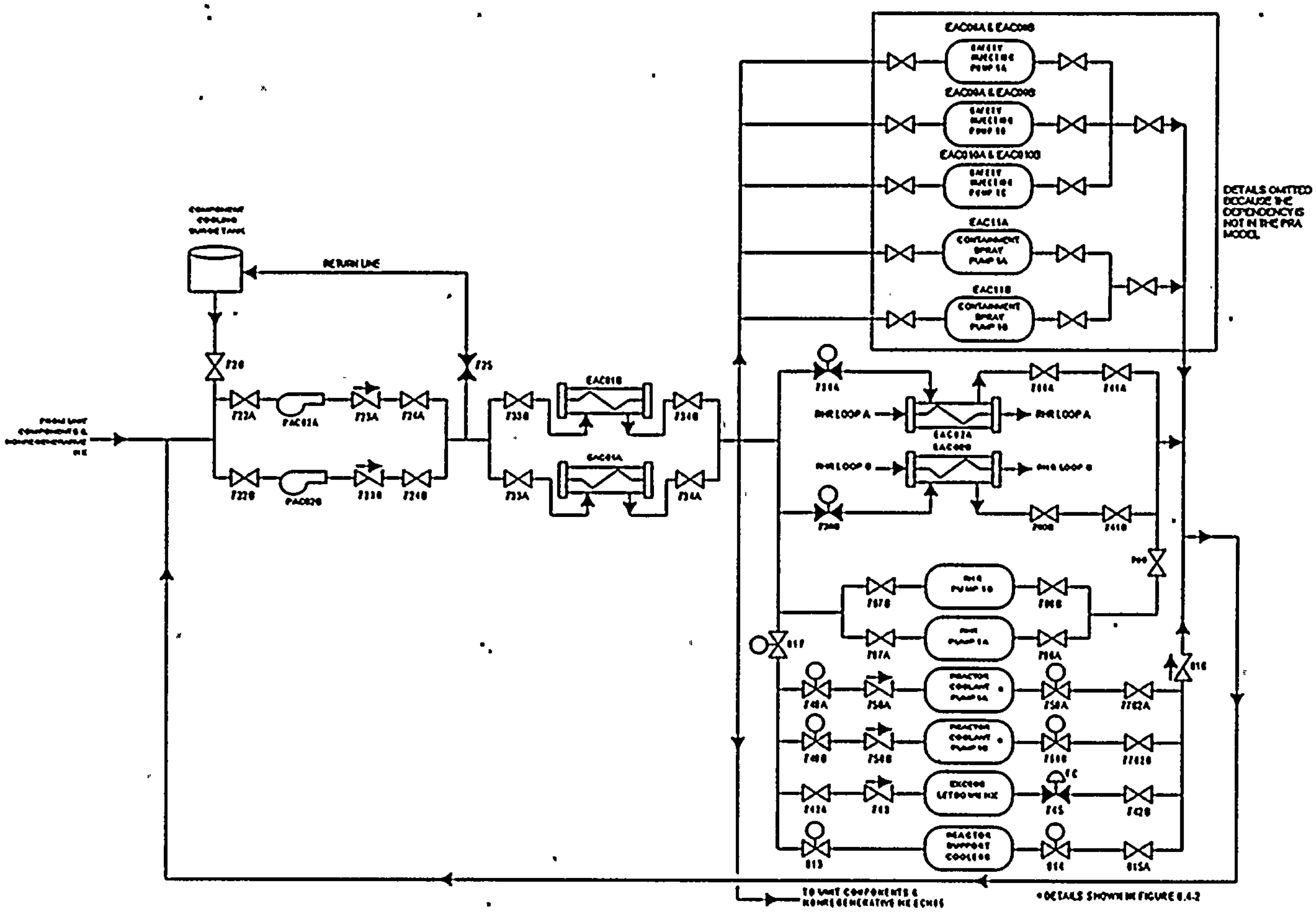


Figure 6-4.2
CCW Cooling to RCPs

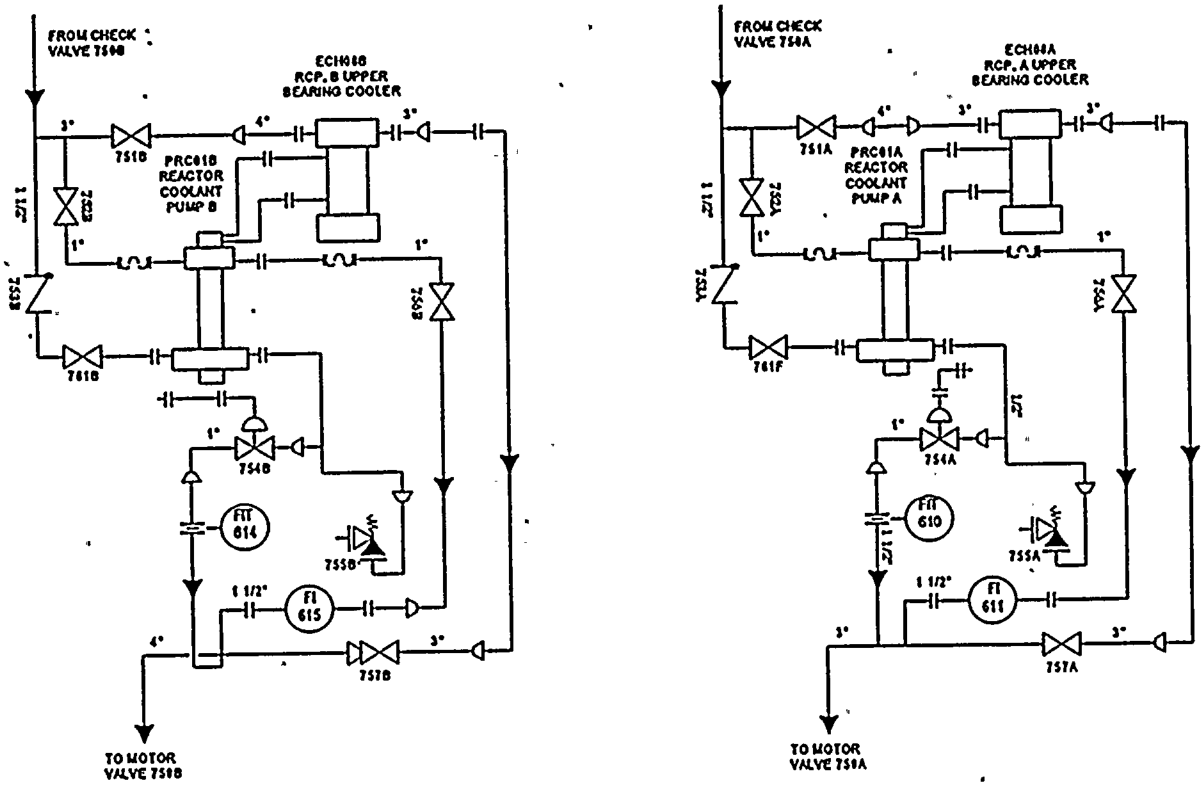


Figure 6-5.1
IA Compressors

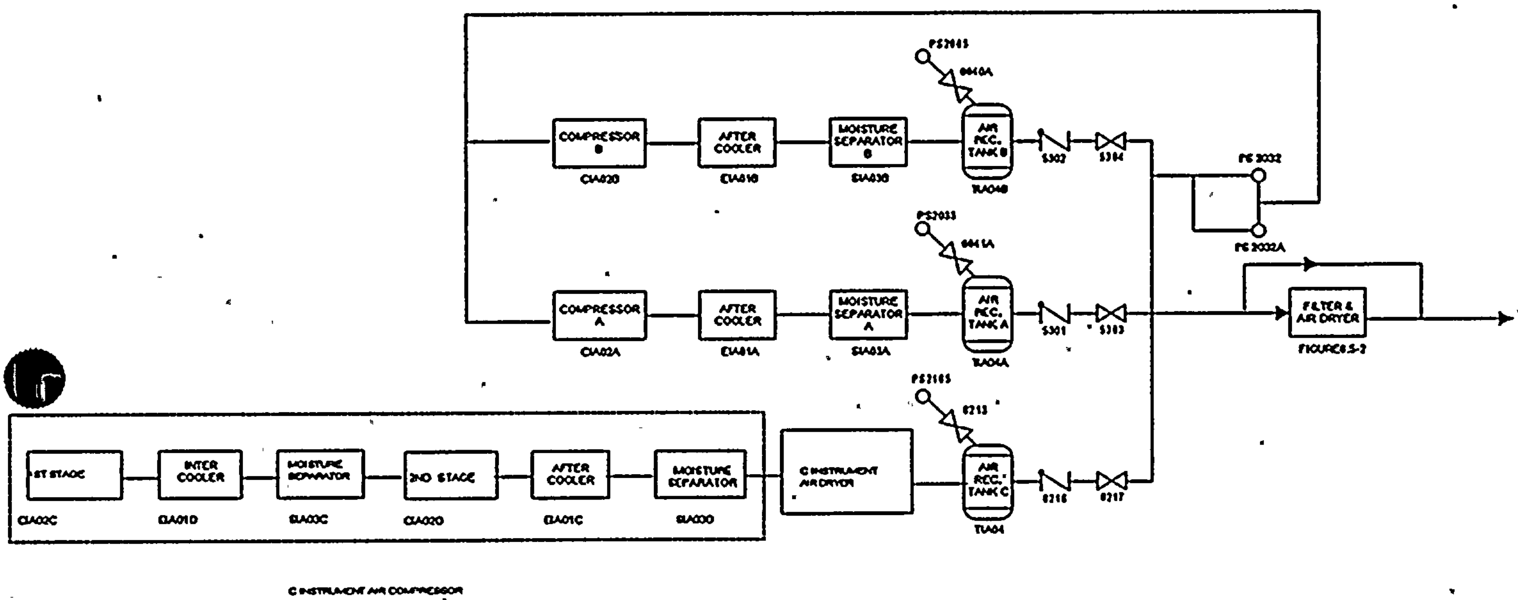


Figure 6-5.2
IA Dryers

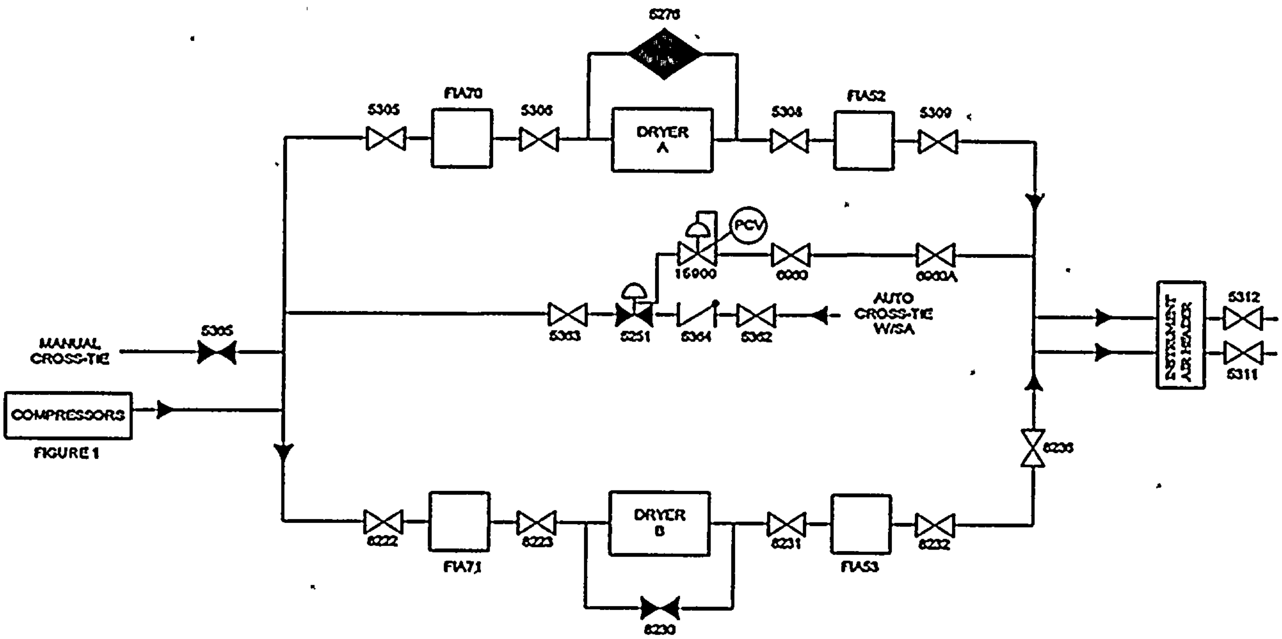


Figure 6-5.3
IA Header Configuration

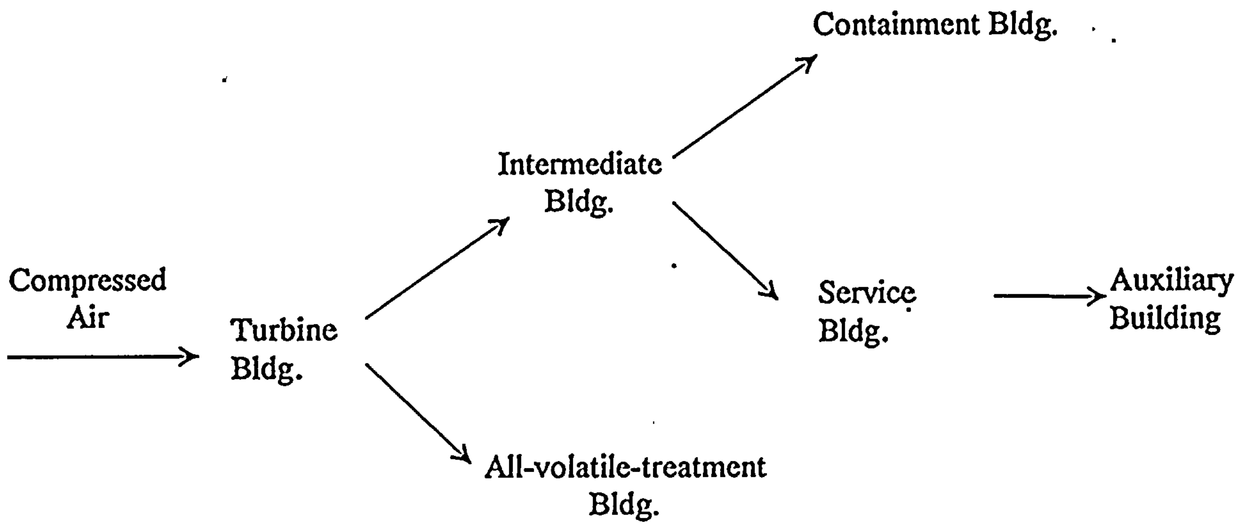


Figure 6-7
CS System

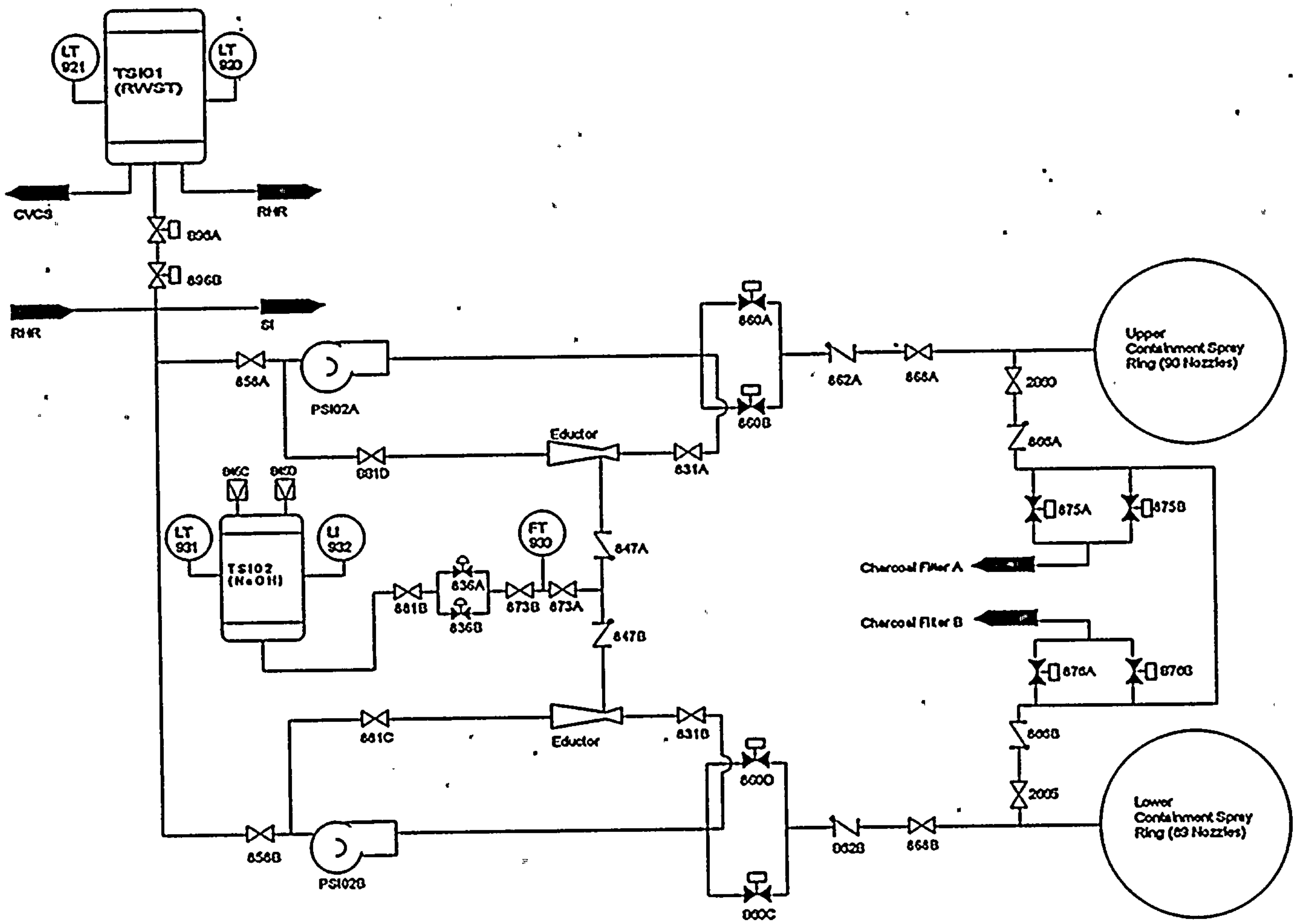


Figure 6-8
DC Power System

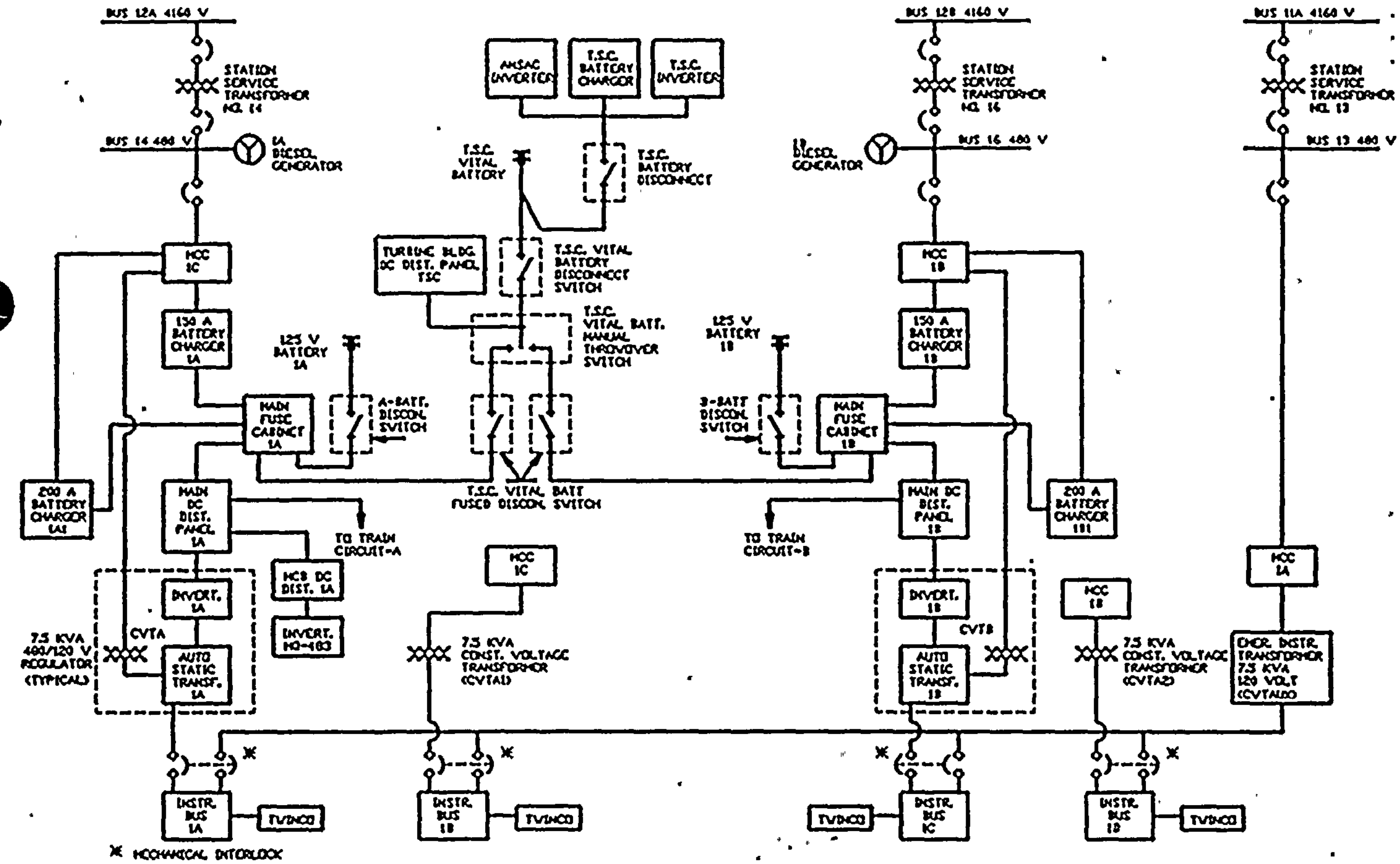


Figure 6-11.1
CRFCs

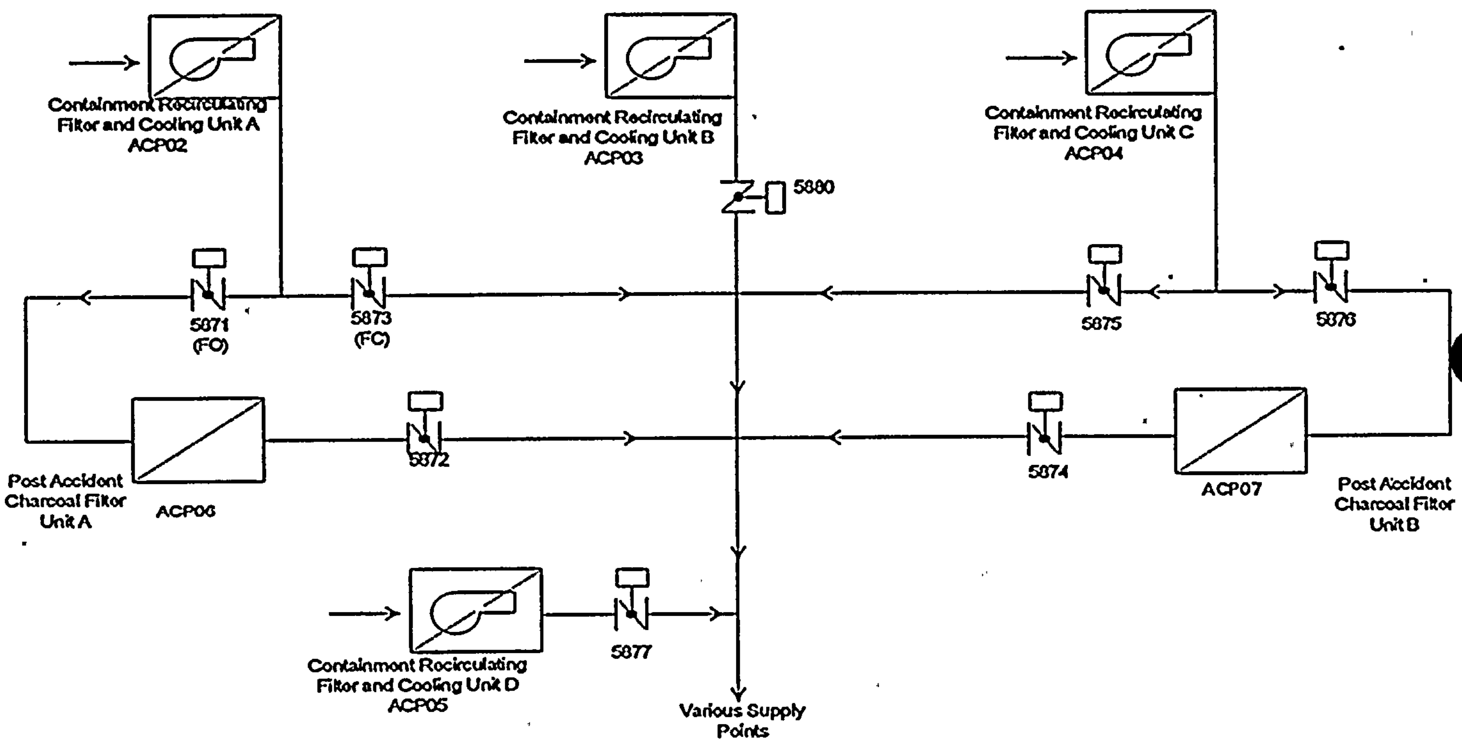


Figure 6-11.2
SW Cooling to CRFCs

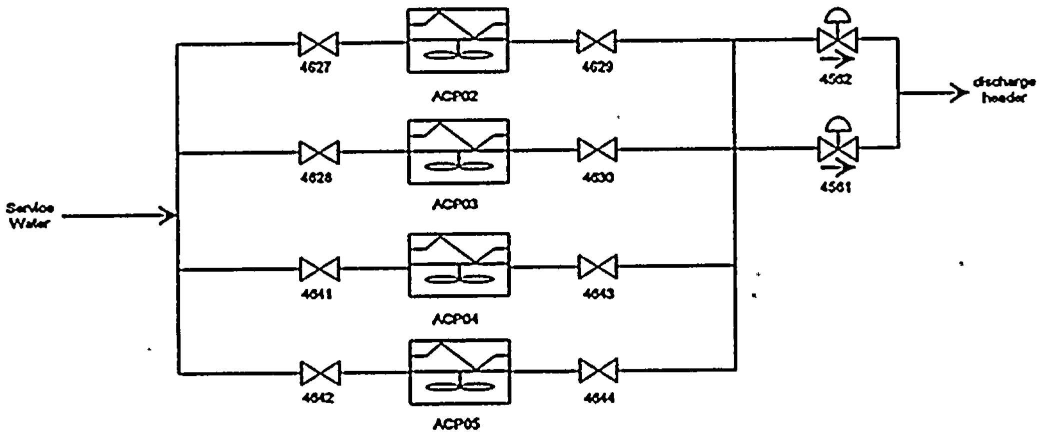
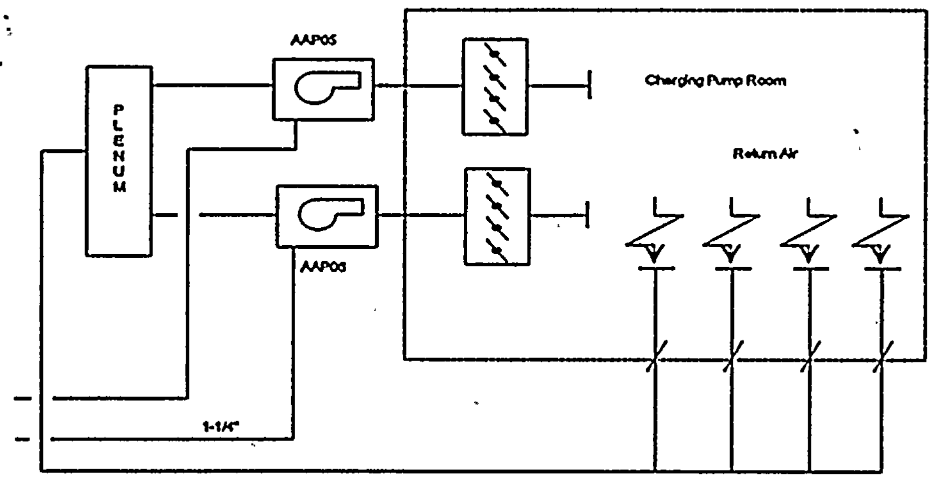


Figure 6-11.3
Charging Pump Room Coolers



Charging Pump
Cooling Unit A and B

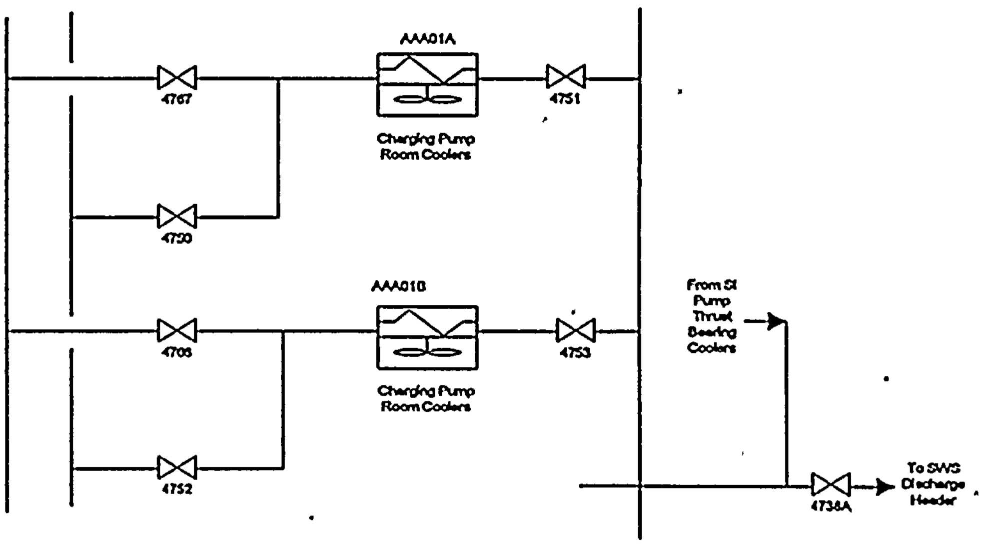
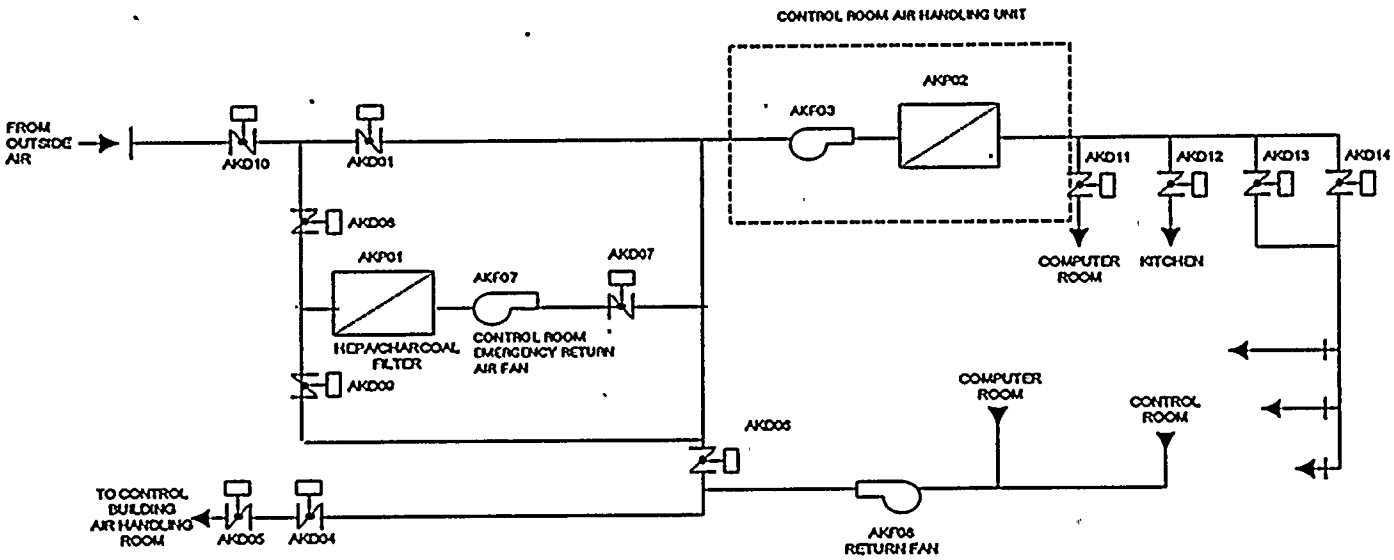


Figure 6-11.4
Control Room Ventilation System



NOTE: ALL DAMPERS EXCEPT AKD06 ARE INSTRUMENT AIR OPERATED

Figure 6-11.5
Relay Room Coolers

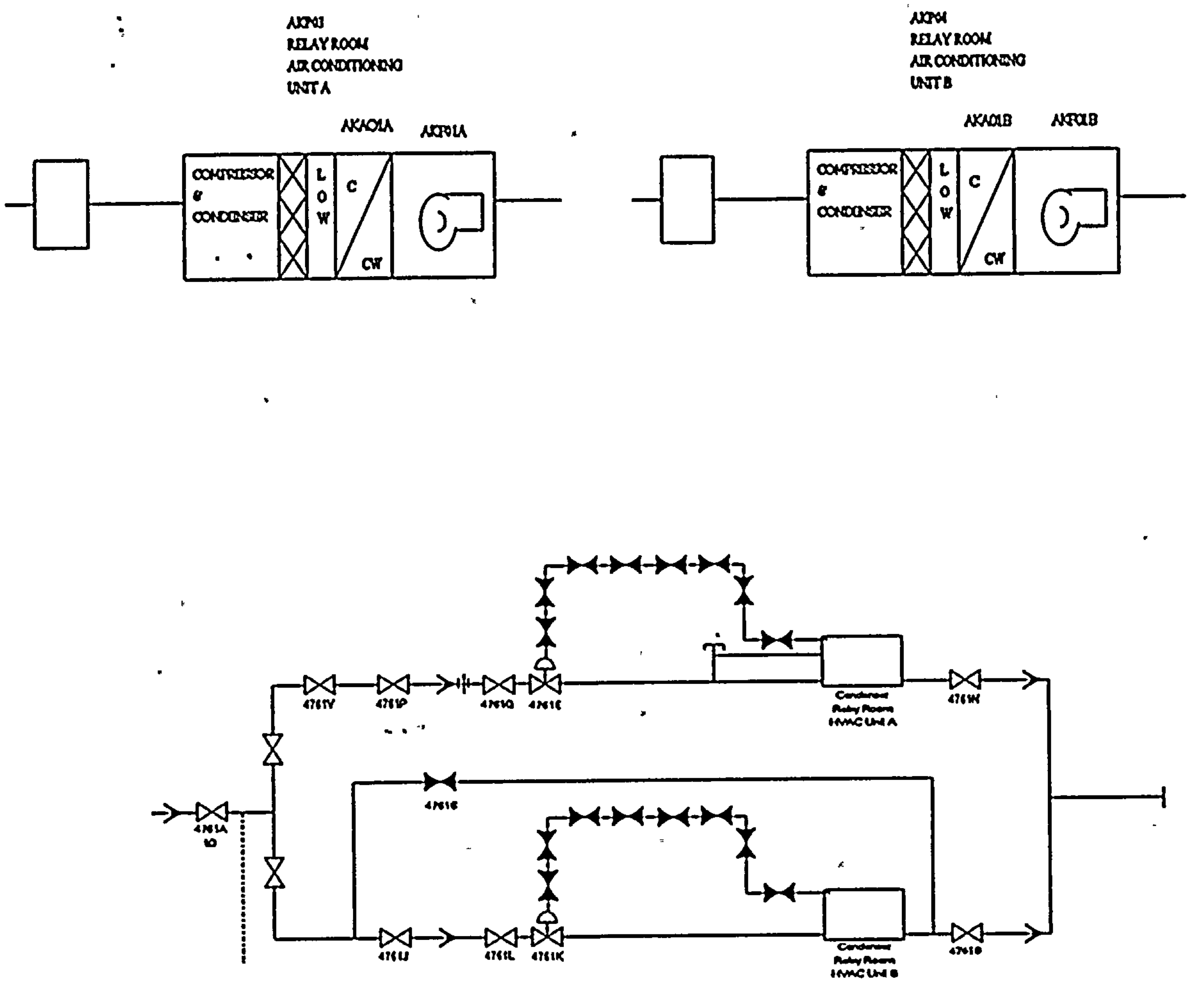
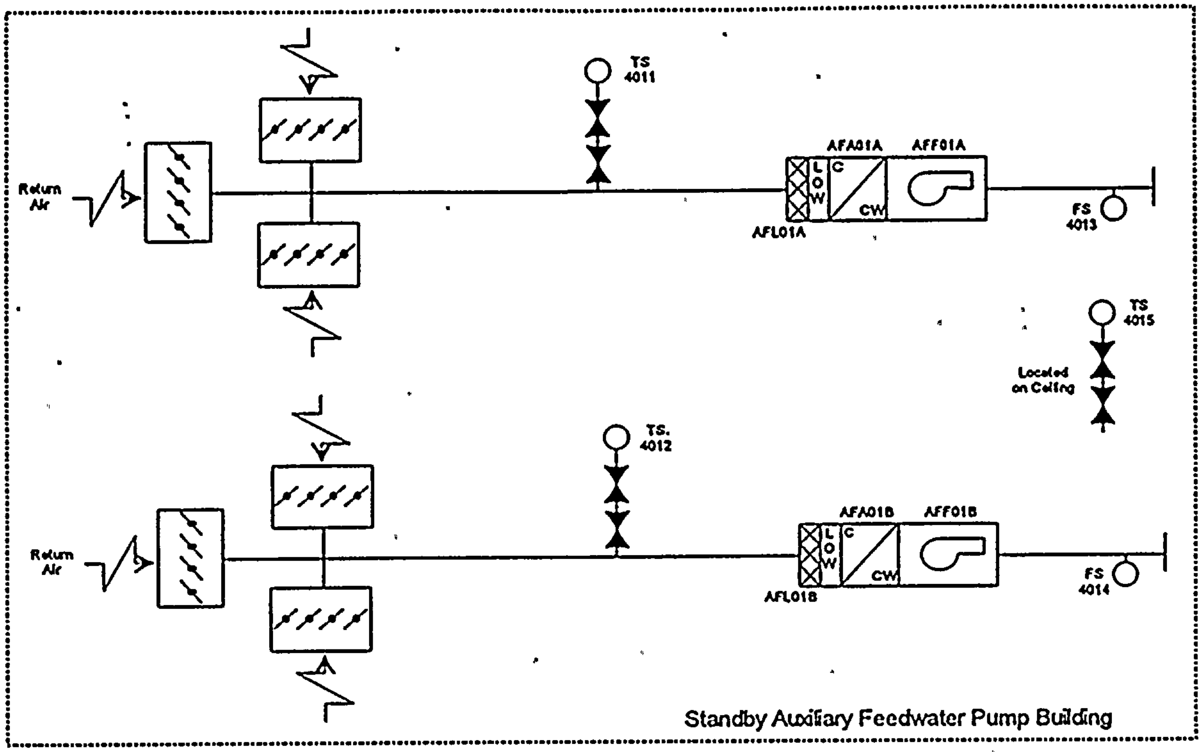


Figure 6-11.6
SAFW Pump Building Ventilation System



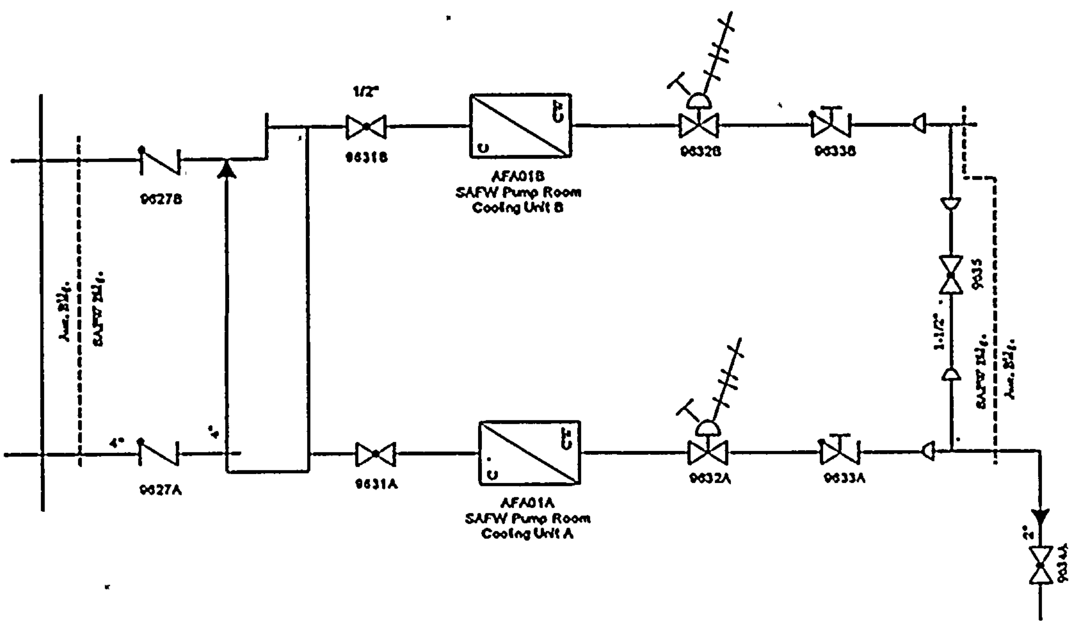


Figure 6-11.7
Intermediate Building Ventilation System

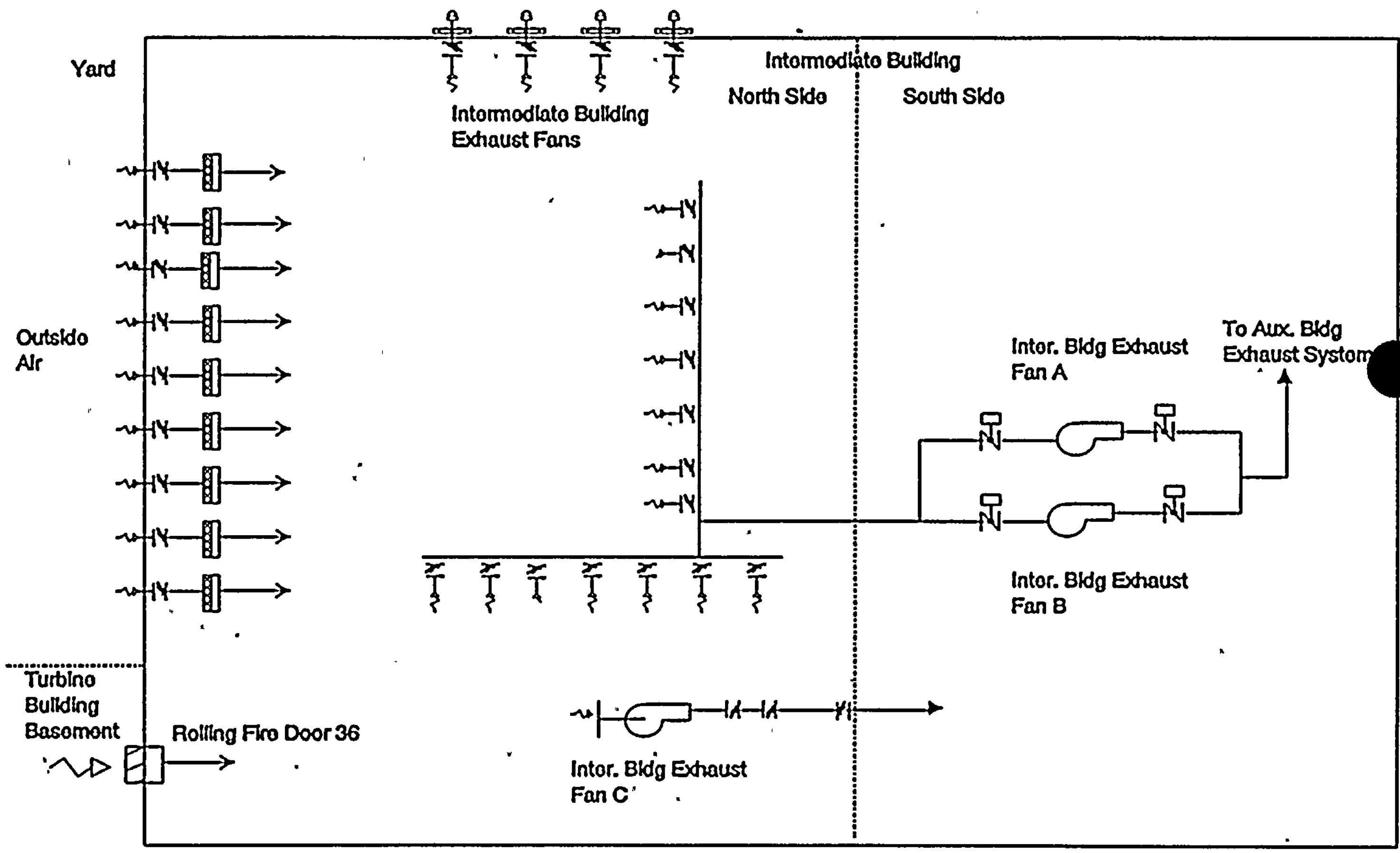


Figure 6-11.8
Control Rod Shroud Fans

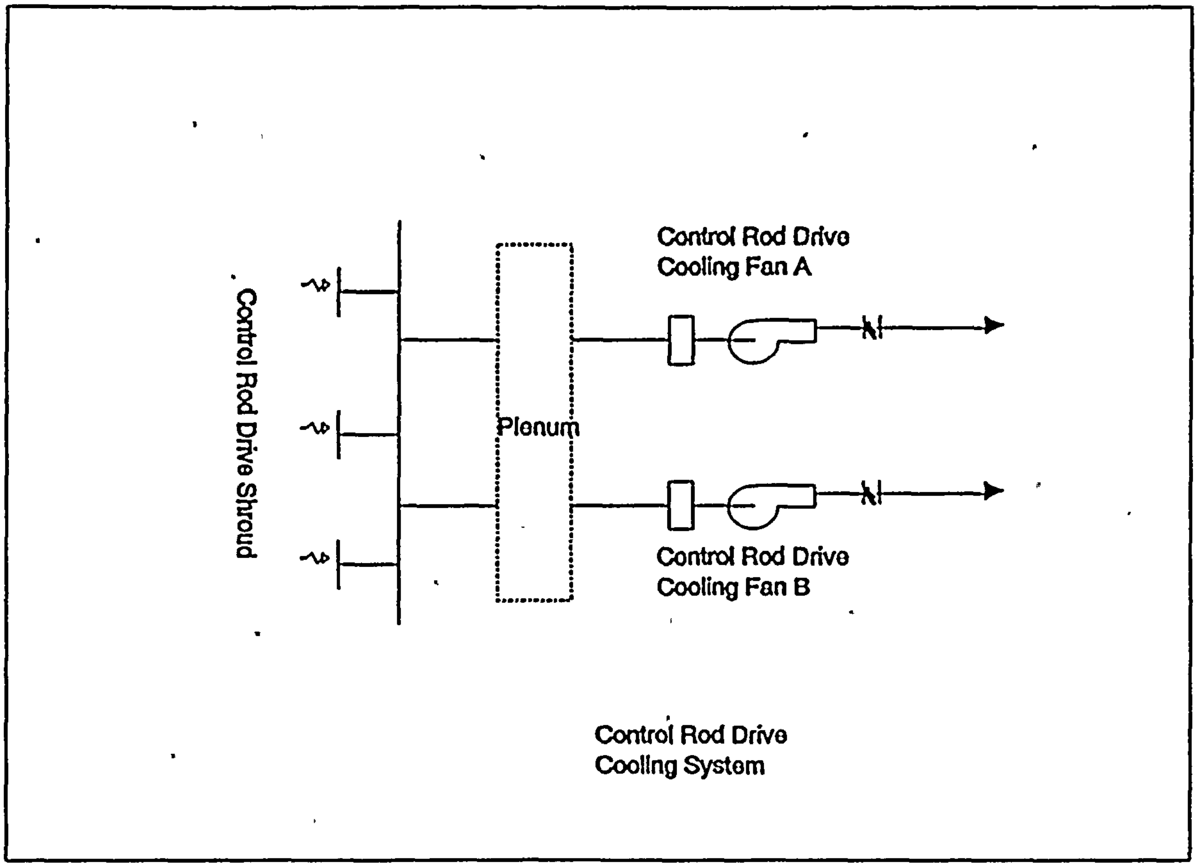


Figure 6-13.1
ARV 3411

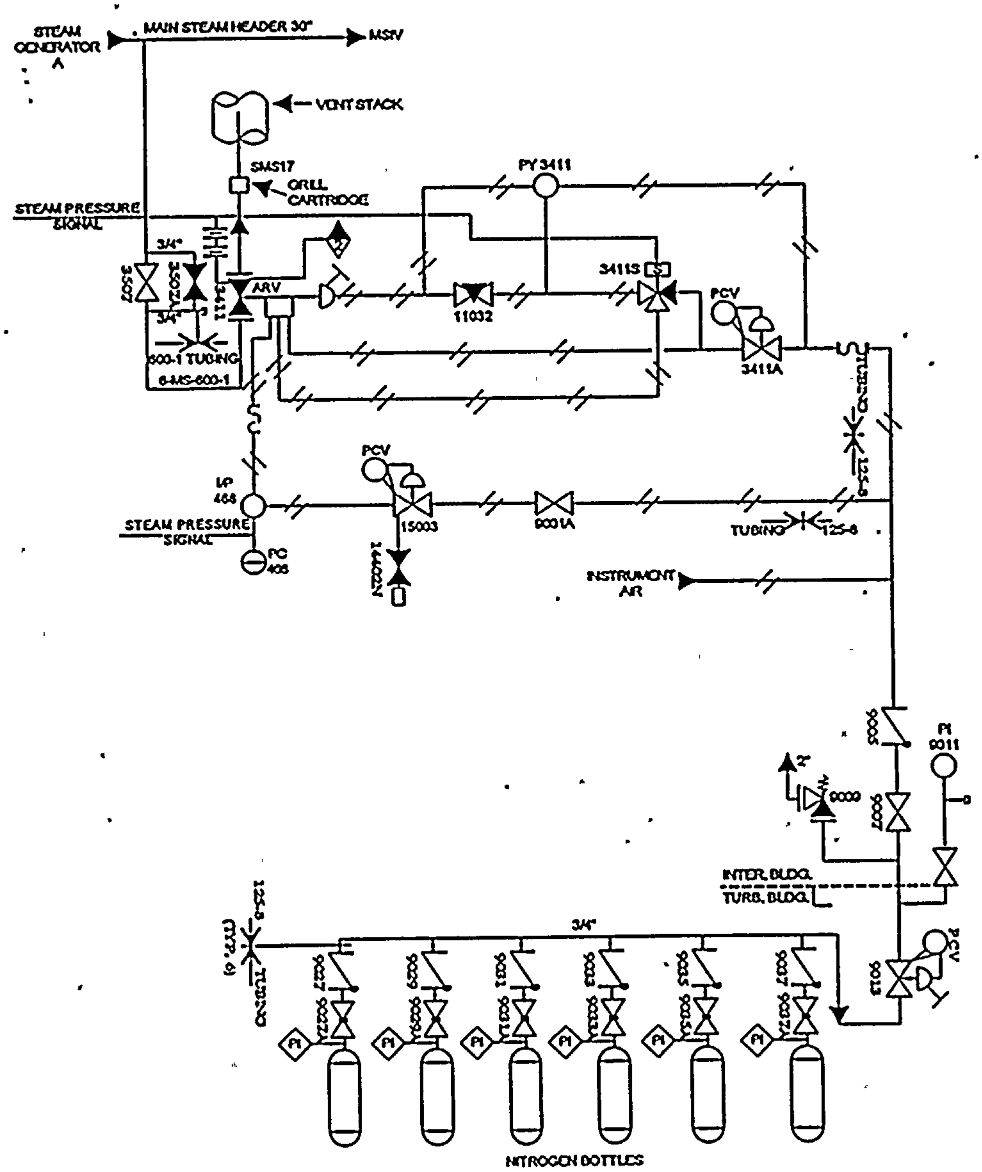


Figure 6-13.2
ARV 3410

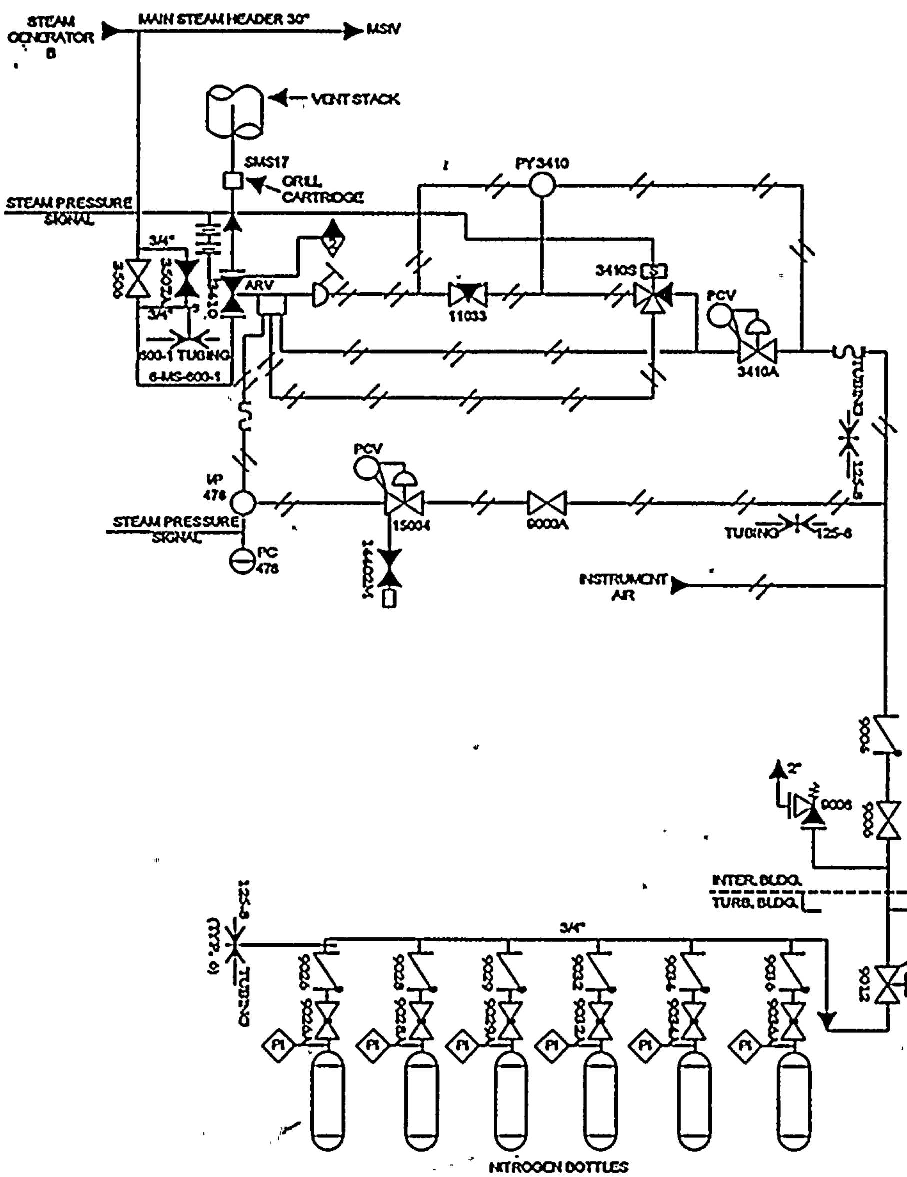


Figure 6-13.3
Main Steam System

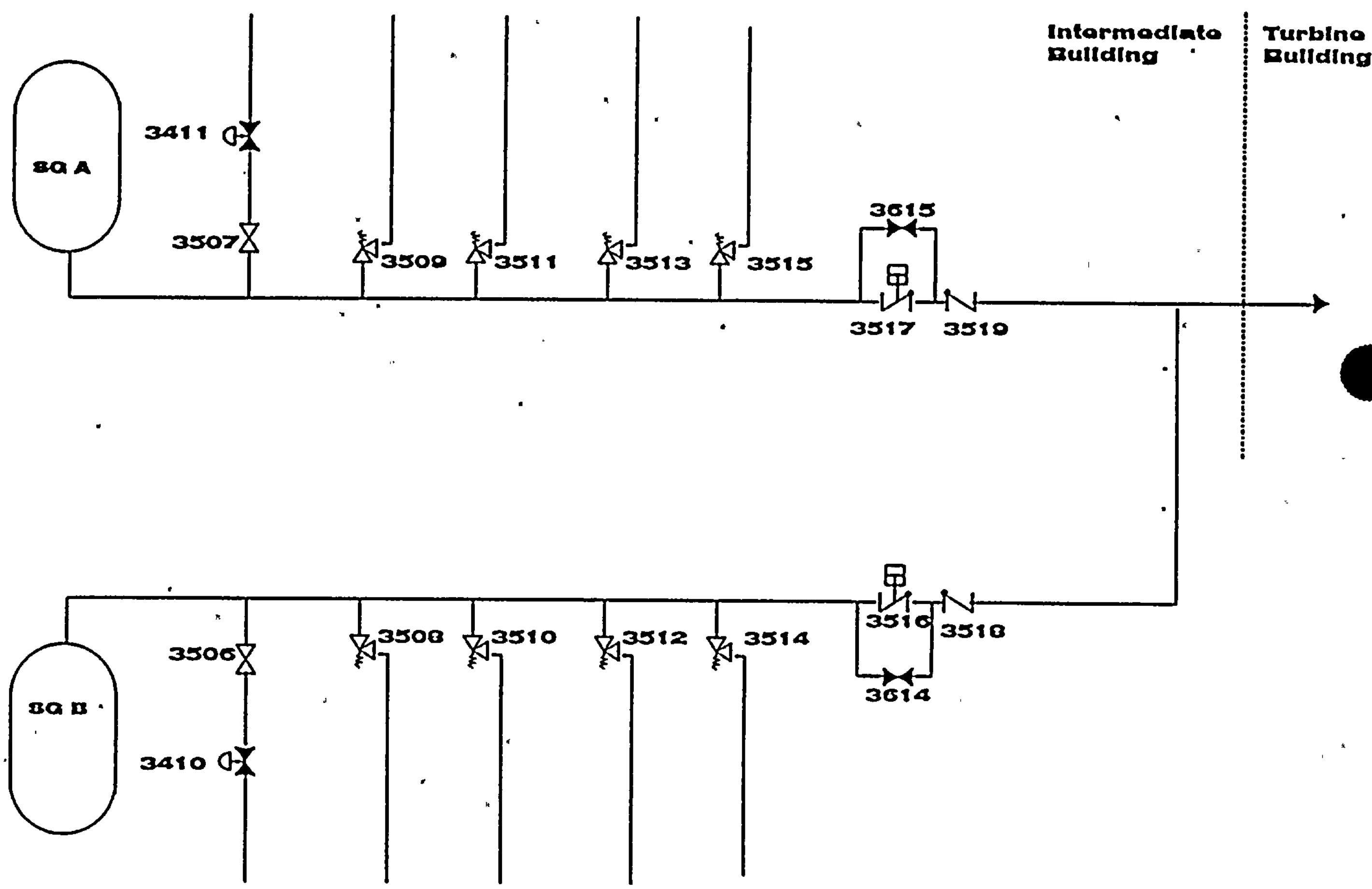


Figure 6-14
MFW System

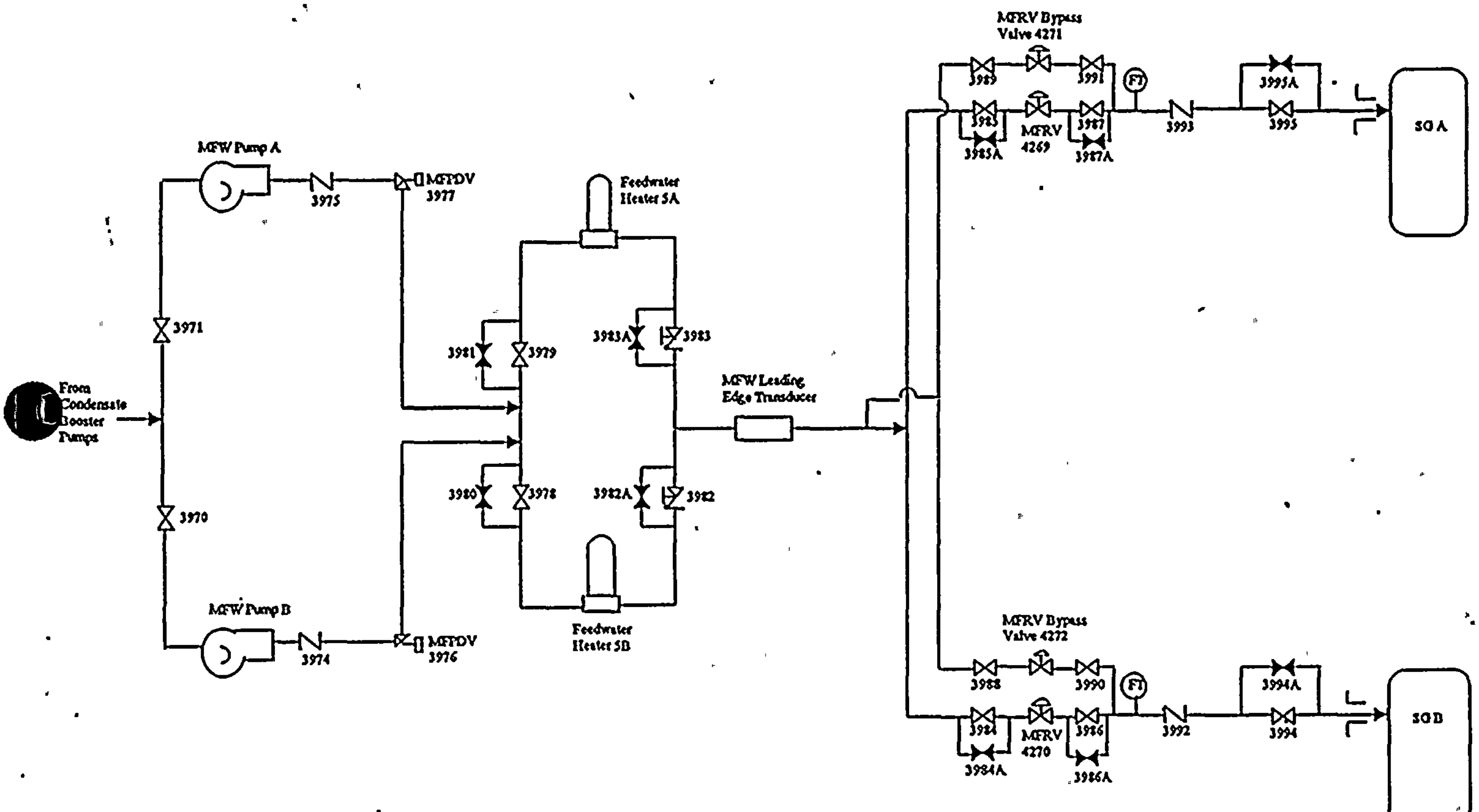


Figure 6-15.1
Pressurizer PORVs and Safety Valves

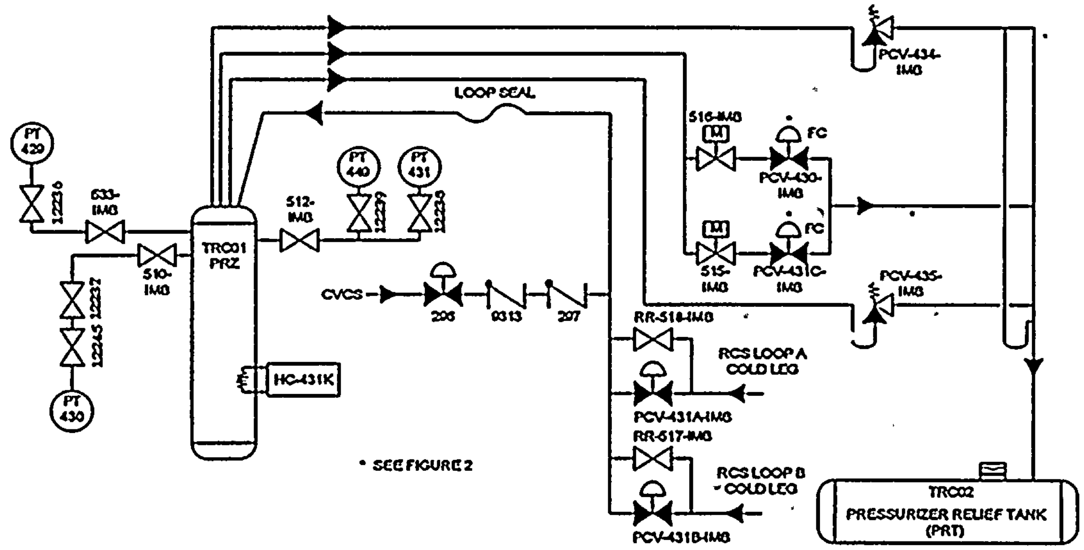


Figure 6-15.2
LTOP System

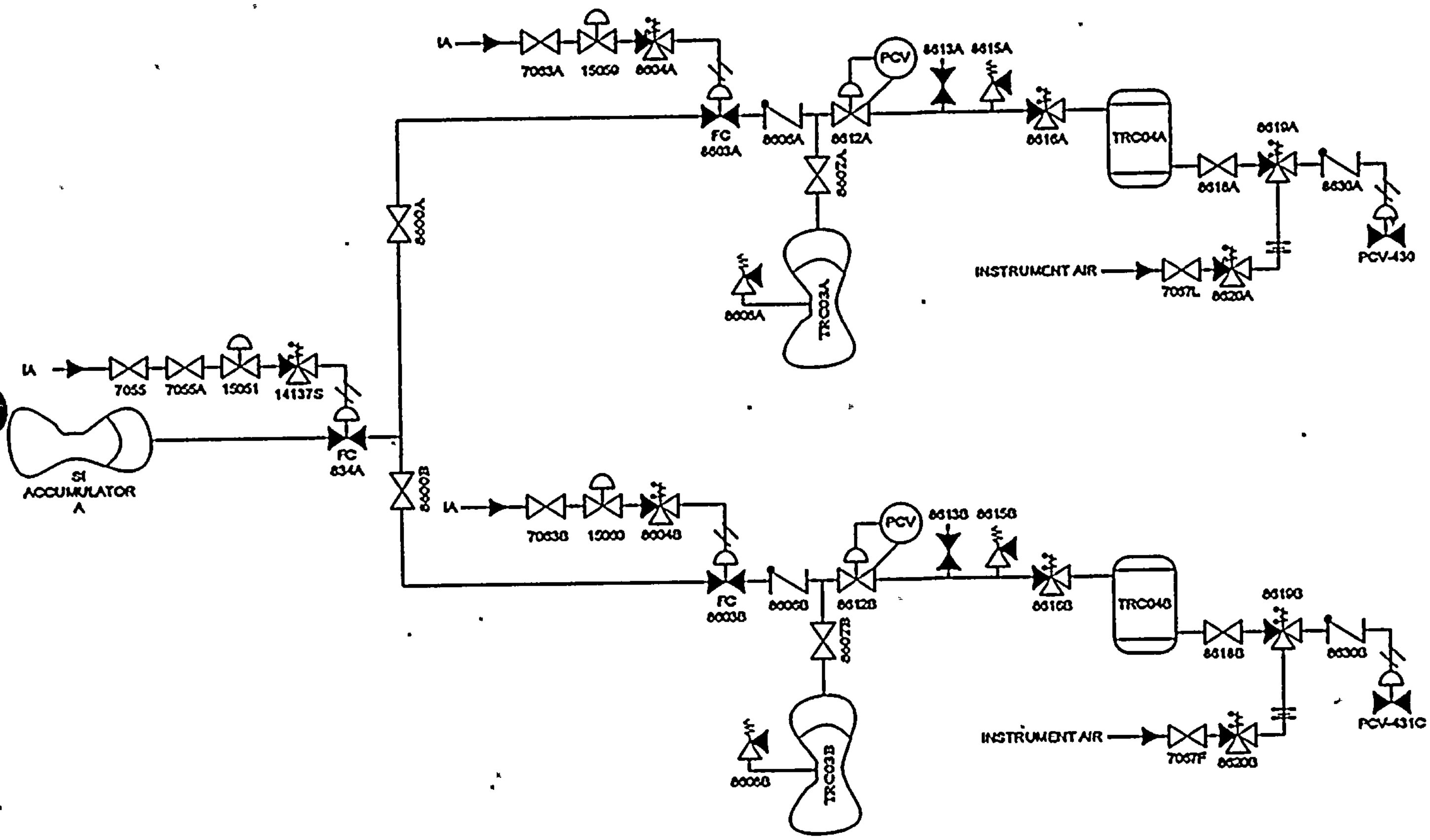


Figure 6-15.3
RCS

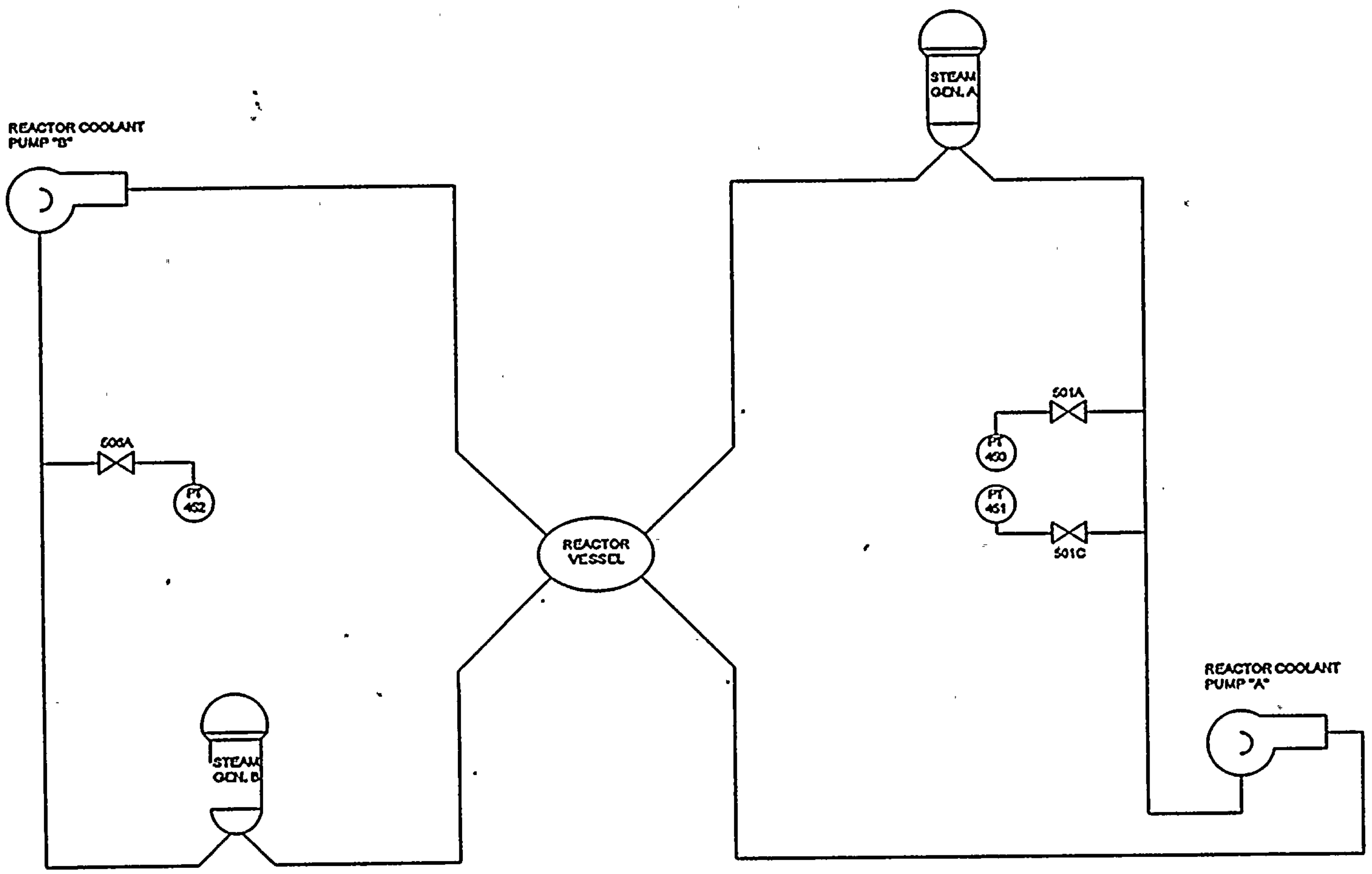


Figure 6-16
RHR System

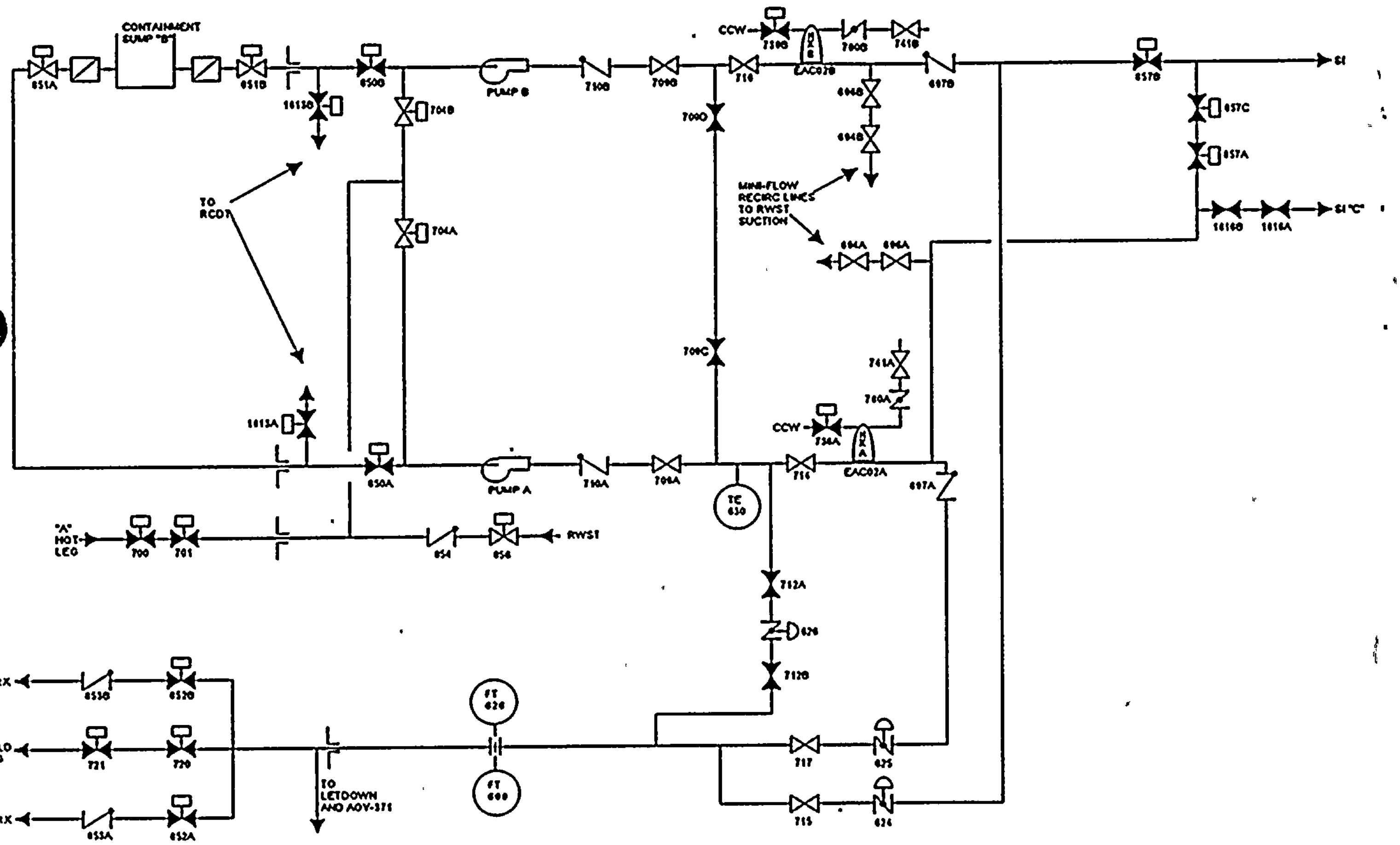


Figure 6-17
SI System

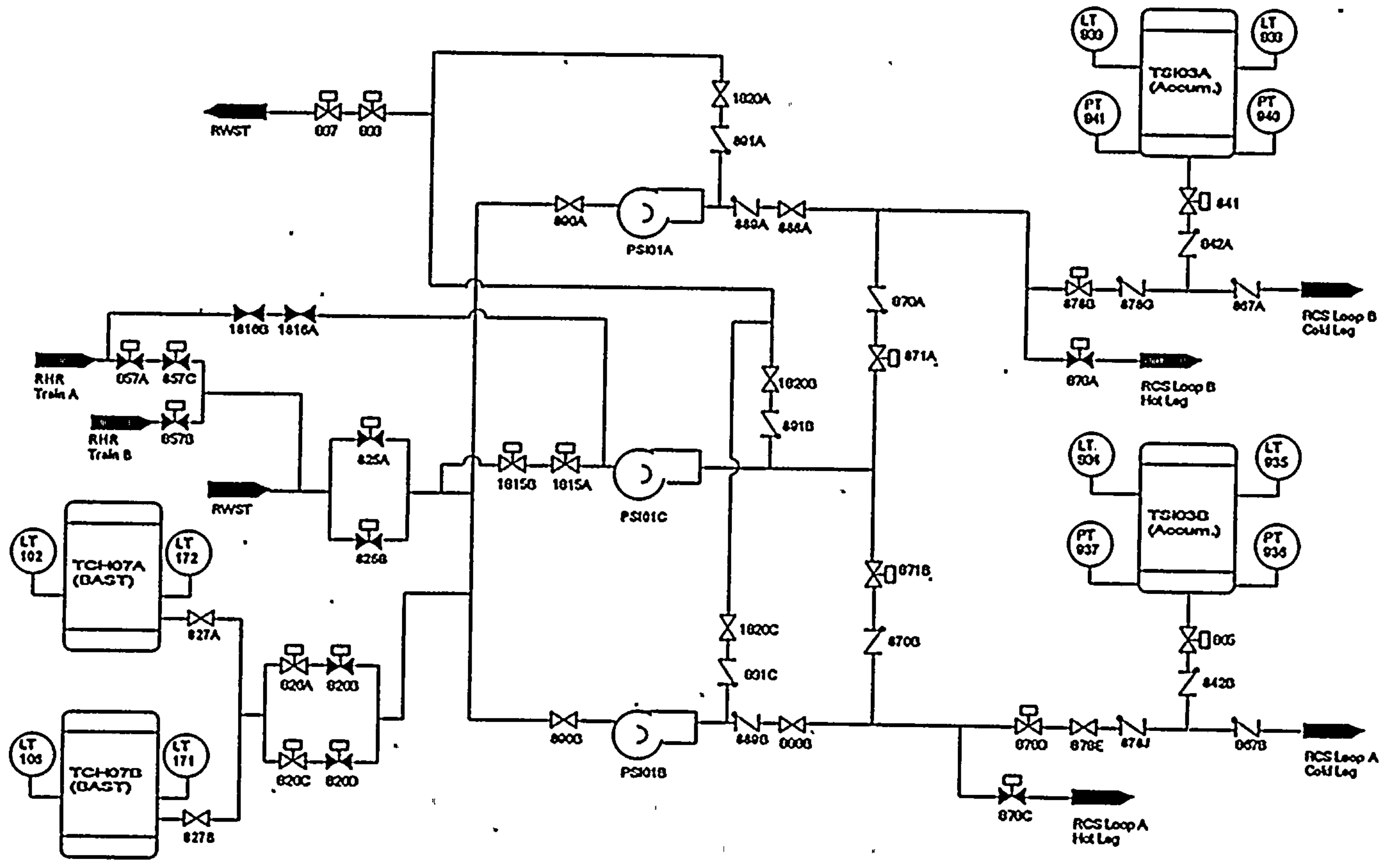


Figure 6-18.1
SW System

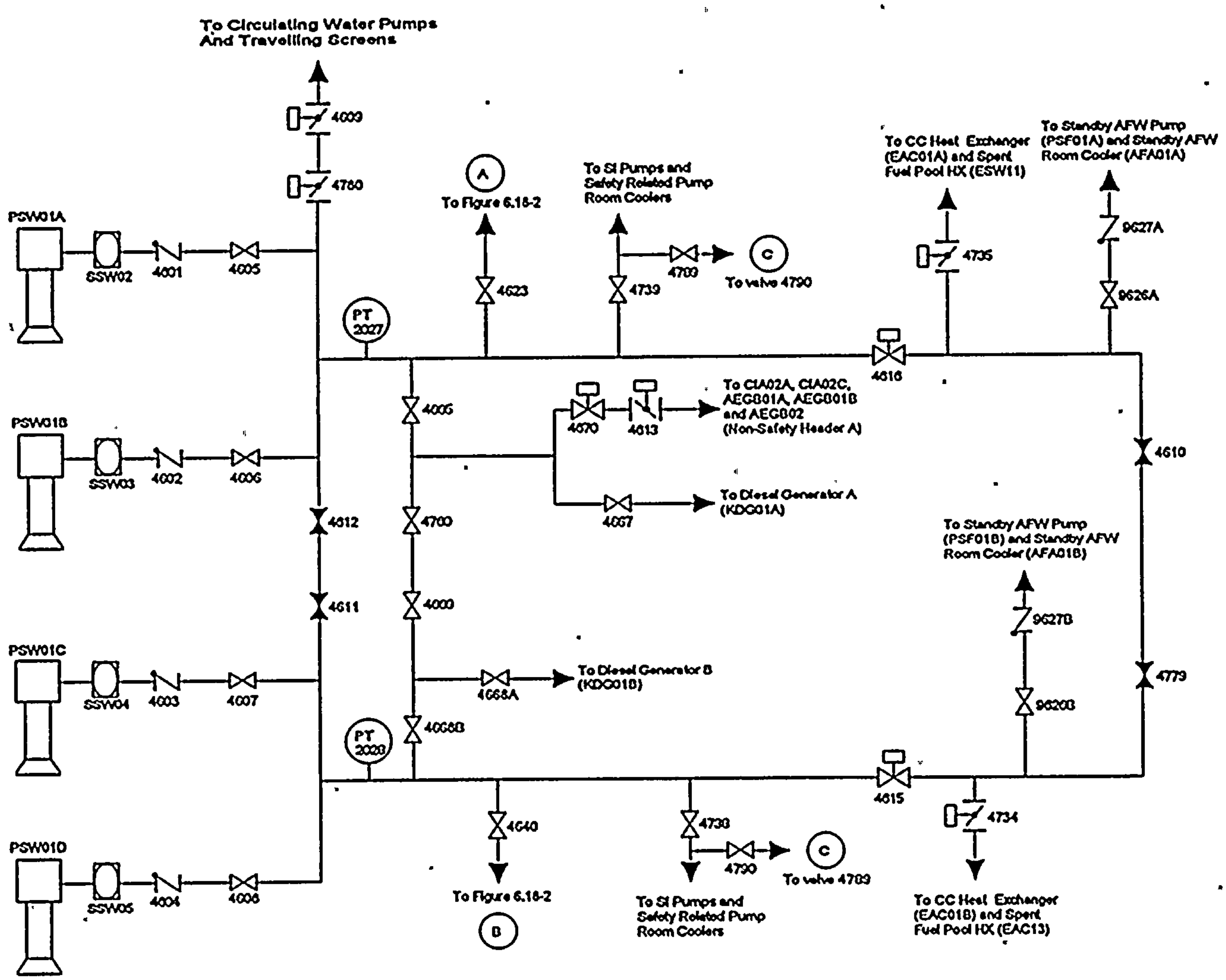
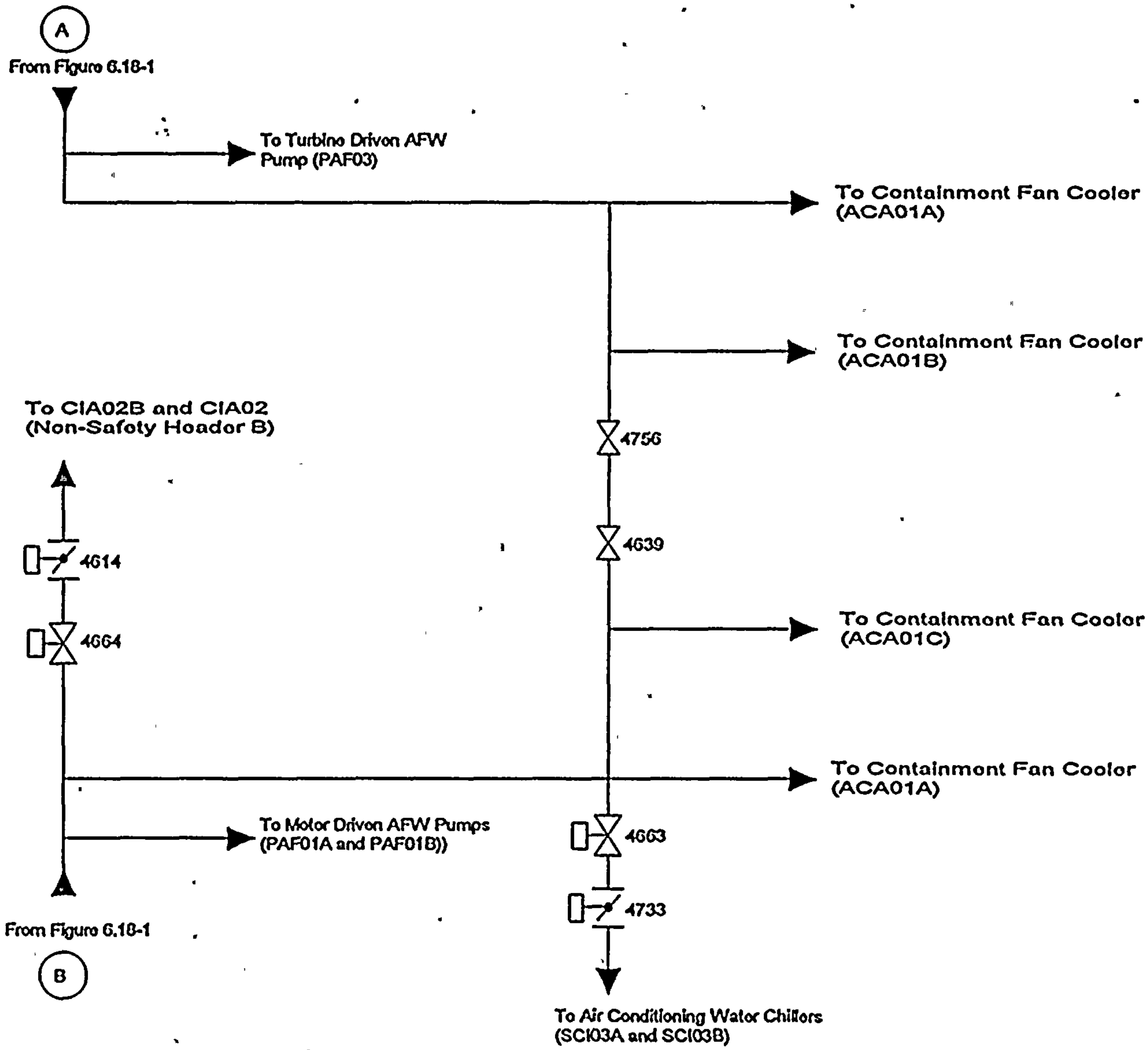


Figure 6-18.2
SW System



7.0 DATA ANALYSIS

7.1 Introduction

Following completion of the event trees and fault tree models, data must be generated for each event in order to quantify. This includes data for hardware-related items (i.e., components), initiating event frequencies, and human error events. Essentially, component and human failure data supports the event trees and fault trees while the initiating event frequencies support the event tree models. This section of the report documents how the data was generated and the final results for each of the three data types.

7.2 Component Failure Data

As discussed in Section 6, the components which are modeled in the Ginna Station PSA range from small items such as fuses and breakers to large equipment such as pumps and their motors. These components can fail due to: (1) random causes, (2) related or common cause failures (CCFs), or (3) being unavailable due to test and maintenance activities. The sources used for this data may be "generic" (i.e., based on industry information or other accepted standards), Ginna-specific, or a combination of both. Each of the three component data requirements is discussed below along with relevant generic and Ginna-specific data sources.

It should be noted that the data analysis task is not necessarily the end result of the system analysis task; rather it is an iterative process which both precedes and follows the system analysis task. This is due to the fact that data must exist or be capable of being generated for each modelled event. In addition, the level of detail for each event must be consistent across the models. For example, if one system analyst models a pump and motor separately while a second system analyst models them as one event, data must be generated for both models separately. It is easier and more consistent to set a common boundary for each modeled component in order to standardize the data needs which was done for the Ginna Station PSA [Ref. 28]. Also, a typical set of failure modes was generated to support the system analysis task (e.g., pump fails to run, pump fails to start).

However, the use of common component boundaries and failure modes does not address all the data needs since system analysts may model component failures on a failure per demand basis or failure per time basis. In addition, the system analysts may identify a unique component or system configuration which they need to model. As such, the data analysis task must also follow the system analysis task to ensure that the appropriate data exists for all modeled events.

7.2.1 Random Component Failures

As discussed above, the fault tree models are generated using previously identified component boundaries and a typical set of failure modes as a starting point. Following completion of the models, data is required for all events in order to quantify. The term "random" failure refers to those component failures which are independent (i.e., cannot be directly related to multiple component failures due to a common root cause such as two pumps failing within hours of each other due to incorrectly installed seals). The final listing of random failure events for which data was generated is provided in Table 7-1. The data which was generated included use of both generic and Ginna-specific sources. Each of these sources, along with the final failure data used, is discussed in detail below.

7.2.1.1 Generic Failure Data

The term generic data refers to component failure estimates based on: (1) the failure experience of nuclear utilities or other process industries, and (2) expert opinion. Generic data was used in the Ginna Station PSA for several reasons:

a. Plant operating experience was limited in several instances due to newly installed components; generic data must be used when credible plant-specific data does not exist.

b. It was not be possible or cost effective to collect plant-specific data on certain components of interest (e.g., relays whose demand history is difficult to ascertain with much precision).

c. The plant-specific data was limited such that generic data formed the basis for the prior distribution in a Bayesian updating process (see Section 7.2.1.3).

For the Ginna Station PSA, generic data was supplied by Science Applications International Corporation (SAIC) in the form of a Generic Data Work Package [Ref. 37]. The work package was generated specifically for commercial nuclear power plant PSA projects and is based on the collected experience and expertise of SAIC PSA engineers. The work package was generated using the method described below. Appendix C provides additional details.

7.2.1.1.1 Scope Determination

The fault tree and top logic basic events defined in previous SAIC conducted PSAs were tabulated and sorted to determine the scope of the generic data base. Similar basic events (i.e., same component type and failure mode) were grouped together. No effort was made to segregate component types based on application or engineering characteristics as existing generic data sources do not provide sufficient detail to warrant such delineation. For example, all motor-driven pumps were placed into the same group regardless of their parent systems, flow capacities, etc. In some cases, failure modes were collapsed or broadened as necessary to match existing generic sources. For example, the events "air-operated valve fails to open on demand" and "air-operated valve fails to close on demand" were combined into the event "air-operated valve fails to operate."

7.2.1.1.2 Source Identification

A list of generic data sources was developed by: (1) surveying the open literature, and (2) reviewing previous PSAs and nuclear reliability studies. An effort was made to identify at least three sources for each component type and failure mode.

7.2.1.1.3 Source Classification

Each generic data source was classified in order to establish its relevance and usefulness. The following attributes were identified for each source:

a. Data sources with the most appropriate origin for commercial nuclear power plant PSAs are based on information relevant to commercial nuclear power plants; use of generic data based on the more general experience of non-commercial nuclear reactors or other process industries is less desirable.

b. Data sources with broad scopes (i.e., which are based on a large population of components) are more desirable than narrow scopes.

c. The term *data source quality* is a measure of the source's credibility. High quality data sources are based on observed equipment failures as documented by plant maintenance records; sources using failures documented by LERs are of lower quality as not all equipment failures initiate a LER. The use of computerized maintenance summaries results in a lower quality source (as compared to a source based on original maintenance records stored as hardcopy, microfilm, etc.) since summaries are, by definition, abbreviated accounts of the failure event and resulting repair activity.

7.2.1.1.4 Source Selection

Multiple generic data sources were identified for most component types and failure modes. The following criteria were used to select the best sources:

a. The component type and failure mode in the generic data source had to closely match the component type and failure mode specified in the list of fault tree basic events. The most difficult issue was the matching of failure modes. In many cases, the failure modes given in generic data sources are too general to provide a good match. For example, a generic data source may list a value for "catastrophic failure" while a fault tree requires "spurious actuation." In these cases, sources with more general failure modes were discarded unless they were the only source available.

b. The estimate contained in a generic data source had to be based on unique information. For example, the IREP and ASEP data sets are mainly based on the WASH-1400 data set; hence, they were only used if the particular component type or failure mode was not addressed in WASH-1400.

c. The generic data source had to be widely available (i.e., not proprietary). This requirement ensures traceability and scrutibility.

d. Mid-level and low quality sources were only used if high quality sources were not available.

e. Sources developed by a Bayesian updating process were not used. Such sources are quasi-generic since they emphasize a particular plant's experience (i.e., the likelihood information) while de-emphasizing the broader generic information (i.e., the prior distribution).

f. Generic data sources based on equipment operating in the same environment as equipment in commercial nuclear power plants were preferred to other sources. It should be noted that the term "environment" refers not only to the physical environment of a component (i.e., ambient temperature, humidity, vibration, etc.) but also to operating conditions (e.g., continuous operation, alternating service, standby service, etc.), maintenance policy (e.g., "do not repair unless it has failed" as opposed to "investigate/repair at the first sign of trouble"), and testing policy (e.g., test frequency, adequacy of the test to detect failure modes of concern, etc.).

g. If only one or two sources were located for a particular component type and failure mode, then those sources with broad scopes (i.e., based on the combined experience of many plants) were preferred to those based on a single plant. This requirement prevented data skew due to the atypical behavior of a single plant.

7.2.1.1.5 Source Aggregation

Following the selection process, three or more generic data sources were identified for about 50% of all component types and failure modes. Two sources were identified for about 25% of the total. These sources were aggregated into a composite estimate using a technique which preserved the tolerance of the individual data sources. The aggregation technique is discussed in [Ref. 37]. The generic data value for each event in the Ginna Station PSA is provided in Table 7-1.

7.2.1.2 Plant-Specific Data

The primary purpose of the plant-specific data collection effort was to assess point values and corresponding uncertainties for the events necessary to quantify accident sequences. A secondary purpose of the data analysis effort was to provide insight into the operational and maintenance history of Ginna Station so that a more accurate representation of the plant's risk profile could be generated. Details of the plant-specific data collection effort are provided below along with a summary of the results. Additional results are provided in Appendix C.

7.2.1.2.1 Analysis Scope

Plant-specific data was collected over the time period from January 1, 1980 to December 31, 1988. This time period was selected as the data collection window for the Ginna Station PSA since it was generally well documented and contained the most representative evidence of Ginna Station history that could be expected to depict future performance. The data collection window starting point of January 1, 1980 was chosen on the basis that it was the earliest time period for which reliability data could be obtained following the Three Mile Island (TMI) accident in March, 1979. The TMI event had large ramifications throughout the nuclear industry, especially in the areas of maintenance and operations which could directly impact the results of the data analysis effort. The end date was selected since it was the last available year in which all work-related activities were expected to be closed out and filed in Ginna Station Central Records before the initiation of the data collection effort. In addition, a nine year period of plant history was expected to yield a large enough population of component exposures and failure events so as to provide statistically useful data.

The component population for which data was collected against and their boundaries were consistent with those used in the Data Analysis task described above [Ref. 28]. In general, the scope of the data collected exceeds the needs of the integrated PSA plant logic model in that data was collected for components and/or failure modes which do not appear in the integrated model. This section only addresses those items that are needed to support the integrated model. The additional data collected was not analyzed; however, the "raw" data is provided in Appendix C for future issues.

7.2.1.2.2 Component Population

Since the data collection activities were initiated prior to development of the system fault tree models, the initial component population was made sufficiently large enough to ensure that all potential fault tree components were included. The following plant systems were included in the data collection effort:

a. Reactor Coolant System (RCS)
b. Engineered Safety Features Actuation System (ESFAS)
c. Residual Heat Removal (RHR) System
d. Diesel Generators (DGs)
e. Chemical and Volume Control System (CVCS)
f. Safety Injection (SI) System
g. Main Feedwater (MFW) System
h. Electrical Distribution - DC
i. Auxiliary Feedwater (AFW) System
j. Electrical Distribution - AC
k. Main Steam (MS) System
l. Containment Isolation System
m. Service Water (SW) System
n. Containment Spray (CS) System
o. Standby Auxiliary Feedwater (SAFW) System
p. Condensate System
q. Circulating Water System
r. HVAC Systems
s. Component Cooling Water (CCW) System
t. Instrument and Service Air Systems
u. Steam Generators (SGs)
v. Turbine / Generator System
w. Fire Protection System
x. Reactor Trip System
y. Control Rod Drive System

Since the above systems contain many different types of equipment, it was decided to limit the components to be included in the data collection effort. Consequently, plant-specific data was only collected for the following types of components:

a. Pumps
b. Valves
c. Breakers (for pumps, diesels, air compressors, large fans, and bus feeders)
d. Dampers (air and motor-operated)
e. Diesel generators

f. Batteries
g. Battery chargers
h. Inverters
i. Safety-related buses (including MCCs)
j. Air compressors
k. Air dryers
l. Fans
m. Heat exchangers
n. Service Water strainers
o. Heat tracing

The boundaries for the above components are provided in Reference 29.

7.2.1.2.3 Component Reliability Parameters Collected

After the component population and boundaries were determined, the following plant-specific information was collected:

a. Number of component failures (demand and time-related),
b. Number of component demands, and
c. Time which the component was in operation/standby.

The approach used to collect this information is described in more detail below.

Plant-Specific Component Failures - Following a review of the available record types at Ginna Station, it was determined that there was no single source of required information. Consequently, *Ginna Station Event Reports* (Forms A-25.1), *Control of Limiting Conditions for Operating Equipment Reports* (Forms A-52.4), *Maintenance Work Requests* (MWRs), and *I&C/Electrical (Safety-Related) Equipment Failure Reports* (Forms A-25.2) were selected as the best sources of information. These records and forms were collected for the years 1980 through 1988 (Note - not all forms were available for entire nine years). During collection of this data, an initial screening was made to eliminate obvious non-failure and non-maintenance events from consideration. Data pertaining to all events that survived the initial screening were then organized by system and necessary information was placed onto screening tables. This included the date and description of the event, components affected, and the data source. Since there were multiple sources of information, the use of screening tables provided a single listing of failure and maintenance events and enabled the identification and elimination of duplicate records.

The screening tables were then reviewed by knowledgeable engineering personnel in order to identify and classify those events that involved component functional failures. Every attempt was made to accurately categorize the failure or maintenance action; consequently, discussions were frequently held with Ginna Station personnel who were familiar with the event in question. Additional information was added as necessary to the screening tables to better understand the circumstances surrounding the event. In addition, due to various configuration management programs and modifications, component tag numbers and identifiers have gone through several iterations over the years. Consequently, Ginna Station personnel also assisted in identification of components as listed on the plant record.

It should be noted that a review was also made of all Ginna Station Nonconformance Reports (NCRs) issued between 1980 and 1981. Since this review failed to identify any additional functional failure events not already accounted for in the system screening tables, no further analysis of the NCRs was performed. In addition, Licensee Event Reports (LERs) issued for Ginna Station between 1980 and 1988 were also reviewed to ensure that all failure and maintenance events were identified.

<u>Calculation Of Component Demands</u> - The types of plant-specific component demands considered in the data collection task included: (1) test demands, (2) normal operational start attempts, (3) reactor trip response demands, (4) preventive maintenance demands, (5) post-maintenance test demands, and (6) interface-related demands. Demands were calculated on a component (versus component type or system) basis since it was considered desirable to understand how component demands affected reliability. The following sections briefly summarize the methods used to determine the number of demands for each of the above categories.

a. *Test Demands* - All Ginna Station periodic test (PT) and refueling shutdown surveillance (RSSP) procedures were reviewed to identify the number of individual component demands per test. A review was then made of all PTs and RSSPs contained in Central Records in order to determine the number of complete and partial tests performed between 1980 and 1988. The number of times each test was performed was then multiplied by the number of times each component was demanded during the test, in order to obtain the total sum of component demands due to testing. This information was then reviewed with Results and Test personnel to ensure that the demands appeared appropriate since plant procedures may have been revised over the data time window.

b. *Normal Operational Start Attempts* - The number of normal start attempts was determined using the two methods described below.

1. *Pumps, diesels, compressors and fans.* The total number of test and operational demands was obtained from a review of the Ginna Station Official Record Log (control room log book). The number of test demands determined above was then subtracted from this value in order to obtain the number of operational start attempts. This approach was used due to the fact that the log books frequently did not state whether the demand was test or start related. In addition, due to these uncertainties, all operational start attempt numbers were reviewed and adjusted, if necessary, by the R-shift for Operations, and/or other appropriate personnel.

2. *All other components.* Since the Official Record Log typically only identifies large pieces of equipment (i.e., pumps, diesels, compressors and fans), a different approach was used for smaller components such as valves. Assuming normal system operational configurations, all components were identified that would be demanded given normal operation of these larger, rotating pieces of equipment for which start demands were known. The total number of operational demands for each of these components was then calculated based on the number of operational start attempts determined from above. Though an estimate, this approach was considered appropriate due to the limited information available for these smaller types of equipment.

c. *Reactor Trip Response Demands* - After reviewing Ginna Station procedures E-0 and ES-0.1, it was determined that following a normal reactor trip, the majority of plant components are affected by being turned off (e.g., main feedwater pumps). This is of no consequence for counting demands until the equipment is turned back on. However, starting a pump is usually listed in the Official Record Logs, and therefore, already accounted for. The component demands which were most likely not listed in the logs are as follows:

1. AOV 4269 (MFW) - 1 demand for every cold shutdown (approx. 25 events)
2. AOV 4270 (MFW) - 1 demand for every cold shutdown (approx. 25 events)
3. AOV 4271 (MFW) - 1 demand for every cold shutdown (approx. 25 events)
4. AOV 4272 (MFW) - 1 demand for every cold shutdown (approx. 25 events)
5. AOV 427 (CVCS) - 1 demand every other trip (23 trips/2)
6. AOV 431A (RCS) - 1 demand every other trip (23 trips/2)
7. AOV 431B (RCS) - 1 demand every other trip (23 trips/2)

These demands were considered conservative and assume a "typical" reactor trip.

d. *Preventive Maintenance Demands* - It was assumed that each component would be demanded after preventive maintenance was performed on it to ensure its operability. To calculate the number of demands, Ginna maintenance procedures were reviewed to determine the preventive maintenance (PM) frequency for each component included in the data analysis population. These frequencies were then used to calculate the number of PMs performed on each component over the nine-year data period. For conservatism, each calculated number was rounded off to the lowest integer.

e. *Post-Maintenance Test Demands* - The system screening tables discussed above were reviewed in order to identify all failure and maintenance events for each component. One demand was assumed if the component was removed from service for maintenance at power or if a functional failure occurred. This is considered appropriate since in many cases a component can be demanded several times to ensure its operability. The only event for which this is non-conservative relates to failure events for which there was no maintenance. However, the total number of failure/no maintenance events is relatively small. In addition, if the component actually failed, it would most likely be tested in an attempt to duplicate the failure even if no maintenance was performed. Also, only non-preventative maintenance demands were included since these demands were previously accounted for.

f. *Interface-Related Demands* - Interface-related demands, as discussed here, refer to demands placed on a component to isolate another component for maintenance. For every failure and maintenance event at power, P&IDs were reviewed to determine if the component in question required isolation. The isolating components were then assigned one interface-related demand for each failure or maintenance event that occurred against the specified component while the reactor was critical. Events which occurred during shutdown were not included in the interfacing demand counts since in most cases isolation would not be required.

g. *Component Time in Operation and Standby* - The time in operation for pumps, diesels, compressors and fans (i.e., rotating equipment) was determined by summing the running hour totals for each component as recorded in the Ginna Station Auxiliary Operator Running Hour Log and the Control Room Running Hour Log. These two documents contain a record of the run time for rotating machinery on a shift basis and are totaled monthly and annually. For rotating equipment that was not tracked in the running hour logs, the time in operation was determined (i.e., estimated) based on discussions with plant operations personnel or other cognizant RG&E representatives. For small, non-rotating equipment (e.g., valves), the time in operation was determined based on an approach similar to that discussed above. That is, these smaller components were matched with a piece of rotating machinery for which operating time was known. Every attempt was made to accurately reflect the different test and operational system configurations to better represent component exposure times. The time in standby for all components was determined by subtracting the time in operation from nine (9) years calendar time.

7.2.1.2.4 Plant-Specific Failure Data Base

The plant-specific data which was compiled (i.e., number of component failures, demands and time in operation/standby) was entered into an electronic data base. The data as entered was also reviewed by an independent checker to ensure accuracy. This data base was required since the data was provided on a component level while the data analysis task required it on a system and component type basis. Therefore, a data base was used to determine the total number of failures and total associated exposure for component types (e.g., motor-operated valves, etc.) and failure modes (e.g., "fails to open") on a system basis. Note that the data base also provides summarized maintenance unavailability data (total out-of-service hours and total on-line hours). The total on-line time is assumed to be equal to the total number of reactor critical hours during the data window (64,054.35) multiplied by the size of the associated component population. Appendix C provides summary listings of the data base. Table 7-1 identifies if plant-specific data was collected for a given component type.

7.2.1.3 Final Reliability Parameters

In general, reliability parameters based on Ginna-specific experience are preferred for final integrated logic model quantification. For certain component types and/or failure modes, few (or no) occurrences have been observed at Ginna Station. Consequently, strict use of plant-specific data is questionable (or, in the case of no occurrences, impossible). In these cases, a Bayesian analysis was performed to combine the Ginna-specific experience with appropriate generic data. The Bayesian process has been implemented through the concept of conjugate prior distributions (i.e., gamma distributions for failure rates, and beta distributions for failure-on-demand probabilities) as shown in Appendix C. In general, where one or less plant-specific failures were observed, a Bayesian analysis was performed. If there were two or more failures, only plant-specific data was used.

A summary report of all final reliability parameters (sorted by system, component type, and failure mode) is provided in Appendix C. This report provides the plant-specific estimates, the relevant generic data, the results of any Bayesian analysis performed, and the final values. Note that the value contained in the row labeled *Final* and the column labeled *P1* is the final log-normal error factor for use in uncertainty analyses. The following sections discuss the calculated final results.

7.2.1.3.1 Plant-Specific Data Insights

Plant-specific data is used in the determination of the failure rate or probability for approximately 70% of the failure modes in the integrated PSA logic model. The only failure modes which do not use Ginna-specific data are those related to small electrical devices such as relays and transmitters, and rare events (e.g., sump plugging). A comparison of the Ginna-specific and generic data points was performed with the following results:

a. Almost 25% of the calculated plant-specific values are within a factor of three (3) of the generic value;
b. 8% of the calculated plant-specific values are greater than a factor three (3) higher than generic data;
c. 7% of the calculated plant-specific values are greater than a factor three (3) lower than generic data; and
e. The remaining 60% of the plant-specific data contained no observed failures over the nine year data window.

The "factor of three" criterion was chosen since any smaller difference could most likely be attributed to uncertainty in the data. In addition, it should be noted that during the plant-specific data collection effort, failures were assigned to "questionable" events. That is, if the analyst was unable to positively conclude that no failure had actually occurred (i.e., incipient versus catastrophic), a failure was conservatively assigned. These data points were only reviewed in more detail if the resulting plant-specific value was significantly higher than generic data (i.e., greater than a factor of three). At the conclusion of this final review, the following plant-specific failure modes were found to have a higher value than generic data (i.e., greater than a factor of three):

a. CS pumps (failure to run)
b. HVAC fans (failure to start)
c. SI pumps (failure to run)
d. AC electrical buses (all operating voltages except 120 VAC)
e. BAST level transmitters (fails high and fails to respond)
f. CVCS piping (plugs)
g. CVCS relief valves (transfer open)
h. IA dryer (failure to deliver flow)
i. IA receiver (local faults)
j. IA piping (rupture)
k. Main Steam Isolation Valves (MSIVs) (failure to close)
l. Atmospheric Relief Valves (ARVs) (failure to open)

The observed plant-specific history for these components is described in detail below.

CS Pumps - There was only one failure of a CS Pump (1B) to run which occurred on May 31, 1988. This failure was the result of the back-up packing gland and shaft sleeve for the pump making contact which resulted in excessive heat and galling and eventual seizing of the pump. However, since there was only 67 hours of run time associated with the containment spray pumps over the nine year data window, the plant-specific failure rate was calculated to be 1.49E-02/hour (versus a generic value of 8.45E-05/hour). Since there were no other failures to run and no failures to start, it appears that the high plant-specific failure to run value is attributed to the limited exposure (i.e., run time) of the pumps and does not necessarily indicate a problem with the pumps. There have not been any other failures related to these pumps. As such, Bayesian analysis was used due to the limited data set.

HVAC Fans - A total of seven failure to start events related to motor-driven fans was found in the plant-specific data collection effort which resulted in a failure probability of 6.91E-04 (versus a generic value of 2.08E-04). A similar ratio of plant-specific versus generic data was also calculated for a standby fan fails to start. Failures were observed against Battery Room Exhaust Fan 1A, the Reactor Compartment Cooler Fans, SI Pump Cooler Fan C, and SAFW Cooler Fan B. Consequently, no single component or group of components is causing the higher than generic values. However, three of the failure to start events were attributed to breakers being found in the open versus closed position. The breakers for these components are now maintained locked closed. The remaining failures were due to motor failures, bad DC coils, and switch faults.

SI Pumps - There was only one failure of a SI pump to run found in the plant-specific data. This event occurred on March 3, 1981 when a review of the results from an earlier test of SI Pump C indicated that the thrust bearing for the pump approached the procedural limit of 160°F after just 45 minutes of run time. The problem was subsequently found to be excessive sediment in the pump cooling lines and was assumed to result in a pump failure over an extended period of time. This single failure resulted in plant-specific failure rate of 3.80E-03/hour as compared to a generic value of 8.45E-05. The data was Bayesian updated to a final value of 4.66E-04/hour. Since the exposure for the SI pumps is only 263 hours, and this is the only run failure, the high plant-specific failure to run value is most likely caused by the limited exposure (i.e., run time) of the pumps.

AC Electrical Buses - There were two failures of a 480V bus found in the plant-specific data. The first failure occurred on April 17-18, 1982 when Bus 16 tripped on undervoltage several times. After investigation, the DC fuse disconnect switch for the bus was found loose and retightened. However, only one failure was assigned for this event since the bus trips after the initial fault occurred during troubleshooting. The second failure occurred on February 10, 1988 when the contactor assembly for Bus 14 failed causing the bus to spuriously trip on undervoltage when no such condition existed. Since there were only two failures in the plant-specific data, Bayesian updating was used. Consequently, the final mean value was calculated to be 7.84E-07/hour which is slightly higher than the generic value of 1.19E-07/hour.

BAST Level Transmitters - There were numerous failures of the BAST level transmitters to either respond or failing high. These failures appear to be the result of the design of the transmitter sensing lines in that boron tends to crystallize near the end of the lines inside the tank. Attempts to heat trace these lines have not proven successful in resolving the problem. However, the safety function of the BAST is not required except for emergency boration issues. In addition, the lines are currently on an aggressive PM schedule (once a week). This practice was implemented at the end of the data collection period; consequently, the plant-specific data which was collected may not be truly representative of the transmitter's current reliability.

CVCS Piping - There were four observed instances of CVCS piping being plugged over the nine year period, the majority of which are related to the blender and boric acid tank system. The first event occurred on January 7, 1984 when operators attempted to borate the RCS, but a suspected steam bubble in the system prevented flow through MOV 354. Flow was then accomplished by using MOV 350; however, a subsequent investigation could find no definite cause. The second and third events occurred on February 20, 1985 and October 27, 1988 when the piping downstream of FCV 110A was found blocked preventing a flush of the blender. This portion of the piping contains two 90° elbows in a short run with a support that was acting as a heat sink for the heat tracing. The boron was subsequently flushed after adjusting the heat tracing near the support. The final plugging event occurred on December 8, 1988 when the flow through MOV 350 was found blocked during performance of RSSP-5.0. A heat gun was applied to the line and the block was quickly flushed. These events resulted in a plant-specific failure rate of 6.24E-05/hour versus a generic value of 5.53E-07/hour. Since the BAST boron concentrations have been reduced since the data collection effort, the generic value was used.

CVCS Relief Valves - There were numerous failures associated with the discharge relief valves to the Volume Control Tank for Charging Pumps PCH01B and PCH01C. These valves experienced a total of thirteen excessive leakage events (i.e., transfers open) which were evenly distributed over the nine year data period. The valves were either replaced or rebuilt following each failure. No cause for this problem could be found in the data records. These failures are important with respect to diversion of flow from the charging pumps. Discussions with Results and Tests indicate that the problem appears to have been resolved since they have not had any recent relief valve failures. However, the calculated plant-specific failure rate is 2.72E-05/hour versus a generic value of 1.69E-06/hour.

IA Dryer - Ten failures of the IA dryers were found in the plant-specific data which resulted in a failure rate of 6.34E-05/hour versus a generic value of 5.23E-07. The majority of these failures were caused by leaking or otherwise failed solenoid valves. These failures were evenly distributed throughout the data period and among the air dryers. Since there are two air dryers per IA header for a total of four dryers, the relatively high frequency of solenoid failures is probably not important. It should also be noted that there were no concurrent (or common cause) failures of air dryers observed in the plant-specific data.

IA Receiver - There was only one failure of an IA receiver which occurred on June 16, 1985 when relief valve 5321 for receiver TIA04A stuck open causing high temperature alarms on IA Compressor A. This single failure resulted in a plant-specific failure rate of 4.61E-06/hour as compared to a generic value of 6.00E-07/hour. Consequently, it appears that the high plant-specific value is attributed to the limited exposure of the receivers and does not necessarily indicate a problem with the receivers themselves.

IA Piping - There were four failures of IA piping observed over the nine year data period. Three of these failures were attributed to personnel stepping on or bumping the IA lines. The remaining event occurred on October 20, 1984 when the 1/2 inch IA line to the "2B" MSR steam admission valve ruptured. The affected line was subsequently isolated by an Auxiliary Operator who was in the area. These four pipe breaks were all quickly isolated and had limited impact on the IA system and the plant. However, the number of events produced a plant-specific failure rate of 5.07E-05/hour as compared to 5.53E-07/hour for generic data.

MSIVs - There were two failures of MSIV 3516 to close at power over the data window. The first occurred on June 9, 1983 and was the result of a failed switch in the ESFAS cabinets. The second occurred on February 7, 1987 when the valve failed to close during shutdown; however, no cause was provided. These two events resulted in a Ginna-specific failure probability of 8.81E-03 as compared to a generic value of 2.17E-03.

ARVs - There was only one failure of an ARV to open which occurred on February 16, 1987 when ARV 3410 failed due to a steam cut on the seat. This resulted in a standby failure probability of 6.34E-06/hour as compared to a generic value of 5.88E-07/hour. Since there was only one failure and a total of 83 demands calculated for the ARVs, the high plant-specific value appears to be caused by the limited exposure of the valves and does not necessarily indicate a problem. Therefore, Bayesian updating was performed.

In addition to the events having "high" failure rates, the following components demonstrated a higher reliability than generic data (i.e., greater than a factor of three):

a. Circuit breakers (fails to operate);
b. AFW motor-driven pumps (fails to start);
c. AFW motor-operated valves (fails to close);
d. CCW pump (fails to run);
e. DG (fails to start);
f. Air-operated dampers (transfers closed);
g. Air-oeprated dampers (fails to open);
h. Air compressor (fails to start);
i. Air compressor (fails to run); and
j. SW check valves (fails to close).

7.2.1.3.2 IPE Requirements

NUREG-1335 requires the assessment of plant-specific data for major equipment affecting core-damage sequence results, including AFW and ECCS pumps, batteries, feed pumps, electrical buses, breakers, and DGs. Each of these component types has been included within the scope of the Ginna-specific data effort, and Ginna-specific reliability parameters for them have been provided. Figures 7-1 through 7-7 compare the Ginna-specific experience to relevant generic data for these items.

7.2.2 Common Cause Failures

CCFs are a subset of dependent failures (i.e., those failures which defeat the redundancy or diversity that is employed to improve the availability of plant safety functions). CCFs, similar to other dependent failures, have been addressed in the Ginna Station PSA by incorporating appropriate common cause basic events in the integrated plant logic model. The technique used for generating the data for the common cause basic events is provided below.

7.2.2.1 General Technical Approach

The beta factor method has been used to model CCFs in the Ginna Station PSA. Common cause basic events have been directly incorporated into the fault tree models, and represent the failure of all components within a defined group (termed the common cause group) by a specified failure mode (e.g., all SI pumps fail to start on demand) due to all relevant common causes. It should be noted that:

a. Components within a common cause group have similar attributes and failure mechanisms, and are functionally redundant with respect to each other;

b. Only the failure to perform a specific function is modeled (e.g., valve fails to open is modeled while valve spuriously opening is not modeled due to low probability) except for ESFAS related transmitters and relays spuriously generating signals;

c. In general, only the common cause failure of large active components are modeled (e.g., pumps, valves) and not smaller or passive devices such as fuses due to lack of data and low probability of occurrence; and

d. The specific origins of common cause failure (e.g., shock, high temperature, manufacturing defects, etc.) are not specifically defined.

The probabilities of common cause basic events are determined by:

$$Pr\{CCF\} = Pr\{single\ \ component\ \ fails\} \cdot \beta \qquad (1)$$

where β, termed the beta factor, denotes the probability that all components within the common cause group fail given the failure of any single component within the group.

The beta factor method has been widely used in previous nuclear power plant PSAs. Estimates for beta factors can be made from examination of plant-specific experience; generic estimates for major equipment types have also been published.

7.2.2.2 Generic CCF Data

Generic estimates for beta factors, obtained through a literature search, are listed in Table 7-2. For components and/or failure modes not expressly listed in Table 7-2 (i.e., generic data was unavailable) a beta factor of 0.1 was used. This is considered appropriate since if industry CCF programs have not identified a beta factor for the subject component, it has most likely not exhibited a high failure rate due to common cause. When performing the quantitative uncertainty analysis, these values should be taken as the mean value of a log-normal distribution with an error factor of 3.0 [Ref. 38]

7.2.2.3 Plant-Specific CCF Data

The plant-specific data developed for the Ginna Station PSA was examined for indications of CCFs and sixteen events were identified (see Appendix D). In assessing the usefulness of this information in the estimation of CCF beta factors for use in the Ginna Station PSA, several observations are relevant:

a. The data window for the Ginna Station PSA covers nine calendar years, from January 1, 1980 until December 31, 1988. Since CCF events are less likely than independent failures, it is not surprising that only a few events were identified.

b. The plant-specific data analysis scope does not address all components modeled in the PSA which are susceptible to common cause failure; however, the data scope also included additional components not included in the PRA.

Accordingly, it was decided to use the generic data as discussed above.

7.2.2.4 Results

Final common cause beta factors used in the Ginna Station PSA are listed in Table 7-3. The Multiple Greek Letter CCF methodology was conservatively not used as a single common cause event was added to the fault trees for each group listed in the table. Also, CCFs among all five AFW and SAFW pumps was not postulated since:

a. The two sets of pumps are of difference manufacturers (Worthington vs. Ingersol) and were installed at Ginna Station approximately 10 years apart;

b. The AFW pumps normally operate during plant shutdown and startup while SAFW is only used in the test mode (i.e., the pumps have very different operating characteristics);

c. The pumps are located in different buildings with diverse operating conditions (i.e., the AFW pumps are located in the basement of the Intermediate Building below main steam and MFW piping while the SAFW pumps are located in their own "bunkered" building); and

d. The maintenance and testing procedures are different between the two systems.

However, since the three AFW pumps (i.e., two motor-driven and one turbine-driven pumps) share a common manufacturer and operating environment, a common cause event was included to address their common failure potential.

7.2.3 Test and Maintenance Unavailabilities

Test and maintenance events are added to the fault tree models to account for the fact that certain components may be disabled due to maintenance (either preventative or corrective) or testing while the plant is in operation and, therefore, unavailable to perform their safety-related function in the event of an accident. Since technical specification allowed outage times, fuel cycles, and maintenance practices can vary significantly between plants, test and maintenance events are very plant-specific (i.e., generic data really is not relevant unless plant-specific data is unavailable). The approach used for generating data for these events is provided below.

7.2.3.1 General Technical Approach

The data collected in support of the generating Ginna-specific component reliability parameters constitutes the major input to this task (see Section 7.2.1.2). The data which was collected was placed in an electronic data base for ease of use and contains summarized maintenance unavailability data (total out-of-service hours and total on-line hours) for component types within each system. Testing unavailabilities were generated in a separate document on a procedure (or train) basis. Each of these items is discussed in more detail below.

7.2.3.1.1 Maintenance Unavailability Data

There were two types of maintenance activities considered in the data collection and analysis task: corrective and preventative. Corrective maintenance refers to the repair of a component after it has failed or exhibited degraded performance while preventative maintenance (PM) is related to planned activities which are performed to maintain equipment reliability. In a perfect world, the performance of preventative maintenance would eliminate the need for most, if not all, corrective maintenance. However, this approach can also have its downfall since a component that is removed from service too frequently for PM activities can have a higher unavailability than if it was only removed from service due to corrective maintenance. Consequently, both types of maintenance must be optimized, and as such, are important contributors to the PSA results. In addition, only maintenance events performed at power were included in the data collection task since the system fault tree models reflect full power conditions.

The assessment of corrective maintenance was performed in parallel with the determination of component reliability parameters as discussed the Section 7.2.1.2. That is, various plant records were collected for the years 1980 through 1988. These records included *Ginna Station Event Reports* (Forms A-25.1), *Control of Limiting Conditions for Operating Equipment Reports* (Forms A-52.4), *Maintenance Work Requests* (MWRs), *Licensee Event Reports* (LERs), and *I&C/Electrical (Safety-Related) Equipment Failure Reports* (Forms A-25.2). During collection of this data, an initial screening was made to eliminate obvious non-failure and non-maintenance events from consideration. Data pertaining to all events that survived the initial screening was then organized by system and necessary information was placed onto screening tables. This included the date and description of the event, components affected, and the data source. Since there were multiple sources of information, the use of screening tables provided a single listing of maintenance and failure events and enabled the identification and elimination of duplicate records.

The screening tables were then reviewed by knowledgeable engineering personnel in order to identify those events that involved corrective maintenance while the reactor was critical. For equipment covered by LCOs, maintenance out-of-service times were obtained from a review of A-52.4 forms for the years 1982 through 1988 (the years in which they were available). The A-52.4 forms provide the exact times at which Operations was informed that the component was both removed from service and returned to service. For events involving equipment covered by LCOs for the years 1980 and 1981, and for events involving equipment not covered by LCOs, maintenance out-of-service times were obtained from a review of the hold records in Ginna Control Records. If an out-of-service time was not available for an event, an estimate of the duration was made based on other similar events or through consultation with knowledgeable RG&E personnel (e.g., Results and Tests). Approximately 15 percent of maintenance out-of-service times were estimated using this technique.

The approach used for determining unavailabilities due to preventative maintenance activities was slightly different. First, maintenance procedures were reviewed to determine the frequency of PM activities. It should be noted that these frequencies have changed over the years based on reliability centered maintenance program recommendations and changes to operational practices (e.g., limiting the number of voluntarily entered LCOs at power). Consequently, the number of PM activities performed while the reactor is critical for the systems included in the data analysis is small. Since Ginna Station operated on a 12 month refueling cycle for the data window, most PM activities were performed during refueling outages; therefore, only a few systems (e.g., Service Water) had PM activities performed on them at power. For these few systems, the out-of-service time due to PM was taken either from A-52.4 forms or estimated based on information provided by Results and Tests personnel.

The out-of-service times were added to the electronic data base to provide sorting capability. The following equation was used to calculate average *component-level* maintenance unavailabilities based on the information contained in the database:

$$\bar{a}_M = \frac{T_R}{T_{OL}} \tag{2}$$

where:

T_R = total repair (out-of-service) hours during plant on-line operation for a specified component type within a given system

T_{OL} = total on-line hours during the data window for the specified component type and system.

The application of Equation (2) to the summarized maintenance unavailability data contained in the electronic data base is provided in Appendix E.

7.2.3.1.2 Testing Unavailability Data

Testing related unavailability data was generated based on the total number of complete and partial periodic tests (PTs) performed at power during the years 1980 through 1988, and the mean duration for these tests. After a review of Ginna Station procedures, it was determined that PTs were the only type of test that was performed consistently while the reactor was critical. Other types of testing, such as Special Tests or refueling shutdown surveillances (RSSPs), were not considered for determining testing unavailability. The number of complete and partial PTs performed at power was obtained through a review of all the PTs contained on microfilm in Ginna Station Central Records. The mean duration for these tests was then estimated through a review of the Ginna Station Official Record, A-52.4 forms, and discussions with RG&E Results and Tests personnel.

The following equation was used to calculate average equipment-train-level testing unavailabilities:

$$\bar{a}_T = f_T \cdot \tau_T \tag{3}$$

where:

f_T = test frequency / per year
τ_T = test duration

This information is summarized in Appendix E.

7.2.3.1.3 Test / Maintenance Event Probability Estimation

The probability of a test and maintenance event can be conservatively bounded by summing the contributions from component-level maintenance unavailabilities and equipment-train-level testing unavailabilities:

$$\bar{a}_{T/M\ event} = \sum_i \bar{a}_M^{(i)} + \sum_j \bar{a}_T^{(j)} \tag{4}$$

In order to apply Equation (4), it was necessary to define the event boundaries in terms of the separate EINs whose unavailabilities (either maintenance-related or test-related) cause the occurrence of the basic event. Test and maintenance were identified through review of relevant P&IDs, system-level fault tree work packages, and other information provided by the system analysts, and are documented in Appendix E.

7.2.3.2 Final Results

Estimates of test and maintenance event mean probabilities based on plant-specific data are given in Table 7-4. Since the estimates do not, in general, contain unavailability due to elective on-line maintenance activities, the data values used to quantify the fault trees and accident sequences were revised to use the performance criteria developed in support of RG&E's implementation of the Maintenance Rule (10 CFR 50.65). The new values essentially are based on the allowed LCO provided by technical specifications and allow equipment unavailabilities up to a maximum of 28 total days per operating cycle. The revised test and maintenance event mean probabilities are also provided in Table 7-4.

7.3 Initiating Event Frequencies

The second category of events for which data must be collected are initiating events. An initiator is an event or sequence of events (e.g., equipment failures, operators errors, etc.) which either directly causes a reactor trip or requires an immediate reactor trip in order to prevent core damage. In the integrated plant logic model (the combination of event trees, top logic fault trees, and system-level fault trees), initiators are represented by basic events. However, initiators differ from other modeled basic events in that their value is represented by a frequency in reactor years versus a probability. The calculation of each initiator frequency is described below.

7.3.1 General Technical Approach

Estimation of initiator frequencies began with a review of reactor trip history from January 1, 1980 through December 31, 1995. Various plant operational records and Licensee Event Reports (LERs) were included within this review (see Table 3-3). Table 7-5 lists the individual reactor trips by occurrence date and time during the data window, and shows their classification according to the PSA project initiators (see Table 3-4).

The results provided in Table 7-5 show that all reactor trips which occurred during this time frame (except for the 1982 Steam Generator Tube Rupture event) were classified as TIRXTRIP, or a reactor trip, for the purposes of the Ginna Station PSA. In addition, seven of the twenty-one events (33%) that were classified as TIRXTRIP were attributed to either maintenance or calibration errors while six of the events (29%) were attributed to faulty instrumentation actuations. These events are distributed evenly throughout the data analysis window prior to 1993 after which the trip frequency significantly decreases.

A total of seventeen reactor trips were not classified for the purposes of the Ginna Station PSA Project. These trips occurred during startup or controlled shutdown activities and were typically due to feedwater control problems. Prior to the installation of the Advanced Digital Feedwater Control System (ADFCS) in 1991, feedwater was manually controlled by operators until approximately 15% reactor power was reached, at which time the system was placed in automatic operation. The new ADFCS automatically controls feedwater flow over all ranges of operation. Since the installation of ADFCS, the feedwater control problems have ceased to occur. Consequently, low-power reactor trips caused by manual feedwater control problems or problems in transitioning to/from manual control were ignored.

The estimation of initiator frequencies was a combination of generic and plant-specific experience (incorporated using Bayesian analysis). The determination of these frequencies is described in the following sections.

7.3.1.1 TIRXTRIP - Reactor Trip

The frequency of initiator TIRXTRIP has been estimated using Bayesian methods which uses a prior distribution (i.e., industry data) supplemented with Ginna-specific data. The prior distribution is based on industry-wide data collected by INEL [Ref. 39] which is an update of earlier work performed by EPRI (see Table 3-3). Table 7-6 lists relevant statistical data from the INEL report.

The prior distribution is assumed to be a gamma distribution with mean and variance equal to the pooled INEL data. The gamma distribution is a two-parameter distribution (parameters α and β); the parameters are related to the distribution's mean and variance as follows:

$$\begin{aligned} \text{mean} &= \frac{\alpha}{\beta} \\ \text{variance} &= \frac{\alpha}{\beta^2} \end{aligned} \tag{5}$$

Table 7-6 shows the estimated parameter values, which have been calculated using Equation (5). Assuming that reactor trip events (n events in T years or 21 events in 12.99 reactor years) follow a Poisson process, then the Bayesian posterior distribution is also a gamma distribution with parameters:

$$\begin{aligned} \alpha' &= \alpha + n \\ \beta' &= \beta + T \end{aligned} \tag{6}$$

Thus, $\alpha' = 3.49 + 21 = 24.49$, and $\beta' = 0.42 + 12.99 = 13.41$. Using Equation (5), the posterior mean and variance are, respectively, 1.82 and 0.136.

7.3.1.2 Loss of Offsite Power

The offsite power scheme for Ginna Station consists of two independent sources of offsite power: (1) Circuit 767 (fed from Transformer 6 in the Ginna switchyard using a "breaker-and-a-half" scheme) which feeds Station Auxiliary Transformer (SAT) 12A, and (2) Circuit 751 (fed from Station 204) which feeds SAT 12B (see Figure 3-1). Each SAT can feed 4160 V buses 12A and 12B which in turn supply the 480 V safeguard buses (Buses 14, 16, 17, and 18). As such, the station can be in the following configurations:

a. *50/50 Mode (Normal)* - SAT 12A supplies Buses 14 and 18 and SAT 12B supplies Buses 16 and 17;

b. *50/50 Mode (Alternate)* - SAT 12A supplies Buses 16 and 17 and SAT 12B supplies Buses 14 and 18;

c. *0/100 Mode* - SAT 12A supplies all four safeguards buses; or

d. *100/0 Mode* - SAT 12B supplies all four safeguards buses.

The typical alignment is 50/50 Mode #1; however, the plant is expected to go to the 100/0 mode in the near-term following completion of a voltage regulator modification. Based on the discussion presented in Sections 3.4.2.2 and 3.4.2.3, three initiators have been defined to address losses of offsite power (LOSP) for Ginna Station:

a. TIGRLOSP - this is defined as a complete loss of all alternating current electrical power from all offsite sources caused by a failure of the RG&E transmission network as described below:

   1. Transmission network up to, but not including, the breaker connecting RG&E Station 204 to SAT 12A; and

   2. Transmission network up to, but not including, Station 13A (the Ginna Station switchyard).

b. TISWLOSP - this is defined as a loss of all alternating current electrical power in the Ginna Station switchyard exclusive of those failures addressed by TIGRLOSP. This event includes failures in the Ginna Station switchyard which cause an electrical load rejection and failure of Circuit 767 (including Transformer 6).

c. TI48LOSP - this is defined as a loss of all alternating current electrical power to the 480 V safeguards buses (exclusive of those failures addressed by TIGRLOSP) combined with the subsequent failure of both DGs. This event leads to a manual reactor trip.

In addition to the initiators, there are three additional post-trip events related to loss of offsite power:

a. ACLOPRTALL - this is defined as a loss of all offsite power following reactor trip. The event is analogous to TIGRLOSP, but may happen following the occurrence of any initiating event.

b. ACLOPRT751 - this is defined as a loss of offsite power from Circuit 751 following a reactor trip.

c. ACLOPRT767 - this is defined as a loss of offsite power from Circuit 767 following a reactor trip. This event is analogous to TISWLOSP, but may happen following the occurrence of any initiating event.

The above events were added to the models since Ginna Station often supplies a significant portion of the transmission system's VARs; consequently, following a reactor trip, the sudden loss of generation from Ginna Station may challenge the transmission grid stability. This event is also considered within the accident analysis.

Ginna Station has not experienced a loss of offsite power as defined by any of three initiating events, including both on-line and shutdown periods, in the 16 year data window (i.e., 1980 through 1995). The loss of offsite power event on April 18, 1981 (Table 3-3, LER 81-07) was only a precursor to TI48LOSP in that the power source to the 480 V safeguards buses was lost; however, both DGs started such that there was no reactor trip. It should also be noted that in 1981, Ginna Station only had one offsite power source such that it essentially operated in the 100/0 configuration.

As such, generic data has been used to generate the initiator frequencies while the post reactor trip LOSP event probabilities were generated based on work performed by electrical engineering. The generic data for the LOSP frequencies was taken from an EPRI data base [Ref. 40] which contains all loss of offsite power events which have occurred at U.S. nuclear power plants between 1980 and 1995. These events are classified into four categories as follows:

a. *Category I* - No offsite power available and the plant trips offline or is already offline. This is further broken down into two categories based on time (i.e., either ≥ 30 minutes or < 30 minutes).

b. *Category II* - Loss of startup (or shutdown or reserve) offsite power but if the plant was on-line, the main generator remained connected to the normal offsite power system and the plant received power from the unit auxiliary transformer or its equivalent.

c. *Category III* - Loss of normal offsite power (and loss of feed through the unit auxiliary transformer) but backup offsite power is available via a startup, shutdown, or reserve source by either automatic or manual switching from the control room.

d. *Category IV* - No offsite power available during cold shutdown due to special maintenance conditions that do not occur during or immediately following operation.

Based on the above definitions, Category I events are equivalent to TIGRLOSP, Category II events are the initial input to TI48LOSP events, and Category III events are equivalent to TISWLOSP events. It should be noted that the allocation of initiators to EPRI categories is conservative since the Ginna Station offsite power scheme is different than most other plants in that the safeguards buses are not supplied from the unit transformer. Instead, they are supplied by either a separate offsite power source or by an independent offsite source powered from the switchyard. Due to the unique offsite power configuration at Ginna Station, this event will be developed from the plant-specific data contained in Table 3-3 instead of using the Category II events. Category IV events do not apply to at power PSAs and are, therefore, excluded.

The EPRI data base covers 1517.7 calendar years of nuclear power plant experience. Converting this to reactor years was accomplished by assuming an average of 75% reactor criticality over the 16 year data window. This results in 1138.28 reactor years of experience.

The EPRI data lists the following number of events for each of the relevant categories:

a. *Cateogry I* - 55
b. *Category II* - 9
c. *Category III* - 44

Included within the above totals are several weather related events that are not relevant to the location of Ginna Station (e.g., salt spray, hurricanes). Also, the data base double counts events which occur at multi-unit sites even though they are due to the same reason and cause which is not applicable to Ginna Station. Finally, several events classified as Category I by EPRI are not really grid LOSP events consistent with the Ginna Station offsite power scheme and should be re-classified. As such, the final number of events is as follows:

a. *Cateogry I* - 55 - 7 (weather) - 4 (double counting) - 8 (N/A to Ginna Station) - 10 (actually Category II and III events) = 26
b. *Category II* - 9 - 2 (double counting) + 3 (transfers from Cat I) = 10
c. *Category III* - 44 - 3 (weather) - 3 (double counting) + 7 (transfers from Cat I) - 2 (N/A to Ginna Station) = 46

Using the above number events and the previously calculated reactor years yields the following frequencies:

a. *f (TIGRLOSP)* = 26 events / 1138.28 reactor years = 2.28E-02/yr
b. *f (TISWLOSP)* = 30 events / 1138.28 reactor years = 4.04E-02/yr

Consequently, the combined loss of offsite power frequency (i.e., TIGRLOSP + TISWLOSP) is 6.32E-02 per reactor year. Since Ginna Station has not had a loss of offsite power event in the 16 year data window, this value is considered appropriate. It is noted that the Ginna Station SBO evaluation per NUMARC 87-00 calculated a severe weather induced LOSP frequency of 1.24E-02/yr [Ref. 41] which is less than the total value calculated for the PSA. Since the data is based on generic information, the above frequencies apply whether the station is in the 50/50, 100/0, or 0/100 mode.

Event TI48LOSP was calculated using plant-specific information from Table 3-3. As can be seen from this table, there were 4 failures of Circuit 751 over an 8 year window and 2 failures of Circuit 767 over a 16 year window (however, 1 of these latter events is no longer applicable due to a design change). Applying this to the four possible offsite power configurations yields:

a. 0/100 Mode = f_{751} = 4 events / 8 years = 0.5/ryr

b. 100/0 Mode = f_{767} = 1 event / 16 years = 6.25E-02/ryr

c. 50/50 Mode (Either) = (f_{751} * P_{767} (1 hr)) + (f_{767} * P_{751} (1 hr)) = 8.78E-06/ryr

The EPRI database cannot be used to estimate the probability that offsite power is lost following a reactor trip since the necessary information is not always provided. RG&E electrical engineering has estimated a failure probability of 1.0E-02 that a trip of Ginna Station directly results in a loss of offsite power given that a SI signal occurs due to the rapid loading of large pump motors onto the 480 V buses. Therefore, for conditions without a SI signal (i.e., no sequencing occurs), a value of 1.00E-03 was used (i.e., a factor of 10 reduction). In addition to occurring as a result of a reactor trip, offsite power may be lost during the typical 24 hour mission time following the accident. As such, the post-trip LOSP probabilities were generated as follows:

a. ACLOPRTALL = 1E-02 (SI event) + {[24 hrs * *f(TIGRLOSP)*] / [8760 hours * 81% critical]} =
   1.00E-02 (for SI events)
   1.00E-03 (for non-SI events)

b. ACLOPRT751 = 1E-02 (SI event) + {[24 hrs * f_{751} * 8760 hours * 81% critical]} =

   1.19E-02 (for SI events)
   2.69E-03 (for non-SI events)

c. ACLOPRT767 = 1E-02 (SI event) + {[24 hrs * f_{767} * 8760 hours * 81% critical]} =

1.00E-02 (for SI events)
1.21E-03 (for non-SI events)

The probability of restoring offsite power is described in Appendix B.

7.3.1.3 TIFWLOSS - Loss of Main Feedwater

The frequency of initiator TIFWLOSS was estimated in the same manner as initiator TIRXTRIP. Table 7-7 lists the information relevant to development of the prior distribution. It should be noted that only the complete or unrecoverable loss of MFW is being considered within this initiator since recoverable losses of MFW are included within initiator TIRXTRIP. As such, using equation (6), $\alpha' = 0.098 + 0 = 0.209$, and $\beta' = 0.67 + 12.99 = 13.66$. Using Equation (5), the posterior mean and variance are, respectively, 1.53E-03 and 1.12E-03.

It is noted that an advanced digital feedwater control system (ADFCS) was installed at Ginna Station during the 1991 refueling outage in response to the large number of reactor trips which have occurred during low power operations. These low-power trips were ignored for the purposes of the data analysis task since they are not considered representative of full-power operation and there have been no low-power loss of feedwater related events since installation. Also, there were no loss of feedwater events in the data window following synchronization of the turbine/generator (e.g., above 20%); consequently, the impact of this system for estimating the frequency of TIFWLOSS is considered minimal. This is significant since NUREG/CR-5622 [Ref. 42] reports that 61% of MFW related trips are due to problems with feedwater control.

7.3.1.4 Steamline and Feedline Breaks

The specific location of a high-energy line break impacts plant safety system response in several ways as discussed in Section 3.4.2:

a. Steamline breaks located in the segments of pipe between the SGs and the MSIVs fail the turbine-driven AFW pump steam supply due to NPSH concerns regardless of whether the break is isolated or not.

b. Feedline breaks located in the segments of pipe downstream of the MFW check valves to each SG fail feedwater flow (MFW, AFW, and SAFW) to one SG.

c. Pipe breaks outside the containment cause steam flooding which may fail equipment. Of particular concern are breaks located in the Intermediate Building (impact the AFW pumps) and the Turbine Building (impact MCC 1A and IA).

d. Pipe breaks in the Turbine Building near the Intermediate Building block wall can fail AFW and various SW isolation valves located in the Intermediate Building since the block wall is not designed for high energy loads.

e. In general, high-energy line breaks result in SI actuation due to low pressurizer pressure and low steamline pressure; breaks located inside containment actuate both SI and CS due to high containment pressure. In addition to starting the SI and RHR pumps, SI actuation results in MSIV closure, containment isolation, feedwater isolation, and motor-driven AFW pump start. (Note that regardless of the location of the high-energy line break, the AFW pumps will start on low steam generator level.)

f. High-energy line breaks inside containment result in CS actuation (see item e above); thus, these initiators imply a "wet" reactor cavity for Level 2 PRA phenomenology purposes.

Based on the discussion above, several high-energy line break initiators were defined:

a.	TISLBACT	Steamline Break in Line for SG A Inside Containment
b.	TISLBBCT	Steamline Break in Line for SG B Inside Containment
c.	TISLB0TB	Steamline Break in Turbine Building
d.	TISLBAIB	Steamline Break in Line for SG A Inside Intermediate Building
e.	TISLBBIB	Steamline Break in Line for SG B Inside Intermediate Building
f.	TI0SLBSD	Steamline Break Through the Steam Dump
g.	TISLBSVA	Inadvertent Safety Valve Operation on Both SGs
h.	TISLBSGB	Exterior Steam Line Break On SG B
i.	TIFLBACT	Feedline Break in Line For SG A Inside Containment
j.	TIFLBBCT	Feedline Break in Line for SG B Inside Containment
k.	TIFLB0TB	Feedline Break in Turbine Building
l.	TIFLBAIB	Feedline Break in Line for SG A Inside Intermediate Building
m.	TIFLBBIB	Feedline Break in Line for SG B Inside Intermediate Building
n.	TIFLBSGB	Exterior Feedline Break on SG B

Estimation of high energy line break frequencies was based upon a review of similar events defined in previous PSAs and safety studies. Table 7-8 identifies the sources that were reviewed, along with the frequency data that was obtained during the review. Several of these data sources are discussed in more detail below.

Two data sources are based on actual reviews of industry events (NUREG/CR-4407 [Ref. 43] and 5622 [Ref. 42]) while the remaining sources are based in part, on engineering judgement or literary searches. NUREG/CR-4407 identifies two feedwater line breaks and no steamline breaks in almost 485 reactor critical years. However, the two feedwater line breaks occurred post-trip as a result of water hammer effects. Consequently, these events are not actual feedwater line break initiating events such that there were no events in 485 years of data. The data presented in NUREG/CR-5622 does not specify how many events were actual piping ruptures; therefore, it is unknown as to how many (if any) events were actual catastrophic ruptures. Also, one study suggests that breaks outside containment are more likely to occur than inside containment while a second study assumes that they are equivalent.

As such, the following was assumed for high energy line break frequencies:

a. *Feedwater Line Breaks* - The following are the frequencies provided in Table 7-8 revised per the above discussion:

   1. 2.06E-03 (conservatively one event in 484.73 reactor years per NUREG/CR-4407);
   2. 3.17E-03 (one event in 315.17 reactor years per NUREG/CR-5622);
   3. 9.3E-04 (NSAC-060); and
   4. 2.5E-05 (WASH-1400).

   Considering each value equally results in an estimated frequency of 1.55E-03/reactor year.

b. *Steamline Break* - The following are the frequencies provided in Table 7-8 revised per the above discussion:

   1. 2.06E-03 (conservatively one event in 484.73 reactor years per NUREG/CR-4407);
   2. 3.17E-03 (one event in 315.17 reactor years per NUREG/CR-5622);
   3. 4.4E-04 (Ringhals-2 study);
   4. 6.4E-04 (combined inside and outside frequencies for German Risk Study);
   5. 1.88E-03 (combined inside and outside frequencies for Zion study); and
   6. 3.9E-04 (WASH-1400)

   Considering each value equally results in an estimated frequency of 1.43E-03/reactor year.

The above values for feedwater and steamline breaks are relatively equal. They are also slightly higher than the value assumed in the accident analysis for a large high energy line break (i.e., between 10^{-4} and 10^{-6} for a Condition IV event).

Based on the above high energy line break values, each initiator's frequency has been estimated by: (1) partitioning the total steamline break and feedline break frequencies according to the relative amount of piping contained in specific locations, and (2) considering the contributions due to non-pipe break sources (e.g., inadvertent steam line safety valve lift and spurious condenser steam dump operation).

Figure 7-8 shows the appropriate location of steam and feedwater piping in the containment, Intermediate, and Turbine Buildings. Based on a review of the relevant general arrangement drawings, the following relationships were estimated:

a. The length of steamline piping inside containment is the same for both steam headers ($S_{A\text{-}RB} = S_{B\text{-}RB}$).

b. The length of steam header A piping inside containment is the same as the length inside the Intermediate Building ($S_{A\text{-}RB} = S_{A\text{-}IB}$).

c. The combined length of steam header B piping located outdoors (behind the facade) and inside the Intermediate Building is three times the length inside the containment ($S_{B\text{-}F} + S_{B\text{-}IB} = 3S_{B\text{-}RB}$).

d. The length of steam header B piping located outdoors is the same as the length inside the Intermediate Building ($S_{B\text{-}F} = S_{B\text{-}IB}$).

e. Approximately 90% of all steam piping is located within the turbine building, and is not missile or tornado protected.

f. The above relations also apply to feedwater piping.

If f_{SB} denotes the total steamline break frequency, then:

$$f_{SB} = \text{TISLBACT} + \text{TISLBBCT} + \text{TISLB0TB} + \text{TISLBAIB} + \text{TISLBBIB} + \text{TI0SLBSD} + \text{TISLBSVA} + \text{TISLBSGB}$$

where:

$$0.9\, f_{SB} = \text{TISLB0TB}$$

$$0.1\, f_{SB} = 2{*}f_{TISLBACT}[\text{CNMT}] + \{f_{TISLBACT} + 1.5 * f_{TISLBACT})\}[\text{IB}] + 1.5{*}f_{TISLBACT}[\text{Facade}]$$

$$= 6\, f_{TISLBACT}$$

Solving for $f_{TISLBACT}$ yields:

$$0.1\ (1.43E\text{-}03/yr) = 6 f_{TISLBACT}$$

$$f_{TISLBACT} = 2.38E\text{-}05/yr$$

Solving for the remaining steamline break frequencies yields:

$$f_{TISLBBCT} = f_{TISLBACT} = 2.38E\text{-}05/yr$$

$$f_{TISLBAIB} = f_{TISLBACT} = 2.38E\text{-}05/yr$$

$$f_{TISLBBIB} = 1.5 f_{TISLBACT} = 3.58E\text{-}05/yr$$

$$f_{TISLBSGB} = 1.5 f_{TISLBACT} = 3.58E\text{-}05/yr$$

$$f_{TISLBOTB} = 0.9 f_{SB} = 1.29E\text{-}03/yr$$

Initiator TISLBSVA addresses inadvertent ARV lifts on both SGs due to an instrumentation failure in ADFCS. This frequency is estimated in the same manner as initiator TIRXTRIP. Table 7-9 lists the information relevant to development of the prior distribution. Note that ADFCS has only been installed since 1991. As such, using equation (6), $\alpha' = 0.012 + 0 = 0.012$, and $\beta' = 0.617 + 3.65 = 4.26$. Using Equation (5), the posterior mean and variance are, respectively, 2.82E-03 and 6.61E-04.

Initiator TIOSLBSD addresses inadvertent operation of the condenser steam dump system. NUREG/CR-5622 reports a total of two reactor trips in 315.17 reactor years involving the turbine bypass system; no data is provided concerning the uncertainty in this estimate due to statistical confidence or plant-to-plant variability. Martz and Waller [Ref. 44] describe a method for estimating the parameters of a gamma distribution given values for the 95th and 5th percentiles. In applying this method, two assumptions were made:

a. The ratio of the 95th percentile to the 5th percentile is 100.0.

b. The gamma distribution mean is 6.35E-03/y (2 events in 315.17 years).

Using the figures and tables provided by Martz and Waller, the following values were determined:

α	= 0.84
β	= 132.29
5th percentile	= 2.02E-02
95th percentile	= 2.02E-02
mean	= 6.35E-03
variance	= 4.80E-05

As such, using equation (6), $\alpha' = 0.84 + 0 = 0.84$, and $\beta' = 132.29 + 12.99 = 145.28$. Using Equation (5), the posterior mean and variance are, respectively, 5.78E-03 and 3.98E-05.

For feedline breaks, relations among the relative frequencies exist similar to those for steamline breaks with the only difference being the initiator frequencies:

$$0.1 f_{FB} = 2{*}f_{TIFLBACT}\,[\text{CNMT}] + \{f_{TIFLBACT} + 1.5 * f_{TIFLBACT})\}[\text{IB}] + 1.5{*}f_{TIFLBACT}\,[\text{Facade}]$$

$$= 6\, f_{TIFLBACT}$$

where:

$f_{TIFLBBCT} = 2.58\text{E-}05/\text{yr}$

$f_{TIFLBACT} = f_{TIFLBBCT} = 2.58\text{E-}05/\text{yr}$

$f_{TIFLBAIB} = f_{TIFLBACT} = 2.58\text{E-}05/\text{yr}$

$f_{TIFLBBIB} = 1.5\, f_{TIFLBACT} = 3.87\text{E-}05/\text{yr}$

$f_{TIFLBSGB} = 1.5\, f_{TIFLBACT} = 3.87\text{E-}05/\text{yr}$

$f_{TIFLBOTB} = 0.9\, f_{FB} = 1.40\text{E-}03/\text{yr}$

A log-normal uncertainty distribution (error factor = 15.0) is used for all high-energy line break initiators. It is noted that the Ginna Station licensing basis credits leak-before-break for certain MS and MFW piping. Since there is no readily available information with respect to factoring this consideration into pipe break frequencies, it was conservatively ignored.

7.3.1.5 TIIALOSS - Loss of Instrument Air

The initiator frequency for loss of IA was determined by solving the IA model assuming that the plant was operating for 81% of a year. This yielded a frequency of 4.15E-02/yr with the dominant cutsets related to common cause failures of the air compressors. A log-normal uncertainty distribution (error factor = 15.0) is used for TIIALOSS.

7.3.1.6 Loss of Coolant Accidents

The Electric Power Research Institute (EPRI) has formulated a methodology [Ref. 45] for estimating the frequencies of pipe breaks, including an example of how to apply this methodology to the estimation of LOCA frequencies. The fundamental equations are:

$$Z_l = Z * C_3 * P_{3/3} * n_3$$

$$Z_m = Z * [C_2 * P_{2/2} * n_2 + C_3 * P_{2/3} * n_3]$$

$$Z_s = Z * [C_1 * n_1 + C_2 * P_{1/2} * n_2 + C_3 * P_{1/3} * n_3]$$

where:

Z_l = LOCA frequency for pipes > 6"

Z_m = LOCA frequency for pipes between 2" and 6"

Z_s = LOCA frequency for pipes < 2"

Z = generic rupture failure rate

C_i = size attribute value

$P_{i/j}$ = conditional probability that a rupture of size i occurs in a larger pipe of size j

n_i = number of pipe sections of size n

Table 7-10 shows the parameter values determined in the EPRI report (all values are shown in Table 4.4-2 of Ref. 45 except for the pipe segment counts which are shown in Table 307 of Ref. 45). Substituting in the above equations for these values yields:

Z_l = (2.9E-10/hr) * (1.4) * (7 / 15) * (109)

= 2.1E-08/hr = 1.8E-04/yr

Z_m = (2.9E-10/hr) * [(0.6) * (9 / 10) * (195) + (1.4) * (1 / 3) * (109)]

= (4.5E-08/hr = 4.0E-04/yr

Z_s = (2.9E-10/hr) * [(1.2) * (339) + (0.6) * (1 / 10) * (195) + (1.4) * (1 / 5) * (109)]

= 1.3E-07/hr = 1.1E-03/yr

The LOCA sizes used in the Ginna Station PSA generally match the EPRI data ranges; uncertainty in establishing the Ginna-specific LOCA sizes (e.g., due to use and interpretation of MAAP results, etc.), coupled with uncertainty in the EPRI methodology and its supporting data suggests that the EPRI methodology produces results acceptable for use in the Ginna Station PSA. Thus:

$f(LLOCA)$ = 1.8E-04/yr

$f(MLOCA)$ = 4.0E-04/yr

$f(SLOCA) + f(SSLOCA)$ = 1.1E-03/yr

The small LOCA range is 1" to 1.5"; the small-small LOCA range is 0" to 1". There is little data regarding the amount of piping within these ranges at Ginna Station. In addition, random failure of the RCP seals is not included in the EPRI frequency estimation (i.e., only pipe breaks are addressed, not seal failures independent of RCP seal support system failures.). Accordingly, it was decided to conservatively apply the entire small break frequency to small LOCAs and increase the frequency by a factor of 5 for small-small LOCAs (note - Ginna Station only has two RCPs). This results in the following:

$f(SLOCA)$ = 1.1E-03/yr

$f(SSLOCA)$ = (5) * (1.1E-03/yr) = 5.5E-03/yr

For comparison purposes, Table 7-11 provides a sample listing of LOCA frequencies used in other PSAs. As can be seen, the Ginna-specific LOCA frequencies are comparable.

The EPRI data does not apply to a reactor vessel rupture event (LIRVRUPT). The NUREG-1150 studies of Surry and Sequoyah estimated that the core-damage frequency due to reactor vessel ruptures was on the order of 1.0E-08/yr. With the exception of pressurized thermal shock (PTS), no specific failure mechanisms (e.g., thermal cycling, fatigue, overpressure, etc.) were identified that lead to reactor vessel rupture; thus, the NUREG-1150 analysis is based solely on an assessment of PTS core-damage risk at Robinson presented in NUREG/CR-4183 [Ref. 46]

Reactor vessel failure may occur due to brittle fracture during severe overcooling transients. Three conditions must exist in order to cause brittle fracture:

a. The reactor vessel materials must be at low temperature and be susceptible to brittle fracture;
b. A flaw (crack or notch) must be present; and
c. A tensile stress of sufficient magnitude must exist.

Conditions a and c are possible during transients such as small LOCAs and main steamline breaks, during which relatively cold SI flow is added to the reactor vessel. It should be noted that these transients do not result in complete RCS depressurization since SI flow will exceed the LOCA break flow and the rate of coolant shrinkage during steamline break events. Condition b is always possible since reactor vessel inspection techniques cannot detect flaws below approximately 0.25 inches.

Brittle fracture susceptibility is governed by many factors such as flaw geometry and vessel material properties. In general, and specifically for Ginna Station, the most likely initiation point for a brittle fracture are the welds in the vessel due to: (1) the high neutron fluence these welds acquire over the plant lifetime, and (2) the presence of copper in the weld material. Industry practice is to summarize these factors using the reference temperature for pressurized thermal shock (RT_{PTS}), which relates typical flaw sizes and material properties to the vessel temperature during PTS transients.

The NUREG/CR-4183 study of Robinson determined a core-damage frequency on the order of 1.0E-8/yr for an RT_{PTS} value of 270°F. 10CFR50.61 establishes the following screening criteria for the RT_{PTS} of reactor beltline materials:

a. 270°F for plates, forgings, and axial weld materials
b. 300°F for circumferential weld materials

Plant-specific evaluations for Ginna Station [Ref. 47] indicate the RT_{PTS} values will remain below these criteria throughout the expected operating lifetime of the plant. Thus, in keeping with the NUREG-1150 risk assessments of Surry and Sequoyah, it is concluded that the core-damage frequency of Ginna due to reactor vessel rupture is less than 1.0E-08/yr.

A log-normal distribution (ef = 15.0) is used for as an uncertainty distribution for all LOCAs.

7.3.1.7 LIOSGTRn - Steam Generator Tube Ruptures

Adams and Sattison [Ref. 48] report a total of five (5) single SG tube rupture (SGTR) events in Westinghouse and C-E plants, based on examination of the operating experience of all such plants from 1974 until 1987 (512 reactor years). One of the events identified in this data occurred at Ginna Station on 1/25/82 in SG B due to a tool leftover in the SG from a previous outage. Since that time, Ginna Station has replaced SGs (in 1996) and installed a foreign material detection system (DIMMS) such that this event is not considered relevant as a plant-specific occurrence. Therefore, generic data will be used for this frequency based on Reference 49 (which includes the 1982 Ginna Station SGTR event). As such, the frequency for LIOSGTRA and LIOSGTRB is 4.84E-03/yr (or 9.67E-03/yr total). These values are also consistent with those presented in Table 7-11 for other PSAs.

A log-normal distribution (ef = 15.0) is used for as an uncertainty distribution.

7.3.1.8 Loss of Service Water

Initiators TI000SWA and TI000SWB refer to a loss of SW from the safety-related 20" headers A or B, respectively, while TI0000SW refers to the complete loss of all SW. Ginna Station has experienced two precursor events to a total loss of SW flow due to icing of the traveling screens: (1) 12/13/82, where screens "B" and "D" failed, and (2) 2/7/88, where all four screens failed (note - the SW system remained available for both events). The event on 12/13/82 happened when the plant was on-line; the 2/7/88 event happened during shutdown. It should be noted that water from the discharge canal can be recirculated back to the intake structure to minimize the possibility of freezing; experience shows that this is effective when the plant is operating. Further, failure of the traveling screens does not imply immediate loss of SW since adequate flow will pass under the ice dam for some time.

More recent experience with frazil ice buildup has caused instances where power has been reduced as the screenhouse bay level has dropped reducing available NPSH for the circulating water pumps. The SW pumps have much lower NPSH requirements such that frazil ice would have to be significant in order to fail all four pumps. RG&Es response to these instances has led to more conscious use of the circulating water recirculation feature and use of electrical heaters on the intake crib screens. As such, a failure of 1E-04/yr was used for a common suction fault of all four SW pumps.

The initiator frequency for loss of each SW header was determined by solving the SW model. This yielded a frequency of 1.32E-04/yr for the loss of two of four SW pumps (for TI000SWA and TI000SWB) with the dominate cutsets related to failures of the pumps to run. The frequency for complete loss of SW was determined to be 1.43E-04 (TI0000SW) with the dominate cutsets related to common suction faults (e.g., screenhouse failures), common cause failure of the pumps, and bus failures. While the loss of one header versus all SW is relatively equal in value, only the loss of one header can be recovered. The equivalency in frequencies is due to the addition of the travelling screens to TI0000SW only.

7.3.1.9 TI000CCW - Loss of Component Cooling Water

The frequency of initiator TI000CCW was estimated in the same manner as initiator TIRXTRIP. Table 7-12 lists information relevant to development of the prior distribution. Using equation (6), $\alpha' = 0.018 + 0 = 0.018$, and $\beta' = 0.889 + 12.99 = 13.888$. Using Equation (5), the posterior mean and variance are, respectively, 1.30E-03 and 9.33E-05.

7.3.1.10 TI000DCn - Loss of DC Buses

The initiator frequency for DC bus failures was determined by solving the electric power model assuming that the plant was operating for 81% of a year. This yielded a frequency of 5.54E-03 for each DC bus respectively, with the dominate cutsets related to disconnect switch, DC panel, and fuse failures. A log-normal distribution (ef = 15.0) is used for as an uncertainty distribution.

7.3.1.11 ATWS Events

The initiator frequency of an ATWS event is the sum of all the reactor trip frequencies, since all initiators will be evaluated in the ATWS event tree, multiplied by the failure of the reactor trip system. Specifically, the following values are used for the reactor trip system failure probabilities as taken from Reference 17:

a. TLCCFMATWS - Mechanical Scram Failure Probability = 1.80E-06
b. TLCCFEATWS - Electrical Scram Failure Probability (Signal Only) = 1.40E-06
c. TLCCFBRKRF - Electrical Scram Failure Probability (Breakers Only) = 1.30E-05
d. RP200 - Turbine Trip Signal and AFW Initiation Signal Failure = 1.00E-02
e. ATWS Mitigation System Actuation Circuitry (AMSAC) Fail = 1.00E-02

7.3.1.12 TIRCPROT - Reactor Coolant Pump Locked Rotor

The accident analysis considers this event as a Condition IV accident with a frequency between 1.0E-04/yr and 1.0E-06/yr since it entails the failure of a RCP rotor such that flow through one RCS loop is lost. A review of generic data sources did not reveal any available information. As such, a frequency of 1.0E-04/yr will be assumed. A log-normal distribution (ef = 15.0) is used for as an uncertainty distribution.

7.3.2 External Event Initiators

[LATER]

7.3.3 Results

Table 7-13 summarizes the Ginna Station PSA initiator frequencies.

7.4 Human Reliability Analysis

There are two types of human errors included within the Ginna Station PSA models as follows:

a. Errors in restoring systems to normal operating status following test or maintenance (i.e., pre-initiator errors); and

b. Operator errors in responding to an accident (i.e., post-initiator errors).

A discussion of how data was generated for both types of human errors is provided below.

7.4.1 Pre-Initiator Restoration Errors

For many systems, components can be temporary taken out of service during normal plant operation for corrective and preventative maintenance and necessary testing. However, errors can occur in restoring these components back to their proper operating state which would prevent them from performing their intended function. Several factors related to each test and maintenance action were examined with respect to component unavailability due to restoration errors. For example, many tests and maintenance activities require an operational test of the system or component following completion of the work to verify that the system is operable. In other cases, even when a component is left in the wrong position after test or maintenance, it would automatically return to its proper position when an actuation signal is received. Unless either of these factors were present, a basic event was included within the fault tree models as a restoration failure mode, typically at a train level.

All restoration errors were assigned a generic value of 3.0E-03. This value is derived as part of the developmental effort in the Risk Methods Integration and Evaluation Program (RMIEP) and was adopted for the Accident Sequence Evaluation Program (ASEP) [Ref. 49] human reliability analysis procedure. The restoration failure probability is made up of the following inputs:

(Error in Commission + Error in Omission) * Failure to Recover

The error in commission is that portion of the maintenance or testing activity whereby plant personnel perform something different than what is intended. For example, maintenance personnel close instead of opening a valve specified in plant procedures. A value of 0.02 is assigned for this type of error. The error of omission relates to that portion of the maintenance or testing activity whereby plant personnel fail to complete an required step. For example, testing personnel fail to close a pump test line isolation valve following a test as instructed in procedures. A value of 0.01 was assigned for this error.

A recovery factor was also assigned due to the fact that there are status indications of component positions in the control room which are normally checked at least once per shift. In addition, auxiliary operators perform system walkdowns to verify proper positioning of safety-related systems on a monthly basis. A recovery factor of 0.1 was assigned based on Table 20-22 of NUREG/CR-1278 [Ref. 50].

A detailed description of each restoration error that was included within the fault tree models is provided in Appendix F.

7.4.2 Post-Initiator Operator Errors

The post-initiator operator errors included in the Ginna Station PSA are only those which are currently proceduralized or addressed within operator training (i.e., "heroic actions were not included). In general, there are two types of operator errors:

a. Failure to initiate a standby system in the normal course of responding to an initiating event; and

b. Failure to recover a failed component or system.

Most post-initiator operator (or human) actions are included within the fault tree models to specifically address which events and scenarios can be recovered within the models (versus reviewing each cutset independently). However, this creates the potential to have multiple human error events appear in the same cutset after sequence quantification. To address this concern, all cutsets with multiple human errors were reviewed to confirm independence between the events. If not, a change to the model or human error probabilities was made to correctly model the dependency between the human errors. Table 7-14 contains a listing of those human errors which appeared together in the same cutsets for various sequences.

For the initial sequence quantification, a conservative probability of 1.0E-01 was assigned as a screening value for all post-initiator human errors. Quantification of the fault trees was then performed at various truncation limits (all ≤ 1.0E-09) utilizing this screening value. For those human events which were considered important (i.e., were found among the top cutsets), detailed human error probability estimates were derived. Table 7-15 lists the final values used for all human error events contained in the integrated plant model (i.e., this list does not include all human errors described in Section 6, only those contained in the fault tree logic that was ultimately used). A more detailed description of these events and all human error probability estimations is provided in Appendix F.

The detailed human reliability analysis was performed using the methodology specified in NUREG/CR-4772 (commonly known as the ASEP method) which provides a simplified version of the method contained in Reference 50. The ASEP method produces human error probabilities that are more conservative than would be realized from a full scope application of the THERP method [Ref. 50], but less conservative than the screening values. The major elements of the ASEP methodology for post-initiator human errors are as follows:

a. Diagnosis of the event is a time-reliability correlation graph with a time dependency between diagnosis and post-diagnosis tasks included.

b. Abbreviated tables of human error probabilities (generally conservative) for each critical action which accounts for different stress levels are generated.

c. Abbreviated recovery factors are developed and associated with the appropriate stress levels.

d. Estimates are made to the effects of using symptom-oriented emergency operating procedures.

e. Explicit consideration of the human error probabilities for memorized immediate emergency actions is included.

f. Additional guidance on assessment of stress levels for each accident sequence is included.

The human error probabilities from the detailed analysis were substituted for the screening values used in the quantification effort. In all cases, the human error probabilities results from the detailed analysis were lower than the screening value of 1.0E-01. Therefore, no information was missed during the initial quantification effort using the screening values (i.e., there would be no additional cutsets if the final quantification would have been performed using the human error probabilities from the detailed analysis).

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
AC A	Air Cooling Unit	Fails to Start	D	2.08E-04	
AC F	Air Cooling Unit	Fails to Run	H	1.05E-05	
AD F	Air Dryer	Fails to Deliver Flow	H	5.23E-07	IA
AF F	Air Filter	Fails to Deliver Flow	H	7.23E-06	HV, IA
AM A	Air Compressor	Fails to Start	D	1.27E-01	IA
AM F	Air Compressor	Fails to Run	H	2.48E-03	IA
AR F	Air Reciever	Local Faults	H	6.00E-07	IA
AV CN	Air-Operated Valve	Fails to Open / Close	D	2.17E-03	CV, IA, MS, RC, SW
AV F	Air-Operated Valve	Fails to Throttle	H	3.74E-06	RH
AV FKR	Air-Operated Valve	Spurious Operation	H	3.74E-06	AF, CC, CT, IA, MS, RC, RH, SW
AV PX	Air-Operated Valve	Fails to Open / Close	H	1.98E-06	AF, CS, CV, MS, RC
B1 F	> 4 kV Bus	Fault	H	4.50E-08	AC
B2 F	< 4 kV Bus	Fault	H	1.19E-07	AC
B4 F	120 V Bus	Fault	H	1.19E-07	IB
BC F	Battery Charger	No Output	H	7.78E-06	DC
BD F	DC Bus	Fault	H	4.50E-08	DC
BE F	Electrical Penetration	Failure	H	1.00E-06	
BF F	Blind Flange	Fails	H	2.54E-05	CT
BI F	Bistable	Spurious Operation	H	1.03E-06	
BI N	Bistable	Fails to Operate on Demand	D	2.25E-07	
BT D	Battery	No Output (Demand)	D	1.19E-05	DC
BT F	Battery	No Output (Hourly)	H	1.93E-06	DC
CB DN	AC Breaker	Fails to Operate / Open	D	1.16E-03	AC
CB K	AC Breaker	Transfers Closed	H	2.02E-06	
CB O	AC Breaker	Fails to Operate	H	1.06E-06	AC
CB R	AC Breaker	Transfers Open	H	1.87E-06	AC, IB
CD D	DC Breaker	Fails to Trip (Overcurrent)	D	8.83E-04	
CD R	DC Breaker	Transfers Open	H	3.80E-06	IB
CF RX	Fuse	Fails Open	H	6.38E-07	DC

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
CI R	DC Interrupter	Transfers Open	D	2.00E-08	
CS R	DC Disconnnect Sw.	Transfers Open	H	1.41E-06	
CT CN	Contact	Fails to Open / Close	D	2.27E-06	
CT KR	Contact	Spurious Operation	H	7.05E-08	
CV C	Check Valve	Fails to Close	D	1.63E-03	AF, CC, CS, DG, MS, RH, SI, SW
CV K	Check Valve	Transfers Closed	H	1.69E-06	CC, CV, IA, SW
CV N	Check Valve	Fails to Open	D	1.45E-04	CV, DG, IA, RC, SW
CV P	Check Valve	Fails to Open	H	1.32E-07	AF, CS, CV, IA, MS, RH, SI, SW
CV R	Check Valve	Transfers Open	H	9.46E-07	CT, SI
DG A	Diesel Generator	Fails to Start	D	1.76E-02	DG
DG F	Diesel Generator	Fails to Run	H	2.25E-03	DG
EI D	E/I Converter	Fails to Respond	H	2.19E-07	
EJ F	Expansion Joint	Fails	H	2.85E-08	
EP D	E/P Converter	Fails to Respond	H	1.00E-07	
FC F	Dropout Register	Fails to Fall	D	1.00E-06	
FD F	Water Filter	Fails	H	4.07E-06	
FD P	Fuel Oil Strainer	Plugged	H	2.66E-05	
FE F	Flow Element	Fails	H	9.16E-06	
FS D	Flow Switch	Fails to Respond	D	1.00E-08	
FS HL	Flow Switch	Fails to High / Low	H	2.80E-06	
FT D	Flow Transmitter	Fails to Respond	H	1.81E-06	
FT H	Flow Transmitter	Fails High	H	2.04E-06	
FT L	Flow Transmitter	Fails Low	H	1.83E-06	
HE F	Room Heater	Fails to Operate	H	1.16E-06	HV
HN F	PZR Heater	Fails	H	1.67E-06	
HR F	Hydrogen Recombinr	Fails to Recombine	H	2.68E-06	
HT F	Heat Trace	Fails	H	5.60E-07	CV
HX F	Heat Exchanger	Cooling Capability Fails	H	1.95E-05	CC, RH
HX J	Heat Exchange	Tube Rupture	H	2.61E-05	CC

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
HX P	Heat Exchanger	Plugs	H	2.20E-06	CC, CV, RH
IN F	Inverter	No Output	H	2.87E-05	DC, IB
IP D	I/P Converter	Fails to Respond	H	1.00E-07	
IR F	Regulating Rectifier	No Output	H	1.07E-06	
IV F	Static Volt Regulator	No Output	H	7.11E-06	
LC D	Logic Circuit	Fails to Generate Signal	H	3.89E-06	
LS S	Level Switch	Fails to Respond	D	3.00E-08	
LS H	Level Switch	Fails High	H	2.31E-06	
LS L	Level Switch	Fails Low	H	2.31E-06	
LT D	Level Transmitter	Fails to Respond	H	2.14E-06	CV
LT H	Level Transmitter	Fails High	H	2.02E-06	CV
LT L	Level Transmitter	Fails Low	H	2.06E-06	
LY DL	Signal Processor	Fails to Respond/Fails Low	H	6.42E-07	
MB CN	Backflow Damper	Fails to Operate	D	2.18E-03	
MB KR	Backflow Damper	Spurious Operation	H	6.42E-07	
MC CN	Air-Operated Damper	Fails to Operate	D	2.18E-03	
MC KR	Air-Operated Damper	Spurious Operation	H	5.09E-06	HV
MD CN	Motor-Op Damper	Fails to Operate	D	2.18E-03	HV
MD KR	Motor-Op Damper	Spurious Operation	H	5.09E-06	
MF A	Motor-Driven Fan	Fails to Start	D	2.08E-04	HV
MF F	Motor-Driven Fan	Fails to Run	H	1.24E-05	HV
MF S	Motor-Driven Fan	Fails to Start	H	1.90E-07	HV
MP A	Motor-Driven Pump	Fails to Start	D	4.84E-03	AF, CS, CC, CV, DG, SW
MP F	Motor-Driven Pump	Fails to Run	H	8.45E-05	CC, CV, DG, RC, RH, SI, SW
MP S	Motor-Driven Pump	Fails to Start	H	4.42E-06	AF, CS, RH, SI
MV C	Motor-Op Valve	Fails to Close	D	6.01E-03	AF, CC, MS, SI, SW
MV D	Motor-Op Valve	Fails to Throttle	H	2.25E-06	AF
MV K	Motor-Op Valve	Transfers Closed	H	1.52E-06	AF, CC, CS, CV, RC, RH, SI, SW
MV N	Motor-Op Valve	Fails to Open	D	5.07E-03	CV, SW

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
MV P	Motor-Op Valve	Fails to Open	H	4.63E-06	AF, CC, CS, MS, RC, RH, SI, SW
MV R	Motor-Op Valve	Transfers Open	H	1.36E-06	CS, MS, RH
MV X	Motor-Op Valve	Fails to Close	H	5.49E-06	AF, CS, RC, RH, SI
PC D	Pressure Controller	Fails to Respond	H	1.47E-06	
PP JP	Piping	Failure	H	5.53E-07	CV, IA
PS DR	Pressure Switch	Fails to Respond	D	4.50E-05	
PS HL	Pressure Switch	Fails High / Low	H	8.45E-07	
PT D	Pressure Transmitter	Fails to Respond	H	1.47E-06	
PT H	Pressure Transmitter	Fails High	H	1.49E-06	
PT L	Pressure Transmitter	Fails Low	H	1.47E-06	
PV K	Pressure Control Vlv	Transfers Closed	H	3.33E-06	
PV R	Pressure Control Vlv	Transfers Open	H	1.06E-05	
PX F	Power Supply	No Output	H	1.40E-06	
RA F	Radiation Element	Fails to Respond	H	3.42E-06	
RE BE	Relay	Fails to Operate on Demand	F	7.65E-05	
RE KR	Relay	Operational Failure	H	3.94E-07	
RT D	Time Delay Relay	Fails to Energize	D	7.65E-05	
RU BE	UV Relay	Fails to Operate on Demand	D	7.65E-05	
RV C	Relief Valve	Fails to Close	D	5.18E-03	MS
RV N	Relief Valve	Fails to Open	D	2.12E-04	CV
RV P	Relief Valve	Fails to Open	H	1.94E-07	CV, MS
RV R	Relief Valve	Spurious Open	H	1.69E-06	DG, RC
RV Z	Relief Valve	Fails to Close (Liq Release)	D	1.00E-01	
RY N	PZR Safety, MSSV	Fails to Open	D	1.40E-04	
RY Q	PZR Safety, MSSV	Fails to Reseat After Liquid	D	1.00E-01	
RY T	PZR Safety, MSSV	Fails to Reseat After Steam	D	7.45E-03	MS
RZ N	PORV	Fails to Open	D	4.15E-03	
RZ P	PORV	Fails to Open	H	6.32E-07	RC
RZ Q	PORV	Fails to Reseat After Liquid	D	5.00E-03	

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
RZ T	PORV	Fails to Reseat After Steam	D	5.00E-03	
SC DN	Stop-Check Valve	Fails to Operate	D	1.61E-03	
SM P	Containment Sump	Plugged	D	2.2E-05	
ST A	Motor-Driven Strainer	Fails to Start	D	2.08E-04	
ST F	Motor-Driven Strainer	Fails to Run	H	7.85E-06	
SV CN	Solenoid Valve	Fails to Operate	D	2.83E-03	
SV KR	Solenoid Valve	Transfers Closed / Open	H	4.09E-07	SW
SV PN	Solenoid Valve	Fails to Open	H	2.58E-06	DG, RC, SW
SV X	Solenoid Valve	Fails to Close	H	1.47E-06	
SW C	Hand Switch	Fails to Close	D	2.59E-08	
SW K	Hand Switch	Transfers Closed	H	8.00E-08	
SW N	Hand Switch	Fails to Open	D	2.00E-08	
SW R	Hand Switch	Transfers Open	H	8.00E-08	
SX N	Speed Switch	Fails to Open	D	2.46E-04	
SZ C	Valve Position Switch	Fails to Close	D	2.46E-04	
SZ KR	Valve Position Switch	Transfers Open / Closed	H	4.44E-06	
T1 F	kV Transformers	Fault	H	2.08E-06	AC
T6 F	480V - 240V Trans	Fault	H	1.90E-06	IB
TK B	Tank Bladder	Ruptures	H	3.31E-06	
TK GJ	Tank	Leakage / Rupture	H	5.52E-06	AF, CC, CS, CV, DG
TN F	Travelling Screen	Fails to Run	H	6.85E-04	
TP A	Turbine-Driven Pump	Fails to Start	D	2.62E-02	
TP F	Turbind-Driven Pump	Fails to Run	H	8.91E-05	AF
TP S	Turbine-Driven Pump	Fails to Start	H	2.39E-05	AF
TR D	Agastat Relay	Fails	H	6.80E-06	
TS BE	Temperature Switch	No Function With Signal	D	1.20E-07	
TS HL	Temperature Switch	Function Without Signal	H	9.20E-07	
TT D	Temp Transmitter	Fails to Respond	H	1.47E-06	CC, CS, MS, SW
TT HL	Temp Transmitter	Fails High / Low	H	1.81E-06	AF, CC, CS, CV, DG, MS, RC, RH, SI, SW

Table 7-1
Component Failure Data

Type Code	Component	Failure Mode	Hourly/ Demand	Generic Value	PS-Data Collected (System)?
TV D	Temp Controller	Fails to Respond	H	2.12E-06	CS, CV, RH
TV HL	Temp Controller	Fails High/ Low	H	1.36E-06	
VB P	Vacuum Breaker	Fails	H	1.03E-06	
XV CN	Manual Valve	Fails to Operate	D	3.47E-04	
XV K	Manual Valve	Transfers Closed	H	1.94E-07	
XV PX	Manual Valve	Fails to Open / Close	H	9.63E-07	AF, MS, RH, SW
XV R	Manual Valve	Transfers Open	H	1.30E-07	

Table 7-2
Generic Common Cause Beta Factors

Description	*Value*	*Reference*
Air-operated valve fails to open or fails to close	0.191	NUREG/CR-2770, p. 52
Battery failures	0.08	NUREG/CR-4780, p. 4-71
Check valve fails to open or fails to close	0.06	NUREG/CR-4780, Table 3-7
Check valve transfers closed (plugged)	0.337	NUREG/CR-2770, p. 62
Check valve reverse leakage	0.104	NUREG/CR-2770, p. 64
Core flux sensors (except LPRMs) inoperable	0.511	NUREG/CR-3289, p. C-20
Diesel generator fails to start or fails to run	0.05	NUREG/CR-4780, Table 3-7
Level, pressure, flow sensor inoperable	0.01	NUREG/CR-3289 , p. C-44
Local power range monitors inoperable	0.689	NUREG/CR-3289, p. C-30
Motor-driven fan fails to start or run	0.13	NUREG/CR-4780, Table 3-7
Motor-operated valve fails to open or fails to close	0.08	NUREG/CR-4780, Table 3-7
Motor-operated valve transfers closed (plugged)	0.669	NUREG/CR-2770, p. 92
Pressure and level switches inoperable	0.232	NUREG/CR-3289, p. C-6
Pump (AFW) fails to start or fails to run	0.03	NUREG/CR-4780, Table 3-7
Pump (service water, component cooling water, river water, intake cooling water, salt water cooling, cooling tower, or reactor equipment cooling) fails to start or fails to run	0.03	NUREG/CR-4780, Table 3-7
Pump (alternating service, normally operating part of the time) fails to start	0.093	NUREG/CR-2098, p. 68
Pump (alternating service, normally operating part of the time) fails to run	0.041	NUREG/CR-2098, p. 71
Pump (standby service, not normally running except for test) fails to start	0.311	NUREG/CR-2098, p. 128
Pump (standby service, not normally running except for test) fails to run	0.141	NUREG/CR-2098, p. 130
Pump (safety injection, high pressure injection) fails to start or fails to run	0.17	NUREG/CR-4780, Table 3-7
Pump (residual heat removal, low pressure injection) fails to start or fails to run	0.11	NUREG/CR-4780, Table 3-7
Pump (containment spray) fails to start or fails to run	0.05	NUREG/CR-4780, Table 3-7
Pump (charging) fails to start	0.252	NUREG/CR-2098, p. 144
Pump (charging) fails to run	0.016	NUREG/CR-2098, p. 146
PWR safety/relief valve fails to open	0.07	NUREG/CR-4780, Table 3-7
Reactor coolant temperature detector inoperable	0.216	NUREG/CR-3289, p. C-36

Table 7-2
Generic Common Cause Beta Factors

Description	*Value*	*Reference*
Signal conditioning system (source range flux, intermediate range flux, power range flux, power-to-flow, rate of change of flux, T-average/delta T, overpower/delta T, over temperature/delta T, reactor outlet temperature, reactor coolant pressure, pressure/temperature or thermal margin/low pressure, reactor coolant flow, steam flow/feed flow mismatch, steam generator water level, pressurizer level, steam generator pressure, containment pressure, flow unit) inoperable	0.219	NUREG/CR-3289, p. C-62
Steam line radiation monitor inoperable	0.075	NUREG/CR-3289, p. C-90

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
AC Power	DG breaker fails to close	52/EG1A1, 52/EG1A2, 52/EG1B1, 52/EG1B2	1.00E-01
AC Power	Agastat timing relays fail	2/BLA, 2/BLB	1.00E-01
AC Power	Inverter fails	INVTA, INVTB	1.00E-01
AFW	Check valve fails to open	9574A, 9588A	6.00E-02
AFW	Check valve fails to open	4014, 4016, 4017	6.00E-02
AFW	Check valve fails to open	4009, 4010, 3998	6.00E-02
AFW	Check valve fails to open	9705A, 9705B	6.00E-02
AFW	Check valve fails to open	9700A, 9700B	6.00E-02
AFW	Check valve fails to open	4000C, 4000D, 4003, 4004	6.00E-02
AFW	Flow transmitter fails to respond	PT-4084, PT-4085	1.00E-02
AFW	Flow transmitter fails high	PT-4084, PT-4085	1.00E-02
AFW	Motor-driven pump fails to run	PAF01A, PAF01B	4.10E-02
AFW	Motor-driven pump fails to run	PSF01A, PSF01B	4.10E-02
AFW	Motor-driven pump fails to start	PAF01A, PAF01B	9.30E-02
AFW	Motor-driven pump fails to start	PSF01A, PSF01B	9.30E-02
AFW	Motor-operated valve fails to throttle flow	4007, 4008	1.00E-01
AFW	Motor-operated valve fails to throttle flow	9701A, 9701B	1.00E-01
AFW	Motor-operated valve fails to open	4000A, 4000B	8.00E-02
AFW	Motor-operated valve fails to open	9703A, 9703B	8.00E-02
AFW	All 3 AFW pumps fail to start	PAF01A, PAF01B, PAF03	2.05E-02
AFW	All 3 AFW pumps fail to run	PAF01A, PAF01B, PAF03	2.05E-02
CCW	Motor driven pump fails to start	PAC02A, PAC02B	3.00E-02
CCW	Motor driven pump fails to run	PAC02A, PAC02B	3.00E-02

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
CCW	Motor-operated valve fails to open	738A, 738B	8.00E-02
CS	Check valve fails to open	862A, 862B	6.00E-02
CS	RWST level transmitter fails to respond	LT-920, LT-921	1.00E-01
CS	RWST level transmitter fails low	LT-920, LT-921	1.00E-01
CS	Motor driven pump fails to run	PSI02A, PSI02B	1.41E-02
CS	Motor driven pump fails to start	PSI02A, PSI02B	3.11E-02
CS	Motor-operated valve fails to open	860A, 860B, 860C, 860D	8.00E-02
CNMT Isol	Air-operated valve fails to close	1723, 1728	1.91E-02
CNMT Isol	Air-operated valve fails to close	1721, 1003A, 1003B	1.91E-02
CVCS	Air-operated valve fails to close	200A, 200B, 202	1.91E-02
CVCS	Motor driven pump fails to run	PCH01A, PCH01B, PCH01C	4.10E-02
CVCS	Motor driven pump fails to start	PCH01A, PCH01B, PCH01C	9.30E-01
DC	Battery charger fails	BYCA, BYCA1, BYCB, BYCB1	1.00E-01
DG	Fuel oil check valve fails to close	5919, 5920	6.00E-01
DG	Fuel oil check valve fails to close	5955, 5956	6.00E-02
DG	Fuel oil check valve fails to open	5919, 5920	6.00E-02
DG	Fuel oil check valve fails to open	5955, 5956	6.00E-01
DG	DG fails to start	KDG01A, KDG01B	5.00E-02
DG	DG fails to run	KDG01A, KDG01B	5.00E-02
DG	Fuel oil strainer plugs	5919, 5920	1.00E-01
DG	Fuel oil strainer plugs	NDG04, NDG08	1.00E-01
DG	Fuel oil pump fails to start	PDG02A, PDG02B	3.11E-01
DG	Fuel oil pump fails to run	PDG02A, PDG02B	1.41E-01

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
ESFAS	Agastat time delay relay fails to energize	2/CF1A, 2/CF1B, 2/CF1C, 2/CF1D, 2/MAFP1A, 2/MAFP1B, 2/RHRP1A, 2/RHRP1B, 2/SIP1C1, 2/SIP1C2, 2/SWP1AC, 2/SWP1BD	1.00E-01
ESFAS	Bistable fails to respond	FC-464A, FC-465A, FC-474A, FC-47BA, PC-429C, PC-430E, PC-431G, PC-945AB to PC-950AB, PC-468A, PC-469A, PC-478A, PC479A, PC-482A, PC-483A, TC-401A, TC-402A, TC-403A, TC-404A	1.00E-01
ESFAS	Flow transmitter fails to respond	FT-464, FT-465, FT-474, FT-475	1.00E-01
ESFAS	Flow transmitter fails low	FT-464, FT-465, FT-474, FT-475	1.00E-01
ESFAS	Pressure transmitter fails to respond	PT-429, PT-430, PT-431	1.00E-01
ESFAS	Pressure transmitter fails to respond	PT-945, PT-946, PT-947, PT-948, PT-949, PT-950	1.00E-01
ESFAS	Pressure transmitter fails to respond	PT-468, PT-469, PT-478, PT479, PT-482, PT-483	1.00E-01
ESFAS	Pressure transmitter fails high	PT-429, PT-430, PT-431	1.00E-01
ESFAS	Pressure transmitter fails high	PT-468, PT-469, PT-478, PT-479, PT-482, PT-483	1.00E-01
ESFAS	Pressure transmitter fails low	PT-945, PT-946, PT-947, PT-948, PT-949, PT-950	1.00E-01
ESFAS	Radiation monitor fails to respond	R-11, R-12	1.00E-01

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
ESFAS	Relay fails to energize	SI-10X thru SI-18X, SI-20X thru SI-28X	1.00E-01
ESFAS	Relay fails to energize	SI-A1, SI-A2, MS1, MS2, MS3, MS4, S1, S2, V1, V2	1.00E-01
ESFAS	Relay fails to energize	PC-945BX1, PC-945BX2, PC-946BX1, PC-946BX2, PC-947BX1, PC-947BX2, PC-948BX1, PC-948BX2, PC-949BX1, PC-949BX2, PC-950BX1, PC-950BX2	1.00E-01
ESFAS	Relay fails to de-energize	ALL ESFAS SENSING INSTRUMENTATION AUX RELAYS	1.00E-01
ESFAS	Temperature transmitter fails to respond	TE-401A, TE-401B, TE-402A, TE-402B, TE-403A, TE-403B, TE-404A, TE-404B	1.00E-01
ESFAS	Temperature transmitter fails high	TE-401A, TE-401B, TE-402A, TE-402B, TE-403A, TE-403B, TE-404A, TE-404B	1.00E-01
ESFAS	Spurious actuation of bistable	FC-464A, FC-465A, FC-474A, FC-47BA, PC-429C, PC-430E, PC-431G, PC-945AB to PC-950AB, PC-468A, PC-469A, PC-478A, PC479A, PC-482A, PC-483A, TC-401A, TC-402A, TC-403A, TC-404A	1.00E-01
ESFAS	Spurious actuation flow transmitter (high)	FT-464, FT-465, FT-474, FT-475	1.00E-01
ESFAS	Spurious actuation of pressure transmitter (high)	PT-945, PT-946, PT-947, PT-948, PT-949, PT-950	1.00E-01
ESFAS	Spurious actuation of pressure transmitter (low)	PT-429, PT-430, PT-431	1.00E-01

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
ESFAS	Spurious actuation of pressure transmitter (low)	PT-468, PT-469, PT-478, PT-479, PT-482, PT-483	1.00E-01
ESFAS	Spurious energization of relay	SI-10X thru SI-18X, SI-20X thru SI-28X	1.00E-01
ESFAS	Spurious energization of relay	SI-A1, SI-A2, MS1, MS2, MS3, MS4, S1, S2, V1, V2	1.00E-01
ESFAS	Spurious energization of relay	PC-945BX1, PC-945BX2, PC-946BX1, PC-946BX2, PC-947BX1, PC-947BX2, PC-948BX1, PC-948BX2, PC-949BX1, PC-949BX2, PC-950BX1, PC-950BX2	1.00E-01
ESFAS	Spurious de-energization of slave relays	ALL ESFAS SENSING INSTRUMENTATION AUX RELAYS	1.00E-01
ESFAS	Spurious actuation of temperature transmitter (low)	TE-401A, TE-401B, TE-402A, TE-402B, TE-403A, TE-403B, TE-404A, TE-404B	1.00E-01
HVAC	Air-operated valve fails to close	7970, 7971	1.91E-01
HVAC	Air-operated damper fails to close	5873, 5875	1.00E-01
HVAC	Air-operated damper fails to open	5871, 5872, 5874, 5876	1.00E-01
HVAC	Motor-driven fan fails to start	ACF08A, ACF08B, ACF08C, ACF08D	1.30E-01
HVAC	Motor-driven fan fails to run	ACF08A, ACF08B, ACF08C, ACF08D	1.30E-01
IA	Air compressor A, B, or SA fails to start	CIA02A, CIA02B, CSA02	1.00E-01
IA	Air compressor A, B, or SA fails to run	CIA02A, CIA02B, CSA02	1.00E-01
IA	Air compressor A, B, C, or SA fails to start	CIA02A, CIA02B, CIA02C, CSA02	1.50E-02

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
IA	Air compressor A, B, C, or SA fails to run	CIA02A, CIA02B CIA02C, CSA02	1.50E-02
MS	Air operated valve fails to close	5735, 5736 5737, 5738	1.91E-01
MS	MSIV fails to close	3516, 3517	1.91E-01
MS	ARV fails to open (air operation)	3410, 3411	1.91E-01
MS	Check valve fails to open	3504B, 3505B	6.00E-02
MS	Motor-operated valve fails to open	3504A, 3505A	8.00E-02
MS	ARV fails to close	3410, 3411	1.91E-01
MS	ARV fails to open (manual operation)	3410, 3411	1.00E-01
RCS	Air-operated valve fails to open	431A, 431B	1.91E-01
RCS	Motor-operated valve fails to open	515, 516	8.00E-02
RCS	Motor-operated valve fails to close	515, 516	8.00E-02
RCS	PORV fails to open	430, 431C	7.00E-02
RHR	RHR check valve fails to open	853A, 853B	6.00E-02
RHR	RHR check valve fails to open	710A, 710B	6.00E-02
RHR	RHR check valve fails to open	697A, 697B	6.00E-02
RHR	Pump fails to run	PAC01A, PAC01B	1.10E-01
RHR	Pump fails to start	PAC01A, PAC01B	1.10E-01
RHR	Motor-operated valve fails to open	852A, 852B	8.00E-02
RHR	Motor-operated valve fails to open	857A, 857B, 857C	8.00E-02
SI	Check valve fails to open (demand)	842A, 842B	6.00E-02
SI	Check valve fails to open (standby)	870A, 870B, 889A, 889B	6.00E-02
SI	Check valve fails to open (standby)	878G, 878J	6.00E-02
SI	Check valve fails to open (standby)	867A, 867B	6.00E-02
SI	Check valve fails to open (standby)	889A, 889B	6.00E-02

Table 7-3
Final Common Cause Beta Factors

System	*Description*	*Component EINs*	*Mean Beta Factor*
SI	Accumulator level transmitter fails high	LT-934, LT-935, LT-938, LT939	1.00E-01
SI	Pump fails to run	PSI01A, PSI01B, PSI01C	1.70E-01
SI	Pump fails to start	PSI01A, PSI01B, PSI01C	1.70E-01
SI	Accumulator pressure transmitter fails high	PT-936, PT-937, PT-940, PT-941	1.00E-01
SW	Check valve fails to open (demand)	4601, 4602, 4603, 4604	6.00E-02
SW	Check valve fails to open (standby)	9627A, 9627B	6.00E-02
SW	Expansion joint failures	SSW02, SSW03, SSW04, SSW05	1.00E-01
SW	Pump fail to start	PSW01A, PSW01B, PSW01C, PSW01D	3.00E-02
SW	Pump fails to run	PSW01A, PSW01B, PSW01C, PSW01D	3.00E-02
SW	Motor-operated valve fails to close	4609, 4613, 4733, 4734, 4735, 4780	8.00E-02
SW	Motor-operated valve fails to close	4613, 4615, 4616, 4663, 4664, 4670	8.00E-02
SW	Motor-operated valve fails to open (standby)	4013, 4027, 4028	8.00E-02
SW	Solenoid-operated valve fails to open	4324, 4325, 4326	1.00E-01
UV	Relay fails to de-energize	27/14, 27B/14, 27/16, 27B/16, 27/17, 27B/17, 27/18, 27B/18	1.00E-01
UV	Relay fails to de-energize	27D/14, 27D/B/14, 27D/16, 27D/B/16, 27D/17, 27D/B/17, 27D/18, 27D/B/18	1.00E-01

Table 7-4
Final Test and Maintenance Unavailability Values

T/M Event	*Description*	*P-S Data Based Value*	*Maint Rule Based Value*[1]
AFTM004048	Alternate suction source for AFW pumps	1.10E-03	*
AFTM0AFWAB	Motor-driven AFW pumps cross-connect lines	4.33E-03	*
AFTM0TDAFW	Turbine-driven AFW pump train	9.04E-03	3.00E-02
AFTMCONDPP	Condensate transfer pump (PDC04)	2.91E-03	*
AFTMMAFSGA	Motor-Driven AFW Train A to SG A	5.67E-03	5.30E-02
AFTMMAFSGB	Motor-Driven AFW Train B to SG B	5.67E-03	5.30E-02
AFTMOUTCON	Outside condensate storage tank valves	1.10E-03	*
AFTMSAFWPC	SAFW Train C to SG A	8.40E-03	5.60E-02
AFTMSAFWPD	SAFW Train D to SG B	1.02E-03	5.70E-02
AFTMSAFWAB	SAFW cross-connect line	4.33E-03	*
AFTMTDAFWA	TDAFW train injection line to SG A	1.50E-03	4.90E-02
AFTMTDAFWB	TDAFW train injection line to SG B	1.50E-03	4.90E-02
CCTM000HXA	CCW heat exchanger Train A	2.13E-04	3.50E-03
CCTM000HXB	CCW heat exchanger Train B	2.13E-04	3.50E-03
CCTM_PUMPA	CCW pump train A	2.13E-04	7.00E-03
CCTM_PUMPB	CCW pump train B	2.13E-04	7.00E-03
CSTMTRAINA	CS pump train A	3.89E-03	2.40E-02
CSTMTRAINB	CS pump train B	3.89E-03	2.40E-02
CVTMCHPMPA	CVCS pump train A	8.57E-03	1.02E-01
CVTMCHPMPB	CVCS pump train B	8.10E-03	1.02E-01
CVTMCHPMPC	CVCS pump train C	8.10E-03	1.02E-01
DGTM00001B	DG A	5.86E-03	1.30E-02
DGTM00001B	DG B	5.86E-03	1.30E-02
HVTMAAIF02	IB exhaust fan AAIF02	1.56E-03	*
HVTMABSTRA	AB HVAC train A	1.28E-03	*
HVTMABSTRB	AB HVAC train B	1.28E-03	*

Table 7-4
Final Test and Maintenance Unavailability Values

T/M Event	*Description*	*P-S Data Based Value*	*Maint Rule Based Value*[1]
HVTMAIF01A	IB exhaust fan AIF01A	1.28E-03	*
HVTMAIF01B	IB exhaust fan AIF01B	1.28E-03	*
HVTMCHARGA	CVCS pump room HVAC train A	1.03E-03	*
HVTMCHARGB	CVCS pump room HVAC train B	1.03E-03	*
HVTMCTMT_A	Containment recirculation fan cooler train A	3.24E-03	1.00E-02
HVTMCTMT_B	Containment recirculation fan cooler train B	1.02E-03	1.00E-02
HVTMCTMT_C	Containment recirculation fan cooler train C	3.24E-03	1.00E-02
HVTMCTMT_D	Containment recirculation fan cooler train D	1.02E-03	1.00E-02
HVTMCTRLRM	Control room HVAC train	2.28E-03	2.30E-02
HVTMRELAYA	Relay room HVAC train A	9.05E-04	*
HVTMRELAYB	Relay room HVAC train B	8.93E-04	*
HVTMSAFW_A	SAFW pump room HVAC train A	3.80E-03	1.10E-01
HVTMSAFW_B	SAFW pump room HVAC train B	3.80E-03	1.10E-01
IATMCOMPRA	IA compressor A	6.74E-03	8.00E-02
IATMCOMPRB	IA compressor B	6.74E-03	8.00E-02
IATMCOMPRC	IA compressor C	4.51E-03	8.00E-02
IATMSACOMP	Service air compressor	6.74E-03	1.00E-01
MSTM003410	ARV B	3.98E-04	9.00E-03
MSTM003411	ARV A	3.98E-04	9.00E-03
RCTM000515	MOV 515 closed due to seat leakage	6.47E-02	*
RCTM000516	MOV 516 closed due to seat leakage	5.32E-04	*
RHTM00000A	RHR pump train A	2.90E-03	2.00E-02
RHTM00000B	RHR pump train B	2.90E-03	2.00E-02
SITM00871A	MOV 871A closed	3.20E-03	5.71E-03
SITM00871B	MOV 871B closed	9.84E-04	5.71E-03
SITM0PSI1A	SI pump A	2.37E-03	5.71E-03

Table 7-4
Final Test and Maintenance Unavailability Values

T/M Event	*Description*	*P-S Data Based Value*	*Maint Rule Based Value(1)*
SITM0PSI1B	SI pump B	2.37E-03	5.71E-03
SITM0PSI1C	SI pump C	2.82E-03	5.71E-03
SITMTRAINA	SI train A discharge valves	3.65E-03	5.71E-03
SITMTRAINB	SI train B discharge valves	2.54E-03	5.71E-03
SWTM4613MT	MOV 4613	4.97E-04	1.00E-03
SWTM4614MT	MOV 4614	4.97E-04	1.00E-03
SWTM4615MT	MOV 4615	4.97E-04	1.00E-03
SWTM4616MT	MOV 4616	4.97E-04	1.00E-03
SWTM4664MT	MOV 4664	4.97E-04	1.00E-03
SWTM4670MT	MOV 4670	4.97E-04	1.00E-03
SWTM4734MT	MOV 4734	4.97E-04	1.00E-03
SWTM4735MT	MOV 4735	4.97E-04	1.00E-03
SWTM9627AM	SW header to SAFW train A	8.65E-06	*
SWTM9627BM	SW header to SAFW train B	8.65E-06	*

Notes:

(1) * = no data available so plant-specific data is used.

Table 7-5
R. E. Ginna Reactor Trip History (1/1/80 - 12/31/95)

Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*[a]	*PSA Initiator Category*	*Source (LER)*	*Notes*[b]
14 NOV 81	?	100	Manual reactor trip due to inadvertent actuation of the Fire Suppression System which caused 2 rods in Bank C to drop.	3	TIRXTRIP	A-25.1	
25 JAN 82	0928	100	Automatic reactor trip due to RCS pressure drop which resulted from a tube rupture in S/G B.	n/a	LIOSGTRB	A-25.1	
23 MAY 82	1458	HSD	Automatic reactor trip on ΔT_{avg} during calibrations.	39	n/a	A-25.1	1
06 AUG 82	0908	100	Automatic reactor trip caused by isolation of the pressurizer level vent line during maintenance.	39	TIRXTRIP	A-25.1	
17 JAN 83	1124	100	Automatic reactor trip on steam/feed flow mismatch in S/G A during I&C calibration of S/G level. Operators attempted manual control of feed flow but could not prevent trip.	39	TIRXTRIP	A-25.1	
18 JAN 83	0246	5	Automatic reactor trip during startup due to low level in S/G B.	21	n/a	A-25.1	2
18 JUN 83	?	25	Automatic reactor trip caused by failed Intermediate Range instrumentation during startup.	39	TIRXTRIP	A-25.1	
20 JUN 83	0013	20	Automatic reactor trip during startup due to low feedwater flow to S/G A.	21	n/a	A-25.1	2
16 SEP 83	0027	17	Automatic reactor trip caused by operator error while reducing power for LCO requirements (BAST concentration).	21	n/a	83-027-00	2
30 MAY 84	2221	83	Automatic reactor trip following failure of generator excitor.	34	TIRXTRIP	A-25.1, 84-007-00	
06 APR 85	1902	5	Automatic reactor trip on low level in S/G B during startup. Trip occurred during calibration of the feedwater flow circuitry.	39	n/a	A-25.1, 85-006-00	

Table 7-5
R. E. Ginna Reactor Trip History (1/1/80 - 12/31/95)

Date	Time	Initial Power Level	Description	EPRI PWR Category[a]	PSA Initiator Category	Source (LER)	Notes[b]
06 APR 85	2341	12	Automatic reactor trip on low level in S/G B during startup (feedwater was being manually controlled). Turbine failed to trip automatically and had to be manually tripped.	21	n/a	A-25.1, 85-007-00	2
07 APR 85	1039	13	Automatic reactor trip on low-low level in S/G A during startup (feedwater was being manually controlled).	21	n/a	A-25.1, 85-008-00	2
08 APR 85	0536	18	Automatic reactor trip during load reduction for turbine overspeed test.	21	n/a	85-009-00	1
11 APR 85	1220	7	Automatic reactor trip on low condenser vacuum while reducing power to investigate circulating water leak.	25	TIRXTRIP	A-25.1, 85-011-01	
06 JUN 85	1049	100	Automatic reactor trip on ΔT_{avg} during I&C testing of source range detector N31 concurrent with a spike on Instrument Bus D.	39	TIRXTRIP	85-014-00	
28 SEP 85	2205	30	Manual reactor trip due to EH control problems following a leak in an EH oil cooler. Reactor power was initially reduced in an attempt to eliminate excursions.	33	TIRXTRIP	A-25.1, 85-018-00	
25 NOV 85	1335	85	Automatic trip on steam/feed flow mismatch following power reduction initiated by trip of Circulating Water Pump B. Operators were attempting to stabilize secondary side when trip occurred.	30	TIRXTRIP	A-25.1, 85-019-00	
29 JUL 86	0351	100	Manual reactor trip following rupture of the steam line elbow between the 2A MSR drainline and the 5B heater.	28	TIRXTRIP	A-25.1, 86-004-00	
30 JUL 86	1855	25	Automatic reactor trip due to faulty relays in the Intermediate Range blocking circuitry.	39	TIRXTRIP	A-25.1, 86-005-00	

Table 7-5
R. E. Ginna Reactor Trip History (1/1/80 - 12/31/95)

Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*[a]	*PSA Initiator Category*	*Source (LER)*	*Notes*[b]
23 OCT 86	0852	100	Automatic reactor trip following I&C technician error on high pressurizer pressure. Technician caused a short in S/G wide range level circuitry which resulted in a 60% turbine runback.	39	TIRXTRIP	A-25.1, 86-008-00	
28 NOV 86	1116	100	Automatic reactor trip on high pressurizer pressure after operator inadvertently shut both MSIVs.	18	TIRXTRIP	A-25.1, 86-011-00	
05 FEB 88	1857	HSD	Automatic reactor trip on high flux while shutting down due to failed N-31 source range detector.	39	n/a	A-25.1	
10 MAR 88	1856	27	Automatic reactor trip on steam/feed flow mismatch for S/G A during synchronization of turbine generator.	21	n/a	A-25.1, 88-003-00	2
01 JUN 88	1932	98	Automatic reactor trip on low feedwater flow to S/G B after operator took flow into manual following conflicting S/G level indications (failed flow transmitter fuse).	22	TIRXTRIP	A-25.1, 88-005-00	
16 JUL 88	1355	0	Manual reactor trip after control rod failed to insert during controlled shutdown following a partial loss of off-site power.	3	TIRXTRIP	A-25.1	
01 JUN 89	1332	53	Automatic reactor trip on AMSAC due to procedural error to reset bistable during post-installation testing.	39	TIRXTRIP	89-04	
23 MAR 90	1804	HSD	Automatic reactor trip on high source range count due to failed source range monitor during shutdown activities.	39	n/a	90-03	1
10 MAY 90	0219	88	Automatic reactor trip on SG low level coincident with SG feed flow / steam flow mismatch due to a short in MFW flow controller.	39	TIRXTRIP	90-07	
09 JUN 90	0411	97	Automatic reactor trip on SG low level coincident with SG feed flow / steam flow mismatch due to a failed MFW flow controller.	39	TIRXTRIP	90-10	

Table 7-5
R. E. Ginna Reactor Trip History (1/1/80 - 12/31/95)

Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*[a]	*PSA Initiator Category*	*Source (LER)*	*Notes*[b]
26 SEP 90	1100	97	Automatic reactor trip on turbine autostop valve closure signal due to dropped flashlight in relay cabinet.	39	TIRXTRIP	90-12	
11 DEC 90	1517	97	Automatic reactor trip from AMSAC due to faulty vendor system design.	39	n/a	90-13	3
12 DEC 90	2322	3	Automatic reactor trip on high Intermediate Range due to bus transfer activities which momentarily de-energized bistable.	39	n/a	90-16	1
21 DEC 90	1237	16	Automatic reactor trip on low SG level due to trip of MFW pump on low Δp following operator error to place necessary number of condensate pumps into service.	21	n/a	90-19	1
03 FEB 92	2220	23	Automatic reactor trip on low SG level due to operator inability to manually control level following a turbine trip.	33	n/a	92-02	1
29 FEB 92	1992	97	Automatic reactor trip on low SG level due to trip of MFW pump from plugged instrument tubing for seal injection Δp.	39	TIRXTRIP	92-03	
12 MAR 93	1425	HSD	Manual reactor trip after operators discover both source ranges are inoperable.	40	n/a	93-01	1
10 NOV 93	0848	97	Automatic reactor trip on low SG level due to failed linkage arm on MFRV.	15	TIRXTRIP	93-06	
22 NOV 93	0644	HSD	Automatic trip on high source range due to operator failure to block trip function during startup activities.	39	n/a	93-07	1

Table 7-5
R. E. GINNA REACTOR TRIP HISTORY (1/1/80 - 12/31/95)

EPRI PWR Category[a]

(1) All reactor trips caused by calibrations or testing were identified as category 39 (Auto trip - no transient condition) unless otherwise noted.

(2) All reactor trips caused by feedwater control problems during startup prior to 1991 were identified as category 21 (Feedwater flow instability - operator error) since feedwater was under manual control (prior to the installation of the Advanced Digital Feedwater Control System).

Notes[b]

(1) No PSA initiator category was assigned since the trip occurred during Hot Shutdown (HSD) or low power conditions due to causes which would not exist during normal power operations (e.g., calibration activities, reactor startup, etc.).

(2) No PSA initiator category was assigned since the trip occurred during low power conditions (i.e., before turbine synchronization) where feedwater control problems prevailed. These feedwater control problems were not observed during normal power operations; therefore, they were excluded.

(3) No PSA initiator category was assigned since trip occurred due to faulty vendor designed AMSAC which has since been corrected.

Table 7-6 Development of Prior Distribution for TIRXTRIP - Reactor Trip				
EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
1	Loss of RCS flow (1 loop)	0.28	0.63	0.3969
2	Uncontrolled rod withdrawal	0.28	0.10	0.0100
3	CRDM problem and/or rod drop	0.50	1.57	2.4649
4	Leakage from control rods	0.02	0.19	0.0361
5	Leakage in primary system	0.05	0.26	0.0676
6	Low pressurizer pressure	0.03	0.16	0.0256
7	Pressurizer leakage	0.005	0.07	0.0049
8	High pressurizer pressure	0.03	0.27	0.0729
9	Inadvertent safety injection signal	0.05	0.27	0.0729
10	Containment pressure problems	0.005	0.10	0.0100
11	Containment pressure problems	0.03	0.20	0.0400
12	Pressure, temperature, power imbalance - rod position error	0.13	0.55	0.3025
14	Total loss of RCS flow	0.03	0.19	0.0361
15	Loss or reduction in feedwater flow (1 loop)	1.50	2.17	4.7089
17	Full or partial closure of MSIV (1 loop)	0.17	0.60	0.3600
18	Closure of all MSIV	0.04	0.24	0.0576
19	Increase in feedwater flow (1 loop)	0.44	1.17	1.3700
20	Increase in feedwater flow (all loops)	0.02	0.18	0.0300
21	Feedwater flow instability - operator error	0.29	0.76	0.5776
22	Feedwater flow instability - miscellaneous mechanical causes	0.34	0.86	0.7396
23	Loss of condensate pumps (1 loop)	0.07	0.30	0.0900
26	Steam generator leakage	0.03	0.20	0.0400
27	Condenser leakage	0.04	0.24	0.0576
28	Miscellaneous leakage in secondary system	0.09	0.31	0.0961
30	Loss of circulating water	0.05	0.30	0.0900
33	Turbine trip, throttle valve closure, EHC problems	1.19	1.56	2.4336
34	Generator trip or generator caused faults	0.46	0.88	0.7744

Table 7-6
Development of Prior Distribution for TIRXTRIP - Reactor Trip

EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
36	Pressurizer spray failure	0.03	0.17	0.0289
38	Spurious trips - cause unknown	0.08	0.38	0.1444
39	Auto trip - no transient condition	1.42	1.90	3.6100
40	Manual trip - no transient condition	0.47	0.96	0.9216
	TOTAL	8.17		19.8656
		α	3.43	
		β	0.41	

Table 7-7
Development of Prior Distribution for TIFWLOSS - Loss of Main Feedwater

EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
16	Total loss of feedwater flow (all loops)	0.16	0.51	0.26
24	Loss of condensate pumps (all loops)	0.01	0.10	0.0100
25	Loss of condenser vacuum	0.14	0.43	0.1849
	TOTAL	0.31		0.46
		α	0.209	
		β	0.67	

Table 7-8
High Energy Line Break Frequencies Used in Previous PSAs

Source	*Description*	*Frequency (/y)*
NUREG/CR-4407	feedwater line breaks (2 events in 484.73 reactor years)	4.10E-02
	steamline breaks (0 events in 484.73 reactor years)	5.00E-04
NUREG/CR-5622	trips related to feedwater piping (9 events in 315.17 reactor years)	2.86E-02
	trips related to steamline piping (2 events in 315.17 reactor years)	6.34E-03
NSAC-060, Table 5.9	feedwater line break	9.3E-04
IAEA Summary for Ringhals-2	steamline break	4.4E-04
IAEA Summary for German Risk Study	steamline break inside containment	1.6E-04
	steamline break outside containment	4.8E-04
WASH-1400	feedwater line break	2.5E-05
	steamline break	3.9E-04
NUREG/CR-4550 analysis of Zion	steamline break inside containment	9.4E-04
	steamline break outside containment	9.4E-04

Table 7-9
Development of Prior Distribution for TISLBSVA- Inadvertent Steam Generator ARV Lift

EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
29	Sudden opening of steam relief valves.	0.02	0.18	0.0324
	TOTAL	0.02		0.0324
		α	0.012	
		β	0.617	

Table 7-10
EPRI LOCA Frequency Correlation Parameter Values

Parameter	*Value*
Z	2.9E-10 / h
C_1	1.2
C_2	0.6
C_3	1.4
$P_{2/3}$	1 / 3
$P_{1/2}$	1 / 10
$P_{1/3}$	1 / 5
$P_{2/2}$	9 / 10
$P_{3/3}$	7 / 15
n_1	339
n_2	195
n_3	109

Table 7-11
LOCA Frequencies Used in Previous PSAs

Source	*Description*	*Frequency (/y)*
NSAC-060, Table 5.9	large LOCA (> 4 in^2)	9.3E-04
	small LOCA (.5 - 4 in^2)	3.0E-03
	SG tube rupture (> 100 gpm)	8.6E-03
IAEA Summary for Ringhals-2	large LOCA (> 15 cm)	4.0E-04
	medium LOCA (5 - 15 cm)	8.1E-04
	small LOCA	1.1E-02
	SG tube rupture	9.7E-3
NUREG-4550, Vol. I	large LOCA (> 6 inches)	5.0E-04
	medium LOCA (2 - 6 inches)	1.0E-03
	small LOCA (.5 - 2 inches)	1.0E-03
	small-small LOCA (< .5 inches)	1.3E-02
IAEA Summary for German Risk Study	large LOCA (>400 cm^2)	2.7E-04
	medium LOCA (80 - 400 cm^2)	8.0E-04
	small LOCA (2 - 80 cm^2)	2.7E-03
IREP-ANO1	large LOCA (> 13.5 inches)	7.5E-05
	large LOCA (10 - 13 inches)	1.2E-05
	medium LOCA (4 - 10 inches)	1.6E-04
	small LOCA (1.66 - 4 inches)	3.8E-04
	small LOCA (1.2 - 1.66 inches)	3.1E-04
	small-small LOCA (0.38 - 1.2 inches)	2.0E-02
Sequoyah PSA	large LOCA (> 6 inches)	4.7E-5
	medium LOCA (2 - 6 inches)	9.8E-4
	small LOCA (0.5 - 2 inches)	1.8E-3
WASH-1400	large LOCA (> 6 inches)	1.0E-4

Table 7-12
Development of Prior Distribution for Initiator TI000CCW - Loss of CCW

EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
31	Loss of component cooling	0.02	0.15	0.0225
	TOTAL	0.02		0.0225
		α	0.018	
		β	0.889	

Table 7-13
Final Listing of Initiating Event Frequencies

	Description	*Designator*	*Frequency/yr*
1.	Reactor Trip	TIRXTRIP	1.82
2.	Loss Of Offsite Power - Grid	TIGRLOSP	2.28E-02
3.	Loss Of Offsite Power - Switchyard	TISWLOSP	4.04E-02
4.	Loss of Offsite Power - 480 V Trains	TI48LOSP	Varies
5.	Loss Of Offsite Power Following Reactor Trip (All) - SI	ACLOPRTALL	1.00E-02
5a.	Loss Of Offsite Power Following Reactor Trip (All) - No SI	ACLOPRTALL	1.00E-03
6.	Loss Of Offsite Circuit 751 Following Reactor Trip - SI	ACLOPRT751	1.19E-02
6a.	Loss Of Offsite Circuit 751 Following Reactor Trip - No SI	ACLOPRT751	2.69E-03
7.	Loss Of Offsite Circuit 767 Following Reactor Trip - SI	ACLOPRT767	1.00E-02
7a.	Loss Of Offsite Circuit 767 Following Reactor Trip - No SI	ACLOPRT767	1.21E-03
8.	Loss of Main Feedwater	TIFWLOSS	1.53E-02
9.	Feedwater Line Break In Line For SG A Inside Containment	TIFLBACT	2.58E-05
10	Feedwater Line Break In Line For SG B Inside Containment	TIFLBBCT	2.58E-05
11.	Feedwater Line Break In Turbine Building	TIFLB0TB	1.40E-03
12.	Feedwater Line Break In Line For SG A Inside Intermediate Building	TIFLBAIB	2.58E-05
13.	Feedwater Line Break In Line For SG B Inside Intermediate Building	TIFLBBIB	3.87E-05
14.	Exterior MFW Line Break on SG B	TIFLBSGB	3.87E-05
15.	Steam Line Break In Line For SG A Inside Containment	TISLBACT	2.38E-05
16.	Steam Line Break In Line For SG B Inside Containment	TISLBBCT	2.38E-05
17.	Steam Line Break In Turbine Building	TISLB0TB	1.29E-03
18.	Steam Line Break In Line For SG A Inside Intermediate Building	TISLBAIB	2.38E-05
19.	Steam Line Break In Line For SG B Inside Intermediate Building	TISLBBIB	3.58E-05
20.	Steam Line Break Through The Steam Dump System	TI0SLBSD	5.78E-03
21.	Inadvertent Safety Valve Operation On Both SGs	TISLBSVA	2.82E-03
22.	Exterior Steam Line Break On SG B	TISLBSGB	3.58E-05
23.	Loss of Instrument Air	TIIALOSS	4.15E-02
24.	Reactor Vessel Rupture	LIRVRUPT	1.00E-08
25.	Large LOCA	LILBLOCA	1.80E-04
26.	Medium LOCA	LIMBLOCA	4.00E-04
27.	Small LOCA	LISBLOCA	1.10E-03
28.	Small-Small LOCA	LISSLOCA	5.50E-03
29.	Steam Generator Tube Rupture In SG A	LI0SGTRA	4.84E-03
30.	Steam Generator Tube Rupture In SG B	LI0SGTRB	4.84E-03
31.	Intersystem LOCA	LIISLOCA	N/A
32.	Loss Of Service Water Header A	TI000SWA	1.32E-04
33.	Loss Of Service Water Header B	TI000SWB	1.32E-04
34.	Total Loss of Service Water	TI0000SW	1.43E-04
35.	Loss Of Component Cooling Water	TI000CCW	1.30E-03
36.	Loss Of Main DC Distribution Panel A (DCPDPCB03A)	TI000DCA	5.54E-03
37.	Loss Of Main DC Distribution Panel B (DCPDPCB03B)	TI000DCB	5.54E-03
38.	Locked RCP Rotor	TIRCPROT	1.00E-04

Table 7-14
Multiple Human Error Events In Same Cutset

Sequence	*Human Error Events*	*Value*
SBO	RRHFDSUCTN - Operators Fail to Manually Open RHR Suction Valves SWHFDSTART - Operators Fail to Start Standby SW Pump Or Isolate Loads	1.00E-01 5.00E-03(1)
	RCHFDRHRSB - Operators Fail to Rapidly Depressurize to RHR or Use AFW SWHFDSTART - Operators Fail to Start Standby SW Pump Or Isolate Loads	5.00E-03(1) 5.00E-03(1)
ATWS	CVHFDBORAT - Operators Fail to Implement Emergency Boration RCHFDSCRAM - Operators Fail to Trip Rod Drive MG Sets	1.00E-02 1.00E-02
SGTR	RCHFDCDDPR - Ops Fail to Cooldown and Depressurize to Prevent Overfill RCHFDCOOLD - Ops Fail to Rapidly Cooldown to RHR After ARV Sticks Open	9.7E-03 3.07E-02
	RCHFDCDDPR - Ops Fail to Cooldown and Depressurize to Prevent Overfill RRHFDSUCTN - Operators Fail to Manually Open RHR Suction Valves	9.7E-03 1.00E-01
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW MFHFDMF100 - Operators Fail to Re-Establish MFW Following Plant Trip	6.7E-03 1.2E-02
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW AFHFDSUPPL - Operators Fail to Supply Alternate Sources of Water to AFW	6.7E-03 1.0E-03
	RCHFDCDDPR - Ops Fail to Cooldown and Depressurize to Prevent Overfill RRHFDTHROT - Operators Fail to Throttle RHR Flow for NPSH Concerns	9.73E-03 1.00E-01
	RCHFDCDDPR - Ops Fail to Cooldown and Depressurize to Prevent Overfill RCHFDCDOVR - Ops Fail to Rapidly Cooldown to RHR After SG Overfill Occur	9.7E-03 3.07E-02
	MSHFDISOLR - Operators Fail to Isolate Ruptured SG RRHFDSUCTN - Operators Fail to Manually Open RHR Suction Valves	7.24E-03 1.00E-01
LOCA	RCHFDCDOSS - Operators Fail to Cooldown to RHR After SI Fails SRHFDRECRC - Operators Fail to Shift SI System to Recirculation	9.1E-03(2) 1.30E-03
	RCHFDCDOSS - Operators Fail to Cooldown to RHR After SI Fails RCHFDRECRC - Operators Fail to Shift RHR System to Recirculation	9.1E-03(2) 1.2E-03
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW AFHFDSUPPL - Operators Fail to Supply Alternate Sources of Water to AFW	6.7E-03 1.0E-03
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW MFHFDMF100 - Operators Fail to Re-Establish MFW Following Plant Trip	6.7E-03(2) 1.2E-02
Trans LOCAs	RCHFDLOCA - Operators Fail to Close PORV Block Valve to Terminate LOCA RRHFDRECRC - Operators Fail to Shift RHR System to Recirculation	1.00E-01 1.2E-03
	RCHFDLOCA - Operators Fail to Close PORV Block Valve to Terminate LOCA CVHFD00371 - Operators Fail to Manually Isolate AOV 371 to Prevent ISLOCA	1.00E-01 2.0E-02
	RCHFDLOCA - Operators Fail to Close PORV Block Valve to Terminate LOCA RRHFDTHROT - Operators Fail to Throttle RHR Flow for NPSH Concerns	1.00E-01 1.00E-01

Table 7-14
Multiple Human Error Events In Same Cutset

Sequence	*Human Error Events*	*Value*
Seal LOCAs	CVHFDSUCTN - Operators Fail to Manually Open Suction Line to CVCS Pumps SWHFDSTART - Operators Fail to Start Standby SW Pump	2.04E-02 5.00E-03(1)
	CVHFDSUCTN - Operators Fail to Manually Open Suction Line to CVCS Pumps IAHFDCSA03 - Ops Fail to Place CNMT Breathing Air Compressor In Service IAHFDCSA04 - Operators Fail to Place Diesel Air Compressore In Service	2.04E-02 1.00E-01 1.00E-01
Transients	AFHFDALTTD - Operators Fail to Provide Fire Water Cooling for TDAFW Pump SWHFDSTART - Operators Fail to Start Standby SW Pump	6.7E-03 5.00E-03(1)
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW AFHFDSUPPL - Operators Fail to Supply Alternate Sources of Water to AFW	6.7E-03 1.0E-03
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW MFHFDMF100 - Operators Fail to Re-Establish MFW Following Plant Trip	6.7E-03(2) 1.2E-02
	AFHFDSAFWX - Operators Fail to Correctly Align SAFW RCHFD01BAF - Operators Fail to Implement Bleed and Feed	6.7E-03 Varies(3)
	AFHFDALTTD - Operators Fail to Provide Fire Water Cooling for TDAFW Pump RCHFD01BAF - Operators Fail to Implement Bleed and Feed	6.7E-03 Varies(3)
	SWHFDSTART - Operators Fail to Start Standby SW Pump RCHFD01BAF - Operators Fail to Implement Bleed and Feed	5.00E-03(1) Varies(3)

Notes:

(1) Value is based on both human error and equipment failures.

(2) Value is set to 1.0E-01 for this specific combination.

(3) Values are determined based on number of human actions in cutset.

Table 7-15
Post-Initiator Human Errors

Event Name and Description		*Final Value*
ACHFDCR751 - Operators Fail to Realign Offsite Power Supply to Circuit 751		1.00E-01
ACHFDCR767 - Operators Fail to Realign Offsite Power Supply to Circuit 767		1.00E-01
AFHFDALTTD - Operators Fail to Provide Fire Water Cooling For TDAFW Pump		6.7E-03
AFHFDSAFWX - Operators Fail to Correctly Align SAFW		5.19E-03
AFHFDSUPPL - Operators Fail to Supply Alternate Sources of Water to AFW		1.00E-03
AFHFDTDAFW - Operators Fail to Start TDAFW Pump During SBO		1.00E-01
CCHFDCCWAB - Operators Fail to Start Standby CCW Pump When Auto Start Signal Fails		6.7E-03
CCHFDSTART - Operators Fail to Start a CCW Pump Following a LOOP and SI Condition		6.7E-03
CVHFD00313 - Operators Fail to Manually Isolate MOV 313 (Seal Return) to Prevent ISLOCA		1.20E-03
CVHFD00371 - Operators Fail to Manually Isolate AOV 371 (Letdown)	(Large LOCA) (Medium LOCA) (Small LOCA)	1.3E-02 5.3E-03 1.2E-03
CVHFDBORAT - Operators Fail to Implement Emergency Boration		1.00E-02
CVHFDPUMPST - Operators Fail to Manually Load Charging Pump		6.7E-03
CVHFDSUCTN - Operators Fail to Manually Open Suction Line to CVCS Pumps		2.04E-02
HVHFDABVLP - Operators Fail to Re-Start Aux Bldg Exhaust Ventilation Following LOOP		1.00E-01
HVHFDIBVEN - Operators Fail to Re-Start Intermediate Bldg Exhaust Fans Following LOOP		1.00E-01
HVHFD_CTMT - Operators Fail to Re-Start Containment Cooling		1.00E-01
IAHFDCSA03 - Operators Fail to Place CNMT Breathing Air Compressor In Service		1.00E-01
IAHFDCSA04 - Operators Fail to Place Diesel Air Compressor In Service		1.00E-01
MFHFDMF100 - Operators Fail to Re-Establish Main Feedwater	(SI Exists) (No SI)	1.2E-02 9.3E-03
MSHFDISOLA - Operators Fail to Isolate Ruptured SG Using Secondary Non-Automatic Valve		1.00E-01
MSHFDISOLR - Operators Fail to Isolate Ruptured SG		7.24E-03
MSHFDMSIVX - Operators Fail to Close MSIV After Signal Fails		1.00E-01
TLHFDPN110 - Operators Fail to Recover ISLOCA Through Penetration 110		2.07E-01
TLHFDPN111 - Operators Fail to Recover ISLOCA Through Penetration 111		1.88E-01
TLHFDPN140 - Operators Fail to Recover ISLOCA Through Penetration 140		1.90E-01

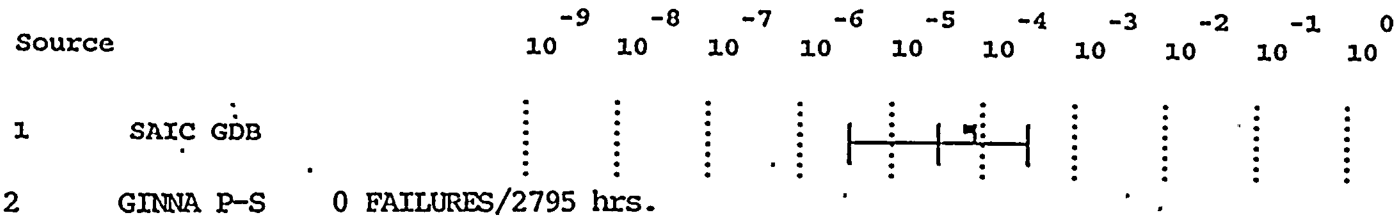
Table 7-15
Post-Initiator Human Errors

Event Name and Description	*Final Value*
RCHFD00MRI - Operators Fail to Manually Insert Rods	1.00E-02
RCHFD00RCP - Operators Fail to Trip RCPs Within 2 Minutes	1.61E-02
RCHFD01BAF - Operators Fails to Implement Feed and Bleed (SI Exists, Single Actions) (SI Exists, Multiple Human Actions) (No SI, Single Action) (No SI, Multiple Human Actions)	5.3E-02 4.07E-01 2.9E-02 6.2E-02
RCHFDCD0SS - Operators Fail to Cooldown to RHR After SI Fails -LOCAs	9.1E-03
RCHFDCDDPR - Operators Fail to Cooldown and Depressurize RCS Prior to SG Overfill	9.61E-03
RCHFDCDOVR - Operators Fail to Cooldown to RHR Conditions After SG Overfill Occurs	3.07E-02
RCHFDCDTR2 - Operators Fail to Cooldown to RHR Conditions After SI Fails During SGTR	3.07E-02
RCHFDCOOLD - Operators Fail to Cooldown to RHR Conditions After ARV Sticks Open	3.07E-02
RCHFDHEATR - Operators Fails to Load Pressurizer Heaters Following LOOP	2.58E-04
RCHFDPLOCA - Operators fail to Close PORV Block Valve to Terminate LOCA W/In 3 Min	1.00E-01
RCHFDRHRSB - Operators Fail to Rapidly Depressurize to RHR (Or Use AFW Long-Term)	5.00E-03
RCHFDSCRAM - Operators Fail to Trip Rod Drive MG Sets During ATWS	1.00E-02
RRHFDRECRC - Operators Fail to Correctly Shift RHR System to Recirculation Phase (Large) (Medium LOCA) (Small LOCA)	1.3E-02 5.3E-03 1.2E-03
RRHFDSEALX - Operators Fail to Identify and Trip RHR Pump With Leaking Seals	1.00E-01
RRHFDSUCTN - Operators Fail to Manually Open RHR Suction Valves	1.00E-01
RRHFDTHROT - Operators Fails to Throttle RHR Flow For NPSH Concerns	1.00E-01
SIHFDSTRTP - Operators Fail to Manually Start SI Pump on Loss of Signal	1.00E-01
SRHFDRECRC - Operators Fail to Shift SI System to Recirculation	1.3E-03
SWHFDSTART - Operators Fail to Start Standby SW Pump Or Isolate System	5.0E-03
UVHFDBREAK - Operators Fail to Manually Close DG onto 480 V Bus	1.00E-01

Figure 7-1
Comparison of Generic and Plant-Specific Data for AFW Pumps

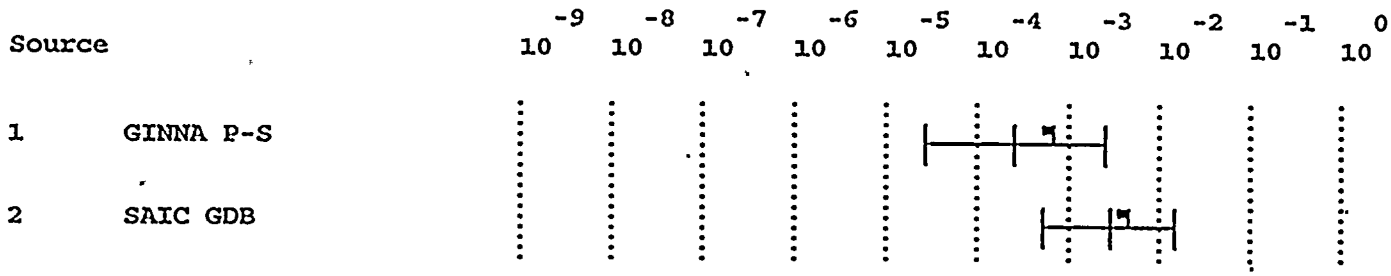
Component Type Code: AF
Failure Mode Type Code: MP F

Component Name: MOTOR-DRIVEN PUMP
Failure Mode: FAILS TO RUN



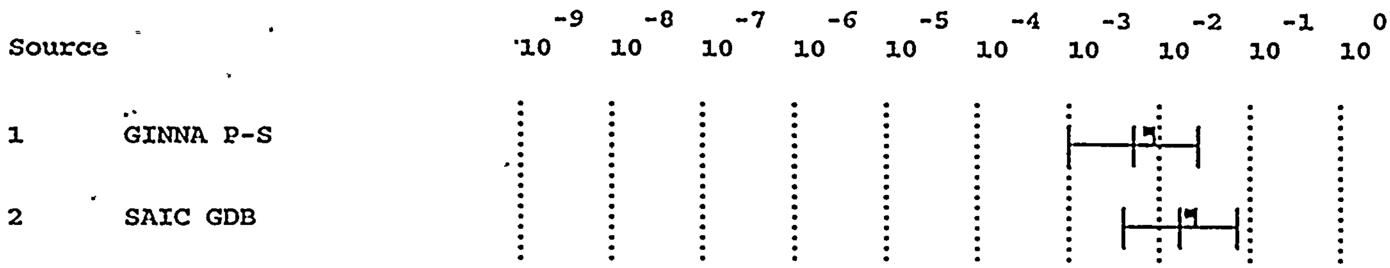
Component Type Code: AF
Failure Mode Type Code: MP A

Component Name: MOTOR-DRIVEN PUMP
Failure Mode: FAILS TO START



Component Type Code: AF
Failure Mode Type Code: TP A

Component Name: TURBINE-DRIVEN PUMP
Failure Mode: FAILS TO START



Component Type Code: AF
Failure Mode Type Code: TP F

Component Name: TURBINE PUMP
Failure Mode: FAILS TO RUN

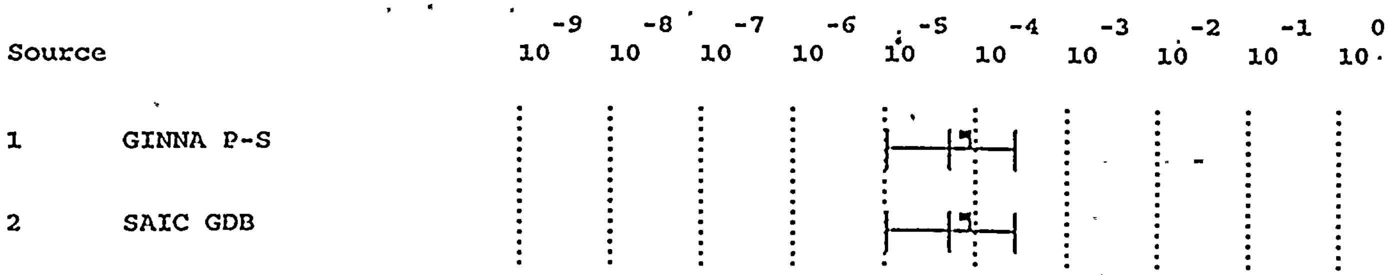
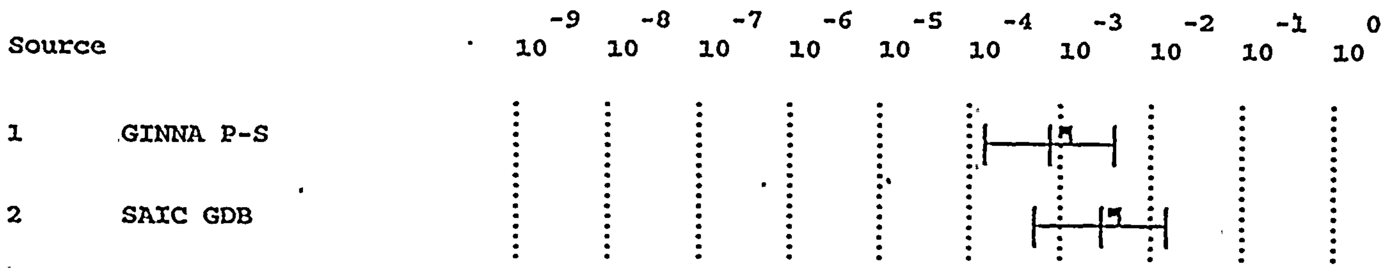


Figure 7-2
Comparison of Generic and Plant-Specific Data for ECCS Pumps

Component Type Code: ECCS
Failure Mode Type Code: MP A
Component Name: MOTOR-DRIVEN PUMP
Failure Mode: FAILS TO START



Component Type Code: ECCS
Failure Mode Type Code: MP F
Component Name: MOTOR-DRIVEN PUMP
Failure Mode: FAILS TO RUN

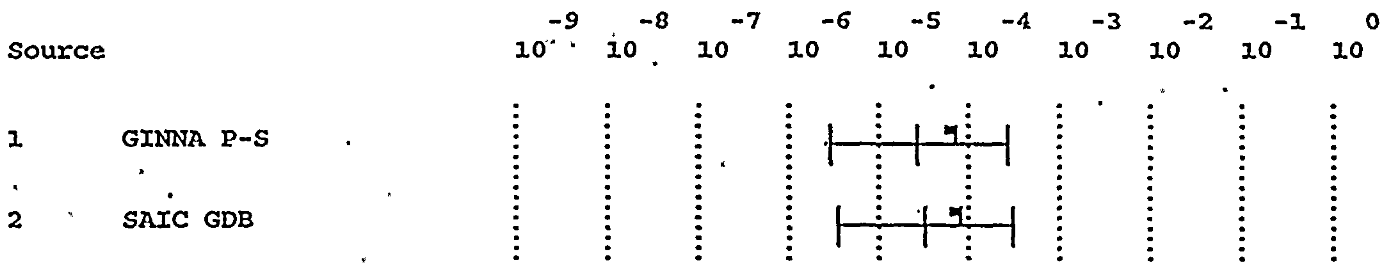
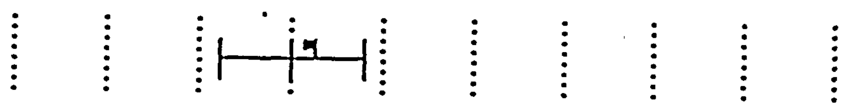


Figure 7-3
Comparison of Generic and Plant-Specific Data for Batteries

Component Type Code: DC Component Name: BATTERY
Failure Mode Type Code: BT F Failure Mode: NO OUTPUT (HOURLY)

Source 10^{-9} 10^{-8} 10^{-7} 10^{-6} 10^{-5} 10^{-4} 10^{-3} 10^{-2} 10^{-1} 10^{0}

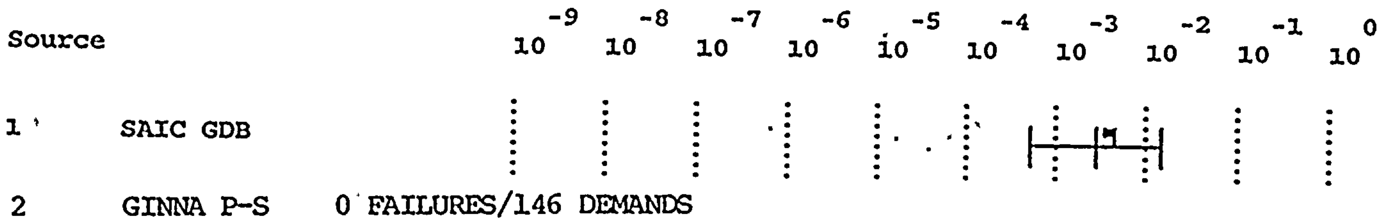
1 SAIC GDB



2 GINNA P-S 0 FAILURES/236732 hrs.

Figure 7-4
Comparison of Generic and Plant-Specific Data for MFW Pumps

Component Type Code: MF Component Name: MOTOR-DRIVEN PUMP
Failure Mode Type Code: MP A Failure Mode: FAILS TO START



Component Type Code: MF Component Name: MOTOR-DRIVEN PUMP
Failure Mode Type Code: MP F Failure Mode: FAILS TO RUN

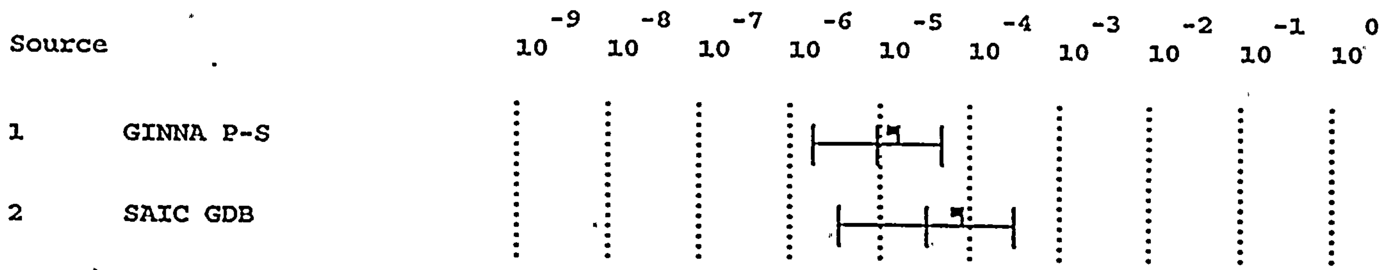


Figure 7-5
Comparison of Generic and Plant-Specific Data for AC Electrical Buses

Component Type Code: AC   Component Name: <4 KV BUS
Failure Mode Type Code: B2 F   Failure Mode: FAULT

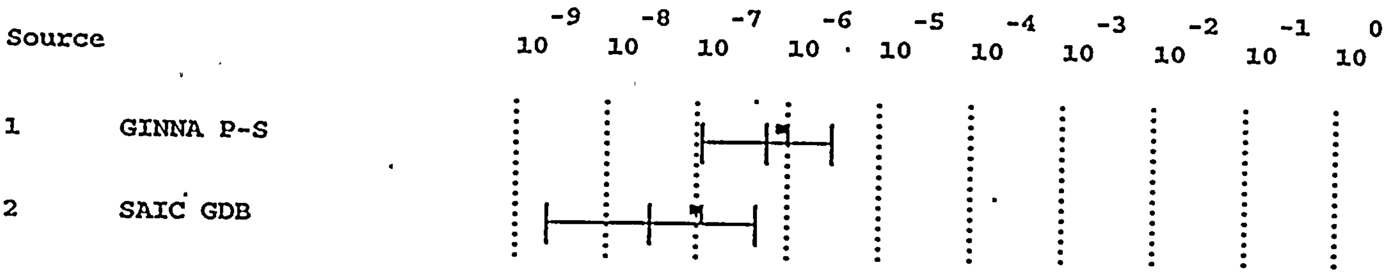


Figure 7-6
Comparison of Generic and Plant-Specific Data for AC Breakers

Component Type Code: AC
Failure Mode Type Code: CB D

Component Name: AC BREAKER
Failure Mode: FAILS TO OPERATE

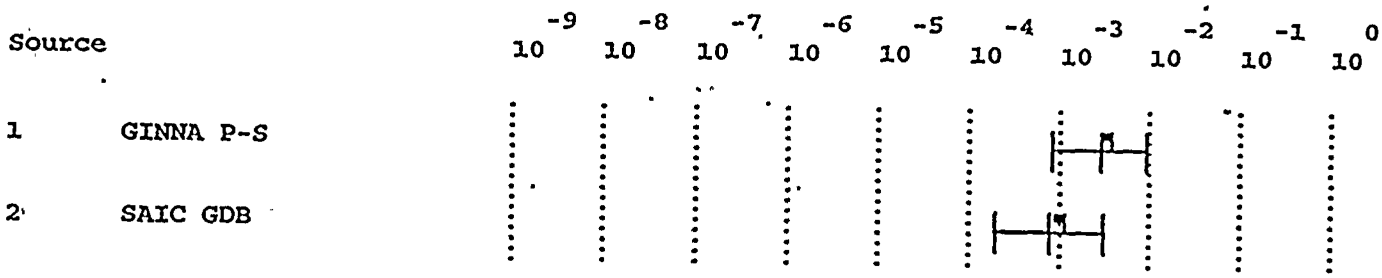
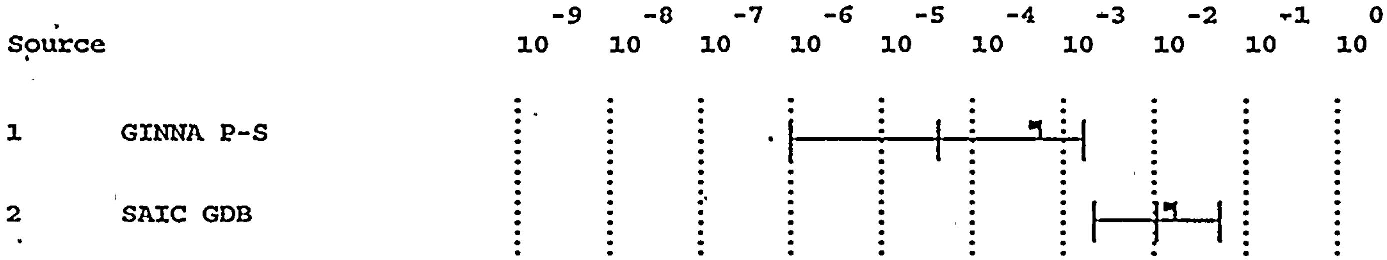


Figure 7-7
Comparison of Generic and Plant-Specific Data for DGs

Component Type Code: DG
Failure Mode Type Code: DG A

Component Name: DIESEL GENERATOR
Failure Mode: FAILS TO START



Component Type Code: DG
Failure Mode Type Code: DG F

Component Name: DIESEL GENERATOR
Failure Mode: FAILS TO RUN

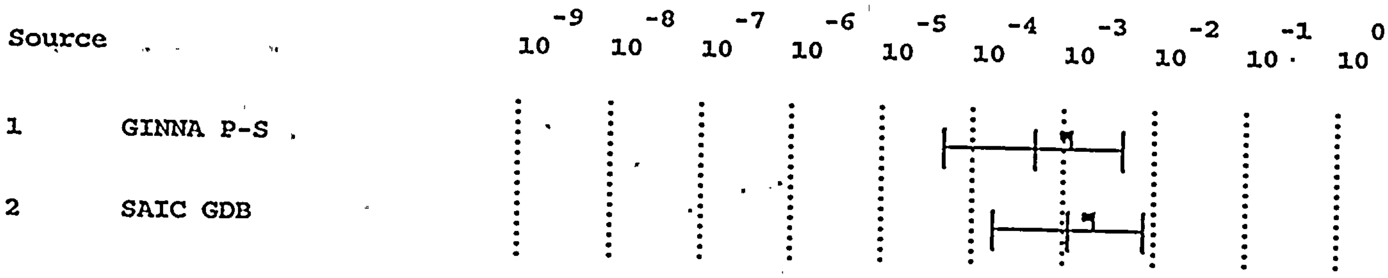
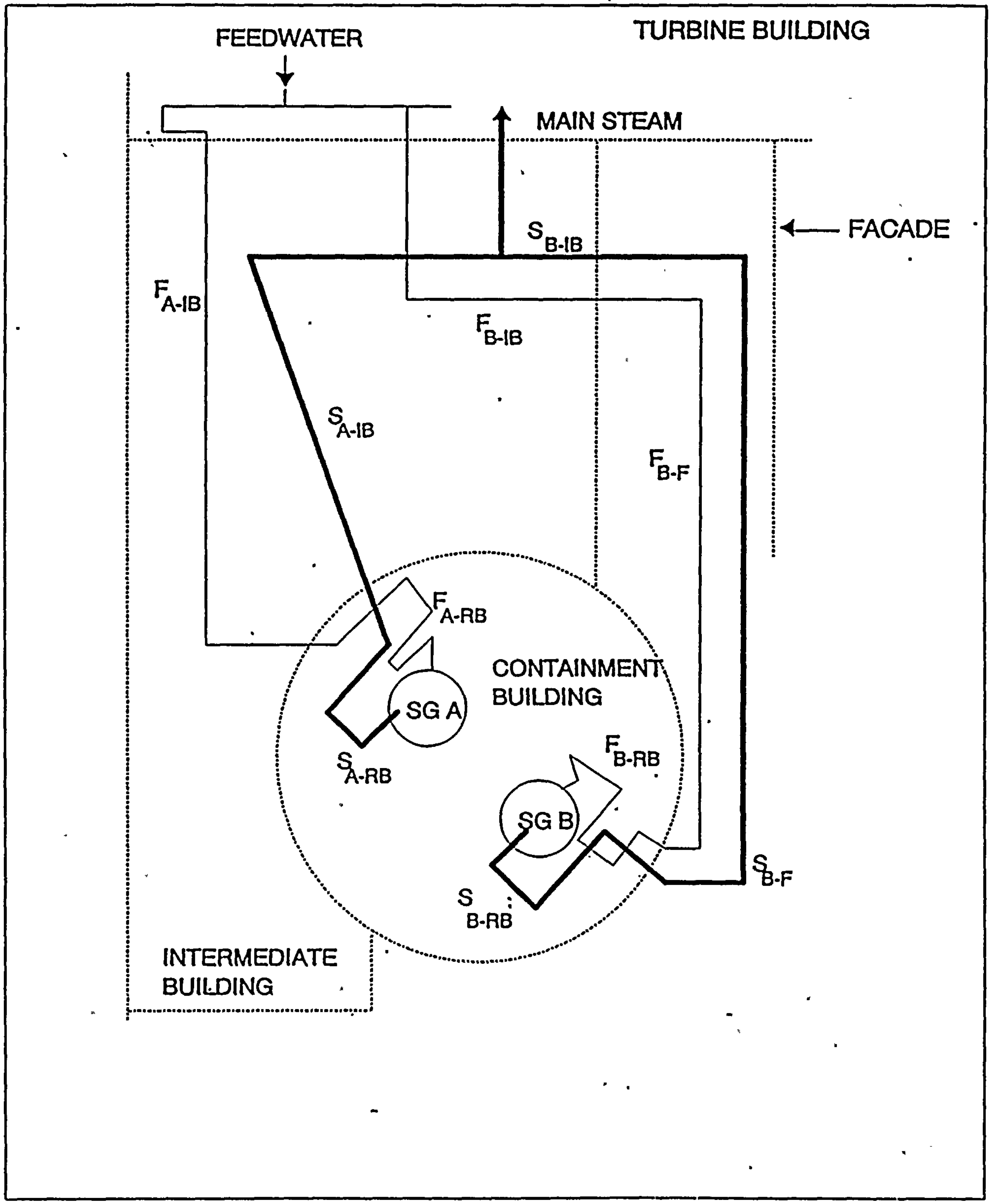


Figure 7-8
High Energy Piping Configurations



8.0 QUANTIFICATION

Quantification refers to the solution of the accident sequences in order to generate an estimated frequency of core damage. There are three general types of quantification which were used in the Ginna Station PSA as follows:

a. Internal event solution;

b. Interfacing System Loss-of-Coolant Accident (ISLOCA) evaluation; and

c. External event solution.

Each one of these quantification efforts is described in detail below.

8.1 Internal Event Solution

The solution of the Ginna Station PSA internal event model is essentially the solution of the accident sequences delineated in the event trees provided in Section 5. This solution is an involved and iterative process. However, to fully understand the quantification process, all activities which precede this process must be understood. These activities are summarized below:

a. The list of potential initiating events must first be developed (Section 3). For the Ginna Station PSA, initiators are those events which directly or procedurally lead to a reactor trip. Internal events are those initiators which originate within the plant systems (e.g., loss of main feedwater).

b. Following the identification of potential initiators, success criteria must be developed (Section 4). Success criteria refers to those functions which must be accomplished in order to prevent core damage following a given initiator. The success criteria are broken down into four main core protection functions: reactivity control, reactor coolant system (RCS) pressure control, RCS inventory control, and RCS heat removal.

c. Once the success criteria are identified, they must be transposed into logical accident sequence progressions referred to as event trees (Section 5). Event trees identify which front-line systems must be successful during the accident progression for each of the four main functions listed above. This description of the accident sequence is referred to as an event tree since it is a basically a "tree" comprised of multiple branches. Each branch represents the success or failure of the four core protection functions defined with respect to systems. A downward branch represents failure of the system while an upward branch represents success. Thus, following the event tree along the branches is the accident sequence progression.

d. Following the development of the event trees, the system fault tree models must be developed that represent the failure of an event tree branch (Section 6). Since the event trees only identify front-line systems (e.g., safety injection (SI)), necessary support systems must also be developed. The data necessary to support the fault tree model solution is provided in Section 7.

Once the above steps are performed, the quantification process can begin. A summary of the process is provided below:

a. *Integrated Plant Model* - An integrated plant model must be generated to support all of the event tree branches. Since the Ginna Station PSA utilizes a small event tree/large fault tree approach, this means that there are relatively few front-line systems directly called by the event trees; however, the necessary fault tree models may be quite large. The system fault tree models were generated independently of one another with "transfers" into supporting systems as necessary (e.g., the AFW model identifies certain transfers into the electric power model for various pumps and valves). The integrated plant model is generated by combining all system fault tree models into a single file. As such, the AFW system model will include all the necessary logic from the electric power and ventilation systems so that its top gate can be solved.

b. *Logic Flags* - The system fault tree models were developed with the intention of allowing any plant configuration which may exist at 100% power (e.g., identify which charging pumps are operating). In addition, the fault tree models may require a different response based on initial configurations (e.g., the number of service water (SW) pumps initially in service may affect the system isolation requirements). As such, all logic flags must be identified and appropriately controlled prior to quantification.

c. *Model Solution* - Following the above steps, the integrated model is solved using available industry computer codes. The solution of the integrated model yields "cutsets" or those minimal combination of events which lead to core damage for the accident sequence of concern.

d. *Recovery Analysis* - Once the cutsets have been generated, they must be reviewed to add possible recovery actions. Essentially, the recovery process consists of adding additional operator responses to the cutsets. This is performed based on a review of the overall accident sequence and determining additional actions or options which would be available to the operators in the event that the preferred modelled approach fails. The conclusion of the recovery analysis yields the final core damage cutsets or results.

Each of the above steps is discussed in more detail below.

8.1.1 Integrated Plant Model

The first step in the quantification process is to combine the individual fault tree logic models for each system described in Section 6 into an integrated plant model. This model is made up of four computer files required for the EPRI Computer Aided Fault Tree Analysis (CAFTA) suite of codes as follows:

a. The CAFTA fault tree file GINNA.CAF;

b. The CAFTA basic event database file GINNA.BE;

c. The CAFTA type code database file GINNA.TC; and

d. The CAFTA gate definition database file GINNA.GT.

Once all fault tree models have been combined to form the integrated plant model (i.e., GINNA.CAF), all model transfers (i.e., linking between individual models) are verified to be correct. In addition, "circular logic" checks are made of the models to make sure that a given model does not both support and require support of another model (e.g., SW requires the diesel generators (DGs) following a loss of offsite power event; however, the DGs also require SW in order to provide necessary cooling). Circular logic issues are addressed by typically creating duplicated logic. For example, the SW model for cooling to the DGs will include failure of the SW pumps and failure of the DGs; however, failure of the DGs due to lack of SW cooling will not be included for this specific model. Instead, the failure of SW cooling to the DGs will be modeled for all other portions of the integrated plant model (e.g., loss of electric power to AFW).

As part of this step, the data files (i.e., GINNA.BE and GINNA.TC) are also reviewed to ensure consistency between the individual models and to ensure that model boundaries are correct (e.g., all AC breakers should be within the AC power system and not in SW or AFW). Essentially, GINNA.BE contains the failure probability for each basic event in the fault tree model while GINNA.TC contains the failure rates used for common classes of equipment. Following this review, the appropriate model changes are made such that the integrated plant model is ready for solution. GINNA.GT only contains descriptions of gates within the model and does not contain any specific information required for quantification.

8.1.2 Logic Flags

Various logic flags have been incorporated into the Ginna Station PSA logic models. When used, a logic flag is not a basic event within the model; instead a logic flag is used to re-configure or shape the logic models by setting the flag to either TRUE or FALSE (in the Boolean sense) depending on the desired outcome. However, a logic flag may have a probability associated with it when it is not being used to define the actual model configuration. There are two types of logic flags which are used:

a. *Configuration logic flags* - These flags are used to set operating configurations for systems with multiple trains where one or more of the trains is in operation and the remainder are in standby at the beginning of the accident. Probabilities are actually assigned to these flags since it is desirable to know which plant configurations result in the greatest risk (i.e., these flags will show up in the final cutsets). However, defining these events as flags will allow the Ginna Station PSA models to be used for future studies of specific system train alignments by setting these events to TRUE or FALSE.

b. *Sequence logic flags* - These flags are used to properly configure the integrated model for each accident sequence solution. As is typical of logic models when employing the small event tree/large fault tree modeling approach, the Ginna Station PSA logic models have been constructed to answer a variety of possible top event success criteria. The use of sequence logic flags provides the flexibility needed to correctly address each event tree branch.

The configuration logic flags are identified in Section 6 for each system fault tree model. The sequence logic flags consist of the following:

a. AAAAA0ATWS (*ATWS Has Occurred*) is used to configure the fault tree logic before solving anticipated transient without SCRAM (ATWS) sequences;

b. AAAAAFISSG (*Operators Isolate SG affected By Tube Rupture [I1 Success]*) is set to TRUE for when SGTR event tree top event I1 succeeds;

c. AAAAES0BAF (*ECCS Manually Started To Support Bleed And Feed Operation*) is set to TRUE when solving sequences involving event tree top event UH1 (bleed and feed operation) and FALSE when solving sequences involving event tree top event UH2 (LOCAs);

d. AAAATRANSI (*Transient Initiating Event Which Eventually Results in SI Conditions*) is set to FALSE for all sequences except for event tree top events Q1 (subset of PORVs and safety valves fail to reseat), Q2 (All PORVs and safety valves fail to reseat), and Q4 (RCP seal cooling failures) since these LOCAs can be initiated by transients which do not initially generate a SI signal; and

e. AAAANONMIN (*Flag for Non-Minimal Sequences in Model*) is set to FALSE for all sequences when it is not desirable to solve each event tree branch separately (i.e., the cutsets for each event tree will be placed into a single cutset file).

In addition to the above flags, in order to support more rapid quantification of the models, initiators and some configuration logic flags were also treated as sequence logic flags where appropriate. For example, all transient initiators were set to FALSE during the LOCA runs. A complete list of sequence logic flags and their settings is given in Table 8-1.

8.1.3 Model Solution

After creating the integrated Ginna Station PSA model, minimal cutsets are generated for each accident sequence. The generation of sequence cutsets is a three-step process as described below:

a. Logic flags are set to configure the integrated model for the specific sequence being solved;

b. The CAFTA Windows work station is used to generate cutsets from the integrated plant logic model; and

c. Generated cutsets are reviewed to identify and remove mutually exclusive events.

The CAFTA Windows work station was used to automatically set the logic flags, generate the cutsets, and remove the mutually exclusive events. As such, the only manual steps involved was to set up the logic flag file, integrated plant model file, and the mutually exclusive files. The logic flag and integrated plant model files were previously discussed above. The process for defining the mutually exclusive files is described below.

Solution of the integrated logic model for any selected sequence will generate cutsets that contain mutually exclusive events. The term "mutually exclusive" refers to combinations of events which are not considered likely such as multiple initiating events (e.g., a cutset containing initiating events for both feedwater line breaks and loss of coolant accident) and double maintenance events (e.g., a cutset containing events for having both trains of SI in maintenance at the same time). The likelihood of mutually exclusive events is considered to be significantly small such that it would be a gross overprediction to multiply the frequencies of multiple initiators or multiple maintenance events. In addition, certain configurations may not be allowed by the Ginna Station technical specifications (e.g., both trains of SI being out of service for maintenance). Therefore, a cutset file was created to delete those cutsets which contain the "illegal" combination of events from the final results.

In addition to the "illegal" event combinations, it is important to account for the various events which may succeed in any given sequence. For example, the sequence RB1L1 in the steam generator tube rupture (SGTR) event tree assumes the success of event tree top events I1 and UH2. In other words, sequence RB1L1 cannot occur if any one of the two other events (I1 or UH2) have failed. The correct Boolean algebra statement of sequence RB1L1, therefore, is:

R * /I1 * /UH2 * B1 * L1

There are two methods of solving this issue. The first method is to solve each event tree top event separately while the second method is comprised of solving the entire event tree at once. The first method involves the concept of cutset deletion where:

RB1L1 = R * B1 * L1 - (I1 + UH2)

For this example, cutsets for sequence RB1L1 are generated by solving event tree top events I1 and UH2 in addition to RB1L1. Any cut set appearing in sequence RB1L1 that also appears in any of the two success events (I1 or UH2) would then be deleted. However, this is a long process since most sequences involve one or more success events.

The second process involves solving the entire event tree at once by essentially creating one large OR gate comprised of each event tree top event. Based on the concept of "minimal cutsets," the resulting solution will automatically generate the correct cutsets. Using the same example as above, the solution of the SGTR event tree would include an OR gate comprised of RB1 + RL1 + RI1 + RUH2. If any given cutset failed both RB1 and RI1, it would only be counted once regardless of which event tree top it originated within. However, using this approach results in a loss of identification of which specific sequence produced the resulting cutset since the output from all sequences is placed into a single cutset file.

The Ginna Station PSA utilized the latter approach for quantification. Essentially, all cutsets for a given event tree are placed into a single common file and then "subsumed" (i.e., all non-minimal cutsets are eliminated). For certain event trees (e.g., large LOCA), all cutsets were generated at one time and placed into a single file. For other event trees (e.g., transients), certain sequences are solved independently due to different flag settings. The cutsets for all sequences are then placed into a common file and subsumed. This approach provides the greatest efficiency while still providing necessary risk ranking information. Deleting "illegal" cutsets (i.e., first method) was only used for removing station blackout cutsets from the transient and small LOCA event trees.

Prior to using the above three step approach, each event tree top event was solved independently to verify the resulting cutsets. This step essentially confirmed the integrated plant model since the cutsets were reviewed in detail to:

a. *Confirm symmetrical results were obtained* - This essentially verifies all transfers within the fault tree models. For example, Ginna Station was designed to provide two independent trains for each front-line system or function. If a cutset shows that only one train fails a given function, then the fault tree model was reviewed in detail to ensure that this is the accurate representation. In most instances, the offending fault tree was found to reference the wrong electric power transfer gate.

b. *Confirm common cause failure (CCF) events were in the results* - As described above, Ginna Station was designed with two independent trains for each front-line system or function. However, CCFs exist which could conceivably fail both trains. These CCFs typically have a failure rate of 10% of the individual failure probability of one train. As such, these CCFs should show up near the top of the results.

c. *Identify the appropriate truncation limit for the sequence solution* - The truncation limit is the point at which cutsets are no longer generated by CAFTA since they are not expected to significantly contribute to the final results. Observing the number of cutsets generated for each event tree top event ensures that an appropriate trunction limit is selected. The truncation limit used for each sequence was 1.0E-10.

Following the above review of each event tree top event, the integrated plant model was solved for the event tree sequences. Table 8-2 provides a description of how each event tree was solved.

8.1.4 Recovery Analysis

Once the fault tree models have been solved, the recovery analysis effort can begin. This effort consisted of the following:

a. Examination of the accident sequence minimal cutsets confirming the solution method and ensuring that each core-damage cut set is consistent with the plant design, technical specifications, and operating procedures;

b. Identification of the possible means by which core damage may be averted through the use of alternative equipment or operator actions;

c. Quantification of the likelihood that recovery scenarios are unsuccessful; and

d. Integration of recovery scenarios into the plant risk model on a minimal cutset basis, thereby allowing the calculation of a final realistic core-damage frequency.

During the minimal cutset review, cutsets with relatively high frequencies were carefully examined to ensure that such cutsets represented credible, yet realistic, core-damage scenarios. As described in Section 7, the initial cutsets were generated based upon the use of conservative screening data for post-trip human failure events (i.e., a failure probability of 1.00E-01). In addition, the integrated logic model does not consider all possible ways in which core damage may be averted (e.g., the use of alternative equipment or operator actions). Consequently, it is important to closely look at cutsets with high frequencies and make appropriate corrections to them to ensure that the final risk profile (i.e., overall core-damage frequency and its dominant contributors) is meaningful for Ginna Station.

In general, two approaches have been used:

a. If the cutset contains a post-trip human failure event that has been quantified using conservative screening data, then these events were reexamined and requantified using more realistic data. Section 7.4 and Appendix F contain this evaluation.

b. If the use of alternative equipment would avert core damage, then a non-recovery event was appended to the cutset to reflect that such usage was unsuccessful. The specific non-recovery events are provided in Table 7-15. The following guidelines have been applied for the non-recovery events:

    1. Non-recovery events were not added to cutsets containing post-trip human failure events; rather, the post-trip human failure events have been refined to address the additional considerations (see Section 7.4).

    2. Non-recovery events have been added to as-quantified cutsets where appropriate, subject to the following rules:

        - The postulated recovery action must be implemented through existing plant procedures and training; no credit is taken for novel or "heroic" operator actions.

        - Only one non-recovery event is applied to a cutset, except as noted below.

        - The restoration of offsite power is assumed to be independent of all other recovery actions; it is permitted to append two non-recovery events to a cutset as long as one, and only one, pertains to offsite power restoration.

        - Common-cause failures are assumed to be non-recoverable.

        - Repair of failed equipment is not considered.

Non-recovery events have been quantified using several approaches, depending on the specific nature of each event. The probability of restoring offsite power is based on an analysis of generic data, as described in Appendix B. Other non-recovery events consist of a hardware-related contribution and a human reliability contribution which are summed together to estimate the overall non-recovery event probability. The human reliability contribution is described in Section 7.4 while the hardware contribution is provided below.

The hardware contribution considers failure of the alternative equipment used to implement the recovery action (e.g., failure of the standby SW pump to start and run, etc.). In principle, hardware contributions could be addressed by developing a fault tree model and joining its resulting cutsets with the appropriate as-quantified cutsets. Often, however, the hardware contribution is negligible, depending on the probability of the hardware contribution failure, the frequency of the cutset to which it is applied, and the sequence truncation limit:

$$Pr\{hardware\} < \frac{truncation\ limit}{as\text{-}quantified\ cut\ set\ frequency} \rightarrow \text{neglect hardware contribution}$$

In addition, the human error contribution is typically a conservative value. As such, the hardware failure contribution was typically ignored.

The results of the internal event quantification effort are provided in Section 9.

8.2 ISLOCA Quantification

The first nuclear power plant PSA, WASH-1400 [Ref. 51], identified a LOCA that resulted in a loss of RCS inventory outside containment, referred to as Event V. This event is of concern since RCS inventory is being released outside containment which effectively bypasses the capability to utilizes containment sump recirculation once the RWST has been emptied. Also, through bypassing containment, the radiological consequences may be significant. The Event V Sequence eventually became known as an interfacing system LOCA (ISLOCA). To be considered as a potential ISLOCA sequence, a system must penetrate containment and connect with the RCS so as to provide a high/low pressure interface that could overpressurize and challenge plant safety systems. SGTRs can be included within this type of LOCA, but historically have been distinguished as a separate LOCA initiator for various reasons (initiators LI0SGTRA and LI0SGTRB for the Ginna Station PSA). A breach of two or more of the three-stage seals of the reactor coolant pumps (RCPs) is also included within this type of LOCA, but is separately assessed as well since it typically includes the loss of systems such as component cooling water and CVCS that can be better evaluated within the overall logic model.

The main concern of WASH-1400 was with respect to the pressure boundary interface between the RCS and the residual heat removal (RHR) system, an interface consisting of check valves for the plant of concern (i.e., Surry). The failure of two or more check valves not only could initiate an ISLOCA, but could fail the entire RHR system due to the surge of high pressure water into a system that is designed for much lower pressures. This would assure core damage (whether early or late) based entirely on the initiator alone. The WASH-1400 estimate for the ISLOCA frequency was 6.0E-06/yr, which was acknowledged to be approximately an order of magnitude high if appropriately consideration was taken for testing the leak tight status of the check valves.

Several years later, the Oconee PRA [Ref. 52] more explicitly modeled the initiator types related to ISLOCAs. This analysis recognized the possibility of several different types of valve failure scenarios: simultaneous rupture of multiple in-series valves, leak through of multiple in-series valves, and combination of valve rupture leak and leak through. The analysis also recognized the possibility that the LOCA may remain within containment since a portion of piping for many low pressure systems begins inside containment. These considerations made the assessment of ISLOCAs much more difficult to quantify.

More recent NRC studies (NUREG/CR-4550 for Surry and Sequoyah) assumed that the WASH-1400 frequency of ISLOCA applied (which it obviously did for Surry) and used a value of 1.00E-06/yr for the initiator and thus core damage frequency with minimal additional study [Ref. 53]. In addition, several industry reports have been released documenting various methods of performing detailed ISLOCA evaluations, including the evaluation of the type of valve and piping failures caused by overpressurization [Ref. 54][Ref. 55][Ref. 56][Ref. 57][Ref. 58]. The approach to be used for the Ginna Station PSA is a compilation of these methods, designed to identify all potential ISLOCA scenarios, but only perform detailed evaluations of the most likely sequences.

8.2.1 Methodology

The RCS at Ginna Station "communicates" with other water systems, many of which are designed to a lower pressure than the approximately 2250 psig normal operating pressure of the primary system. Ultimately, some of these systems' water must be taken outside containment where pumps or other equipment of the system are housed. Any system entering or exiting containment is normally provided with at least two isolation boundaries or valves which are designed to close and isolate containment following an accident for non-emergency lines (e.g., CVCS) or be capable of being closed for emergency lines (e.g., SI system). These isolation boundaries also typically serve to provide a barrier between the RCS and low pressure interfacing systems where applicable. Any breach of a RCS interface that results in water exiting the RCS and containment is called an ISLOCA.

Since piping that interfaces with the RCS varies in diameter from less than an inch to 10 or more inches, it is impossible to categorize an ISLOCA as a small, medium or large LOCA. Another characteristic of ISLOCAs is that, because of the surge of high pressure water into a system that is typically designed for much lower pressures, the low pressure interfacing system is more likely to fail. Hence, the potential likelihood of an ISLOCA must also be accompanied by an assessment of the consequence of the event.

As such, the assessment of the ISLOCA impact on core damage risk for Ginna Station consisted of the following tasks:

a. Identifying the systems that interface with the RCS and enter/exit the containment through a mechanical penetration. This effectively determined the penetrations that contain high/low pressure interfaces.

b. Identifying the scenarios for each identified penetration (i.e., the equipment and the types of failures that could lead to an ISLOCA) and identifying the consequences.

c. Screening each scenario and if it is greater than the 1.00E-07/yr truncation limit required by GL 88-20 for containment releases, recover the scenario, where appropriate, and quantify it in detail.

Each task is presented below.

8.2.2 Identification of System Interfaces With the RCS

Figure 8-1 shows the major system connections to the RCS that also enter/exit the containment (a break inside containment is assessed as a LOCA within the plant model). The bases for including or excluding each line shown on Figure 8-1 is discussed below.

8.2.2.1 Penetrations 111 and 140

These two penetrations contain the RHR piping used for: (1) low pressure safety injection, (2) the suction line from RCS Hot Leg A, and (3) the injection lines for RHR during shutdown or non-emergency conditions. Since the RHR piping lines are not designed for full RCS pressure and temperature conditions, these two penetrations were included in the ISLOCA assessment.

8.2.2.2 Penetrations 101 and 113

These two penetrations contain the high pressure SI lines to both RCS cold and hot legs. The SI system for Ginna Station is not normally operating and has a design pressure of only 1750 psig which is lower than the normal RCS operating pressure of 2250 psig. Therefore, these two penetrations were included in the ISLOCA assessment. In addition, there is a SI pump test line that is common to both penetrations. This test line exits containment through penetration 110b and was also included.

8.2.2.3 Penetrations 100 and 102

These two penetrations contain the Chemical and Volume Control System (CVCS) lines associated with normal and alternate charging. Both of these lines are designed for full RCS system pressure and temperature with normal charging being used during power operation. In order for a pipe break outside containment to occur, multiple valves would have to fail to close that are specifically installed for such circumstances. Since the CVCS piping is designed for these conditions, penetrations 100 and 102 were excluded from further consideration as a possible ISLOCA location. It is noted that the CVCS fault tree model includes a pipe break in these lines with respect to causing a system failure. UFSAR Section 9.3.4.4.5.1 [Ref. 2] provides additional information with respect to a break of the CVCS piping related to these penetrations.

8.2.2.4 Penetration 112

This penetration contains the CVCS piping associated with letdown. The letdown line contains orifices which reduce primary system pressure prior to exiting containment; consequently, the piping leaving containment is not rated for full RCS pressure and temperature. Since there are three air-operated containment isolation valves (200A, 200B, and 202) downstream of the orifices, any failure of an orifice must include a failure of the associated valve to close in order for an ISLOCA to occur. As such, this penetration could potentially be ignored from an ISLOCA standpoint due to the low frequency of an orifice failure. However, the penetration piping is connected to the lines associated with penetration 111 which is being addressed with respect to ISLOCAs. Therefore, this penetration was included in the ISLOCA evaluation.

8.2.2.5 Penetrations 205, 206a, and 207a

These three penetrations contain the RCS Hot Leg sample lines, and the pressurizer liquid and steam sample lines. These systems are operated on an intermittent basis and can be used during full power, shutdown, or post-accident conditions. Consequently, the lines are designed for full RCS system pressure and temperature [Ref. 2, Table 9.3-2]. There are also two air-operated valves in the line for all three penetrations which close on a containment isolation signal, the loss of air, or control power. In addition, there is also a throttled valve outside containment to reduce the sampling system pressure for each line. Finally, the line exiting containment for penetration 205 is only 3/8 inch and has a "delay coil" which provides at least a 60 second transient period for fluid leaving containment [Ref. 2, Section 9.3.2.1.2.2]. Therefore, based on the system design, these penetrations were not included in the ISLOCA assessment.

8.2.2.6 Reactor Coolant Drain Tank Penetrations

There is only one line which directly connects the RCS to the Reactor Coolant Drain Tank (RCDT). The remaining lines connected to the RCDT are associated with leakoffs from the RCPs and the Reactor Vessel O-rings and are not considered as credible LOCA paths. The 2 inch line in question contains two normally closed manual valves whose failure would create a leak path from the RCS to the RCDT inside containment. However, the tank has a 1 inch relief valve with a setpoint of 25 psig and a capacity of 30 gpm that leads to Containment Sump A. This would provide immediate indication of a leak and would produce an initial, though limited, release path from the tank. It is noted that there are several additional lines from the tank that exit containment (penetrations 123, 129, and 143). However, each of these lines has two containment isolation valves which will close on a containment isolation signal. Therefore, at least 4 valves must fail before a release path outside of containment is created. Consequently, the lines associated with the RCDT were not considered for the ISLOCA assessment.

8.2.2.7 Excess Letdown Heat Exchanger Penetrations

Excess letdown is used to balance the flow between the normal letdown and charging portions of CVCS, and for additional letdown when necessary. The cooling water supply for the excess letdown heat exchanger is provided by component cooling water (CCW) which is not designed for RCS temperature and pressure and which penetrates containment through penetrations 124a and 124c. Consequently, the heat exchanger is the high/low pressure interface and a break in the heat exchanger tubes could produce an ISLOCA. Therefore, penetrations 124a and 124c were included in the ISLOCA assessment.

8.2.2.8 Reactor Coolant Pump Penetrations

The reactor coolant pumps have a three-stage seal assembly that utilizes CVCS as the source for seal injection and return. The failure of the seal assembly is considered in the plant model and is not evaluated further in this analysis. However, CCW is used for the RCP thermal barrier cooling coil and provides a high/low pressure interface that penetrates containment. Therefore, a break in the cooling coil was considered as a possible ISLOCA location and penetrations 125, 126, 127, and 128 were included. It is noted that these penetrations are not typically included in an ISLOCA evaluation. However, NRC Information Notice 89-54, "Potential Overpressurization of the CCW System," required extensive assessment of these penetrations, and consequently, they were included in this analysis.

8.2.2.9 Summary

Based on the above assessment, penetrations 101, 110b, 111, 112, 113, 124a, 124c, 125, 126, 127, 128, and 140 will be included within the final ISLOCA assessment. As a further confirmation of this selection, it is noted that the Ginna Station technical specifications with respect to RCS pressure isolation valves (LCO 3.4.14) only deal with penetrations 101, 110b, 111, and 113. These four penetrations were identified by the NRC as being the most risk-significant with respect to ISLOCAs based on generic studies [Ref. 59]. Since no other penetrations were identified by the NRC, the proposed evaluation scope is considered bounding and appropriate.

8.2.3 Identification of ISLOCA Scenarios and Their Consequences

An assessment of each of the penetrations identified in Section 8.2.2.9 with respect to their ISLOCA potential is provided below. This assessment essentially consisted of determining what combination of equipment failures could result in an ISLOCA and the consequences of these failures. Initially, it was conservatively assumed that the introduction of primary system fluid into low pressure piping outside of containment would result in an ISLOCA. This assumption greatly streamlines the evaluation of the ISLOCA scenarios and is only addressed further if the frequency of the event is too high (i.e., greater than 1.00E-07/yr). However, it is noted that NUREG/CR-5102 [Ref. 54] and NUREG/CR-5862 [Ref. 55] both show that most low pressure piping can withstand RCS pressures and temperatures for short periods of time before leaking or rupturing, depending on the type of component in the line and ISLOCA sequence. Ginna Station P&IDs were relied on extensively to determine the potential break locations outside of containment while the event trees provided in Section 5 were used to evaluate the consequences. The assignment of failure probabilities and frequencies for the identified scenarios is provided in Section 8.2.4.

8.2.3.1 Penetration 101

Figure 8-2 shows a simplified diagram of the equipment and layout related to containment penetration 101. This penetration contains a 4 inch line from the SI pumps that splits into two separate injection lines: one 2 inch line to Hot Leg A and one 10 inch line (containing accumulator B) to Cold Leg A. Consequently, there are two potential paths for initiating the ISLOCA for this penetration. The first path from Hot Leg A requires the failure of two check valves (877B and 878H) and a locked closed, de-powered, motor-operated valve (MOV 878C). The second path from Cold Leg A requires the failure of two check valves (867B and 878J).

The SI lines associated with this penetration are seamless or welded stainless steel piping as described in Table 8-3. As shown on this table, the SI system piping downstream of the pumps is designed and tested for high pressure service and would most likely withstand the introduction of primary system fluid except for potentially the flanges associated with the pumps. There are essentially two general break locations for this penetration as described below:

a. *A break in the SI piping located between check valves 889B and 870B, and containment.* This location would fail SI Pumps B and C (assuming that Pump A has not failed to start which causes 871B to close, and that the majority of water from Pump C goes out the break since it is of lower pressure). The break may also fail the RHR system due to drainage issues (see Section 8.2.3.3). However, it should be noted that this section of piping is very short since check valves 889B and 870B are containment isolation valves and are located close to the containment wall (only 105 feet of piping versus 150 feet of piping inside containment [Ref. 60]). The piping is also rated to 1785 psig. Therefore, a pipe break in this specific location is unlikely, but will be considered.

b. *A break in the SI piping located between SI Pump B and check valve 889B or a break between SI Pump C and check valves 870A and 870B.* However, these break locations would only fail one pump unless the opposite check valve were also assumed to fail (i.e., either 889B or 870B). Since these two check valves see different system operating conditions than the check valves located in the Cold and Hot Leg injection lines, a common cause failure of 889B or 870B with the check valves initiating the ISLOCA was not considered credible. In addition, 889B and 870A are verified to close during quarterly testing of the pumps. Consequently, since an independent check valve failure would have to be included, and only one SI pump is affected (versus two), this scenario was not considered any further.

As described above, there are two potential ISLOCA initiating event paths with one break location for this penetration.

8.2.3.2 Penetration 110b

Figure 8-3 shows a simplified diagram of the equipment and layout related to containment penetration 110b. This penetration contains the SI pump test line to the Refueling Water Storage Tank (RWST) and is directly related to penetrations 101 and 113 (Figures 8-2 and 8-5, respectively). The isolation valves located between the test line and the RCS and whose failure initiates the ISLOCA for this penetration are discussed in Sections 8.2.3.1 and 8.2.3.4. In addition to the ISLOCA paths, the potential for LOCAs through the SI check valves against RCS pressure (867A and 867B) and accumulator check valve test lines (839B and 840B) exist.

As can be seen from Table 8-3, the SI test line piping is welded stainless steel piping designed for high pressure service and would most likely withstand the introduction of primary system fluid (except for the branch line to the RWST containing manual valve 884 during testing conditions). Since a break in the branch line containing manual valve 882 requires an additional failure, this branch line was ignored and only the following potential ISLOCA scenario were considered:

a. *A break in the SI test line between manual valve 879 and containment.* This break location can be assumed to fail all three SI pumps due to the test line location and the fact that it is common to all three SI pumps. It should be noted that this section of piping is short since manual valve 879 is a containment isolation valve and is located close to the containment wall. Therefore, a pipe break in this specific location is unlikely, but will be considered.

b. *An ISLOCA during quarterly testing of the SI pumps when the test line is opened to the RWST.* This ISLOCA is similar to scenario (a); however, the subject piping to the RWST is rated for much lower pressure with the RWST being open to the Auxiliary Building. This path is capable of being isolated by the operators using MOVs 897 and 898.

As described above, there are four ISLOCA initiating event paths with two break locations for this penetration.

8.2.3.3 Penetrations 111 and 112

Figure 8-4 shows a simplified diagram of the equipment and layout related to containment penetrations 111 and 112. Penetration 111 contains the RHR injection lines to the reactor vessel (through MOVs 852A and 852B) and Cold Leg B (through MOVs 720 and 721) while penetration 112 contains letdown piping associated with CVCS. As can be seen from the figure, there are three potential paths for initiating an ISLOCA: one through check valve 853A and normally closed MOV 852A, a second through check valve 853B and normally closed MOV 852B, and the third through normally closed MOVs 720 and 721.

As shown in Table 8-3, the introduction of primary system fluid into the RHR system and CVCS would most likely result in an ISLOCA due to the limited design rating of the low pressure piping. It is noted that there is a relief valve 203 located inside containment for penetration 112 which relieves to the Pressurizer Relief Tank with a setpoint of 600 psig and a capacity of 70,000 lb/hr (approximately 185 gpm) [Ref. 2, Section 5.4.5.3.1.2]. However, this capacity would not be sufficient to relieve a significant loss of RCS fluid through the RHR injection lines. Therefore, the impact of this relief valve was only considered with respect to the size of the ISLOCA (i.e., small RCS "leaks" could effectively be ignored). There are two general break locations for these penetrations as described below:

a. *A pipe break in the basement floor area of the Auxiliary Building.* Any break in this location (except between check valve 697B and the RHR HX Room) would prevent the entire RHR system from injecting into the reactor vessel. In addition, a review of the floor drains for the basement level indicates that they eventually drain to the Auxiliary Building sump located in the RHR Pump Pit [Ref. 2, Section 11.2.2.5]. There are two sump pumps located in the pit; however, these pumps are only rated for 50 gpm each [Ref. 2, Section 5.4.5.3.5] and would not provide much relief for a large break. Consequently, it is initially assumed that any ISLOCA in the basement area would result in the loss of both RHR pumps due to flooding. Since a pipe break in the RHR Heat Exchanger Room or the RHR Pump Pit requires the failure of at least one check valve in addition to the ISLOCA initiator valves, these break locations were not considered further.

b. *A pipe break in the CVCS letdown line associated with penetration 112 outside of containment.* A break in this location initially has two sources of RCS fluid; one through the RHR injection lines (ISLOCA initiator) and the second through the normal CVCS letdown line. However, normal letdown is automatically isolated upon a containment isolation signal which will occur quickly due to the drop in RCS pressure resulting from the pipe break. There is also an air-operated containment isolation valve (371) located next to the containment wall (2 feet [Ref. 61]) such that it is highly unlikely the pipe break would occur between containment and this valve. This AOV may not initially be able to close against the high line pressure, but once the RCS pressure drops sufficiently, the spring in the valve will force it shut and thus isolate the ISLOCA. There is also a second air-operated valve (135) just downstream of AOV 371 which can be used if necessary provided that IA and control power is available to the valve. Consequently, RHR can begin injection into the reactor vessel (relief valve 203 should close once the system pressure drops to 600 psig). The only potential concern is the availability of sufficient NPSH for the RHR pumps once the recirculation phase begins due to the lost inventory outside of containment. However, operators are aware of this concern and should be able to take necessary recovery actions (e.g., stopping one RHR pump). The failure of relief valve 203 to close would be a LOCA within containment. Therefore, this ISLOCA break location is not evaluated further since it can be automatically isolated.

As such, there are three potential ISLOCA initiating event paths and one break location. However, it should be noted that there is significant piping inside containment (325 feet [Ref. 62]) which also has the potential of breaking versus the 135 feet of piping between containment and the RHR check valves located in the RHR basement [Ref. 63]. UFSAR Section 5.4.5.3.2 [Ref. 2] provides additional details with respect to overpressurization events during non-full power conditions.

8.2.3.4 Penetration 113

Figure 8-5 shows a simplified diagram of the equipment and layout related to containment penetration 113. Note that this penetration is completely analogous to that of penetration 101. That is, this penetration contains a 4 inch line from the SI pumps that splits into two separate injection lines: one 2 inch line to Hot Leg B and one 10 inch line (containing accumulator A) to Cold Leg B. Consequently, there are two potential paths for initiating the ISLOCA. The first path from Hot Leg B requires the failure of two check valves (877A and 878F) and a locked closed, de-powered, motor-operated valve (MOV 878A). The second path from Cold Leg B requires the failure of two check valves (867A and 878G).

Since Table 8-3 confirms that penetrations 101 and 113 are completely analogous, the same pipe break location will be considered for both penetrations (i.e., a break in the SI piping located between check valves 889A and 870A, and containment). It is noted that this section of piping is of short length (100 feet [Ref. 64]) since check valves 889A and 870A are containment isolation valves and located close to containment by design.

8.2.3.5 Penetrations 124a and 124c

Figure 8-6 shows a simplified drawing of the equipment and layout related to containment penetrations 124a and 124c. These penetrations contain the CCW supply and return lines, respectively, for the excess letdown heat exchanger. Based on a review of plant operating experience, this system is normally isolated at both the CCW and RCS lines and is in operation less than 2% of the time. However, a heat exchanger tube failure has the potential to create an ISLOCA that would fail the entire CCW system. Based on the significance of this ISLOCA scenario, it was evaluated in more detail.

As can be seen from Table 8-3, any introduction of RCS fluid into the CCW system would most likely cause a pipe break. However, this ISLOCA scenario was not investigated any further due to the following considerations:

a. The excess letdown system is only used less than 2% of the time during power operation;

b. The failure of AOV 310 (transfers open) in conjunction with a heat exchanger tube rupture is considered very improbable during the remaining 98% of the time;

c. There is sufficient indication available to the operators to identify a break in the excess letdown heat exchanger (including pressure and temperature indications on the RCS return lines from the heat exchanger, and CCW radiation and surge tank level alarms);

d. AOV 310 can be used to quickly isolate the break following identification of the rupture;

e. There is an alarm procedure which provides instructions to operators on actions to be taken if there are indications of a pipe break with a CCW/RCS interface [Ref. 65];

f. CCW check valve 743 or AOV 745 would have to rupture to provide a leak path outside of containment (check valve 743 is located inside containment while AOV 745 is located only 1 foot from the penetration [Ref. 66]); and

g. The normal flow rate through the CCW heat exchanger is only 5,000 lb/hr or 10 gpm [Ref. 2, Table 9.3-7] while CCW relief valve 744 (located inside containment) is designed to relieve 20 gpm.

It is noted that AOV 123 limits RCS flow through the excess letdown heat exchanger and thus, RCS flowrate could be expected to increase if a tube rupture were to occur. However, the RCS supply line is small (3/4 inch) and only one heat exchanger tube is expected to rupture. Therefore, based on the above factors, these two penetrations were removed from further consideration.

8.2.3.6 Penetrations 125 and 128

Figure 8-7 shows a simplified drawing of the equipment and layout related to containment penetrations 125 and 128. These penetrations contain the CCW return and supply lines, respectively, for the RCP B thermal barrier cooler and are normally in operation. A failure of the coils carrying RCS fluid within the thermal barrier cooler could potentially result in an ISLOCA within the CCW system. As noted above, an ISLOCA would also fail the entire CCW system.

Table 8-3 shows that CCW piping can be expected to rupture if RCS fluid is introduced into the system due to the low pressure and temperature design (the piping for the RCPs is only slightly larger than the excess letdown lines listed in the table). As shown on Figure 8-7, there are two potential break locations as discussed below:

a. *A break in the CCW piping outside of containment for penetration 128.* This break location would quickly result in the loss of all CCW; however, it requires the failure of check valve 750B and MOV 749B (located less than 6 inches from the penetration [Ref. 67]) to close. Operators are instructed to close MOV 749B upon loss of CCW surge tank level. The probability of two valves failing to close in addition to a thermal barrier cooling coil rupture is considered very low (i.e., < 1.0E-08). Therefore, this break location was not considered further.

b. *A break in the CCW piping outside of containment for penetration 125*. This break location would require a failure of AOV 754B and MOV 759A to close. Since AOV 754B fails open on loss of power or instrument air, the ability of the valve to successfully close is questionable. An engineering analysis was performed on this break location in response to NRC IEN 89-54. This analysis showed that the maximum leakage rate into the CCW system using industry accepted critical crack propagation techniques is only 32 gpm [Ref. 68]. Consequently, if both 754B and 759A failed to close, the CCW system would not become overpressurized, and in fact, operators would have over 30 minutes to respond to the event before the CCW surge tank overfilled and began to relieve RCS fluid to the waste holdup tank. A catastrophic failure of the thermal barrier cooler (beyond that assumed above) is considered unlikely since CCW flows through the tube side such that the tube would have to implode. However, an evaluation was also performed assuming a guillotine break which resulted in a CCW system pressure of 200 psig at the penetration which is only slightly higher than the design pressure of 150 psig. The CCW system pressure is limited in this case due to the relief valve located inside containment and the physical design of the thermal barrier. While the design limit for closing of MOV 749A is only 140 psig, this value is based on conservative assumptions. In addition, assuming minimal fuel damage (as would be case at power), operators could manually close MOV 749A or its downstream manual valve. Therefore, based on these factors, this break location was also not considered further.

Based on the above discussion, neither penetration 125 or 128 requires consideration as a potential ISLOCA location.

8.2.3.7 Penetration 126 and 127

Figure 8-8 shows a simplified drawing of the equipment and layout related to containment penetrations 126 and 127. As can be seen, these penetrations are completely analogous to penetrations 125 and 128 in that they contain the CCW return and supply lines, respectively, for the RCP A thermal barrier cooler. These lines are normally in operation and a failure of the coils carrying RCS fluid within the thermal cooler could potentially result in an ISLOCA within the CCW system. However, since these penetrations are exactly similar to penetrations 125 and 128, no further consideration of ISLOCAs is made for the reasons discussed in Section 8.2.3.6.

8.2.3.8 Penetration 140

Figure 8-9 shows a simplified diagram of the equipment and layout related to containment penetration 140. This penetration contains the RHR pump suction line from Hot Leg A and is normally only used during shutdown conditions. As can be seen from Figure 8-9, the only potential ISLOCA path is through MOVs 700 and 701.

As shown in Table 8-3, the introduction of primary system fluid into the RHR pump suction lines would most likely result in an ISLOCA due to the design rating of the low pressure piping. There are two potential pipe break locations for this penetration as described below:

a. *A break in the RHR pump suction piping located outside of containment.* As discussed in Section 8.2.3.3 scenario (a), it is irrelevant whether the break occurs in the section of piping in the Auxiliary Building basement or the RHR Pump Pit since the basement level floor drains all lead to the Pump Pit. Therefore, a significant pipe break in this section of piping would fail the RHR pumps due to flooding. However, it should be noted that the RHR mini-flow recirculation valves back to the RWST are maintained normally open such that it is conservative to assume that the RHR system would fail (versus the RWST filling). In addition, flow though relief valve 203 in CVCS letdown would be available to relieve system pressure.

b. *An ISLOCA upstream of check valve 854 (i.e., back to the RWST).* Normally, this pipe break location would be ignored since it requires the independent failure of a third valve. However, this break location would most likely fail RHR, SI, and CVCS by overfilling the RWST and would therefore, quickly lead to core damage. Based on a review of periodic test procedures related to RHR, check valve 854 is not specifically tested to ensure that it correctly backseats. Nonetheless, it can be assumed that if 854 was not backseating correctly, it would be discovered during shutdown conditions when RHR takes suction through MOVs 700 and 701. Also, MOV 856 could potentially be used to isolate this leak path. Consequently, this ISLOCA path was ignored.

As discussed above, there is one potential ISLOCA initiating event path with one break location for this penetration.

8.2.4 Screening Evaluation of Ginna ISLOCA Scenarios

All of the ISLOCA scenarios identified in Section 8.2.3 involve the failure of at least two valves as the initiator. Consequently, the calculation of ISLOCA frequencies involves the failure of multiple valves and the consideration of timing issues. Previous PSAs have utilized several different analytical models to determine ISLOCA frequencies and differ in the type of failure modes considered and initial assumptions. Since the remainder of the Level 1 PSA will be performed using fault tree models, the models presented in Appendix C of NSAC-154 [Ref. 56] will be used for the ISLOCA evaluation to provide consistency. These NSAC-154 models were transposed into the equations shown in Table 8-4 which address human errors, common cause failures, and both valve leakage and rupture random failures. Table 8-5 presents the failure data required by these analytical models. The ISLOCA frequencies which are calculated include consideration of the average number of hours that the reactor is critical in one year to define the frequency on a reactor year basis similar to the remainder of the PSA. The data window for the Ginna Station PSA was from January 1, 1980 through December 31, 1988 or 78,912 hours. The number or reactor critical hours in this time period was 64,054 hours or 81% of the time.

The evaluation of the five scenarios described in Section 8.2.3 is provided below. The final results are summarized in Section 8.2.5.

8.2.4.1 Penetration 101

Section 8.2.3.1 identifies two potential ISLOCA initiating event paths with one break location for this penetration. The first path involves the failure of check valves 867B and 878J on the SI injection line to Cold Leg A. The testing procedures for Ginna Station were reviewed and it was found that 867B is only leak tested once every refueling outage (i.e., 18 months). Check valve 878J is leak tested once each quarter following the quarterly SI pump tests. It could be postulated that any leakage through 878J would be discovered due to changes in accumulator level and pressure which are verified every 12 hours; however, this will be conservatively ignored since it would require that the SI piping be unfilled or the test line opened to create this leakage path. Therefore, using Table 8-4 Equation 1, and the data presented in Table 8-5 (as summarized below) we find:

$\lambda_L = 6.8E\text{-}07/hr$ $\qquad CCF_L = 3.0E\text{-}06\ \lambda_L$
$\lambda_R = 1.0E\text{-}07/hr$ $\qquad CCF_R = 3.0E\text{-}06\ \lambda_R$
$T_{CV1} = 0.5\ (1.5\ yrs)(8760\ hrs/yr) = 6570\ hrs$
$T_{CV2} = 0.5\ (8760\ hrs)(3/12\ months) = 1095\ hrs$

$$\langle\lambda\rangle = \{[(6.8E\text{-}07/hr + 1.0E\text{-}07/hr)(6570\ hrs)]^* [(6.8E\text{-}07/hr + 1.0E\text{-}07/hr)(1095\ hrs)] + (3.0E\text{-}03)(1.0E\text{-}07/hr)(1095\ hrs) + (3.0E\text{-}03)(6.8E\text{-}07/hr)(1095\ hrs)\} / 0.81\ ryr$$

$$\langle\lambda\rangle = \{(5.12E\text{-}03)(8.54E\text{-}04) + 3.29E\text{-}07 + 2.23E\text{-}06\} / 0.81 = 6.94E\text{-}06/ryr$$

The second path involves the failure of check valves 877B, 878H, and MOV 878C located on the SI injection line to Hot Leg B. This line is normally isolated as a SI path due to PTS concerns and the check valves and MOV are only leak tested once every 40 months per the Technical Specifications. The verification of the MOV position every shift, use of locks, and depowering of this MOV, eliminate the potential for human error. Therefore, using Table 8-4 Equation 2, and the data presented in Table 8-5 (as summarized below), we find:

$\lambda_L = 6.8E\text{-}07/hr$ $\quad$ $CCF_L = 3.0E\text{-}06\ \lambda_L$
$\lambda_R = 1.0E\text{-}07/hr$ $\quad$ $CCF_R = 3.0E\text{-}06\ \lambda_R$
$T = 0.5\ (720\ hrs/month)(40\ months) = 14{,}400\ hrs$
$\lambda_H = 2.7E\text{-}04$ $\quad$ $\lambda_{MH} = 2.7E\text{-}04$
$\lambda_{ML} = 5.7E\text{-}07/hr$ $\quad$ $\lambda_{MR} = 2.7E\text{-}08/hr$

$$\begin{aligned}\langle\lambda\rangle = \{&(14{,}600\ hrs)^2[(6.8E\text{-}07/hr)^2 + 2(6.8E\text{-}07/hr)(1.0E\text{-}07/hr) + (1.0E\text{-}07/hr)^2] \\ &+ (2.7E\text{-}04)(14{,}600\ hrs)[(6.8E\text{-}07/hr) + (1.0E\text{-}07/hr)] \\ &+ (14{,}600\ hrs)[(3.0E\text{-}03)(6.8E\text{-}07/hr) + (3.0E\text{-}03)(1.0E\text{-}07/hr)]\} \\ &*\{(14{,}600\ hrs)(5.7E\text{-}07/hr + 2.7E\text{-}08/hr) + 2.7E\text{-}04\} / 0.81\ ryr\end{aligned}$$

$$= [1.26E\text{-}04 + 3.03E\text{-}06 + 3.27E\text{-}05] * [4.87E\text{-}03] / 0.81\ ryr$$

$$= 1.75E\text{-}06/ryr$$

The sum of these two scenarios is thus:

$$\langle\lambda\rangle_{101} = 6.94E\text{-}06/ryr + 1.85E\text{-}06/ryr = 8.69E\text{-}06/ryr$$

This is a higher value than the 1.0E-07/ryr truncation limit and is dominated by the failure of check valves 867B and 878J. In addition, it is recognized that an ISLOCA in the section of piping between check valves 889B and 870B, and containment could also fail the entire RHR system since floor drains in the Auxiliary Building basement level lead to the RHR Pump Pit (see Section 8.2.3.3). Therefore, an unisolable 4 inch LOCA outside of containment in the SI lines would directly result in core damage since there is only one SI pump available for injection purposes and no RHR for injection or long-term cooldown.

However, there are two very conservative assumptions in this scenario. First is the fact that the check valve isolating accumulator (842B) successfully isolates following the failure of check valve 867B. There have been several industry observed failures of this check valve due to the presence of boric acid, and in fact, a failure probability of 0.93 was calculated in Section A.1.1.2.2 of NUREG-5102 for this check valve to reseat on demand. Crediting the leaking check valve and accumulator relief valve would shorten the time frame in which check valve 867B would leak by unobserved. The second conservative assumption is related to the failure of the SI piping located between check valves 889B and 870B, and containment. This piping is rated to 1785 psig; thus, the yield stress would be well within normal RCS pressure limits. Therefore, the generic failure rate for piping leak/rupture will be used (5.53E-07/hr) assuming that the pipe could fail over the same duration as check valve 878J (1/2 of a quarter year). This will also be adjusted by the ratio of piping outside versus inside containment (105/255 from Section 8.2.3.1) to yield:

$$\langle\lambda\rangle_{101} = (8.69\text{E-06/ryr})(5.53\text{E-07/hr})(0.5)(8760 \text{ hrs})(3/12 \text{ months})(105/255) = 2.17\text{E-09/ryr}$$

This value is considered appropriate due to the design rating of the subject piping and the fact that there is low potential for human error inducing the ISLOCA for this penetration.

8.2.4.2 Penetration 110b

Section 8.2.3.2 identifies four potential ISLOCA initiating event paths for this penetration with two different break locations. Two initiating event paths involve the failure of the isolation valves for penetrations 101 and 113 which are evaluated in Sections 8.2.4.1 and 8.2.4.4, respectively (i.e., the frequency of an ISLOCA through these paths is 8.79E-06/ryr). The remaining two initiating event paths involve the failure of the RCS check valves (867A and 867B) and the test lines associated with the accumulator check valves (manual valves 839B and 840B). As discussed in Section 8.2.4.1, check valves 867A and 867B are only leak tested once every refueling outage. Manual valves 839B and 840B are not leak tested since they are associated with a small test line; however, leakage through these valves would be detected during the quarterly pump runs when the test line is opened back to the RWST. Therefore, using Table 8-4 Equation 4 (replacing MOV with an AOV but using the same failure data as an MOV), and the data presented in Table 8-5 (as summarized below) we find:

$\lambda_L = 6.8E\text{-}07/hr$ $\lambda_R = 1.0E\text{-}07/hr$
$\lambda_{ML} = 5.7E\text{-}07/hr$ $\lambda_{MR} = 2.7E\text{-}08/hr$
$T = 0.5\ (1.5)(8760\ hrs) = 6570\ hrs$ $T_{SI} = T_{AOV} = 0.5(8760\ hrs)(3/12\ months) = 1095\ hrs$
$\lambda_{MO} = 2.68E\text{-}04$ $\lambda_{MS} = 9.7E\text{-}08/hr$
$\lambda_{MH} = 0$ (AOV already exposed to accumulator pressure so no sudden failure potential)

$$\langle\lambda\rangle = \{[6570\ hrs(6.8E\text{-}07/hr + 1.0E\text{-}07)/hr] * [(1095\ hrs)\ (5.7E\text{-}07/hr + 2.7E\text{-}08/hr) + 0 + 2.68E\text{-}04] + [(6570\ hrs)(6.8E\text{-}07 + 1.0E\text{-}07)(9.7E\text{-}08)(1095\ hrs)]\}\ /\ 0.81\ ryr$$

$$= [(5.12E\text{-}03) * (9.22E\text{-}04) + (5.44E\text{-}07)]\ /\ 0.81\ ryr$$

$$= 6.50E\text{-}06/ryr$$

The four initiating event path frequencies must now be combined with the failure probability of the two break locations. The first break location is between manual valve 879 and containment and is similar to the configurations for penetrations 101 and 113. Consequently, the generic failure rate for piping leak/rupture will be used (5.53E-07/hr) assuming that the pipe could fail over the same duration as check valve 878J (1/2 of a quarter year). This yields:

$$(5.53E\text{-}07/hr)(0.5)(8760\ hrs)(3/12\ months) = 6.06E\text{-}04$$

The second break location is during opening of the SI test line which provides a direct leak path to the RWST that is open to the Auxiliary Building. The SI test line is normally opened once every quarter for technical specification required testing and for accumulator filling. However, since check valve 878J is leak tested after each use of SI Pump B or C, and this testing was only assumed once per quarter, the opening of the test line to fill the accumulator will be ignored. Therefore, assuming quarterly 8 hour pump tests equates to 32 hrs/year in which the test line is open.

Converting this to a probability per reactor year yields:

$$(32 \text{ hrs/yr})(1 \text{ yr}/8760 \text{ hrs})(1/0.81) = 4.51\text{E-}03$$

In summary, the ISLOCA frequency for this penetration is the frequency of each of the four initiating event paths multiplied by the pipe break probability:

$$\begin{aligned}\langle\lambda\rangle_{110b} &= (8.79\text{E-}06 + 8.79\text{E-}06 + 6.50\text{E-}06 + 6.50\text{E-}06)(6.06\text{E-}04)\\ &+ (8.79\text{E-}06 + 8.79\text{E-}06 + 6.50\text{E-}06 + 6.50\text{E-}06)(4.51\text{E-}03)\\ &= 1.56\text{E-}07/\text{ryr}\end{aligned}$$

This frequency is dominated by the opening of the test line following failure of the upstream isolation valves. However, since check valve 878J is leak tested following each opening of the test line, the increased use of the test line does not automatically mean an increased risk of an ISLOCA through this penetration. In addition, opening of the test line requires local valve manipulation. As such, plant personnel would be in the vicinity to close one of three in-series manual valves upon indication of an ISLOCA due to RWST level changes and the sound of flow through the pipe. In addition, there are two MOVs downstream of the manual valves which could be closed from the control room. Assuming a failure rate of 1.0E-01 (see Table 8-5) to close any of these five valves yields:

$$\begin{aligned}\langle\lambda\rangle_{110b} &= (8.79\text{E-}06 + 8.79\text{E-}06 + 6.50\text{E-}06 + 6.50\text{E-}06)(6.06\text{E-}04)\\ &+ (8.79\text{E-}06 + 8.79\text{E-}06 + 6.50\text{E-}06 + 6.50\text{E-}06)(4.51\text{E-}03)(1.0\text{E-}01)\\ &= 3.23\text{E-}08/\text{ryr}\end{aligned}$$

8.2.4.3 Penetration 111

Section 8.2.3.3 identifies three potential ISLOCA initiating event paths and one break location for this penetration. The first path involves the failure of MOVs 721 and 720 on the normal RHR injection line to Cold Leg B. The testing procedures for Ginna Station were reviewed and it was found that these two MOVs are leak tested following each cold shutdown and refueling outage using RCS pressure (i.e., valves cannot stick open). In addition, MOV 721 has an interlock preventing the valve from opening when RCS pressure is greater than 410 psig [Ref. 2, Section 5.4.5.3.1.2]. MOV 720 does not have a pressure interlock and relies instead on a key locking device which removes control power to the valve during power operation. Both MOVs also have their breakers locked open and positions verified each shift. Therefore, since MOV 721 cannot be opened at power without first defeating its associated interlock and MOV 720 has its control power removed, human initiated ISLOCA events were ignored for this penetration.

A review of Ginna Station history shows that the plant averaged one cold shutdown a cycle in addition to the refueling outage during the data window used for the Ginna Station PSA. Therefore, using Table 8-4 equation 3 and the data provided in Table 8-5 (as summarized below) we find:

$\lambda_{ML} = 5.7E\text{-}07/hr$ $\quad CCF_{ML} = 3.0E\text{-}03\ \lambda_{ML}$
$\lambda_{MR} = 2.7E\text{-}08/hr$ $\quad CCF_{MR} = 3.0E\text{-}03\ \lambda_{MR}$
$T = 0.5\ (1.5)(8760\ hrs)(0.5) = 3285\ hrs$
$\lambda_{MH} = 2.7E\text{-}04$

$$\langle\lambda\rangle = \{(3285\ hrs)^2[(5.7E\text{-}07/hr)^2 + 2(5.7E\text{-}07/hr)(2.7E\text{-}08/hr) + (2.7E\text{-}08/hr)^2] + [(3285\ hrs)(2.7E\text{-}04)(5.7E\text{-}07/hr + 2.7E\text{-}08/hr] + (3285\ hrs)[(3.0E\text{-}03)(5.7E\text{-}07/hr) + (3.0E\text{-}03)(2.7E\text{-}08/hr)]\} / 0.81\ ryr$$

$$= [3.85E\text{-}06 + 5.30E\text{-}07 + 5.88E\text{-}06] / 0.81\ ryr$$

$$= 1.03E\text{-}05/ryr$$

The second and third paths involve the two low pressure SI lines to the reactor vessel. These lines include a check valve (853A and 853B) and normally closed MOV (852A and 852B) in series. Since these lines are used following a LOCA, the MOVs are not interlocked with respect to RCS pressure and do not have their power removed. The check valves and MOVs are leak tested following each refueling outage using RCS pressure (i.e., valves cannot stick open). Therefore, using Table 8-4 equation 4 and the data provided in Table 8-5 (as summarized below) we find:

$\lambda_L = 6.8E\text{-}07/hr$ $\quad \lambda_R = 1.0E\text{-}07/hr$
$\lambda_{ML} = 5.7E\text{-}07/hr$ $\quad \lambda_{MR} = 2.7E\text{-}08/hr$
$T = 0.5\ (1.5)(8760\ hrs) = 6570\ hrs$ $\quad T_{SI} = T = 6570\ hrs$
$\lambda_{MH} = 2.7E\text{-}04$ $\quad \lambda_{MS} = 7.13E\text{-}06/hr$
$\lambda_{MO} = 2.68E\text{-}04$

$$\langle\lambda\rangle = 2\ \{[6570\ hrs(6.8E\text{-}07/hr + 1.0E\text{-}07)] * [(6570\ hrs)\ (5.7E\text{-}07/hr + 2.7E\text{-}08/hr) + 2.7E\text{-}04 + 2.68E\text{-}04] + [(6570\ hrs)(6.8E\text{-}07 + 1.0E\text{-}07)(7.13E\text{-}06/hr)(6570\ hrs)]\} / 0.81\ ryr$$

$$= 2\ [(5.12E\text{-}03)\ (4.46E\text{-}03) + (2.40E\text{-}04)] / 0.81\ ryr$$

$$= 6.49E\text{-}04/ryr$$

The above frequency is dominated by the last portion of the equation related to an inadvertent SI opening the MOV and relying only on a check valve to protect the RHR system. This event can be mitigated by closing the MOV once the operators realized what has occurred (see procedure ECA-1.2). Using a failure rate of 0.1 for this operator action (per Table 8-5), the above equation becomes:

$$\langle\lambda\rangle = 2\ \{[6570\ \text{hrs}(6.8\text{E-}07/\text{hr} + 1.0\text{E-}07)] * [(6570\ \text{hrs})\ (5.7\text{E-}07/\text{hr} + 2.7\text{E-}08/\text{hr}) + 2.7\text{E-}04 + 2.68\text{E-}04] + [(6570\ \text{hrs})(6.8\text{E-}07 + 1.0\text{E-}07)(7.13\text{E-}06/\text{hr})(6570\ \text{hrs})(0.1)]\}\ /\ 0.81$$

$$= 2\ [(5.12\text{E-}03)\ (4.46\text{E-}03) + (2.40\text{E-}05)]\ /\ 0.81\ \text{ryr}$$

$$= 1.16\text{E-}04/\text{ryr}$$

The sum of these two scenarios is thus:

$$\langle\lambda\rangle_{111} = 1.03\text{E-}05/\text{ryr} + 1.16\text{E-}04/\text{ryr} = 1.26\text{E-}04/\text{ryr}$$

This is significantly higher than the 1.0E-07/ryr truncation limit and is due mainly to the number of potential ISLOCA initiator paths and that each path only has two isolation valves with a large amount of time between leakage testing. These scenarios also have significant consequences since they directly lead to core damage as a result of a 8 inch pipe break (i.e., large LOCA) with no RHR available. However, it is conservative to assume that the ISLOCA will definitely occur in the section of piping between check valves 697A and 697B, and containment even though the piping is only rated to 600 psig. As such, a discussion of pipe break frequency is provided below.

There have been numerous studies performed in an attempt to determine the pipe break frequency for low pressure piping exposed to RCS pressure. However, there are two more recent studies of interest. NUREG/CR-5102, Appendix F contains an evaluation of both BWR and PWR piping and provides look-up tables for various piping failure probabilities with and without corrosion effects. These tables are based on the assumption that the mean failure of piping is at 90% of the ultimate stress value with the 99% percentile of failure at the ultimate stress point. These values are based on burst tests conducted by General Electric and the assumption that the overpressurization is not rapid enough to cause significant dynamic effects (e.g., water hammer). The resulting pipe break probabilities range between 1.0 and 3.0E-04. It should be noted that the NRC considered the General Electric information in their NUREG-1150 evaluations and used a failure probability of 5.0E-03 for all low pressure piping.

NUREG/CR-5744 Appendix F contains additional studies in this area. This evaluation assumed that a pipe would break with a probability of 1.00E-03 at its yield stress value. In other words, this evaluation assumed that there was a significant piping flaw that would fail the piping once every thousand times it was exposed to its yield stress value. The authors of this evaluation acknowledge that this is a conservative assumption which should be investigated further if it proves too risk significant. The tables presented in this document provide pipe break probabilities (ranging from 0.2 to 0.46), flange failure probabilities (1.0E-04), and heat exchanger failure probabilities (0.63).

Based on the above discussion, the Ginna Station PSA will use the look up tables in NUREG/CR-5102, Appendix F for piping failure probabilities. However, in no case will a value less than 5.0E-03 be used. As such, using the data provided in Table 8-3, the pipe break probability between check valves 697A and 697B and containment for penetration 111 is 2.29E-02 (assuming corrosion exists). In addition, Section 8.2.3.3 states that there is 3 times as much RHR piping located inside containment versus that in the identified ISLOCA section. Therefore, the ISLOCA frequency for this penetration is as follows:

$$\langle\lambda\rangle_{111} = (1.26\text{E-}04/\text{ryr})(2.29\text{E-}02)(1/3) = 9.61\text{E-}07/\text{ryr}$$

There does not appear to be any other potential recovery paths for this ISLOCA scenario since it cannot be easily isolated.

8.2.4.4 Penetration 113

As stated in Section 8.2.3.4, this penetration is completely analogous to penetration 101. Therefore, the same ISLOCA frequency of 2.17E-09/ryr is applied (see Section 8.2.4.1).

8.2.4.5 Penetration 140

Section 8.2.3.8 identifies one potential ISLOCA initiating event scenario that is equivalent to the first scenario described in Section 8.2.4.3. That is, there are two normally closed MOVs with the same interlocks, administrative controls, and testing frequencies. Therefore, the same ISLOCA frequency of 1.03E-05/ryr can be used. As shown on Figure 8-9, there are three MOVs (704A/B and 856) which are each located approximately 25 feet from the penetration. These MOVs can be operated from the control room to isolate the ISLOCA once operators have identified its location. While procedure ECA-1.2 [Ref. 69] only requires operators to close the MOVs if MOVs 700 and 701 are opened, the flow transmitters located on the RHR pump mini-flow recirculation lines and the pressurizer relief tank level alarms can be assumed to provide some degree of indication given a disk rupture. Therefore, a human error probability of 0.1 to close these valves after the event will be used per Table 8-5.

If the operators do not isolate the flow path, the RHR piping is vulnerable to failure. As shown in Table 8-3, the subject piping is rated for 600 psig service such that the same failure probability of 2.29E-02 described in Section 8.2.4.3 can be used. Therefore, the final frequency for this penetration is as follows:

$$\langle\lambda\rangle_{140} = (1.03\text{E-}05/\text{ryr})(0.1 \text{ no isolation})(2.29\text{E-}02) = 2.36\text{E-}08/\text{ryr}$$

There are not any other readily available operator actions to recover this scenario.

8.2.5 ISLOCA Results

Table 8-6 summarizes the results of the ISLOCA assessment for Ginna Station. As can be seen, the dominating contributor to the ISLOCA frequency is with respect to penetration 111. This is mainly due to the following considerations:

a. The path only has two isolation valves with a large amount of time between leakage testing;

b. The low pressure rating of the RHR piping and limited pressure relief capacity; and

c. The significant consequences of losing this penetrations (i.e., the loss of all RHR).

The overall risk significance of an ISLOCA event in these penetrations is provided in Section 9.

8.3 External Event Solution

[LATER]

Table 8-1
Flag Setting

Flag/Truncation	*Transient*	*SBO*	*ATWS*	*SSLOCA*	*SLOCA*	*MLOCA*	*LLOCA*	*SGTR*
AAAA0ATWS	F	F	T	F	F	F	F	F
AAAAFISSG	F	F	F	F	F	F	F	T(1)
AAAAES0BAF	T(2)	F	F	F	F	F	F	F
AAAATRANSI	T(3)	F	F	F	F	F	F	F
AAAANONMIN	F	F	F	F	F	F	F	F
SWAASWP1AR (4)	T	T	T	T	T	T	T	T
SWAASWP1BR (4)	F	F	F	F	F	F	F	F
SWAASWP1CR (4)	T	T	T	T	T	T	T	T
SWAASWP1DR (4)	F	F	F	F	F	F	F	F
DG1ANOTRUN (5)	T	T	T	T	T	T	T	T
DG1BNOTRUN (5)	T	T	T	T	T	T	T	T
RRAASEALOC	T(6)	F	F	F	F	F	F	F
ACAA50_50N	T	T	T	T	T	T	T	T
Other offsite power configurations	F	F	F	F	F	F	F	F
Transient Initiators	-	-	-	F	F	F	F	F
LOCA Initiators	F	-	-	F(7)	F(7)	F(7)	F(7)	F(7)

NOTES:

(1) Only for Sequences where I1 is successful.

(2) Only for Sequences involving UH1.

(3) Only for Sequences involving Q1, Q2, and Q4.

(4) One SW pump from each electrical bus and each pump header was selected as normally running while the redundant pump was identified as not running (though it may be in standby). See Section 6.18.4

(5) The DG were selected as not running in test at the time of the accident. This was based on the low probability of the event combined with the failure of the DG to continue running. However, the flag remains within the overall model to address specific configurations at power.

(6) Only for transient induced seal LOCAs where MOV 313 must close to prevent an ISLOCA.

(7) Except for specific LOCA or SGTR initiator.

Table 8-2
Quantification Summary

Event Tree	*Solution Top Gate(s)*	*Top Gate Flag File (*.CAF)*	*Delete-Term File (*.CUT)*	*SBO Deleted*	*QRecover File (*.TXT)*	*Final Value*	*# Cutsets > 1E-07*	*Comments*
ATWS	TL_ATWSM	ATWSFL	MUTEXCL	No	RECOV	1.582E-07	0	Sequence split into 3 files to normalize on three events (mechanical and 2 electrical faults)
	TL_ATWSE	ATWSFL2	MUTEXCL	No	RECOV	6.715E-07	2	
	TL_ATWES	ATWSFL1	MUTEXCL	No	RECOV	3.501E-10	0	
	Total (1)					8.301E-07	2	
Large LOCA	TL_A	LBFLAG	MUTEXCL	No	RECOV	3.032-06	2	
	Total (1)					3.032-06	2	
Medium LOCA	TL_M	MBFLAG	MUTEXCL	No	RECOVM	4.108E-06	7	
	TL_M_TRANS	TRLOCA	MUTEXCL	No	RECOVM	7.011E-09	0	
	Total (1)					4.116E-06	7	
Small LOCA	TL_S	SBLOCA	MEXCSBO	Yes	RECOV1	2.464E-06	5	
	TL_S_TRANS	TRLOCA	MEXCSBO	Yes	RECOV1	1.909E-06	0	
	Total (1)					4.373E-06	5	
Small-Small LOCA	TL_SS	SSLOCA	MEXCSBO	Yes	RECOV1	1.252E-05	16	Seal LOCA split into 3 files: (1) SI transients (TL_Q4), (2) TIRXTRIP (TL_Q4TR1), and (3) all remaining initiators (TL_Q4TR2). Last 2 files include a cutset-to-fault tree gate for the seal LOCA initiation since no SI signal is initially present. Must also delete RCHFD00RCP from all Q4 cutsets.
	TL_Q4	SEALSIFL	MEXCSBO	Yes	RECOV1	5.878E-09	0	
	TL_Q4TR1	Q4TR1FL	MEXCSBO	Yes	RECOV1	3.642E-07	0	
	TL_Q4TR2	Q4TR2FL	MEXCSBO	Yes	RECOV1	5.212E-06	3	
	Total (1)					1.810E-05	19	
SGTR	TL_RA1	RA1FLAG	MEXCSBO	Yes	RECOV	2.492E-06	4	Sequence split into 4 files to: (1) normalize on each SG, and (2) account for isolation of ruptured SG.
	TL_RA3	RA2FLAG	MEXCSBO	Yes	RECOV	1.560E-06	0	
	TL_RB1	RB1FLAG	MEXCSBO	Yes	RECOV	2.476E-06	4	
	TL_RB3	RB2FLAG	MEXCSBO	Yes	RECOV	1.560E-06	0	
	Total (1)					8.086E-06	8	

Table 8-2
Quantification Summary

Event Tree	*Solution Top Gate(s)*	*Top Gate Flag File (*.CAF)*	*Delete-Term File (*.CUT)*	*SBO Deleted*	*QRecover File (*.TXT)*	*Final Value*	*# Cutsets > 1E-07*	*Comments*
Transients	TL_42_01	T2FLG01	MEXCSBO	Yes	RECOV	4.253E-07	2	Sequence split into 6 files to: (1) solve for TIRXTRIP and other initiators separately (extension 01 versus 02), and (2) solve for "bleed," "feed," and MS line breaks separately (42, 52, and TSI).
	TL_42_02	T2FLG02	MEXCSBO	Yes	RECOV	3.794E-09	0	
	TL_52_01	T2FLG01	MEXCSBO	Yes	RECOV	3.410E-06	10	
	TL_52_02	T2FLG02.	MEXCSBO	Yes	RECOV	4.464E-07	0	
	TL_TSI_1	TSIFLG01	MEXCSBO	Yes	RECOV	1.692E-06	5	
	TL_TSI_2	TSIFLG02	MEXCSBO	Yes	RECOV	4.716E-08	0	
	TL_PC_01	T2FLG01	MEXCSBO	Yes	RECOV	3.810E-08	0	
	TL_PC_02	T2FLG02	MEXCSBO	Yes	RECOV	0.000E-00	0	
	Total (1)					4.426E-06	11	
Vessel Rupture & ISLOCA	TL_ZZ	N/A	N/A	N/A	N/A	1.031E-06	1	
	Total (1)					1.031E-06	1	
SBO	TL_SBRX1	SB_RXFL1	MUTEXC	No	RECSBO	4.281E-07	0	Sequence split into 4 files to: (1) solve for TIRXTRIP and other initiators separately (RX versus TR), and (2) to identify whether offsite power can be recovered (grid failure vs. transformer fault). Also, failure to run probabilities were adjusted to account for <24 hr mission time when appropriate.
	TL_SBRX2	SB_RXFL2	MUTEXC	No	RECSBO	2.577E-09	0	
	TL_SBTR1	SB_TRFL1	MUTEXC	No	RECSBO	5.709E-06	4	
	TL_SBTR2	SB_TRFL2	MUTEXC	No	RECSBO	1.756E-08	0	
	Total (1)					6.218E-06	4	
Total (1)						5.021E-05	59	

Notes:

1. Total value may not be the actual sum of "Final Value" and "# Cutsets > 1E-7" columns due to redundant and non-minimal cutsets which are eliminated when combining all cutsets for a given event tree together.

Table 8-3
Piping Evaluation

Pen #	*Section of Piping*	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 650°)*[19]	*Hydro Test Pressure (@ 100°)*	*Flanges*
101	RCS Cold Leg A to Accumulator TSI03B	316/140	10	2580	1733	None
	Accumulator TSI03B to 878D	316/160	2	2580	1733	None
	RCS Hot Leg A to 878C	316/160	2	2580	1733	None
	878C/878D to 888B and 870B	316/80	4	1400	1733	None
	870B to PSI01C and PSI01A	316/80	3	1400	1733	At pumps
	888B to PSI01B	316/80	3	1400	1733	At pump
	PSI01A, PSI01B, PSI01C suction	304/40S	4	370	263	At pumps
110b	872A/872B to 882 and 884	316/80	0.75	1400	1733	FI-929
	882 to RWST	304/10S	0.75	<150	not tested	None
111 112	Rx Vessel to 852A and 852B	316/160	6	2580	2250	None
	RCS to 720	316/160	10	2580	2250	None
	852A/852B/720 to RHR Pumps A and B	304/40S	8	600	750	At pumps
	852A, 852B, and 720 to 135 (CVCS)	304/40S	2	600	750	None
113	RCS Cold Leg A to Accumulator TSI03A	316/140	10	2580	1733	None
	Accumulator TSI03A to 878B	316/160	2	2580	1733	None
	RCS Hot Leg A to 878A	316/160	2	2580	1733	None
	878A/878B to 888A and 870A	316/80	4	1400	1733[23]	None
	870A to PSI01C and PSI01B	316/80	3	1400	1733	At pumps
	888A to PSI01A	316/80	3	1400	1733	At pump

Table 8-3
Piping Evaluation

Pen #	*Section of Piping*	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 650°)[19]*	*Hydro Test Pressure (@ 100°)*	*Flanges*
101	RCS Cold Leg A to Accumulator TSI03B	316/140	10	2580	1733	None
	Accumulator TSI03B to 878D	316/160	2	2580	1733	None
	RCS Hot Leg A to 878C	316/160	2	2580	1733	None
	878C/878D to 888B and 870B	316/80	4	1400	1733	None
	870B to PSI01C and PSI01A	316/80	3	1400	1733	At pumps
	888B to PSI01B	316/80	3	1400	1733	At pump
	PSI01A, PSI01B, PSI01C suction	304/40S	4	370	263	At pumps
110b	872A/872B to 882 and 884	316/80	0.75	1400	1733	FI-929
	882 to RWST	304/10S	0.75	<150	not tested	None
111 112	Rx Vessel to 852A and 852B	316/160	6	2580	2250	None
	RCS to 720	316/160	10	2580	2250	None
	852A/852B/720 to RHR Pumps A and B	304/40S	8	600	750	At pumps
	852A, 852B, and 720 to 135 (CVCS)	304/40S	2	600	750	None
113	RCS Cold Leg A to Accumulator TSI03A	316/140	10	2580	1733	None
	Accumulator TSI03A to 878B	316/160	2	2580	1733	None
	RCS Hot Leg A to 878A	316/160	2	2580	1733	None
	878A/878B to 888A and 870A	316/80	4	1400	1733[23]	None
	870A to PSI01C and PSI01B	316/80	3	1400	1733	At pumps
	888A to PSI01A	316/80	3	1400	1733	At pump

Table 8-4 ISLOCA Frequency Analytical Models				
#	*Configuration*	*Equation*	*Assumptions*	*Source*
1	Two check valves in series (with accumulator located inbetween)	$\langle\lambda^T\rangle = \{[(\lambda_L + \lambda_R)T_{CV1}]^* [(\lambda_L + \lambda_R)T_{CV2}] + CCF_R T_{CV2} + CCF_L T_{CV2}\} / 0.81$ ryr CV1 = check vlv against RCS pressure CV2 = check vlv against accumulator pressure T = 1/2 time interval between leak tests λ_L = leakage > 150 gpm λ_R = rupture CCF_R = CCF (rupture) of both valves CCF_L = CCF (leak) of both valves	• CV1 leaks/ruptures 1/2 time between tests since no leakage detection capability exists except after assuming failure of additional valves. It cannot stick open since leak tested after each opening. Per TS SR 3.4.14.1, T = refueling outage window (18 months). • Leakage thru CV2 might be known due to accumulator parameter changes which must be verified every 12 hrs per TS. Check valve is also leak tested after each opening (i.e., valve cannot stick open). Since check valve is already seated with 700 - 800 psig, sudden failure of valve when exposed to RCS pressure was ignored. • Potential for CCF of both check valves to rupture or leak. However, "T" is based on CV2.	NSAC-154, Fig. C.1-9
2	Two check valves and a normally closed MOV in series. Check valves are on the high pressure side.	$\langle\lambda^T\rangle = \{[T^2(\lambda_L^2 + 2\lambda_L\lambda_R + \lambda_R^2) + \lambda_H T(\lambda_L + \lambda_R) + T(CCF_R + CCFL)] * [T(\lambda_{ML} + \lambda_{MR}) + \lambda_{MH}]\} / 0.81$ T = 1/2 time interval between leak tests λ_L = check valve leakage > 150 gpm λ_R = check valve rupture λ_H = check valve fails to hold on demand CCF_R = CCF (rupture) of check valves CCF_L = CCF (leak) of check valves λ_{ML} = MOV leakage > 150 gpm λ_{MR} = MOV rupture λ_{MH} = MOV fails to hold on demand	• MOV is locked in position and verified every 12 hours such that it cannot be inadvertently opened. • SI is never injected through flowpath so that valves cannot "stick open" • Potential for CCF of both check valves to rupture or leak.	NSAC-154, Fig. C.1-3

Table 8-4
ISLOCA Frequency Analytical Models

#	*Configuration*	*Equation*	*Assumptions*	*Source*
3	Two normally closed MOVs in series with no permanent pressure indicator located inbetween	$\langle\lambda^T\rangle = \{[T^2(\lambda_{ML}{}^2 + 2\lambda_{ML}\lambda_{MR} + \lambda_{MR}{}^2) + \lambda_{MH}T(\lambda_{ML} + \lambda_{MR}) + T(CCF_L + CCF_R)]\} / 0.81$ ryr T = 1/2 time interval between leak tests λ_{MH} = MOV fails to hold on demand λ_{ML} = MOV leak > 150 gpm λ_{MR} = MOV rupture CCF_R = CCF (rupture) of MOVs CCF_L = CCF (leak) of MOVs	• MOVs are leak tested after opening during startup activities so there is no potential to stick open • MOVs are equipped with interlocks and have power removed such that it cannot be inadvertently opened	NSAC-154, Fig. C.1-6.
4	A check valve and normally closed MOV in series with the check valve on the high pressure side and the MOV on the low pressure side	$\langle\lambda^T\rangle = \{[T(\lambda_L + \lambda_R)] * [T(\lambda_{ML} + \lambda_{MR}) + \lambda_{MH} + \lambda_{MO}] + T(\lambda_L + \lambda_R)(\lambda_{MS})T_{SI}\} / 0.81$ ryr T = 1/2 time interval between leak tests T_{SI} = time period for inadvertent SI λ_L = check valve leakage > 150 gpm λ_R = check valve rupture λ_{MH} = MOV fails to hold on demand λ_{ML} = MOV leak > TS limit λ_{MR} = MOV rupture λ_{MS} = MOV opens via spurious SI signal λ_{MO} = Operator inadvertently opens MOV	• Only check valve leakage > 150 gpm is considered since relief valve 203 will address smaller leaks • MOV is verified closed every 12 hours so that operators cannot leave open • T_{SI} = T since CV failure must occur first or during the 20 minutes in which the MOV would be open.	NSAC-154, Fig. C.1-8

Table 8-5
Data for ISLOCA Events

Component	*Failure Mode*	*Value*	*Source*
Check Valve	Leakage > 150 gpm	6.8E-07/hr	NSAC-154, Table A.2-1
	Internal Rupture	1.0E-07/hr	NSAC-154, Table A.2-1
	Failure to Hold on Demand (Dynamic Failure)	2.7E-04	NSAC-154, Table A.2-1
	CCF (Leak) Beta Factor	3.0E-03	NSAC-154, Table A.2-1
	CCF (Rupture) Beta Factor	3.0E-03	NSAC-154, Table A.2-1
Motor-Operated Valves	Leakage > 150 gpm	6.0E-07/hr	NSAC-154, Table A.2-1
	Internal Rupture	2.7E-08/hr	NSAC-154, Table A.2-1
	Failure to Hold on Demand (Dynamic Failure)	2.7E-04	NSAC-154, Table A.2-1
	Inadvertently Opened by Operator	2.68E-04	NSAC-154, Table A.2-1
	Spurious SI Actuation	7.13E-06	1 event in 16 years (times 0.81) per Table 3-3 (LER 84-006)
	Spuriously Opened	9.7E-08/hr	NSAC-154, Table A.2-1
	Operator Fails to Follow Procedure (Recovery Action)	1.00E-01	NSAC-154, Table A.3-5
	CCF (Leak) Beta Factor	3.0E-03	NSAC-154, Table A.2-1
	CCF (Rupture) Beta Factor	3.0E-03	NSAC-154, Table A.2-1

Table 8-6
ISLOCA Results

Pen.	*Frequency (Identifier)*	*Recovery Value (1) (Identifier)*	*Final Frequency*	*LOCA Size*	*Consequence*
101	2.17E-09 (LIPEN101)	N/A	2.17E-09/ryr	4" φ	2/3 SI and all RHR is lost
110b	1.56E-07 (LIPEN110)	0.207 (TLHFDPN110)	3.23E-08/ryr	3/4" φ	All SI and RHR is lost
111	5.11E-06 (LIPEN111)	0.188 (TLHFDPN111)	9.61E-07/ryr	10" φ	All RHR is lost
113	2.17E-09 (LIPEN113)	N/A	2.17E-09/ryr	4" φ	2/3 SI and all RHR is lost
140	2.36E-07 (LIPEN140)	0.1 (TLHFDPN140)	2.36E-08/ryr	10" φ	All RHR is lost
TOTAL	5.50E-06		1.02E-06/ryr		

Notes:

(1) A human failure probability of 0.1 was used in all cases. However, this recovery action is typically only applied to a portion of the potential ISLOCA paths. As such, the value presented in this table is the difference in the final frequency with and without the recovery action.

Figure 8-1
Water Systems Connected to RCS

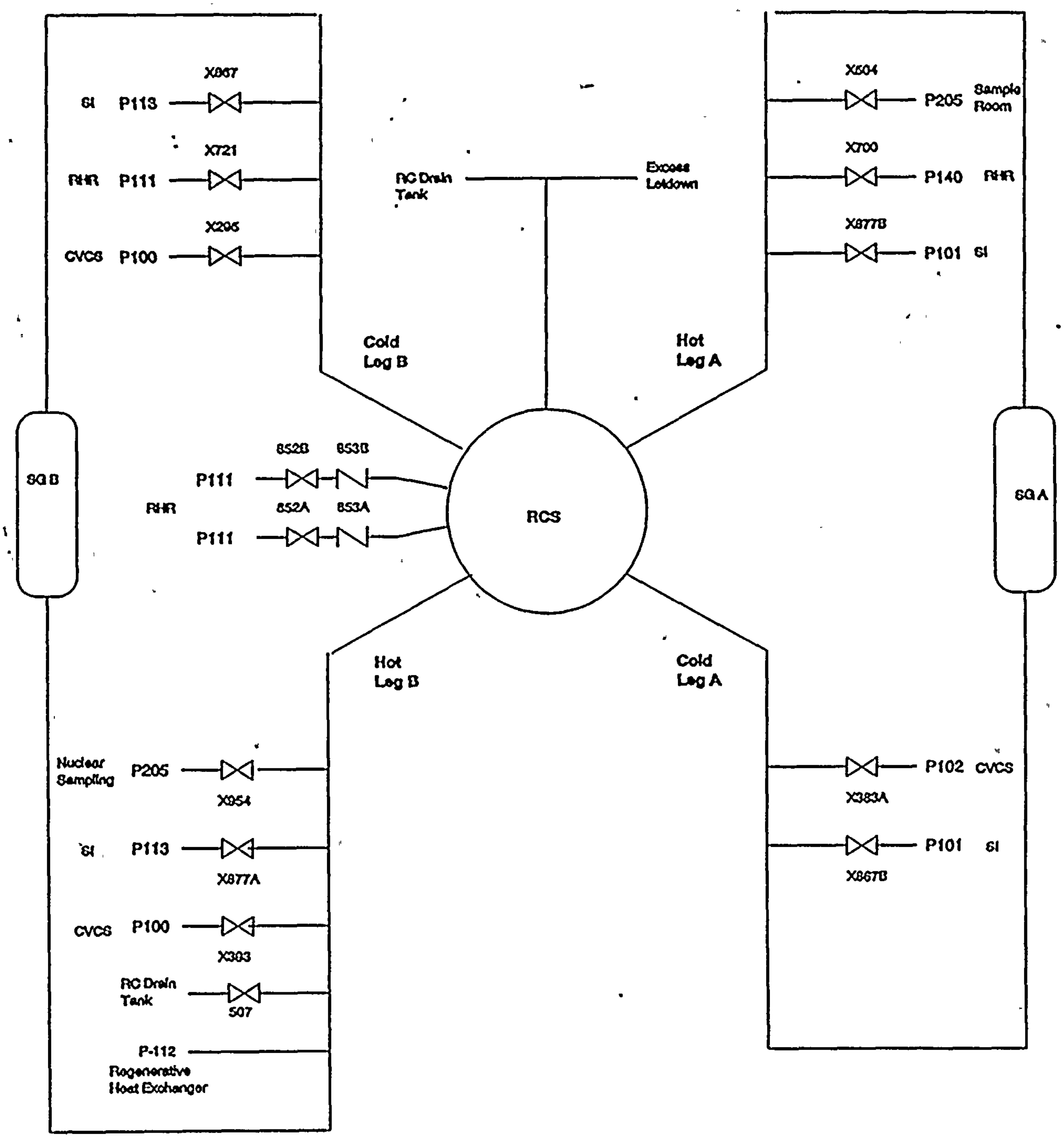


Figure 8-2
Penetration 101 (SI)

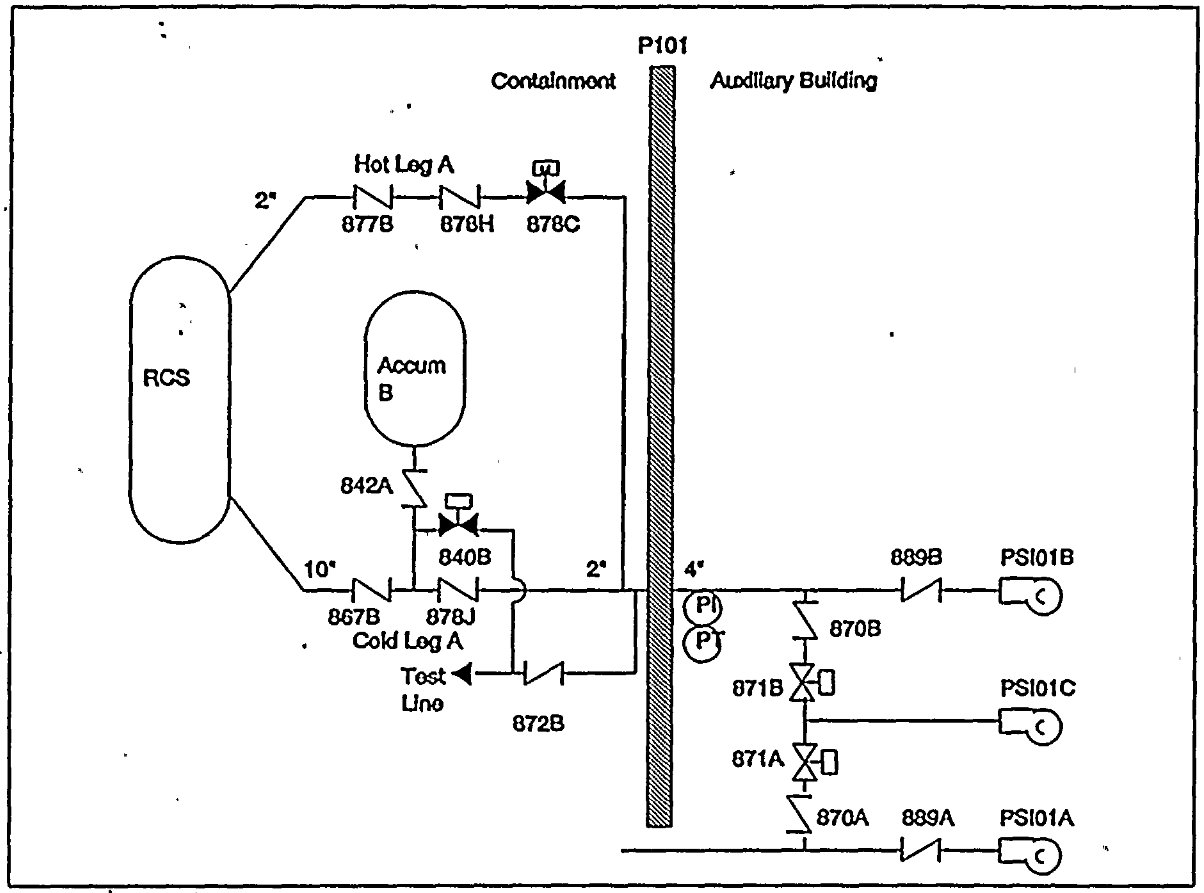


Figure 8-3
Penetration 110b (SI Test Line)

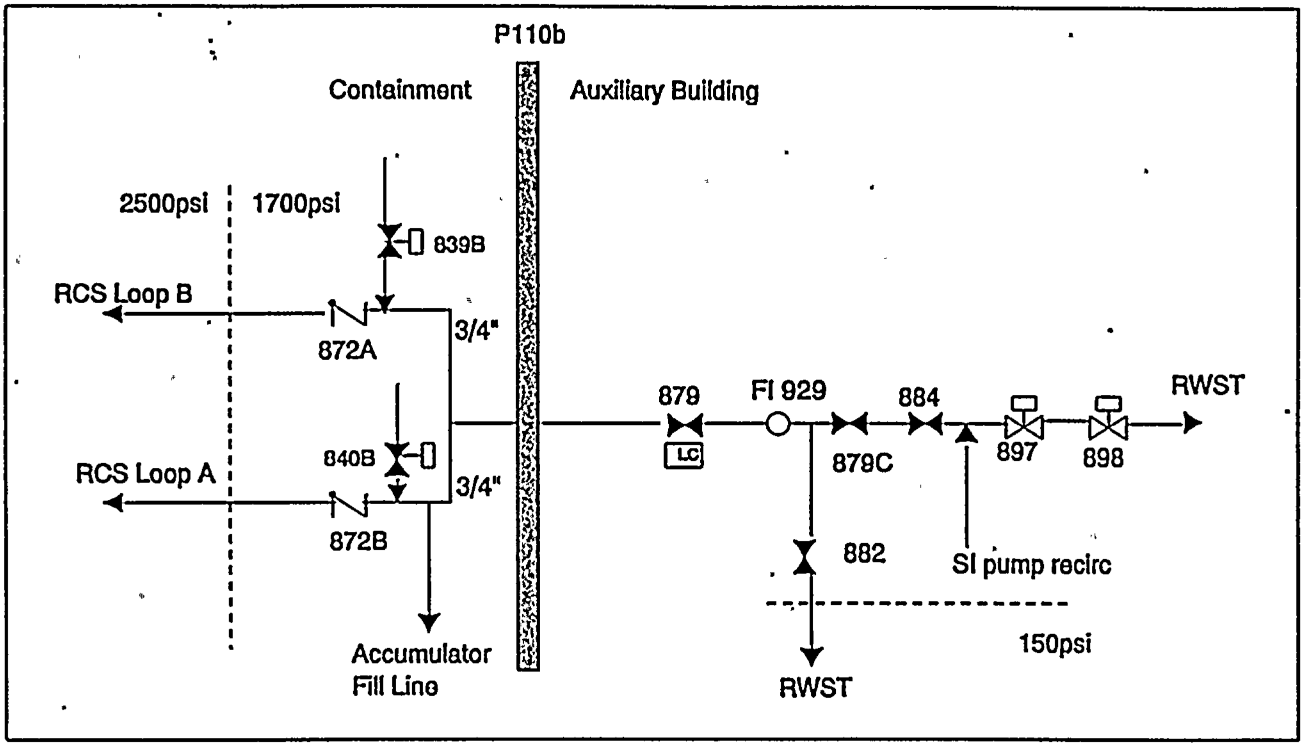


Figure 8-4
Penetrations 111 and 112 (RHR and CVCS)

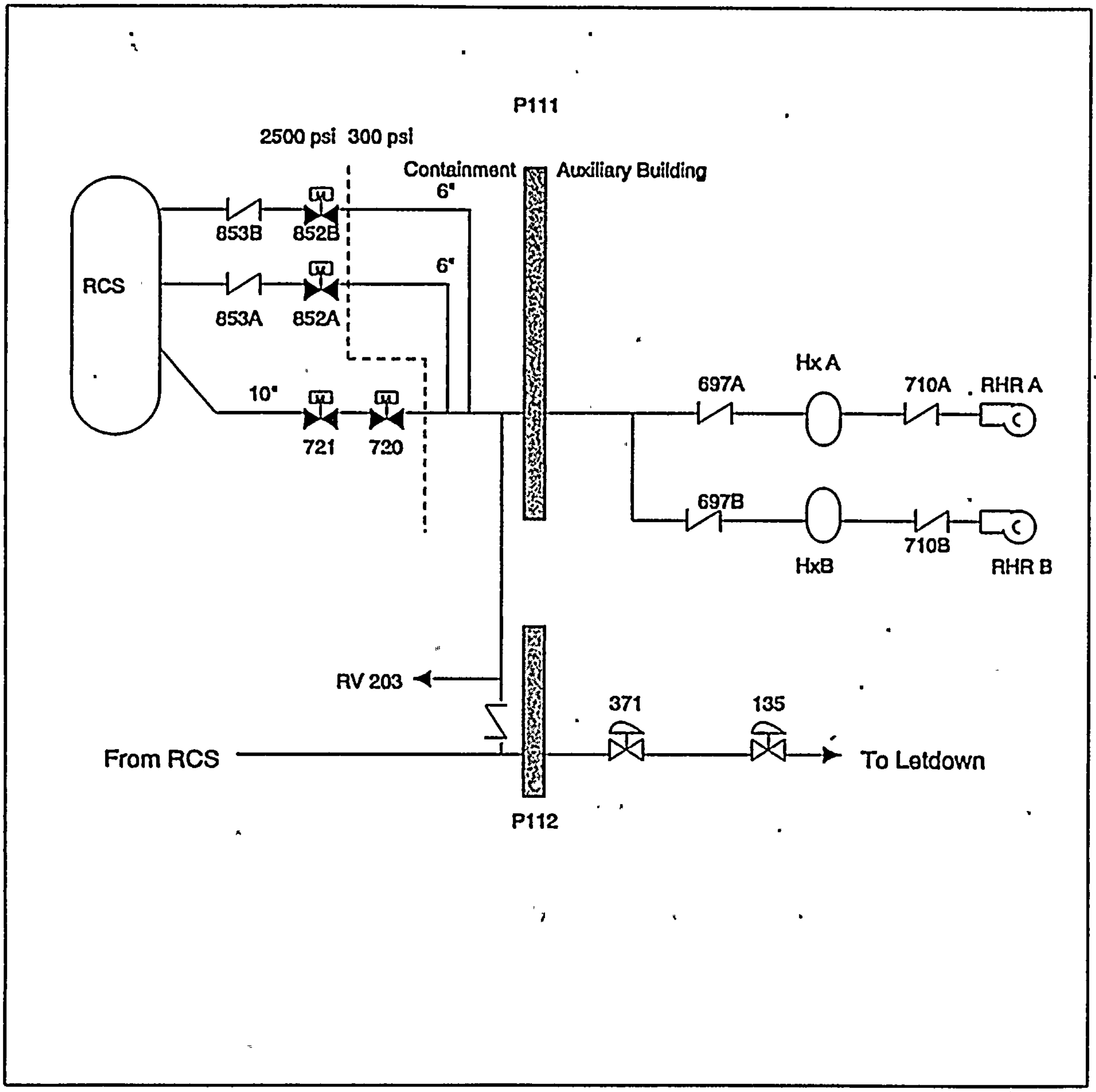


Figure 8-5
Penetration 113 (SI)

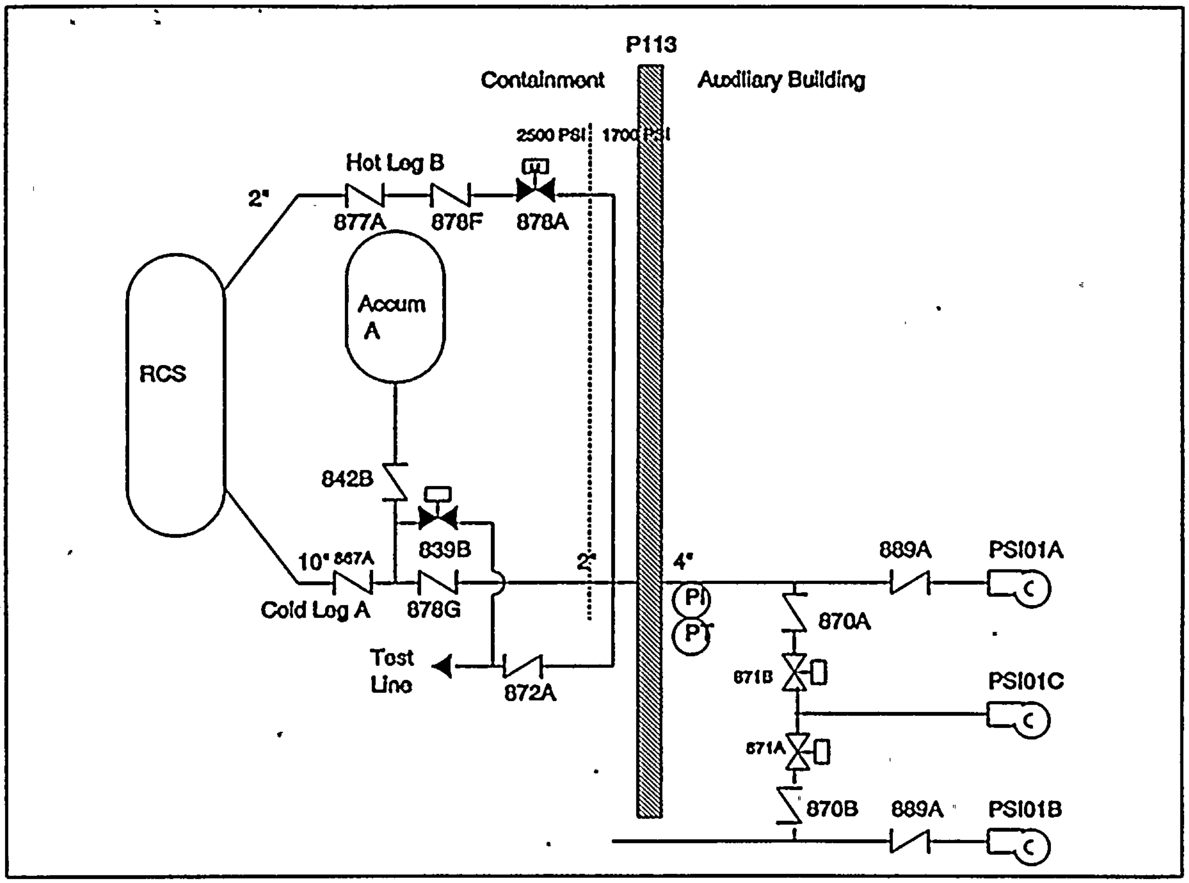


Figure 8-6
Penetrations 124a and 124c (CCW for Excess Letdown HX)

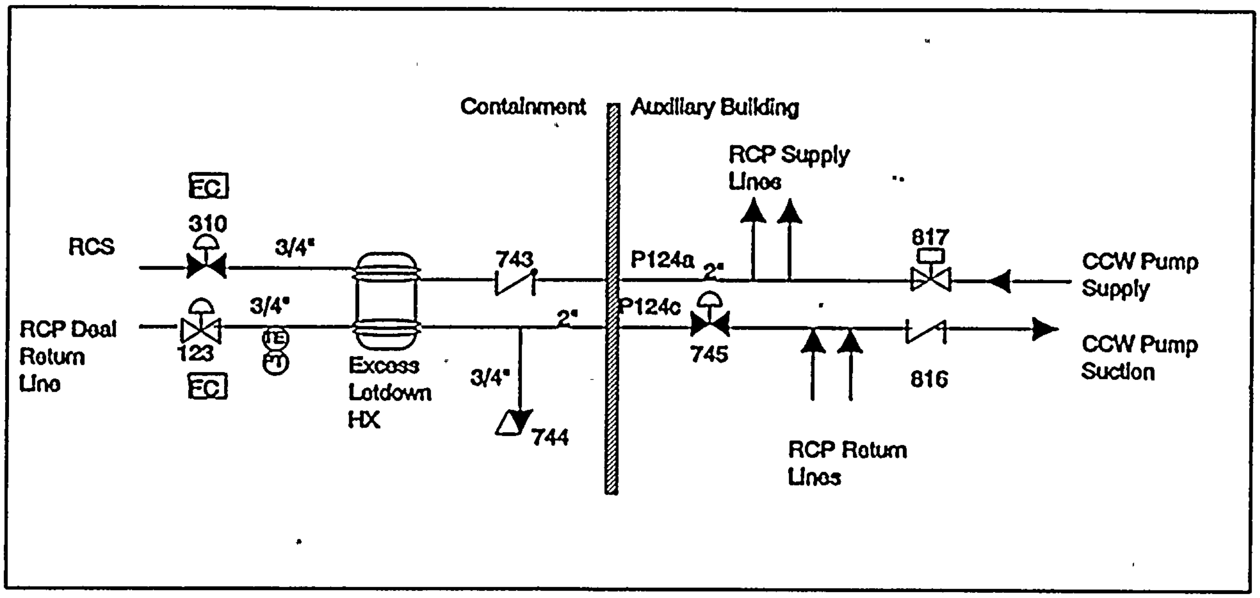


Figure 8-7
Penetrations 125 and 128 (CCW for RCP B)

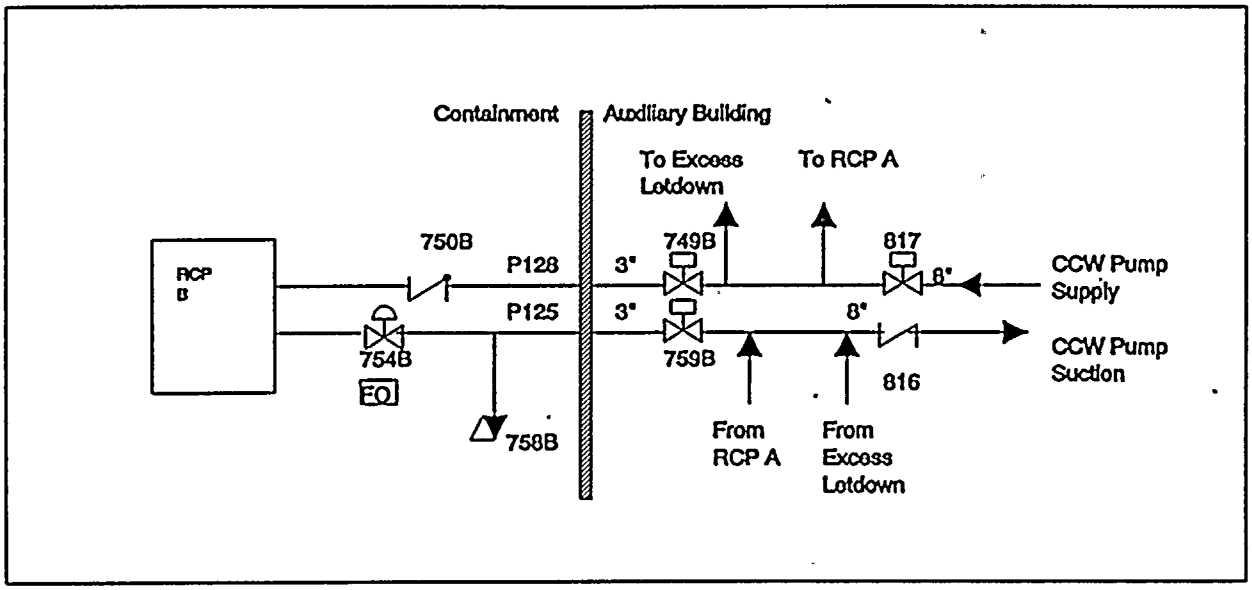


Figure 8-8
Penetrations 126 and 127 (CCW for RCP A)

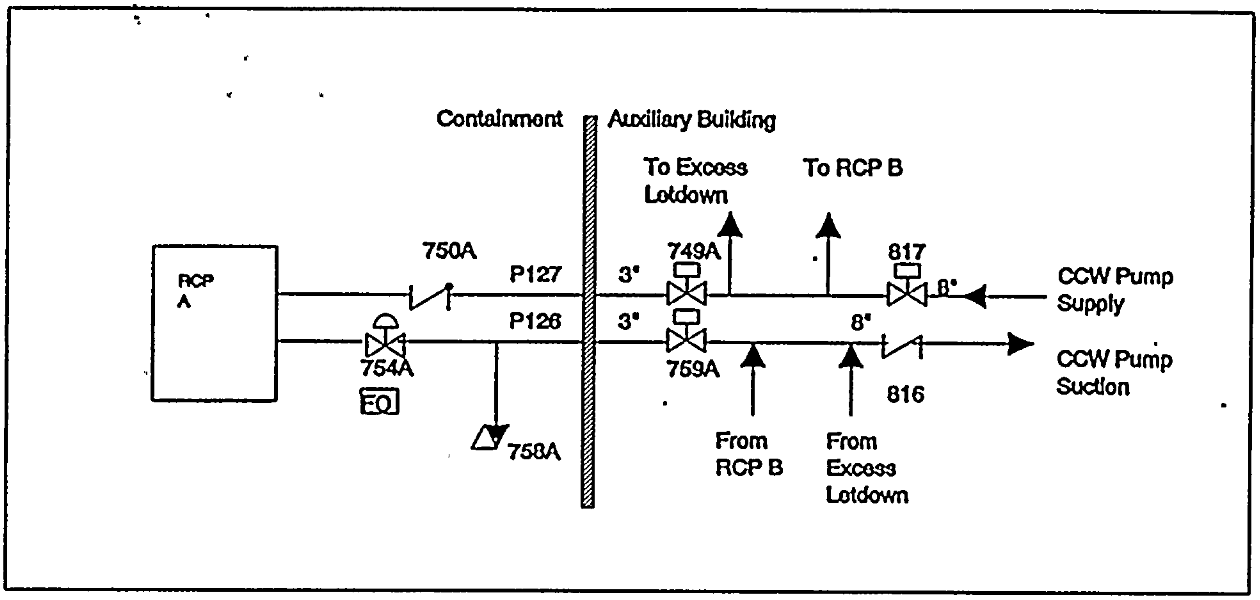
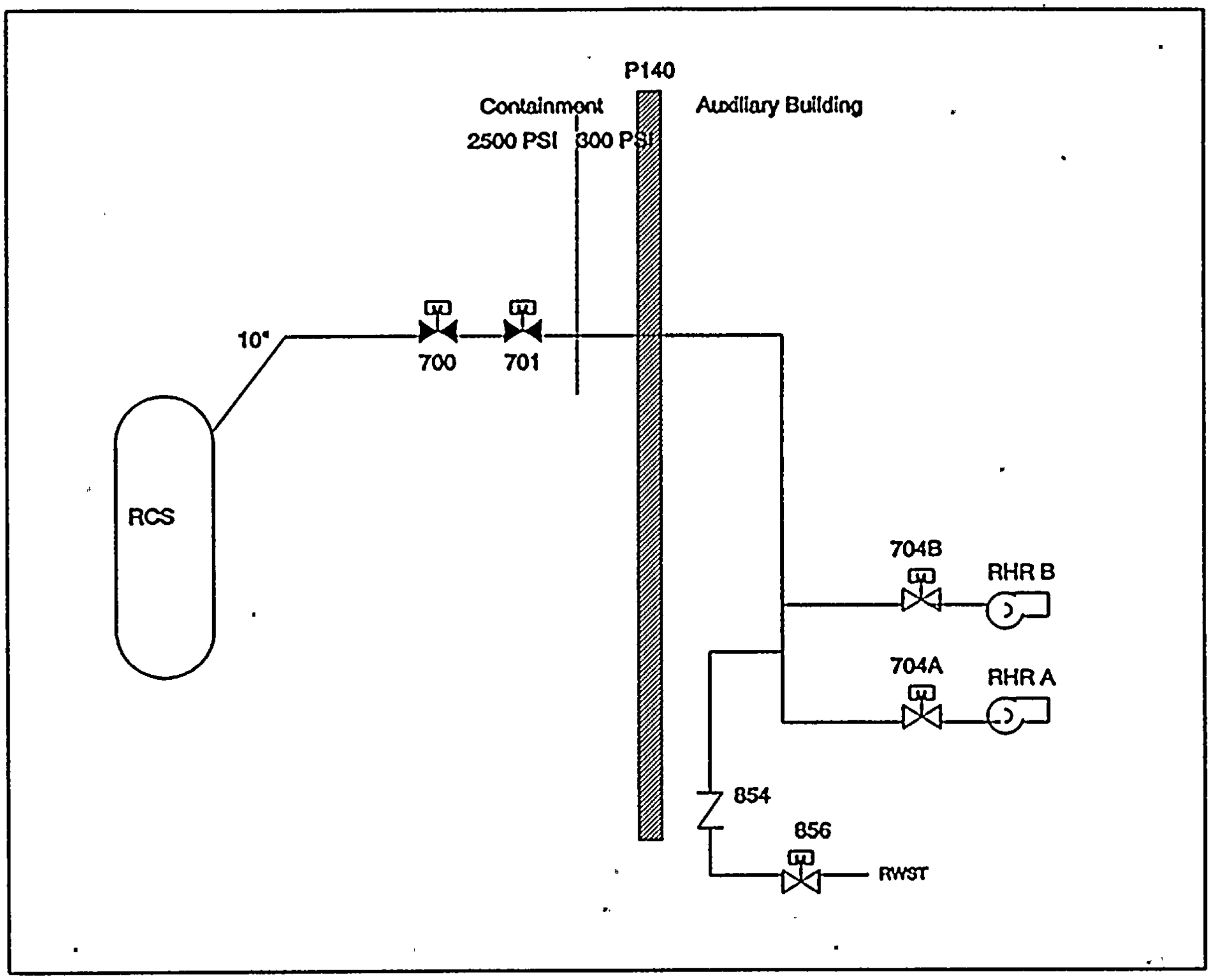


Figure 8-9
Penetration 140 (RHR)



9.0 LEVEL 1 RESULTS

Section 8 describes the process used to quantify the Level 1 models (including external events), and for evaluating intersystem LOCAs (ISLOCAs). This section describes the results of the Level 1 quantification process (including ISLOCAs) and relevant risk insights. The section is organized as follows:

a. Generic Letter (GL) 88-20 reporting requirements;

b. Evaluation of Unresolved Safety Issue (USI) A-45, "Shutdown Decay Heat Removal Requirements;"

c. Sensitivity and importance analysis; and

d. Additional risk insights.

Section 10 provides the Level 2 evaluation results.

9.1 GL 88-20 Reporting Requirements

GL 88-20, Appendix 2 and NUREG-1335 [Ref.1] each contain reporting requirements for the Level 1 PSA. These reporting requirements (or screening criteria) differ only with respect to the type of quantification output. GL 88-20, Appendix 2 discusses results on a "functional sequence" basis while NUREG-1335 discusses "systemic sequences." The only difference between these two type of results is that functional sequence refers to identification of faults on a function level (i.e., the four functions described in Section 4.1) while systemic sequence refers to identification of faults on a component level. Based on the quantification process used, the Ginna Station PSA will use the systemic sequence screening criteria. As such, per NUREG-1335, the following reporting requirements apply:

a. Any systemic sequence that contributes 1E-07 or more per reactor year to core damage;

b. All systemic sequences within the upper 95 percent of the total core damage frequency (CDF);

c. Identification of major contributors to the criteria specified in items a and b above, including an estimate of the total CDF;

d. Any systemic sequences that the utility determines from previous applicable PSAs or by utility engineering judgement to be important contributors to CDF;

e. Identification of sequences that, but for low human error rates in recovery actions, would have been above the applicable core damage screening criteria; and

f. A list of any vulnerabilities identified during the review process, including the criteria used to define vulnerability.

With respect to items a and b above, NUREG-1335 also requires that a list of the identified sequences, including a concise description of accident progression, specific assumptions, sensitive assumptions and parameters, essential equipment subject to environmental conditions beyond the design bases (and those conditions), and applicable human recovery actions be included.

The list of cutsets which are > 1.0E-07/ryr (i.e., item a) are presented in Table 9-1. This table contains cutsets which identify the type of accident, initiating event, the specific component failures, and human errors which lead to core damage. As described above, NUREG-1335 requires specific information with respect to identified sequences. Details of the accident progression can be inferred from the event trees described in Section 5 while significant modeling assumptions (including any environmental considerations) are provided in Sections 6 and 7. The sensitivity of any risk significant assumption is provided in Sections 9.3 and 9.4. It should be noted that credit was not taken for equipment which would have to operate in environments beyond its design basis or supporting engineering evaluations.

The estimated CDF for the Level 1 PSA of Ginna Station is 5.021E-05/ryr. Rather than limit the discussion of the contributors to the Ginna Station CDF to only those sequences which meet the screening criteria specified in items b and c, a discussion of the complete results categorized by accident type is provided in Section 9.1.1. Identified in each section are the initiating events which contribute to core damage, component failures required to reach a condition in which inadequate core cooling occurs, and major operator actions which are important to coping with these accident sequences.

The evaluation of additional important contributors as required by item d is discussed in Section 9.4. Finally, a discussion of human recovery events (item e) is provided in Section 9.1.2 while vulnerabilities are discussed in Section 11 (item f).

9.1.1 Major Contributors to Core Damage

The major contributors to core damage are provided on the basis of the event trees shown in Section 5. A pie chart of each accident sequence's contribution to the final CDF is provided in Figure 11-1. Specific quantification results are also presented in Table 8-2.

9.1.1.1 Transients

The calculated CDF resulting from transients which do not lead to a loss-of-coolant accident (LOCA) or station blackout (SBO) sequence is 4.426E-06/ryr (9% of CDF). The transient event tree is basically organized into three areas: (1) failure of all feedwater to the steam generators (SGs) with subsequent failure of feed and bleed operations; (2) failure to isolate a high energy line break (HELB) with subsequent failure to maintain RCS inventory and pressure, and (3) failure to provide RCS overpressure control. The calculated CDF for each of these three areas is 4.279E-06, 1.739E-06, and 3.810E-08, respectively (note- their total exceeds 4.426E-06 due to common cutsets between areas).

The contribution of each initiating event to the transient sequences is dominated by HELBs in the Turbine Buildings (46%), DC related failures (16%), HELBs in the Intermediate Building (11.5%), and grid failures (8%) (see Appendix A).

The top component failures were related to closure of the Fire Door F36 which potentially fails preferred auxiliary feedwater (AFW), failure of both diesel generators (DGs) to start and run, failures and test and maintenance activities associated with the standby AFW (SAFW) system, and failures of the turbine-driven AFW (TDAFW) pump. The top human events are related to performing feed and bleed operations (RCHFD01BAF), starting the SAFW system (AFHFDSAFWX), starting additional service water (SW) pumps when required (SWHFDSTART), providing fire water cooling to the turbine-driven AFW (TDAFW) pump (AFHFDALTTD), starting the TDAFW pump when no signal exists (AFHFDTDAFW), and providing additional suction sources for the AFW system (AFHFDSUPPL). The reasons for these top contributors are described in more detail below in the summary of the top cutsets which were calculated:

a. A loss of steam generator (SG) cooling caused by a HELB in the Intermediate or Turbine Building which fails the preferred AFW and main feedwater (MFW) systems, with subsequent failures of the SAFW system and human errors related to feed and bleed operations. Failures of the SAFW system are dominated by operator errors with respect to placing the system into service, common cause failures of the pumps and motor-operated valves (MOVs), and test and maintenance activities. It should be noted that the Ginna Station Improved Technical Specifications allow both SAFW trains to be out of service at the same time.

b. Ventilation related failures of the preferred AFW system caused by closure of Fire Door F36, and the failure of forced ventilation within the Intermediate Building due to a loss of offsite power and subsequent failure of DG B. This is followed by failure of SAFW Pump A and the failure of feed and bleed operations.

c. Coincident DC train failures which prevent the ability to start necessary equipment (note, this does not apply for loss of offsite power initiators since it becomes a SBO sequence).

d. Loss of service water (SW) events where the TDAFW pump is in maintenance or otherwise fails such that no AFW is available (SW provides room cooling for the SAFW system, and pump cooling for the motor-driven AFW pumps), combined with operator errors related to feed and bleed operations.

e. Steam line breaks with a common cause failure of the main steam line isolation valves (MSIVs) to close along with various failures related to the Safety Injection (SI) system.

f. Operator errors to start a second SW pump upon failures of one electrical train (this fails the two SW pumps on this train) or to isolate the SW system loads such that one pump can provide cooling water to necessary components (note, this applies to sequences which do not generate a coincident SI and UV signal).

9.1.1.2 Station Blackout

The calculated CDF resulting from SBO sequences is 6.218E-06/ryr (12% of CDF). A SBO sequence is essentially the failure of both DGs combined with the failure of the TDAFW pump leading to core damage prior to restoration of offsite power.

The contribution of each initiating event to the SBO sequences is dominated by grid failures (88%), and reactor trips with a subsequent loss of offsite power (7%) (see Appendix A).

The top DG failures are related to common cause failures to run, start, and failure of 480 V bus breakers to open and close. Significant independent failures of the DGs include failing to run, fuel system failures, ventilation failures, undervoltage failures, test and maintenance activities and failures of SW cooling. The TDAFW pump failures are dominated by test and maintenance activities and failure of the pump to start and run.

The top human events are related to restoring offsite power within the following time frames: (1) 10 hours (i.e., 4 hours after the batteries have been depleted and the TDAFW pump subsequently fails) (ACAALOSP10), and (2) 1 hour if the TDAFW pump fails coincident with the SBO event (ACAADLOSP1). Other human actions include reaching RHR conditions or utilizing AFW long-term following restoration of offsite power (RCHFDRHRSB), the failure to start additional SW pumps when required (SWHFDSTART), the failure to provide fire water cooling to the TDAFW lube oil cooler (AFHFDALTTD), and the failure to manually start the TDAFW pump upon loss of a DC train (AFHFDTDAFW). The later event is a very involved scenario as follows:

a. A single DC train failure results in a reactor trip (e.g., Train A).

b. A subsequent loss of offsite power occurs requiring both DGs to start; however, the DG on the opposite electrical train from the initiating event fails to start (e.g., DG B).

c. The remaining DG starts and loads (utilizing the opposite DC train emergency power source), but no DG fuel oil transfer pump is available due to the initiating event failing control power to its MCC (e.g., MC H). The fuel oil transfer pump from the opposite DG is also unavailable since no AC power is available due to the failure in b. above. Therefore, this DG (e.g., DG A) fails after 1 hour of running, resulting in SBO conditions.

d. Following the failure of the one operating DG and its associated MDAFW pump, the TDAFW pump must now be used. The TDAFW pump receives three potential start signals: (1) AMSAC, (2) low level in both SGs; and (3) undervoltage (UV) on Bus 11A <u>and</u> 11B. The relays for low SG level must energize to actuate and are powered from Instrument Bus D which is lost upon loss of offsite power. Both relays for the UV signal must also energize to actuate; however, one relay is lost from the initiating event. The AMSAC system actuates based on MFW flow and turbine power level. The loss of DC train will fail MFW flow to one SG by closing the feedwater regulating valve; however, flow to the second SG will not be isolated until the loss of offsite power occurs. Since the reactor and turbine are assume to have tripped, AMSAC will not actuate as turbine power level is below 40% when the loss of offsite power occurs. Therefore, the operators must manually start the TDAFW pump in this instance.

9.1.1.3 Small-Small LOCAs

The calculated CDF resulting from small-small LOCAs is 1.810E-05/ryr (36% of CDF). The small-small LOCA event tree is entered one of two ways: (1) pipe breaks within the reactor coolant system (RCS) or random failures of the reactor coolant pump (RCP) seals (i.e., failures not related to support system status), and (2) RCP seal LOCAs caused by failures of support systems (i.e., component cooling water (CCW) and charging). The dominating sequences for this accident are related to the first scenario (i.e., pipe breaks) which contributes 69% of the final value (1.252E-05). With respect to the second scenario, the transient induced small-small LOCA initiating events are dominated by the total loss of SW (20%).

The top component failures are related to common cause failures of the RHR pumps, containment sump B suction MOVs (850A and 850B), the CCW MOVs to the RHR heat exchangers (738A and 738B), and SI pumps. Also included are test and maintenance activities associated with RHR, independent failures of the above equipment, and DG failures. The top human events include failure to align alternate suction sources to the charging pumps (CVHFDSUCTN), operators failing to start additional SW pumps when required (SWHFDSTART), operators failing to cooldown to RHR upon loss of SI (RCHFDCD0SS), failure to successfully implement high-head recirculation (RRHFDRECRC and SRHFDRECRC), and failure to throttle RHR system flow upon loss of instrument air (RRHFDTHROT).

As described above, the small-small LOCAs were dominated by LOCA initiators and not by transients. This is primarily due to the fact that there is no real support system dependices between CCW and CVCS which would lead to a seal LOCA. Consequently, two independent systems must fail which is of low probability if SBO sequences are removed. Since two systems must fail, the subsequent operator failure to trip the RCPs within 2 minutes to prevent seal damage (RCHFD00RCP) was also of limited importance. The top contributors for the RCP seal LOCA were as follows:

a. Loss of SW (initiating event) with subsequent failure of CCW due to overheating and failure of operators to align long-term suction for the CVCS pumps since the loss of SW fails cooling to the instrument air (IA) compressors which then isolates letdown. It is estimated that operators have 30 minutes to perform this activity upon loss of letdown based on available inventory in the volume control tank (VCT). No credit was taken for recovery of SW or CCW.

b. Loss of CCW (initiating event) with loss of offsite power (this fails power to the IA compressors) and failure of operators to align long-term suction for the CVCS pumps. Also included with the CCW initiator are common cause failures of the CVCS pumps and other equipment failures associated with charging flow to the RCPs.

9.1.1.4 Small LOCAs

The calculated CDF resulting from small LOCAs is 4.373E-06/ryr (9% of CDF). The small LOCA event tree is entered one of two ways: (1) pipe breaks within the RCS, and (2) events which result in a stuck open pressurizer PORV or safety valve. The dominating sequences for this accident are related to the first scenario (i.e., pipe breaks) which contributes 56% of the final value (2.464E-06). With respect to the second scenario, the transient induced small LOCA initiating events are dominated by loss of load events (19%), loss of offsite power events (10%), and DC train faults (10%) (see Appendix A).

The top component failures are common cause failures of the RHR pumps, containment sump B suction MOVs (850A and 850B), the CCW MOVs to the RHR heat exchangers (738A and 738B), and SI pumps. Also included are test and maintenance activities associated with RHR, independent failures of the above equipment, PORV and safety valve failures to reseat, and DG failures. The top human events include failure to isolate a PORV LOCA (RCHFDPLOCA), operators failing to cooldown to RHR upon loss of SI (RCHFDCD0SS), failure to successfully implement recirculation (SRHFDRECRC and RRHFDRECRC), and failure to throttle RHR system flow upon loss of instrument air (RRHFDTHROT).

Transient induced small LOCAs were a relatively minor contributor to this accident (1.909E-06). This is primarily due to the fact that multiple events must occur in order for this to lead to a core damage scenario. That is, a transient must occur which challenges the PORVs or safety valves. One of these valves must then fail to re-seat creating the potential for a LOCA (note that PORV LOCAs can potentially be isolated by their respective block valves). Following this, failures to mitigate the LOCA event must occur. Since the frequency of a transient that challenges a PORV or safety valve combined with the failure rate of the valves to re-close is relatively low, transient induced small LOCAs were not a major contributor.

9.1.1.5 Medium LOCAs

The calculated CDF resulting from medium LOCAs is 4.116E-06/ryr (8% of CDF). The medium LOCA event tree is entered one of two ways: (1) pipe breaks within the RCS, and (2) events which result in a multiple stuck open pressurizer PORV and safety valves. The dominating sequences for this accident are related to the first scenario (i.e., pipe breaks) which contributes 99% of the final value (4.108E-06). With respect to the second scenario, the transient induced medium LOCA initiating events are related to loss of load events (see Appendix A).

The top component failures are common cause failures of the RHR pumps, containment sump B suction MOVs (850A and 850B), RHR injection MOVs (852A and 852B), the CCW MOVs to the RHR heat exchangers (738A and 738B), and SI pumps. Also included are SBO sequences, test and maintenance activities associated with RHR, DG failures, and the failure of the RHR pumps due to failure of AOV 371 to close (letdown containment isolation valve). The latter event creates the potential for an ISLOCA outside containment which eventually is routed to the sump pumps located in the RHR pump pit (see Section 6.16.4). It should be noted that failure of AOV 371 does not appear in the smaller LOCA results due to the increased time available to operators to isolate the affected penetration. Based on the human error modeling method, increased time available to the operators to perform an action results in a reduced failure rate.

The top human events include failure to successfully implement recirculation (RRHFDRECRC) and failure to isolate AOV 371 (CVHFD00371).

Transient induced medium LOCAs were an insignificant contributor to this accident (7.011E-09). This is primarily due to the fact that multiple events must occur in order for this to lead to a core damage scenario. That is, a transient must occur which challenges the PORVs or safety valves. At least two of these valves must then fail to re-seat creating the potential for a medium LOCA (note that PORV LOCAs can potentially be isolated by their respective block valves). Following this, failures to mitigate the LOCA must occur (see previous paragraph). Since the frequency of a transient that challenges a PORV or safety valve combined with the failure rate of multiple valves to re-close is sufficiently low, transient induced medium LOCAs were not a major contributor.

9.1.1.6 Large LOCAs

The calculated CDF resulting from large LOCAs is 3.032E-06/ryr (6% of CDF). The top component failures are related to common cause failures of the RHR pumps, containment sump B suction MOVs (850A and 850B), RHR injection MOVs (852A and 852B), and the CCW MOVs to the RHR heat exchangers (738A and 738B). Also included were SBO sequences, test and maintenance of the RHR pumps, and failure of the RHR pumps due to failure of AOV 371 to close (see discussion in Section 9.1.1.5). The top human events include failure to go to recirculation (RRHFDRECRC) and failure to close a redundant isolation valve to AOV 371 (CVHFD00371).

9.1.1.7 Steam Generator Tube Ruptures

The calculated CDF resulting from steam generator tube ruptures (SGTRs) is 8.086E-06/ryr (16% of CDF). The SGTR sequences are dominated by operator actions which results from the operators having multiple activities which they must perform in order to mitigate this accident. The necessary operator actions which must be performed are summarized below (see Section 4.2.2.3.3 for additional details):

a. Identify and isolate the ruptured SG (MSHFDISOLR and MSHFDISOLA);
b. Cooldown the RCS to establish subcooling margin (RCHFDCDDPR);
c. Depressurize the RCS to restore inventory (RCHFDCDDPR); and
d. Terminate SI to stop primary to secondary system leakage (RCHFDCDDPR).

The failure to accomplish any one of these activities is expected to result in SG overfill with the potential for stuck open main steam relief valve. This is essentially a LOCA outside containment (i.e., RCS flows out the ruptured SG tube and through the stuck open relief valve) which must be terminated prior to depletion of the RWST inventory. Termination of this sequence is assumed to be accomplished by cooling down to use the RHR system to stop flow out the relief valve (RCHFDCDTR2 and RCHFDCOOLD).

The top component failures are related to common cause failures of the SI pumps, RHR pumps, and AFW pumps (the latter two systems are important when SI pumps have failed and the plant must rapidly cooldown to RHR). Also included are various stuck open relief valves on the ruptured SG (these are essentially equivalent to the failure of operators to isolate the SG as described above).

9.1.1.8 Anticipated Transient Without Scram

The calculated CDF resulting from anticipated transient without scram (ATWS) events is 8.301E-07/ryr (2% of CDF). The dominating sequences are related to scenarios where both MFW and the pressurizer PORVs are failed by the initiating event during the early portion of the operating cycle when both PORVs are necessary due to reactivity feedback (see Section 4.2.2.1). These failures include the loss of IA and loss of offsite power events which contribute 34% and 21%, respectively, to the calculated CDF (see Appendix A). It is interesting to note that the loss of MFW (which was the basis for installing the ATWS Mitigating System Actuation Circuitry or AMSAC) contributes only 1% to this sequence. In addition, there is a dependency on DC Train B for automatic opening of both PORVs. Failure of the reactor trip system is dominated by electrical signal faults (81%).

9.1.1.9 Miscellaneous Events

The Ginna Station Level 1 PSA model also included random reactor vessel ruptures and ISLOCAs. The calculated CDF resulting from these events is 1.031E-06/ryr (2% of CDF) with ISLOCAs through Penetration 111 contributing over 93% of this value. An ISLOCA through this penetration fails the entire RHR system as described in Section 8.2.

9.1.1.10 External Events

[LATER]

9.1.2 Human Recovery Events

Section 7.4 describes the evaluation of all human action events, including recovery events. In summary, the Ginna Station PSA used a failure probability of 1.00E-01 for all post-initiator operator responses. This failure probability was only revised if the resulting cutsets showed that this value was too conservative. Table 7-15 lists the final values used for all human related events contained within the final integrated plant model. As discussed in Section 7.4, the actions must be proceduralized in order to take credit for their success. While a specific listing of those sequences which would have been above the screening criteria of 1E-07/ryr or above 5% of the total core damage frequency except due to "low human error rates" is not provided per NUREG-1335, the sensitivity of the human error rates is provided in Section 9.3. Included within this sensitivity study is the evaluation of the change in CDF if all human event failure probabilities were increased by a factor of five. Finally, Figure 9-3 only shows one event which does not currently affect the final results but would be expected to significantly affect the final results if its failure probability were increased. This event is related to providing suction sources to preferred AFW (AFHFDSUPPL) for which there are numerous sources. In addition, there is a redundant system (SAFW) to preferred AFW. This is considered to meet the real objective of determining which human actions contribute most to plant risk since the definition of "low human failure rates" is somewhat arbitrary.

9.2 Evaluation of USI-45, Decay Heat Removal

GL 88-20 and NUREG-1335 require an assessment of the decay heat removal issues raised in USI A-45. Essentially, USI A-45 is concerned with maintaining sufficient water inventory in the RCS to support cooling of the fuel and ensuring a means exist to transfer the decay heat from the RCS to the ultimate heat sink following a plant shutdown. Closeout of USI A-45 was provided in GL 88-20 based on performance of a detailed risk assessment of the above concerns.

There are four possible means of removing decay heat from the reactor core at Ginna Station as follows:

a. Secondary cooling through the SGs using MFW, AFW, or SAFW;

b. Bleed and feed cooling utilizing the SI pumps and pressurizer PORVs;

c. RCS injection and recirculation as provided by the SI and RHR pumps during small, medium, and large LOCAs; and

d. Shutdown cooling mode of operation after the RCS has been cooled down and depressurized.

Each means of decay heat removal is evaluated below.

9.2.1 SG Cooling

There are three systems which can be used to provide SG cooling at Ginna Station: (1) MFW, (2) AFW, and (3) SAFW. A description of the systems as modeled in the PSA is provided in Section 6. One train of any of these three systems is required for SG cooling in the transient, SBO, ATWS, SGTR and small-small LOCA event trees as shown in Section 5. They are also used for recovery purposes in the small LOCA trees if SI fails.

It is noteworthy to specifically mention the SAFW system which is unique to Ginna Station. This is a 100% redundant train system installed in a bunkered building totally independent from MFW and AFW. The system was installed due to fire protection and HELB issues, but can obviously be used for any scenario in which MFW or AFW is lost. As shown in Figure 9-5, only the SAFW system is identified as being of medium risk significance while MFW and AFW are of low risk significance. This makes engineering sense as there are a total of 7 pumps between these three systems, any one of which can meet minimum requirements for SG cooling. However, only the SAFW system would be available for all potential accident scenarios.

9.2.2 Bleed and Feed Cooling

This form of cooling would be utilized in the event that all forms of SG cooling are lost during a transient and consists of using the SI pumps and pressurizer PORVs. As shown in Figure 9-5, the SI system is identified as being of medium risk significance while the PORVs (under heading RCS) is of low risk significance. This is based on the fact that there are so many methods of providing SG cooling as discussed in Section 9.2.1 that bleed and feed cooling is not expected to be required. This is confirmed by Table 8-2 which shows that failures of the PORVs (i.e., "bleed") contribute only 4.291E-07 to the final CDF (see TL_42_01 and TL_42_02 under Transients) while failures of SI (i.e., "feed") contribute 3.856E-06 (see TL_52_01 and TL_52_02 under Transients). Their sum is 4.286E-06 or only 8.5% of the final CDF.

9.2.3 RCS Injection and Recirculation

During small, medium, and large break LOCAs, core cooling can be provided by the SI and RHR systems which are also supplying necessary injection to the RCS. The risk significance of these systems is shown in Figure 9-5. As discussed earlier, the SI system is of medium risk significance. The RHR system is shown as being high risk significant since there is no backup in the event that this system were to fail. Also, for many size LOCAs (i.e., small and small-small LOCAs and SGTRs), failure of the SI system can be recovered by rapid cooldown to the RHR system using the atmospheric relief valves (ARVs) and some form of SG cooling. However, there were no vulnerabilities identified for either RHR or SI (see Section 11.1.3).

9.2.4 Shutdown Cooling

The RHR system provides a means of decay heat removal during shutdown cooling modes. The Ginna Station PSA was only performed for full power operation; however, utilizing the RHR system for decay heat removal is a credited option for those scenarios where SI injection is unavailable. As shown in Figure 9-5, the RHR system is identified as being of high risk significance; however, this is primarily due to injection and recirculation functions. The need to use the RHR system as a shutdown function was of only medium importance. However, it should be noted that since the PSA models were not specifically developed for shutdown configurations, alternative means of cooling while shutdown were not modeled (e.g., reflux cooling). Also, no vulnerabilities were identified for RHR.

9.2.5 Conclusions

Given the requirements of maintaining sufficient water inventory in the RCS to support cooling of the fuel and ensuring a means exist to transfer the decay heat from the RCS to the ultimate heat sink following a plant shutdown, the Ginna Station PSA has demonstrated that there are many redundant and diverse means of achieving this. In addition, there is substantial amount of time available to operators to place the decay heat removal systems into service. This is demonstrated by the fact that no significant vulnerabilities were identified by the PSA for these systems overall. Consequently, RG&E considers that it has fulfilled the requirements of USI A-45.

9.3 Sensitivity and Importance Analysis

Following the generation and review of the cutsets, sensitivity and importance evaluations were performed. Essentially, sensitivity analyses consist of evaluating the change in CDF assuming that failure probabilities and frequencies were changed. Meanwhile, importance evaluations rank the risk significance of each modelled event and system. The two analyses are presented below.

9.3.1 Sensitivity Analysis

For the Ginna Station PSA, the sensitivity analysis consisted of increasing and/or decreasing the value used for the following basic events, and evaluating its impact on the total CDF:

a. Human errors;
b. Test and maintenance unavailabilities;
c. Common cause failure events;
d. Initiating event frequencies;
e. Motor-operated valves;
f. Air-operated valves;
g. Diesel Generators; and
h. Pumps.

In addition to evaluating the above events, an evaluation of the adequacy of the truncation limit used during the quantification process was also performed. These analyses are provided below.

9.3.1.1 Human Errors

Two sensitivity studies were performed with respect to human error events. First, all human error events were set to "false" (i.e., all human actions were assumed to be successfully performed). As a result of this change, the CDF decreased by 52% to 2.420E-05. This shows that many sequences are very sensitive to human reliability failure rates (as is expected). Setting the human error events to "false" had the most impact on the following sequences:

a. *ISLOCA* - Decreased by 99%. This is due to the fact that the failure rates for isolating failed penetrations are 5 to 6 orders of magnitude higher than the frequency of the ISLOCA initiating event. Since ISLOCA cutsets involve only a failure of the penetration and a failure of operators to isolate a failed penetration, eliminating the human failure events has a major impact. In addition, the most risk significant scenario is an inadvertent SI signal which opens the RHR injection valves to the reactor vessel, followed by operator failure to reclose the valves prior to the ISLOCA.

b. *Transients* - Decreased by 86.5%. This is due to the significant number of operator actions that are potentially required to mitigate a transient, including aligning an alternate source of water to AFW after the condensate storage tank is empty, aligning SAFW, restoring MFW, and initiating bleed and feed.

c. *Large LOCA* - Decreased by 82%. This is due to the failure rates associated with the operators transferring to sump recirculation and operators manually isolating AOV 371 are high compared to the mechanical equipment failure rates. Therefore, they contribute a significant portion of the risk for this sequence, and eliminating them has a large impact.

d. *SGTR* - Decreased by 69%. This is due to the fact that there are a significant number of human actions required to mitigate a SGTR event (see Section 3.2.2.3.3).

e. *LOCAs* - The medium LOCA, small LOCA, and small-small LOCA sequences decreased by 55%, 38.5%, and 41%, respectively. These decreases are for the same reasons as the large LOCA; however, the magnitudes are not as great because the failure rates for operators transferring to recirculation decrease for theses sequences due to the increased time available to the operators.

The ATWS and SBO sequences are not impacted as greatly due to the relatively few human actions involved in those sequences.

The second study involved increasing the failure probability of all human error events by a factor of five. As a result of this change, the CDF increased by 207% to 1.543E-04. Increasing the probability of human error events had the most impact on the same sequences as discussed above. However, the cutsets with multiple human errors (see Table 7-14) were affected most.

9.3.1.2 Test and Maintenance Unavailabilities

A sensitivity analysis was performed to determine an upper bound for test and maintenance unavailabilities since there is a large uncertainty associated with these values. Therefore, all test and maintenance events listed in Table 7-4 were increased by a factor of five. This change increased the CDF by 83% to 9.208E-05. Increasing the probability of test and maintenance events had the most impact on the following sequences:

a. *Transients* - Increased by 161%. This is due to the fact that for transients, failure of decay heat removal via the SGs is a significant contributor to CDF. Since there are a significant number of test and maintenance events associated with SG cooling (AFW trains, SAFW trains, TDAFW pump, and the DGs which may be required to power the AFW or SAFW pumps), the increase in these events has a large impact.

b. *SBO* - Increased by 122%. This is due two factors: (1) a SBO event includes loss of both DGs and thus, a DG being in test or maintenance has a major impact, and (2) once an SBO event has occurred, the TDAFW pump is the only source of SG cooling so that having it out of service also has a major impact.

c. *Small LOCA* - Increased by 122%. Mitigating a small LOCA relies upon many systems which have a significant number of test and maintenance events associated with them. These include RHR trains, CCW pumps and heat exchangers, SW isolation valves to CCW heat exchangers, DGs, AFW trains, SAFW trains, and the TDAFW pump. This causes a significant increase. However, the increase is not as great as the increase for transients due to the lower initiating event frequency for a small LOCA which causes some of the cutsets containing test and maintenance events to be truncated. There are also some test and maintenance events associated with transient induced small LOCAs (such as ARVs in test or maintenance) which also increase the impact.

d. *Small-Small LOCA* - Increased by 89%. The reasons for this are similar to those for the small LOCA sequence, with the difference that the test and maintenance events associated with a transient induced small-small LOCA (i.e., seal LOCA) are different that those for a transient induced small LOCA.

e. *SGTR* - Increased by 42%. This is due to the fact that in order to terminate break flow, the RCS must be cooled down and depressurized. The cooldown is accomplished via the SGs. Again, the significant number of test and maintenance events associated with SG cooling (AFW trains, SAFW trains, TDAFW pump, and the DGs which may be required to power the AFW or SAFW pumps) causes a large increase.

The large LOCAs, medium LOCAs, and ATWS events increased by factors of 20%, 37%, and 12%, respectively. These sequences had minor increases due to the low initiating event frequencies which causes most cutsets with test and maintenance events to fall below the truncation limit.

9.3.1.3 Common Cause Failure Events

Two sensitivity studies were performed with respect to common cause failure (CCF) events. First, all CCF events were set to "false" (i.e., no CCF events were assumed to occur). As a result of this change, the CDF decreased by 31% to 3.451E-05. This shows that many sequences are very sensitive to CCF rates (as is expected). Setting the common cause events to "false" had the most impact on the following sequences:

a. *ATWS* - Decreased by 100%. This result is expected since both the mechanical and electrical scram failures are modeled as CCFs. Thus, a CCF must occur to have an ATWS since the independent failure rate of two reactor trip system trains is very low.

b. *Small LOCA* - Decreased by 43%. This is due to the fact that the major systems which are required to mitigate a small LOCA event (SI, RHR, CCW, and potentially AFW) are designed with two trains of identical equipment in parallel. Therefore, there are a significant number of common cause events which fail both trains. Note that a CCF of all three AFW pumps is included for reasons discussed in Section 7.2.2.4, but is of little importance because of the SAFW system. There are also CCFs of the ARVs to open which contribute to the transient induced small LOCA (e.g., stuck open PORV).

c. *Small-Small LOCA* - Decreased by 39%. This sequence is similar to the small LOCA sequence, with the difference that the common cause events associated with a transient induced small-small LOCA (i.e., seal LOCAs) are different that those for a transient induced small LOCA (e.g., CVCS).

d. *SBO* - Decreased by 38%. This is due to the fact that an SBO event is predicated on the failure of both DGs. Since the two DG trains are of identical design, there are a significant number of CCFs associated with the diesels (e.g., failure to start and run, fuel oil system failures, etc.).

e. *Medium LOCA* - Decreased by 28%. This is due to the fact that the major systems which are required to mitigate a small LOCA event (SI, RHR, CCW) are designed with two trains of identical equipment in parallel. Therefore, there are a significant number of common cause events which fail both trains. Note that large LOCA is very similar to medium LOCA; however, due to the lower initiating event frequency, some of the cutsets containing common cause events have been truncated and thus the overall impact is much less (decrease of 9%).

Both the SGTR (decreased by 16%) and Transients (decreased by 17%) are not as heavily impacted by common cause events due to the fact that they are heavily dependent on SG cooling. SG cooling includes the motor-driven AFW pumps, the TDAFW pump, and the motor-driven SAFW pumps, which are all of different designs, and are not all in the same location. Also, there are two motor-driven MFW pumps. Therefore, there is no single common cause event which fails all SG cooling.

The second study involved increasing the failure probability of CCF events by a factor of five. However, this change is evaluated in Sections 9.3.1.5 through 9.3.1.8 which adjusts both independent and CCF values for MOVs, AOVs, DGs, and pumps.

9.3.1.4 Initiating Event Frequencies

Two sensitivity studies were performed with respect to initiating event frequencies. First, all frequencies based on generic data (i.e. not based on the 16 years of plant-specific data) were decreased by a factor of five. This included all steamline and feedwater line breaks, LOCAs, RCP locked rotor event, and the loss of IA, SW, and DC buses. As a result of this change, the CDF decreased by 63.5% to 1.832E-05. The sequences most affected by this change are as follows:

a. *Large LOCA and SGTR* - Decreased by 80%. This is due to the fact that all cutsets within these sequences have the large LOCA or one of the SGTR initiators in them, and thus the total contribution to CDF was reduced by a factor of 5.

b. *Medium LOCA* - Decreased by 80%. This is due to the fact that all cutsets within this sequence have the medium LOCA initiator in them except for the transient induced medium LOCA cutsets. Since the contribution from transient induced cutsets is over two orders of magnitude less than the contribution from cutsets with the medium LOCA initiator, the overall contribution decreases by almost the full factor of five.

c. *Small-Small LOCA* - Decreased by 72.5%. This indicates that approximately 91% of the contribution from this sequence is based on cutsets using generic initiator frequencies, while 18% is based on cutsets using plant specific initiator frequencies. This is due to the fact that approximately 31% of the contribution from this sequence comes from transient induced LOCA cutsets, some of which are using plant-specific initiator frequencies.

d. *Transients* - Decreased by 72%. This indicates that approximately 89% of the contribution from this sequence is based on cutsets using generic initiator frequencies, while 11% is based on cutsets using plant-specific initiator frequencies. This is due to the fact that four of the five most risk significant initiating events (TIFLB0TB, TISLB0TB, TI000DCA, and TI000DCB) are based on generic data.

e. *ATWS* - Decreased by 61%. This indicates that approximately 76% of the contribution from this sequence is based on cutsets using generic initiator frequencies, while 24% is based on cutsets using plant-specific initiator frequencies.

f. *Small LOCA* - Decreased by 58.5%. This indicates that approximately 73% of the contribution from this sequence is based on cutsets using generic initiator frequencies, while 27% is based on cutsets using plant-specific initiator frequencies. This is due to the fact that approximately 44% of the contribution from this sequence is from transient induced small LOCA cutsets, some of which are using plant-specific initiator frequencies.

The second study performed was to increase the same initiating event frequencies by a factor of 5 which increased the CDF by 218% to 2.26E-04. The sequences most affected by this change are identical to the ones affected by the decrease, and indicate approximately the same percentage contributions from generic and plant-specific initiating event frequencies.

9.3.1.5 Motor-Operated Valves

The failure data for MOVs was based on nine years of plant-specific data collected between 1980 and 1988. However, to account for the potential for this data to not be reflective of current valve reliability, two sensitivity studies were performed. The first study was to globally decrease the MOV failure rate by a factor of five. This change affects both the failure of individual valves, as well as the CCF rate for identical MOVs within a system. This change decreased the CDF by 19% to 4.059E-05. The sequences most affected by this change are as follows:

a. *Small LOCA* - Decreased by 33%. This is due to the fact that there are several MOVs which must open (738A, 738B, 850A, and 850B) or close (896A and 896B) in order to achieve sump recirculation.

b. *SGTR* - Decreased by 26%. This is due to the fact the failure of long-term RHR cooling is an important recovery system the event that SI is lost and depends upon opening MOVs 700 and 701.

c. *Small-Small LOCA* - Decreased by 26%. This is due to essentially the same reasons as for small LOCA with the addition of some SW isolation valves which were truncated from the small LOCA results due to the lower initiating event frequency.

The large LOCA (decrease by 6.5%) and the medium LOCA (decrease by 11%) sequences rely on the same MOVs that small and small-small LOCA sequences rely on for sump recirculation. However the impact is reduced due to the lower initiating event frequencies for these events which causes some of the cutsets containing MOV failure events to be truncated. The ATWS, Transient, and SBO sequences are all decreased by less that 10% due to the fact that they do not rely on MOVs to any significant degree.

The second study involved increasing the MOV failure rates by a factor of five which increased the CDF by a factor of 109% for a new CDF of 1.049E-04. The sequences which were impacted most by this change are small LOCA (increase of 185%), small-small LOCA (increase of 152%), and SGTR (increase of 140%) for the same basic reasons discussed above. As above, the medium LOCA (increase of 61%) and the large LOCA (increase of 36.5%) sequences increase due to the same valve dependency as small and small-small LOCA, only to progressively lesser degrees, due to lower initiating event frequencies.

9.3.1.6 Air-Operated Valves

Similar to the MOVs, two sensitivity studies were performed on the AOV failure rates. For the first case where the failure rate was globally decreased by a factor of five, the CDF decreased by 1.5% to 4.948E-05. The sequences most affected by this change were the following:

a. *Transients* - Decreased by 7%. This is due to the fact that the MSIV's must close for some transients, and that the SG blowdown isolation valves must close in order to establish adequate AFW flow to the SGs.

b. *Large LOCA* - Decreased by 4%. This is due to the need for AOV 371 to close prior to sump recirculation to prevent a common mode failure of the RHR pumps.

c. *Medium LOCA* - Decreased by 2.4%. This is due to the same dependency on AOV 371 as a large LOCA; however, the magnitude is reduced due to the greater probability of operators manually isolating the valve (based on more time to perform the action) which reduces the risk significance of that valve.

d. *SGTR* - Decreased by 1.5%. This is due to the need to close the SG blowdown isolation valves and the blowdown sample isolation valves to isolate a ruptured SG as well as to establish AFW flow to the intact SG (blowdown valves only).

All other sequences decreased by less than 1%. The small and small-small LOCA sequences have the same dependency upon AOV 371 as do the large and medium LOCAs; however, due to a lower failure rate of the recovery event based on the longer time prior to going to recirculation, the impact is reduced.

For the second study where failure rates were increased by a factor of five, the CDF increased by 8% to 5.410E-05. The sequences most affected by this change are the same as those above with transients increasing by 40%, large LOCA increasing by 18%, medium LOCA increasing by 12%, and SGTR increasing by 7%.

9.3.1.7 Diesel Generators

Similar to the MOVs, two sensitivity studies were performed on the DG failure rates. For the first case where the failure rate for the DGs starting and running were globally decreased by a factor of five, the CDF decreased by 8% to 4.621E-05. Decreasing the probability of the DG "fail to start" and "fail to run" events had the most impact on the following sequences:

a. *SBO* - Decreased by 39.5%. This is an expected result because an SBO event is predicated on the failure of both DGs. Therefore, decreasing the failure rate for the DGs will have a major impact on this accident sequence.

b. *Small LOCA* - Decreased by 6%. This is due to the fact that SG cooling plays in important role in mitigating small LOCAs. Since 4 out of the 5 auxiliary feedwater pumps are motor-driven, failure of a single DG, given a loss of the normal power supply, will fail two pumps.

The transients and small-small LOCA sequences also depend on SG cooling, although it is not as significant for those sequences. As such, these two sequences decreased by 6% and 4%, respectively. All other sequences decreased by less than 3%.

For the second study where failure rates were increased by a factor of five, the CDF increased by 57% to 7.904E-05. The sequences most affected by this change are the same as those above, with SBO increasing by 333%, small LOCAs increasing by 37%, transients increasing by 29%, and small-small LOCAs increasing by 22%.

9.3.1.8 Pumps

Similar to the MOVs, two sensitivity studies were performed on the pump failure rates. For the first case where the failure rate was globally decreased by a factor of five, the CDF decreased by 15% to 4.288E-05. The sequences most affected by this change were as follows:

a. *Small LOCA* - Decreased by 21%. This is due to the fact that mitigating a small LOCA requires a significant number of pumps (SI, RHR, CCW, SW, and AFW pumps).

b. *Small-Small LOCA* - Decreased by 19.5% for the same reasons as small LOCA above.

c. *Medium LOCA* - Decreased by 16%. This is due to the fact that mitigating a medium LOCA requires all the same pumps as a small or small-small LOCA with the exception of the AFW pumps.

d. *SBO* - Decreased by 15%. This is due to the fact that the TDAFW pump is a critical component for SBO sequences. Also, the fuel oil transfer pumps support the DGs and thus, impact SBO sequences.

e. *SGTR* - Decreases by 11%. This is a result of the need for SG cooling and SI.

All other sequences decreased by 5% or less. Although large LOCA is similar to medium LOCA, the decrease was of smaller magnitude (3%) due to the fact that the SI pumps are not needed, and the fact that the lower initiating event frequency for large LOCA causes some cutsets which contain pump failure events to be truncated.

For the second study where failure rates were increased by a factor of five, the CDF increased by a factor of 78% to 8.948E-05. The sequences most affected by this change were again small LOCA (increased by 109%), small-small LOCA (increased by 106%), medium LOCA (increased by 81%), SBO (increased by 92%), and SGTR (increased by 59%).

9.3.1.9 Truncation Limit Evaluation

As a final sensitivity study, the truncation limit was evaluated with respect to its impact on the final results. This was performed by generating a figure which showed the contribution of the cutsets in each "decade" (e.g., 1E-06, 1E-7, 1E-08, etc.) to the final CDF. As can be seen from Figure 9-1, the CDF contained in each decade creates a "step ladder" effect with the cutsets above 1E-09 contributing over 90% of the final CDF. Also, as noted on the figure, over 80% of the cutsets are located between 1E-09 and 1E-10; however, these contribute less than 10% of the final CDF. Consequently, lowering the truncation limit should not significantly impact the calculated CDF. Therefore, it can be concluded that the truncation limit of 1E-10 as used for the Level 1 PSA was appropriate.

9.3.1.10 Sensitivity Analysis Summary

Comparing the sensitivity results for those cases which decreased a specific group of basic event failure rates by a factor of five (i.e., initiating event frequencies, MOVs, AOVs, DGs, and pumps) shows that initiating event frequencies had the most impact on CDF. This is followed by MOVs, DGs, and pumps which essentially had the same impact. AOVs had little impact on the final CDF.

For event groups whose failure probability was increased by a factor of five (i.e., human errors, test and maintenance events, initiating event frequencies, MOVs, AOVs, DGs, and pumps), human errors had the most impact on CDF. Initiating events had some impact while all other events resulted in less than a factor of two change in CDF.

9.3.2 Importance Analysis

The importance of systems and components to the final results is a significant insight into the risk profile for Ginna Station. There are several types of importance measures which can be used depending on the ultimate objective. For the purposes of the Ginna Station PSA, the following two types of importance measures were generated:

a. *Fussell-Vesely (F-V)* - This importance measure presents the fraction of risk associated with each basic event which is calculated as shown below:

$$\frac{\sum Cutsets\ \ with\ \ Event\ \ i}{CDF_{Baseline}}$$

b. *Risk Achievement Worth (RAW)* - This importance measure presents the fractional increase in risk if the subject component is assumed to be failed as shown below:

$$\frac{CDF\ \ with\ \ Event\ \ i\ \ always\ \ failed}{CDF_{Baseline}}$$

As can be seen, the two measures essentially identify: (1) how much the basic event contributes to the baseline CDF, and (2) how much the CDF would increase if the component were assumed to be failed. Per EPRI TR-105396 [Ref. 70], if the F-V value at a component level is > 0.005 (or > 0.05 at the system level), it should be identified as risk significant. Meanwhile, if the RAW value at the component level is > 2 (or > 10 at the system level per [Ref. 71]), then the component should be identified as risk significant. However, a component identified as risk significant using F-V does not necessarily mean it will be risk significant using RAW (or vice versa). Consequently, it is conservative to assume that a component or system which is above the threshold for only one of the two risk measures is as "important" as a component which is above both thresholds. Therefore, for the purpose of the Ginna Station PSA, these two importance measures were combined as follows:

a. If the F-V value is > 0.05 at the system level (> 0.005 at the component level) <u>and</u> the RAW > 10 at the system level (> 2 at the component level), then the system or component will be identified as being "high" risk significant.

b. If the F-V value is > 0.05 at the system level (> 0.005 at the component level) <u>or</u> the RAW > 10 at the system level (>2 at the component level), then the system or component will be identified as being "medium" risk significant.

c. If the F-V value is < 0.05 at the system level (< 0.005 at the component level) <u>and</u> the RAW < 10 at the system level (< 2 at the component level), then the system component will be identified as being "low" risk significant.

The F-V and RAW importance measures were generated for initiating events, human errors, test and maintenance activities, and on a system and component basis. Each of these is described below in detail. Included within these discussions is a reference to a table and figure containing the specific F-V and RAW values. The table is self-explanatory; however, additional information with respect to the figure is necessary to ensure correct interpretation.

In order to provide a visual depiction of the risk profile associated with various events modeled within the Ginna Station PSA, the F-V and RAW importance measures were plotted against one another. In this manner, it can be easily identified which events are of higher risk than others. For example, all human error F-V and RAW values plotted are on Figure 9-3. A "cross-hair" was provided on the figure for F-V values equal to 0.005 (vertical line) and RAW values equal to 2 (horizontal line). Any event to the left of the F-V line or below the RAW line is not risk significant with respect to that specific importance measure. However, an event to the left of the F-V line but <u>above</u> the RAW line is risk significant with respect to RAW only (e.g., AFHFDSUPPL). Similarly, an event to the <u>right</u> of the F-V line but below the RAW line is risk significant with respect to F-V only (e.g., ACAADLOSP1). Events which are to the right of the F-V line and above the RAW line are risk significant with respect to both importance measures (e.g., RRHFDRECRC).

In summary, an event in the upper left hand corner or lower right hand corner is of medium risk significance. An event in the upper right hand corner is of high risk significance while events in the lower left hand corner are of low risk significance. Further insights can also be obtained by which "corner" a given event is in as described below:

a. An event in the upper left hand corner is generally of high reliability; consequently, the event did not contribute significantly to the final CDF. However, if the component were to fail, the impact on the final CDF would be significant. Typically, this corner contains passive components, highly redundant systems, or events which are easily performed by operators.

b. An event in the lower right hand corner is typically of lower reliability than is justified by the fault tree model. That is, the event contributes to the final CDF; however, if the event were assumed to always fail, it is not expected to further affect the final results. Generally, this is due to the fact that the event's failure probability is already close to 1.0 such that increasing its value to 1.0 would not have much of an effect on the CDF. It should be noted that an event's failure probability may have been a conservative value selected by the PSA analyst due to limited data and is not reflective of the specific component history. If so, this is noted in the descriptive text below.

c. An event in the upper right hand corner contributes significantly to the final results and would significantly affect the CDF if it were assumed to always failed. Therefore, this event is very important with respect to the risk profile.

d. An event in the lower left hand corner does not contribute to the final result, and even if it were assumed to fail with a probability of 1.0, would not significantly impact the CDF.

9.3.2.1 Initiating Events

Table 9-2 and Figure 9-2 show F-V and RAW importance measures with respect to the initiating events addressed by the Level 1 PSA models. As can be seen from the figure and table, the initiating events of highest importance are:

a. TI0000SW - Total Loss of Service Water;
b. LILBLOCA - Large LOCA;
c. LIMBLOCA - Medium LOCA;
d LI0SGTRA - Steam Generator Tube Rupture in SG A;
e. LI0SGTRB - Steam Generator Tube Rupture in SG B; and
f. LISSLOCA - Small-Small LOCA.

These initiators were of high importance since they substantially contributed to the final results (i.e., had a F-V value > 5.0E-02) <u>and</u> if the initiator were assumed to be "true" would have a significant impact on CDF (i.e., had a RAW value > 10). Since SW supports almost every system and function, the loss of SW as an initiating event (and its frequency) has a significant impact on plant risk. With respect to LOCAs, the small-small LOCA has the most impact on the CDF (since it is of higher frequency) while the large and medium LOCAs would have a slightly higher impact on the CDF if they were assumed to occur with a probability of 1.0. SGTRs (items e and f) are a special class of LOCA which only differ in risk from a small-small LOCA (same break size) with respect to their frequency. The LOCA initiating events are of high risk significance since they contribute significantly to each cutset. That is, the <u>frequency</u> associated with these initiators is an important consideration to the CDF both in the Ginna Station PSA calculated CDF and an "imaginary CDF" if the initiator were always assumed to occur.

The initiating events of medium importance are:

a. LIPEN## - ISLOCAs;
b. LIRVRUPT - Reactor Vessel Rupture;
c. TI48LOSP - Loss of Offsite Power on 480 V Buses;
d. TISLBIB* - Steam Line Break in Intermediate Building for SG A/B;
e. TIFLBIB* - Feed Line Break in Intermediate Building for SG A/B;
f. TIFLB0TB - Feed Line Break in Turbine Building;
g. TISLB0TB - Steam Line Break in Turbine Building;
h. LISBLOCA - Small LOCA; and
i. TIGRLOSP - Loss of Offsite Power - Grid.

These initiators were of medium importance since they either substantially contributed to the final results (i.e., had a F-V value > 5.0E-02) or if the initiator were assumed to be "true" would have a significant impact on CDF (i.e., had a RAW value > 10). Only the loss of offsite power initiating event frequency (item i) had a F-V value greater than 5.0E-02 (indicating that it is "unreliable"); however, the data for these events was based on industry data [Ref. 41]. The other initiators (i.e., items a, b, c, d, e, f, g, and h) have F-V values < 5.0E-02 which indicates that the initiator frequency is low enough to not significantly contribute to the final results; however, any increase to their frequency would have an effect on the CDF.

The remaining initiating events were determined not to significantly contribute to the final CDF even if they were set to 1.0.

9.3.2.2 Human Errors

Table 9-3 and Figure 9-3 show F-V and RAW importance measures with respect to the human error events addressed by the Level 1 PSA models. As can be seen from the figure and table, the human events of highest importance are:

a. RRHFDRECRC - Operators Fail to Correctly Shift RHR to Recirculation Phase;
b. RCHFDCDDPR - Ops Fail to Cooldown and Depressurize RCS Prior to SG Overfill;
c. CVHFDSUCTN - Operators Fail to Manually Open Suction Lines to CVCS ;
d. RCHFD01BAF - Operators Fail to Implement Feed and Bleed Cooling;
e. ACAALOSP10 - Operators Fail to Restore Offsite Power Within 10 Hours (SBO);
f. RCHFDCOOLD - Operators Fail to Cooldown to RHR After ARV Sticks Open - SGTR;
g. SRHFDRECRC - Operators Fail to Shift SI to Recirculation Phase
h. SWHFDSTART - Operators Fail to Start Standby SW Pump or Isolate System;
i. AFHFDSAFWX - Operators Fail to Correctly Align SAFW;
j. RCHFDRHRSB - Operators Fail to Use RHR or AFW Long-Term Following LOSP; and
k. MSHFDISOLR - Operators Fail to Isolate SG For SGTR.

These human errors were of high importance since they substantially contributed to the final results (i.e., had a F-V value > 5.0E-03) and if the error were assumed to be occur with a probability of 1.0 would have a significant impact on CDF (i.e., had a RAW value > 2). The failure of operators to switchover to recirculation during a LOCA (item a) and the failure to depressurize and cooldown the RCS following a SGTR (item b) was determined to be the most significant human events in the Ginna Station PSA. Their importance is due to the limited time available and potential stress levels which could exist.

The remaining human errors listed above were also identified as being of high importance, though to a lesser degree than the two previously discussed. Item c relates to the need for operators to restore some form of cooling to the RCP seals after both CVCS and CCW have been lost. Item d addresses the need for operators to implement feed and bleed activities given that all AFW is unavailable. Event ACAALOSP10 (item e) is concerned with the ability of operators to restore offsite power within 10 hours following a SBO which is more dependent on availability of the grid than specific operator actions. This cooling is needed within 1 hour to prevent the possibility of a seal LOCA from occurring due to seal degradation. RCHFDCOOLD and MSHFDISOLR (items f and k) are other SGTR related events in which operators fail to cooldown to RHR after the SG has overfilled and the operators fail to isolate the ruptured SG. Item g is the failure of operators to successfully implement high-head recirculation while item h is the failure of operators to start a standby SW pump or isolate the system loads. This is somewhat misleading since this event includes the failure probability of the standby pumps to start and valves to close. The failure of operators to correctly place the SAFW system into service (item i) is important since there are several initiating events which fail both the preferred AFW and the MFW system (e.g., HELBs in the Intermediate Building). However, station procedures do not direct operators to use SAFW until they have attempted to use both AFW and MFW since SAFW uses non-condensate sources for suction. Item j defines additional operator actions during SBO scenarios where cooldown to RHR conditions following restoration of offsite power was shown to be important.

The human errors of medium importance were:

a. AFHFDSUPPL - Operators Fail to Provide Alternate Suction Source for AFW;
b. RCHFDCDOSS - Operators Fail to Cooldown to RHR After SI Fails - LOCAs;
c. RCHFDPLOCA - Operators Fail to Close Block Valves to Terminate LOCA;
d. ACAALOSP1 - Ops Fail to Restore Offsite Power Within 1 Hour After TDAFW Fails;
e. RRHFDSUCTN - Operators Fail to Manually Open RHR Suction Valves;
f. TLHFDPN111 - Operators Fail to Isolate ISLOCA Through Penetration 111;
g. AFHFDALTTD - Operators Fail to Provide Fire Water Cooling to TDAFW Pump;
h. ACHFDIR751 - Operators Fail to Use Alternate Offsite Power CKT 751;
i. RCHFDCDTR2 - Operators Fail to Cooldown to RHR After SI Fails - SGTR;
j. RRHFDTHROT - Operators Fail to Throttle RHR Flow for NPSH Concerns; and
k. CVHFD00371 - Operators Fail to Manually Isolate AOV 371 (Letdown).

These human errors were of medium importance since they either substantially contributed to the final results (i.e., had a F-V value > 5.0E-03) or if the event were assumed to occur with a probability of 1.0 would have a significant impact on CDF (i.e., had a RAW value > 2). Item a has a F-V value < 5.0E-03 which indicates that it does not contribute to the CDF primarily because of its probability (i.e., the operators are considered capable of performing this with a high degree of reliability). The remaining items had F-V values > 5.0E-03. Of these, items c, e, f, h, and j use a screening value of 0.1 for various reasons (i.e., a detailed analysis of these events was not performed). These reasons include lack of data and expected values of close to 1E-01 even after a detailed analysis due to limited time frames for performing the actions. Only items b, d, g, i and k are based on detailed analysis which indicates the need to potentially stress these activities.

The remaining events were determined not to significantly contribute to the final CDF even if their failure probability were set to 1.0. Appendix F contains additional details on all human failure events. It is noted that only the following human error events did not appear in the final cutsets:

a. CCHFDCCWAB - Operators Fail to Start Standby CCW Pump When Auto Signal Fails
b. CCHFDSTART - Operators Fail to Start CCW Pump Following a LOOP and SI
c. HVHFDABVLP - Operators Fail to Re-Start Aux Bldg Exhaust Ventilation After LOSP
d. HVHFDIBVEN - Operators Fail to Re-Start Intermediate Bldg Exhaust Fans - LOSP

Since items c and d use a screening value of 1.0E-01, this indicates that these human actions are truly non-risk significant. Items a and b relate to seal LOCA concerns and use values ranging from 7.0E-03 to 1.20E-03. Given the low contribution of seal LOCAs to the final CDF, these human error events are not in the final results.

9.3.2.3 Test and Maintenance Activities

Table 9-4 and Figure 9-4 shows F-V and RAW importance measures with respect to the test and maintenance events addressed by the Level 1 PSA models. Events considered include: (1) the test and maintenance unavailabilities as assumed for the Maintenance Rule, and (2) human errors to restore equipment to service following these activities. As can be seen from the figure and table, the events of highest risk importance are:

a. DGTM00001B - DG B Out-of-Service (OOS) for Test or Maintenance;
b. DBTM00001A - DG A OOS for Test or Maintenance;
c. RHTM00001A - RHR Pump Train A OOS for Test or Maintenance;
d. RHTM00001B - RHR Pump Train B OOS for Test or Maintenance;
e. CCHFL0780A - CCW Throttling Valve 780A Mispositioned; and
f. CCHFL0780B - CCW Throttling Valve 780B Mispositioned.

These events were of high importance since they substantially contributed to the final results (i.e., had a F-V value > 5.0E-03) and if the event were assumed to be occur with a probability of 1.0 would have a significant impact on CDF (i.e., had a RAW value > 2). Items a and b are dominated by SBO sequences which are essentially the loss of offsite power combined with the failure of the DGs. Consequently, removing a DG from service increases the risk potential with respect to a SBO event. The removal of one DG from service also impacts one entire electrical train if a loss of offsite power were to occur. The slight difference in risk between the two DGs is described in Section 9.3.2.5. Items c, d, e, and f relate to LOCA sequences where RHR is necessary in the injection and recirculation phases of an accident. RHR is also credited for certain transients and small LOCAs following the failure of the SI system. It should be noted that even though risk significant, these six test and maintenance events contribute far less to the plant risk profile than human actions and component failures (note x-y scale of Figure 9-4 versus Figure 9-3 and 9-5).

The following events are of medium importance:

a. AFTM0TDAFW - TDAFW Pump Train OOS for Test or Maintenance;
b. AFTMSAFSGA - SAFW Pump Train C OOS for Test or Maintenance;
c. AFTMSAFSGB - SAFW Pump Train D OOS for Test or Maintenance;
d. HVTMSAFW_A - SAFW HVAC Train A OOS for Test or Maintenance;
e. HVTMSAFW_B - SAFW HVAC Train B OOS for Test or Maintenance; and
f. SWTM4616MT - MOV 4616 OOS for Test or Maintenance.

These events were of medium importance since they either substantially contributed to the final results (i.e., had a F-V value > 5.0E-03) or if the event were assumed to be occur with a probability of 1.0 would have a significant impact on core damage (i.e., had a RAW value > 2). Items a, b, c, d, and e relate to either the TDAFW pump (for SBO sequences) or the SAFW system for reasons discussed above. Item f relates to SW MOV 4616 which provides isolation of CCW Heat Exchanger A and SAFW Pump A on a coincident SI and UV signal. As discussed in Section 9.3.2.5, CCW and SAFW Pump Train A are slightly more important than their counterparts.

The remaining test and maintenance events were determined to not contribute to the final CDF even if their value were set to 1.0. It should be noted that a review was also made to see which test and maintenance events listed in Table 7-4 were not contained within the final cutsets. These are briefly described below:

a. AFW suction sources from the outside condensate storage tank and condensate transfer pumps due to the number of potential sources available to operators. Also, the motor-driven AFW cross-tie valves were not in the final cutsets since the SAFW system can provide this function.

b. The containment spray and containment recirculation fan coolers since these systems are only credited in the Level 1 PSA with respect to maintaining adequate NPSH for the RHR system; therefore, this risk ranking may change based on the Level 2 PSA.

c. Auxiliary Building HVAC and Intermediate Building Exhaust Fan A (note that Fan B is included since it is powered by a safeguards bus).

d. PORV block valves 515 and 516 being closed. This is primarily based on plant-specific data between 1980 and 1988 which showed the valves only being closed an average of 1600 hours (or 67 days) per reactor year. Significant changes to this value could change this risk ranking.

e. SW MOVs 4613, 4670, 4614, 4664, 4734, and 4735 which isolate cooling water to the IA compressors and travelling screens, none of which were identified as being risk significant.

9.3.2.4 System Level

Table 9-5 and Figure 9-5 shows F-V and RAW importance measures on a system basis. As can be seen from the figure and table, the systems of highest risk importance are:

a. RHR;
b. CCW;
c. Undervoltage; and
d. DGs

These systems were of high importance since they substantially contributed to the final results (i.e., had a F-V value > 5.0E-02) <u>and</u> if the system were assumed to fail with a probability of 1.0 would have a significant impact on CDF (i.e., had a RAW value > 10). The RHR system is required for all LOCAs (injection and/or recirculation), and is credited as a recovery option in transients, small LOCAs, and SGTR events when the SI system is failed. The main support system for RHR is CCW (item b). Items c and d essentially support every system and function in the integrated plant model upon loss of offsite power.

The following systems were identified as medium risk significant:

a. SW;
b. Reactor Trip System (RTS);
c. DC Electrical Power;
d. SI;
e. ESFAS;
f. CVCS;
g. HVAC - DGs;

h. Offsite Power;
i. Main Steam (MS); and
j. SAFW.

These systems are of medium importance since they either substantially contribute to the final results (i.e., had a F-V value > 5.0E-02) or if the system were assumed to occur with a probability of 1.0 would have a significant impact on CDF (i.e., had a RAW value > 10). Items a, b, c, d, e, f, and g have F-V values < 5.0E-02 which indicates that the systems are reliable with respect to their PSA required functions; however, they could have a large impact on the CDF if their failure rates were to increase. Items h, i, and j indicate unreliable systems with respect to their fault tree models. However, the offsite power system uses strictly generic data such that the generic data or level of modeling detail may be too high. The MS ranking is due to plant-specific data which identified two failures of a MSIV to close between 1980 and 1988. The SAFW system contributes to the CDF due to the high values used for test and maintenance unavailabilities.

The remaining systems were determined not to significantly contribute to the final CDF.

9.3.2.5 Components

Figure 9-6 and Table 9-6 show F-V and RAW importance measures on a component basis (note that some "components" are actually modularized events or "super components"). As can be seen from the figure and table, the components of highest risk can be directly related to the system risk significance described above (as would be expected).

One of the interesting insights provided by Figure 9-6 is that DG B is slightly more risk significant than DG A. This is due to the fact that the ventilation system in the Intermediate Building where the preferred AFW system is located, relies on one of two functions: (1) natural ventilation through Fire Door F36, or (2) Intermediate Exhaust Fans A and B. However, only Exhaust Fan B is supplied by a DG (i.e., DG B). Therefore, if Fire Door F36 were ever closed coincident with loss of offsite power, then the AFW pumps must rely on DG B to provide necessary room cooling.

9.4 Additional Risk Insights

In addition to the above discussions, there are several issues which the Ginna Station PSA has been asked to specifically address by RG&E management. These issues are described below.

9.4.1 Loss of Service Water to Diesel Generators

In 1989, the NRC performed a Safety System Functional Inspection (SSFI) of the RHR system at Ginna Station. Included within the inspection report [Ref. 72] was an issue related to the common discharge line associated with SW cooling to the DGs. The NRC postulated that this non-seismic 10" line could become crimped following a design basis earthquake such that SW flow would be prevented from flowing through the coolers (see item 89-81-01). It was acknowledged that this potential SBO scenario was a low probability event; however, it was maintained as an open item. RG&E responded to this concern by agreeing to evaluate the potential risk of this beyond design basis scenario in the PSA [Ref. 73].

While the Ginna Station PSA did not specifically evaluate a seismic event, a qualitative evaluation of this scenario can be presented. Essentially, the crimped SW piping following a design basis earthquake is no different than the failure of both DGs as modeled with the Level 1 PSA. That is, the fault tree model for the DGs includes independent and common cause failures of the DGs to start and run. It also includes failure of SW cooling to the DGs. As described in Section 7.3.1.2, the failure probability of both DGs to operate is 2.0E-03. The frequency of loss of offsite power is determined as follows:

a. Per Section 7.3.1.2, the frequency of loss of offsite power as an initiating event is 6.32E-02/ryr.

b. The frequency of losing offsite power following any other initiating event depends on whether the event causes a SI signal or not. The frequency of those initiators which do not cause a SI signal is dominated by a reactor trip (TIRXTRIP) which has a frequency of 1.82/ryr. This value is then multiplied by a loss of offsite power probability of 1.0E-03 (Section 7.3.1.2). The total frequency of initiators which cause a SI signal is approximately 2.0E-02/ryr. This is then multiplied by a loss of offsite power probability of 1.0E-02 (Section 7.3.1.2). Summing these values yields a total loss of offsite power frequency of 2.02E-03/ryr following a reactor trip.

Summing all of the potential loss of offsite power events yields a frequency of 6.52E-02/ryr. Multiplying this by the failure probability of both DGs results in a SBO value of 1.30E-04/ryr. Therefore, the Ginna Station PSA is using a value of 1.30E-04/ryr for the same SBO scenario as postulated by the NRC. It should be noted that the PSA only credits recovery of offsite power and not the failed DGs for this scenario.

RG&E estimates the frequency of a design basis earthquake at Ginna Station to be approximately 4.0E-05/ryr. Conservatively assuming that the earthquake directly results in a loss of offsite power and crimping of the SW piping yields a value of 4.0E-05/ryr for this scenario. This is 3 times smaller than the value used in the Ginna Station PSA using conservative assumptions. Therefore, it can be concluded that this beyond design basis event is of low enough probability to not warrant any special consideration such that the inspection report item can be closed.

Table 9-1
Cutsets > 1.0E-07

#	Class	Inputs	Description	Exposure	Event Prob	Cutset Prob
1	SS	TI0000SW	Total Loss of Service Water	1.43E-04	1.43E-04	3.41E-06
		IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING	9.95E-01	9.95E-01	
		CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA	2.40E-02	2.40E-02	
2	A	LILBLOCA	Large LOCA	1.80E-04	1.80E-04	2.34E-06
		RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION	1.30E-02	1.30E-02	
3	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	2.26E-06
		RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START	4.12E-04	4.12E-04	
4	M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	2.12E-06
		RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION	1.30E-02	1.30E-02	
		MLOCRECIRC	MULTIPLIER FOR MEDIUM LOCA RECIRCULATION FAILURE RATE	4.08E-01	4.08E-01	
5	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.85E-06
		CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN	3.37E-04	3.37E-04	
6	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.69E-06
		RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>	3.08E-04	3.08E-04	
7	SGTR	LIOSGTRA	Steam Generator Tube Rupture in SG A	4.84E-03	4.84E-03	1.43E-06
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
		RCHFDCOOLD	Operators Fail to Rapidly Cooldown to RHR Conditions After ARV Sticks Open	3.07E-02	3.07E-02	
8	SGTR	LIOSGTRB	Steam Generator Tube Rupture in SG B	4.84E-03	4.84E-03	1.43E-06
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
		RCHFDCOOLD	Operators Fail to Rapidly Cooldown to RHR Conditions After ARV Sticks Open	3.07E-02	3.07E-02	
9	MISC	LIPEN111	INTERSYSTEM LOCA THROUGH PENETRATION 111	5.11E-06	5.11E-06	9.61E-07
		TLHFDPN111	OPERATORS FAIL TO ISOLATE PENETRATION 111	1.88E-01	1.88E-01	
10	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	5.11E-07
		CCMM00738A	MOV 738A FAILS TO OPEN	4.65E-03	4.65E-03	
		RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	2.00E-02	2.00E-02	
11	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	5.11E-07
		CCMM00738B	MOV 738B FAILS TO OPEN	4.65E-03	4.65E-03	
		RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	2.00E-02	2.00E-02	
12	S	LISBLOCA	Small LOCA (1-1.5")	1.10E-03	1.10E-03	4.53E-07
		RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START	4.12E-04	4.12E-04	
13	TRAN	TIFLBOTB	Feedline Break in Turbine Building	1.40E-03	1.40E-03	3.85E-07
		AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW	5.19E-03	5.19E-03	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
14	S	LISBLOCA	Small LOCA (1-1.5")	1.10E-03	1.10E-03	3.71E-07
		CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN	3.37E-04	3.37E-04	
15	TRAN	TISLBOTB	Steamline Break in Turbine Building	1.29E-03	1.29E-03	3.55E-07
		AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW	5.19E-03	5.19E-03	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
16	S	LISBLOCA	Small LOCA (1-1.5")	1.10E-03	1.10E-03	3.39E-07
		RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>	3.08E-04	3.08E-04	
17	M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	3.35E-07
		SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO COMMON CAUSE	8.38E-04	8.38E-04	
18	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	3.30E-07
		CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	3.00E-03	3.00E-03	
		RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	2.00E-02	2.00E-02	
19	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	3.30E-07
		CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	3.00E-03	3.00E-03	
		RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	2.00E-02	2.00E-02	

Table 9-1
Cutsets > 1.0E-07

#	Class	Inputs	Description	Exposure	Event Prob	Cutset Prob
20	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	2.81E-07
		RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START	2.56E-03	2.56E-03	
		RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE (INJECTION)	2.00E-02	2.00E-02	
21	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	2.81E-07
		RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START	2.56E-03	2.56E-03	
		RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING (INJECTION)	2.00E-02	2.00E-02	
22	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	2.65E-07
		RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	
		SRHFDRECRC	OPERATORS FAIL TO SHIFT SI SYSTEM TO RECIRCULATION	1.30E-03	1.30E-03	
23	TRAN	TI0SLBSD	Steamline Break Through Steam Dump System	5.78E-03	5.78E-03	2.58E-07
		MSCCCMSIVX	Common Cause Failure of MSIVs to Close	8.41E-04	8.41E-04	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
24	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	2.44E-07
		RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	
		RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION	1.30E-02	1.30E-02	
		SLOCRECIRC	MULTIPLIER FOR SLOCA AND SSLOCA RECIRCULATION FAILURE RATE	9.32E-02	9.23E-02	
25	SBO	TIGRLOSP	Loss of Offsite Power - Grid	2.28E-02	2.28E-02	2.41E-07
		ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours	2.70E-02	2.70E-02	
		DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	2.34E-03	2.34E-03	
		SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO	1.67E-01	1.67E-01	
26	SBO	TIGRLOSP	Loss of Offsite Power - Grid	2.28E-02	2.28E-02	2.37E-07
		ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours	2.70E-02	2.70E-02	
		DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE	3.85E-04	3.85E-04	
27	TRAN	TIFLB0TB	Feedline Break in Turbine Building	1.40E-03	1.40E-03	2.37E-07
		AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M	5.60E-02	5.60E-02	
		AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M	5.70E-02	5.70E-02	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
28	SBO	TIGRLOSP	Loss of Offsite Power - Grid	2.28E-02	2.28E-02	2.21E-07
		ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours	2.70E-02	2.70E-02	
		DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)	3.60E-04	3.60E-04	
29	M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	2.18E-07
		SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO COMMON CAUSE	5.46E-04	5.46E-04	
30	TRAN	TISLB0TB	Steamline Break in Turbine Building	1.29E-03	1.29E-03	2.18E-07
		AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M	5.60E-02	5.60E-02	
		AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M	5.70E-02	5.70E-02	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
31	ATWS	TIIALOSS	Loss of Instrument Air	4.15E-02	4.15E-02	2.10E-07
		TL00076DAY	Less Than or Equal to 76 Days into Cycle	3.89E-01	3.89E-01	
		TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)	1.30E-05	1.30E-05	
32	TRAN	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)	5.54E-03	5.54E-03	1.97E-07
		DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	3.56E-05	3.56E-05	
33	TRAN	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)	5.54E-03	5.54E-03	1.97E-07
		DCMMMAIN1A	Failure of Circuit E14 (To Main DC Distribution Panel 1A)	3.56E-05	3.56E-05	
34	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.71E-07
		SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO COMMON CAUSE	8.38E-04	8.38E-04	
		RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	
35	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.71E-07
		SRCCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN FOR RECIRC. DUE TO COMMON CAUSE	8.38E-04	8.38E-04	
		RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	

Table 9-1
Cutsets > 1.0E-07

# Class	Inputs	Description	Exposure	Event Prob	Cutset Prob
36 SS	TI0000SW	Total Loss of Service Water	1.43E-04	1.43E-04	1.66E-07
	CVCVP00357	check valve 357 fails to open	6.59E+03	1.17E-03	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING	9.95E-01	9.95E-01	
37 M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	1.65E-07
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START	4.12E-04	4.12E-04	
38 TRAN	TIFLB0TB	Feedline Break in Turbine Building	1.40E-03	1.40E-03	1.50E-07
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE	1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F	1.67E-01	1.67E-01	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.10E-01	1.10E-01	
	HVTMSAFW_B	B SAFW ROOM HVAC STRING IN MAINTENANCE	1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
39 SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.41E-07
	CRCCM0896X	COMMON CAUSE FAILURE OF MOVS 896A AND 896B TO CLOSE (RECIRC)	6.91E-04	6.91E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	
40 SBO	TIGRLOSP	Loss of Offsite Power - Grid	2.28E-02	2.28E-02	1.39E-07
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours	2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	2.40E+01	3.00E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.40E+01	3.00E-02	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO	2.50E-01	2.50E-01	
41 TRAN	TISLB0TB	Steamline Break in Turbine Building	1.29E-03	1.29E-03	1.38E-07
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE	1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F	1.67E-01	1.67E-01	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.10E-01	1.10E-01	
	HVTMSAFW_B	B SAFW ROOM HVAC STRING IN MAINTENANCE	1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
42 M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	1.35E-07
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN	3.37E-04	3.37E-04	
43 A	LILBLOCA	Large LOCA	1.80E-04	1.80E-04	1.35E-07
	CVAVX00371	AOV 371 FAILS TO CLOSE	2.21E+03	5.76E-02	
	CVHFD00371	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE)	1.30E-02	1.30E-02	
44 SGTR	LI0SGTRA	Steam Generator Tube Rupture in SG A	4.84E-03	4.84E-03	1.25E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO COMMON CAUSE	8.38E-04	8.38E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR	3.07E-02	3.07E-02	
45 SGTR	LI0SGTRB	Steam Generator Tube Rupture in SG B	4.84E-03	4.84E-03	1.25E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO COMMON CAUSE	8.38E-04	8.38E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR	3.07E-02	3.07E-02	
46 M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	1.23E-07
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>	3.08E-04	3.08E-04	
47 M	LIMBLOCA	Medium LOCA (1.5"-5.5")	4.00E-04	4.00E-04	1.22E-07
	CVAVX00371	AOV 371 FAILS TO CLOSE	2.21E+03	5.76E-02	
	CVHFD00371	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE)	1.30E-02	1.30E-02	
	MLOCRECIRC	MULTIPLIER FOR MEDIUM LOCA RECIRCULATION FAILURE RATE	4.08E-01	4.08E-01	
48 SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.19E-07
	CCMM00738A	MOV 738A FAILS TO OPEN	4.65E-03	4.65E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN	4.65E-03	4.65E-03	
49 ATWS	TIGRLOSP	Loss of Offsite Power - Grid	2.28E-02	2.28E-02	1.15E-07
	TL00076DAY	Less Than or Equal to 76 Days into Cycle	3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)	1.30E-05	1.30E-05	

Table 9-1
Cutsets > 1.0E-07

#	Class	Inputs	Description	Exposure	Event Prob	Cutset Prob
50	TRAN	TIFLBBIB	Feedline Break in Line for SG B Inside Intermediate Building	3.87E-05	3.87E-05	1.15E-07
		AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M	5.60E-02	5.60E-02	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
51	SS	LISSLOCA	Small-Small LOCA (0-1")	5.50E-03	5.50E-03	1.11E-07
		SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO COMMON CAUSE	5.46E-04	5.46E-04	
		RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails (INJECTION OR RECIRC)	3.70E-02	3.70E-02	
52	SS	TI000CCW	Loss of Component Cooling Water	1.30E-03	1.30E-03	1.10E-07
		CVCCMPFABC	COMMON CAUSE FAILURE OF THE CHARGING PUMPS TO RUN	8.49E-05	8.49E-05	
53	TRAN	TISLBBIB	Steamline Break in Line for SG B Inside Intermediate Buildi ng	3.58E-05	3.58E-05	1.06E-07
		AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M	5.60E-02	5.60E-02	
		RCHFD01BAF	Operators Fail To Implement Feed And Bleed	5.30E-02	5.30E-02	
54	SGTR	LIOSGTRA	Steam Generator Tube Rupture in SG A	4.84E-03	4.84E-03	1.06E-07
		RRMVQ00700	MOV 700 FAILS TO OPEN	1.00E+00	2.27E-03	
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
55	SGTR	LIOSGTRA	Steam Generator Tube Rupture in SG A	4.84E-03	4.84E-03	1.06E-07
		RRMVQ00701	MOV 701 FAILS TO OPEN	1.00E+00	2.27E-03	
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
56	SGTR	LIOSGTRB	Steam Generator Tube Rupture in SG B	4.84E-03	4.84E-03	1.06E-07
		RRMVQ00700	MOV 700 FAILS TO OPEN	1.00E+00	2.27E-03	
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
57	SGTR	LIOSGTRB	Steam Generator Tube Rupture in SG B	4.84E-03	4.84E-03	1.06E-07
		RRMVQ00701	MOV 701 FAILS TO OPEN	1.00E+00	2.27E-03	
		RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR	9.61E-03	9.61E-03	
58	S	LISBLOCA	Small LOCA (1-1.5")	1.10E-03	1.10E-03	1.02E-07
		CCMM00738A	MOV 738A FAILS TO OPEN	4.65E-03	4.65E-03	
		RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE (INJECTION)	2.00E-02	2.00E-02	
59	S	LISBLOCA	Small LOCA (1-1.5")	1.10E-03	1.10E-03	1.02E-07
		CCMM00738B	MOV 738B FAILS TO OPEN	4.65E-03	4.65E-03	
		RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING (INJECTION)	2.00E-02	2.00E-02	

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Table 9-2
Initiating Event Importance Ranking

Initiator	*Freq*	*F-V*	*RAW*
HIGH IMPORTANCE			
LISSLOCA - Small-Small LOCA	5.50E-03	2.51E-01	46.31
LI0SGTRA - Steam Generator Tube Rupture in SG A	4.84E-03	8.22E-02	17.9
LI0SGTRB - Steam Generator Tube Rupture in SG B	4.84E-03	8.19E-02	17.84
LILBLOCA - Large LOCA	4.84E-03	6.04E-02	335.27
LIMBLOCA - Medium LOCA	4.00E-04	8.19E-02	204.84
TI0000SW - Total Loss of Service Water	1.43E-04	8.24E-02	574.4
MEDIUM IMPORTANCE			
TIGRLOSP - Loss of Offsite Power - Grid	2.28E-02	1.34E-01	6.74
LISBLOCA - Small LOCA	1.10E-03	4.93E-02	45.73
TIFLB0TB - Feedwater Line Break in Turbine Building	1.40E-03	2.08E-02	15.84
TISLB0TB - Steam Line Break in Turbine Building	1.29E-03	2.06E-02	16.96
TIFLBAIB - Feedwater Line Break in Line for SG A In Intermediate Bldg	2.58E-05	2.00E-03	78.53
TISLBAIB - Steam Line Break in Line for SG A In Intermediate Bldg	2.38E-05	2.12E-03	89.79
TIFLBBIB - Feedwater Line Break in Line for SG B In Intermediate Bldg	7.74E-05	2.93E-03	76.67
TISLBBIB - Steam Line Break in Line for SG B In Intermediate Bldg	3.58E-05	3.11E-03	87.87
TI48LOSP - Loss of Offsite Power - 480 V Trains	8.78E-06	3.50E-04	40.83
LIPEN101 -ISLOCA in Penetration 101	2.19E-09	4.36E-05	19900
LIPEN110 - ISLOCA in Penetration 110b	1.56E-07	6.43E-04	4120
LIPEN113 - ISLOCA in Penetration 113	2.19E-09	4.36E-05	19900
LIPEN111 - ISLOCA in Penetration 111	5.11E-06	1.91E-02	3750
LIPEN140 - ISLOCA in Penetration 140	2.36E-07	4.70E-04	1900
LIRVRUPT - Reactor Vessel Rupture	1.00E-08	1.99E-04	19900
LOW IMPORTANCE			
TI000CCW - Loss of Component Cooling Water	1.30E-03	1.06E-02	9.15
TI000DCA - Loss of Main DC Distribution Panel A (DCPDPCB03A)	5.54E-03	1.14E-02	3.05

Table 9-2
Initiating Event Importance Ranking

Initiator	*Freq*	*F-V*	*RAW*
TI000DCB - Loss of Main DC Distribution Panel B (DCPDPCB03B)	5.54E-03	1.79E-02	4.22
TI000SWA - Loss of Service Water Header A	1.32E-04	4.17E-04	4.16
TI000SWB - Loss of Service Water Header B	1.32E-04	5.03E-04	4.81
TIOSLBSD - Steam Line Break Through Steam Dump System	5.78E-03	7.37E-03	2.27
TIFLBACT - Feedwater Line Break in Line for SG A Inside Containment	2.58E-05	2.60E-06	1.1
TIFLBBCT - Feedwater Line Break in Line for SG B Inside Containment	2.58E-05	2.60E-06	1.1
TIFWLOSS - Loss of Main Feedwater	7.20E-03	4.56E-04	1.06
TIIALOSS - Loss of Instrument Air	4.15E-02	9.39E-03	1.22
TIRCPROT - Locked RCP Rotor	1.00E-04	1.29E-04	2.29
TIRXTRIP - Reactor Trip	1.82	3.36E-02	0.98
TISLBACT - Steam Line Break in Line for SG A Inside Containment	2.38E-05	6.16E-06	1.26
TISLBBCT - Steam Line Break in Line for SG B Inside Containment	2.38E-05	6.16E-06	1.26
TISLBSGB - Exterior Steam Line Break on SG B	3.58E-05	2.93E-05	1.76
TISLBSVA - Inadvertent Safety Valve Operation on Both SGs	2.82E-03	3.98E-04	1.14
TISWLOSP - Loss of Offsite Power - Switchyard	4.04E-02	1.24E-02	1.29

Table 9-3
Human Error Importance Ranking

Human Error Event	*Prob*	*F-V*	*RAW*
HIGH IMPORTANCE			
ACAALOSP10 - Ops Fail to Restore Offsite Power Within 10 Hours - SBO	2.70E-02	6.05E-02	3.18
AFHFDSAFWX - Ops Fail to Correctly Align SAFW	5.19E-03	1.95E-02	4.73
CVHFDSUCTN - Ops Fail to Manually Open Suction Line to CVCS Pumps	2.04E-02	9.46E-02	4.84
MSHFDISOLR - Ops Fail to Isolate SG	7.24E-03	1.23E-02	2.68
RCHFD01BAF - Ops Fail to Implement Feed and Bleed Cooling	5.30E-02	7.45E-02	2.33
RCHFDCDDPR - Ops Fail to Cooldown and Depressurize Prior to SG Over	9.61E-03	7.32E-02	8.54
RCHFDCOOLD - Ops Fail to Cooldown to RHR After ARV Sticks - SGTR	3.07E-02	5.70E-02	2.8
RCHFDRHRSB - Ops Fails to Use RHR or AFW Long-Term After SBO	5.00E-03	1.40E-02	3.78
RRHFDRECRC - Ops Fail to Correctly Shift RHR to Recirculation Phase	1.30E-02	9.58E-02	8.27
SRHFDRECRC - Ops Fail to Shift SI System to Recirculation	1.30E-03	6.99E-03	6.37
SWHFDSTART - Ops Fail to Start Standby SW Pump or Isolate System	5.00E-03	2.13E-02	5.24
MEDIUM IMPORTANCE			
ACAADLOSP1 - Ops Fail to Restore Offsite Power Within 1 Hour - SBO	3.55E-01	2.54E-02	1.05
AFHFDALTTD - Ops Fail to Provide Fire Water Cooling to TDAFW Pump	6.70E-03	5.59E-03	1.83
AFHFDSUPPL - Ops Fail to Supply Alternate Suction Source for AFW	1.00E-03	1.50E-03	2.49
CVHFD00371 - Ops Fail to Manually Isolate AOV 371 (Letdown)	1.30E-02	5.60E-03	1.42
RCHFDCD0SS - Ops Fail to Cooldown to RHR After SI Fails - LOCAs	3.70E-03	3.72E-02	1.97
RCHFDCDTR2 - Ops Fail to Cooldown to RHR After SI Fails - SGTR	3.07E-02	9.09E-03	1.29
RCHFDPLOCA - Ops Fails to Close PORV Block Valve to Stop LOCA	1.00E-01	2.55E-02	1.23
RRHFDSUCTN - Ops Fail to Manually Open RHR Suction Valves	1.00E-01	1.92E-02	1.17
RRHFDTHROT - Ops Fail to Throttle RHR Pumps for NPSH Concerns	1.00E-01	6.09E-03	1.05
TLHFDPN111 - Ops Fail to Mitigate ISLOCA Through Penetration 111	1.88E-01	1.91E-02	1.08
LOW IMPORTANCE			
ACAADLOSP2 - Ops Fail to Restore Offsite Power Within 2 Hours - SBO	1.89E-01	7.89E-04	1
ACAADLOSP5 - Ops Fail to Restore Offsite Power Within 5 Hours - SBO	6.40E-02	3.16E-04	1

Table 9-3
Human Error Importance Ranking

Human Error Event	*Prob*	*F-V*	*RAW*
AFHFDTDAFW - Ops Fail to Start TDAFW Pump During SBO	1.00E-01	1.44E-03	1.01
CVHFD00313 - Ops Fail to Manually Isolate MOV 313 (RCP Seal Return)	1.30E-02	4.25E-06	1
CVHFDBORAT - Ops Fail to Implement Emergency Boration	1.00E-02	6.52E-06	1
CVHFDPMPST - Ops Fail to Manually Load Charging Pump	7.0E-03	2.75E-03	1.39
IAHFDCSA03 - Ops Fail to Place CNMT Breathing Air Comp In Service	1.00E-01	4.76E-06	1
IAHFDCSA04 - Ops Fail to Place Diesel Air Compressor In Service	1.00E-01	4.76E-01	1
MFHFDMF100 - Ops Fail to Re-Establish MFW	1.20E-02	2.73E-03	1.2
MSHFDISOLA - Ops Fail to Isolate Ruptured SG Using Secondary Valve	1.00E-01	3.35E-03	1.03
MSHFDMSIVX - Ops Fail to Close MSIV After Signal Failure	1.00E-01	1.24E-03	1.01
RCHFD00MRI - Ops Fail to Manually Insert Rods	1.00E-02	1.79E-04	1.02
RCHFD00RCP - Ops Fail to Trip RCP Within 2 Minutes	1.61E-02	1.35E-03	1.08
RCHFDCDOVR - Ops Fail to Cooldown to RHR After SG Overfill	3.07E-02	7.28E-05	1
RCHFDHEATR - Ops Fail to Load PZR Heaters on DGs Following LOSP	2.58E-04	2.24E-04	1.72
RCHFDSCRAM - Ops Fail to Trip Rod Drive MG Sets During ATWS	1.00E-02	1.60E-05	1
RRHFDSEALX - Ops Fail to Stop RHR Pump Upon Seal Failure	1.00E-01	1.92E-03	1.02
SIHFDSTRTP - Ops Fail to Manually Start SI Pump	1.00E-01	7.71E-04	1.01
TLHFDPN110 - Ops Fail to Mitigate ISLOCA Through Penetration 110	2.07E-01	6.43E-04	1
TLHFDPN140 - Ops Fail to Mitigate ISLOCA Through Penetration 140	1.00E-01	4.70E-04	1
UVHFDBREAK - Ops Fail to Manually Close 480 V Breakers for DGs	1.00E-01	2.20E-03	1.02

Table 9-4
Test and Maintenance Unavailability Importance Ranking

Human Error Event	*Prob*	*F-V*	*RAW*
HIGH IMPORTANCE			
CCHFL0780A - CCW Throttling Valve 780A Mispositioned	3.00E-03	1.64E-02	6.44
CCHFL0780B - CCW Throttling Valve 780B Mispositioned	3.00E-03	1.64E-02	6.44
DGTM00001A - DG A OOS for Maintenance	1.30E-02	1.97E-02	2.5
DGTM00001B - DG B OOS for Maintenance	1.30E-02	2.34E-02	2.77
RHTM0000A - RHR Pump Train A OOS for Maintenance	2.00E-02	5.32E-02	3.6
RHTM0000B - RHR Pump Train B OOS for Maintenance	2.00E-02	5.33E-02	3.61
MEDIUM IMPORTANCE			
AFTM0TDAFW - TDAFW Pump Train OOS for Maintenance	1.00E-02	9.74E-03	1.96
AFTMSAFSGA - SAFW Pump Train C OOS for Maintenance	5.60E-02	2.11E-02	1.36
AFTMSAFSGB - SAFW Pump Train D OOS for Maintenance	5.70E-02	1.96E-02	1.32
HVTMSAFW_A - SAFW HVAC Train A OOS for Maintenance	1.10E-01	1.03E-02	1.08
HVTMSAFW_B - SAFW HVAC Train B OOS for Maintenance	1.10E-01	7.98E-03	1.06
SWTM4616MT - SW Isolation Valve 4616 OOS for Maintenance	1.00E-03	1.00E-03	2
LOW IMPORTANCE			
AFHFL0AFWA - Failure to Restore AFW Pump A to Service Post-Maint	3.00E-03	6.66E-05	1.02
AFHFL0AFWB - Failure to Restore AFW Pump B to Service Post-Maint	3.00E-03	6.74E-05	1.02
AFHFLS5737 - Ops Leaves Switch 1S1/5737 In Wrong Position	3.00E-03	9.84E-04	1.33
AFHFLS5738 - Ops Leaves Switch 1S1/5738 In Wrong Position	3.00E-03	9.72E-04	1.32
AFHFLSAFWA - Failure to Restore SAFW Pump C to Service Post-Maint	3.00E-03	1.56E-03	1.52
AFHFLSAFWB - Failure to Restore SAFW Pump D to Service Post-Maint	3.00E-03	1.17E-03	1.39
AFHFLTDAFW - Failure to Restore TDAFW Pump to Service Post-Maint	3.00E-03	2.64E-03	1.88
AFTMMAFSGA - MDAFW Pump Train A OOS for Maintenance	5.30E-02	1.39E-03	1.02
AFTMMAFSGB - MDAFW Pump Train B OOS for Maintenance	5.30E-02	1.39E-03	1.02
AFTMSAFWAB - SAFW Cross-Connect Line OOS for Maintenance	4.33E-03	1.12E-04	1.03
AFTMTDAFWA - TDAFW Pump Injection Line to SG A OOS for Maint	4.90E-02	3.90E-03	1.08

Table 9-4
Test and Maintenance Unavailability Importance Ranking

Human Error Event	*Prob*	*F-V*	*RAW*
AFTMTDAFWB - TDAFW Pump Injection Line to SG B OOS for Maint	4.90E-02	3.84E-03	1.07
CCTM_PUMPA - CCW Pump A OOS for Maintenance	7.00E-03	3.95E-03	1.56
CCTM_PUMPB - CCW Pump B OOS for Maintenance	7.00E-03	4.14E-03	1.59
CCTM000HXA - CCW HX A OOS for Maintenance	3.50E-03	8.42E-04	1.24
CCTM000HXB - CCW HX B OOS for Maintenance	3.50E-03	8.42E-04	1.24
CSHFL0896A - Failure to Restore MOV 896A to Service	3.00E-03	2.20E-04	1.07
CSHFL0896B - Failure to Restore MOV 896B to Service	3.00E-03	2.20E-04	1.07
HVHFLSAFWA - Failure to Restore SAFW HVAC Train A to Service	3.00E-03	2.19E-04	1.07
HVHFLSAFWB - Failure to Restore SAFW HVAC Train B to Service	3.00E-03	1.81E-04	1.06
HVTMAIF01B - Intermediate Bldg Fan AIF01B OOS for Maintenance	1.28E-03	3.00E-05	1.02
IATMCOMPRA - IA Compressor A OOS for Maintenance	8.00E-02	1.38E-03	1.02
IATMCOMPRB - IA Compressor B OOS for Maintenance	8.00E-02	8.22E-05	1
IATMSACOMP - Service Air Compressor OOS for Maintenance	1.00E-01	4.76E-06	1
MSHFLARV-A - Failure to Restore ARV to Service After Maintenance	3.00E-03	1.77E-04	1.06
MSTM003410 - ARV 3410 OOS for Maintenance	9.00E-03	7.29E-04	1.08
MSTM003411 - ARV 3411 OOS for Maintenance	9.00E-03	6.98E-04	1.08
RCHFL0431K - Controller PC-431k Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLC429B - Bistable PC-429B Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLC430B - Alarm Bistable PC-430B Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLC431B - Alarm PC-4431B Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLC431F - Alarm Bistable PC-431F Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLLT427 - PZR Level Transmitter 427 Miscalibrated	3.00E-03	1.46E-04	1.05
RCHFLLT428 - PZR Level Transmitter 428 Miscalibrated	3.00E-03	1.46E-04	1.05
RCHFLPC450 - Alarm PC-450 Miscalibrated	3.00E-03	8.99E-05	1.03
RCHFLPC452 - Alarm PC-452 Miscalibrated	3.00E-03	8.99E-05	1.03
RCHFLPT429 - Pressure Transmitter PT-429 Miscalibrated	3.00E-03	1.19E-04	1.04

Table 9-4
Test and Maintenance Unavailability Importance Ranking

Human Error Event	*Prob*	*F-V*	*RAW*
RCHFLPT430 - Pressure Transmitter PT-430 Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLPT431 - Pressure Transmitter PT-431 Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLPT449 - Pressure Transmitter PT-449 Miscalibrated	3.00E-03	1.19E-04	1.04
RCHFLPT450 - Pressure Transmitter PT-450 Miscalibrated	3.00E-03	8.99E-05	1.03
RCHFLPT452 - Pressure Transmitter PT-452 Miscalibrated	3.00E-03	8.99E-05	1.03
RHHFL0000A - Failure to Restore RHR Pump Train A to Service	3.00E-03	1.93E-03	1.64
RHHFL0000B - Failure to Restore RHR Pump Train B to Service	3.00E-03	1.94E-03	1.64
RRHFL00856 - Failure to Restore MOV 856 to Service After Maint	3.00E-03	3.42E-06	1
SIHFL0857B - Failure to Restore MOV 857B to Service After Maint	3.00E-03	6.52E-04	1.22
SIHFL857AC - Failure to Restore MOVs 857A/C to Service After Maint	3.00E-03	7.03E-04	1.23
SITM0PSI1A - SI Pump A OOS for Maintenance	5.71E-03	2.20E-06	1
SITM0PSI1B - SI Pump B OOS for Maintenance	5.71E-03	2.20E-06	1
SITM0PSI1C - SI Pump C OOS for Maintenance	5.71E-03	2.20E-06	1
SITMTRAINA - SI Train A to RCS OOS for Maintenance	5.71E-03	7.33E-04	1.13
SITMTRAINB - SI Train B to RCS OOS for Maintenance	5.71E-03	6.20E-04	1.11
SWTM4615MT - SW Isolation Valve 4615 OOS for Maintenance	1.00E-03	9.22E-04	1.92
SWTM4670MT - SW Isolatino Valve 4670 OOS for Maintenance	1.00E-03	6.19E-05	1.06

Table 9-5
System Importance Ranking

System	*F-V*	*RAW*
HIGH IMPORTANCE		
CCW - Component Cooling Water	1.41E-01	234.3
DG - Diesel Generators	1.02E-01	29.53
RHR - Residual Heat Removal	2.73E-01	158.63
UV - Undervoltage	2.39E-01	16.48
MEDIUM IMPORTANCE		
AC - AC Power System	2.09E-01	6.74
CVCS - Chemical and Volume Control System	1.99E-02	31.79
DC - DC Electrical Power	1.39E-02	500.5
ESFAS - Engineered Safety Features Actuation System	1.99E-03	301.8
HVAC - DG - Ventilation for DG Rooms	1.99E-03	29.01
MS - Main Steam	7.17E-02	8.66
RTS - Reactor Trip System	3.59E-02	1680
SAFW - Standby Auxiliary Feedwater	5.70E-02	4.46
SI - Safety Injection	4.58E-02	343.97
SW - Service Water	9.96E-03	1590
LOW IMPORTANCE		
AFW - Auxiliary Feedwater	1.39E-02	3.16
IA - Instrument Air	1.99E-03	1.62
IB - Instrument Bus	1.79E-04	1.64
MFW - Main Feedwater	2.37E-03	1.2
RCS - Reactor Coolant System	3.98E-02	3.01
HVAC - SAFW - Ventilation for SAFW System	1.99E-03	1.98
HVAC - IB - Ventilation for Intermediate Building	1.39E-02	1.74

Table 9-6
Component Importance Measures

Event Name/EIN	*Prob*	*Fus Ves*	*Ach W*	*Type*[1]	*Rank*[2]
AFMM0TDAFW - TDAFW Pump Train	1.27E-02	1.14E-02	1.89	C	X
AFMMSAFWPC - SAFW Pump C	2.30E-02	5.58E-03	1.24	C	X
CVAVX00371 - Letdown Isolation AOV 371	5.76E-02	5.48E-03	1.09	C	X
DGDGF0001A - DG A Fails to Run	3.00E-02	2.92E-02	1.94	C	X
HVFDRF360P - Fire Door F36 Closed	5.00E-02	1.40E-02	1.27	C	X
MSRYT03508 - MSSV 3508	6.88E-03	6.09E-03	1.88	C	X
MSRYT03509 - MSSV 3509	6.88E-03	6.09E-03	1.88	C	X
MSRYT03510 - MSSV 3510	6.88E-03	6.09E-03	1.88	C	X
MSRYT03511 - MSSV 3511	6.88E-03	6.09E-03	1.88	C	X
MSRYT03512 - MSSV 3512	6.88E-03	6.09E-03	1.88	C	X
MSRYT03513 - MSSV 3513	6.88E-03	6.09E-03	1.88	C	X
MSRYT03514 - MSSV 3514	6.88E-03	6.09E-03	1.88	C	X
MSRYT03515 - MSSV 3515	6.88E-03	6.09E-03	1.88	C	X
RCRYT00434 - PRZR Safety Valve 434	7.45E-03	6.37E-03	1.85	C	X
RCRYT00435 - PRZR Safety Valve 435	7.45E-03	6.37E-03	1.85	C	X
ACLOPRT751 - Offsite Power Circuit 751	1.19E-02	1.59E-02	2.32	C	XY
ACLOPRT767 - Offsite Power Circuit 767	1.00E-02	1.03E-02	2.01	C	XY
ACLOPRTALL - Offsite Power Grid	1.00E-02	3.74E-02	4.7	C	XY
CCCC738A/B - MOVs 738A/B CCF	3.37E-04	5.47E-02	162.79	C	XY
CCMM00738A - MOV 738A Fails to Open	4.65E-03	2.55E-02	6.46	C	XY
CCMM00738B - MOV 738B Fails to Open	4.65E-03	2.55E-02	6.46	C	XY
DGCC000RUN - DGs Fail to Run CCF	2.34E-03	1.14E-02	5.86	C	XY
DGCC0START - DGs Fail to Start CCF	3.60E-04	1.03E-02	29.51	C	XY
DGCCBREAKR - DG Breakers CCF to Close	3.85E-04	1.10E-02	29.53	C	XY
DGDGF0001B - DG B Fails to Run	3.00E-02	3.54E-02	2.15	C	XY
DGMM0AAF04 - DG Load Shedding	3.85E-03	6.51E-03	2.68	C	XY
DGMM0FUELA - DG A Fuel Oil System	6.14E-03	1.09E-02	2.77	C	XY
DGMM0FUELB - DG B Fuel Oil System	6.14E-03	1.26E-02	3.04	C	XY
DGMMASTART - DG A Fails to Start	4.94E-03	8.60E-03	2.73	C	XY
DGMMBRKR14 - Brkr 52/EG1A1 to Bus 14	3.96E-03	5.80E-03	2.46	C	XY
DGMMBRKR16 - Brkr 52/EG1B1 to Bus 16	3.96E-03	6.67E-03	2.68	C	XY
DGMMBRKR17 - Brkr 52/EG1B2 to Bus 17	3.88E-03	6.15E-03	2.58	C	XY
DGMMBRKR18 - Brkr 52/EG1A2 to Bus 18	3.88E-03	5.37E-03	2.38	C	XY
DGMMBSTART - DG B Fails to Start	4.94E-03	9.98E-03	3.01	C	XY
MSCCCMSIVX - MSIVs CCF to Close	8.41E-04	6.45E-03	8.66	C	XY
RCRZT00430 - PRZR PORV 430 Fails to Open	5.00E-03	1.28E-02	3.54	C	XY
RCRZT0431C - PRZR PORV 431C Fails to Open	5.00E-03	1.28E-02	3.54	C	XY
RHCCPUMPAB - RHR Pumps Fail to Start - CCF	4.12E-04	6.61E-02	161.2	C	XY
RHMMAC01AA - RHR Pump A Fails to Start	2.56E-03	1.45E-02	6.64	C	XY
RHMMAC01BA - RHR Pump B Fails to Start	2.56E-03	1.45E-02	6.64	C	XY
RRCC850A/B - MOVs 850A/B Fail to Open - CCF	3.08E-04	4.66E-02	152.05	C	XY
RRMM00850A - MOV 850A Fails to Open	3.08E-03	5.60E-03	2.81	C	XY
RRMM00850B - MOV 850B Fails to Open	3.08E-03	5.77E-03	2.87	C	XY
RRMVQ00700 - MOV 700 Fails to Open	2.27E-03	2.55E-02	12.2	C	XY
RRMVQ00701 - MOV 701 Fails to Open	2.27E-03	2.55E-02	12.2	C	XY
RRPTHPT420 - Press Trans PT-420 Fails High	4.91E-03	5.55E-03	2.12	C	XY

Table 9-6
Component Importance Measures

Event Name/EIN	*Prob*	*Fus Ves*	*Ach W*	*Type*[1]	*Rank*[2]
SICCMPSI1X - SI Pumps Fail to Start - CCF	5.46E-04	1.20E-02	23.05	C	XY
SICCMPSI1Y - SI Pumps Fail to Run - CCF	8.38E-04	1.86E-02	23.16	C	XY
TLCCFBRKRF - RTS Electrical Failure	1.30E-05	1.34E-02	1.01E+03	C	XY
ACB2FBUS14 - Bus 14	1.88E-05	1.52E-04	9.08	C	Y
ACB2FBUS16 - Bus 16	1.88E-05	1.26E-04	7.69	C	Y
ACB2FBUS17 - Bus 17	1.88E-05	1.15E-04	7.12	C	Y
ACB2FBUS18 - Bus 18	1.88E-05	1.28E-04	7.81	C	Y
ACCCAGASTA - Agastat Time Delay Relay - CCF	7.65E-06	1.55E-04	21.2	C	Y
ACMMMCC01C - MCC C	5.07E-05	3.61E-04	8.11	C	Y
ACMMMCC01D - MCC D	5.07E-05	3.21E-04	7.33	C	Y
AFCCAFWRUN - AFW Pumps Fail to Run - CCF	3.16E-05	3.99E-05	2.26	C	Y
AFCCAFWSTR - All 3 AFW Pumps Fail - CCF	1.42E-04	3.07E-04	3.16	C	Y
AFCCDMOVNB - MOVs 9701A/B Fail - CCF	2.51E-04	8.69E-04	4.46	C	Y
AFCCFSAFWA - SAFW Pumps Fail to Run - CCF	2.74E-05	8.59E-05	4.13	C	Y
AFCCPDISCB - Chk Valves 9700A/B Fail - CCF	2.18E-06	6.20E-06	3.84	C	Y
AFCCPSGINB - MOVs 9705A/B Fail - CCF	6.35E-06	1.80E-05	3.84	C	Y
AFCCSSAFWA - SAFW Pumps Fail to Start - CCF	3.56E-05	1.11E-04	4.13	C	Y
CCCCPUMP/R - CCW Pumps Fail to Run - CCF	8.35E-06	1.96E-03	234.3	C	Y
CCCCPUMP/S - CCW Pumps Fail to Start - CCF	5.46E-05	9.54E-04	18.47	C	Y
CCMMRRPMPA - CCW Vlvs for RHR Pump A	4.27E-06	1.15E-05	3.7	C	Y
CCMMRRPMPB - CCW Vlvs for RHR Pump B	4.27E-06	1.15E-05	3.7	C	Y
CCMPAPUMPA - CCW Pump A Fails to Start	1.85E-03	1.88E-03	2.01	C	Y
CCMPAPUMPB - CCW Pump B Fails to Start	1.85E-03	1.97E-03	2.06	C	Y
CCPPJ_COMM - CCW Pipe Rupture	1.33E-05	3.13E-03	235.92	C	Y
CCTKJSURGE - CCW Surge Tank Rupture	1.33E-05	3.13E-03	235.92	C	Y
CCXVK00728 - Valve 728 Fails Closed	2.14E-06	4.41E-04	206.85	C	Y
CCXVK00769 - Valve 769 Fails Closed	1.07E-06	1.53E-04	143.8	C	Y
CCXVK0741A - Valve 741A Fails Closed	9.72E-05	4.35E-04	5.47	C	Y
CCXVK0741B - Valve 741B Fails Closed	9.72E-05	4.32E-04	5.44	C	Y
CCXVK0764C - Valve 764C Fails Closed	1.07E-06	4.33E-06	5.05	C	Y
CCXVK0780A - Valve 780A Fails Closed	9.72E-05	4.35E-04	5.47	C	Y
CCXVK0780B - Valve 780B Fails Closed	9.72E-05	4.32E-04	5.44	C	Y
CRCCM0896X - MOVs 896A/B Fail to Close - CCF	6.91E-04	3.70E-03	6.35	C	Y
CSCCMLDRWT - RWST Level Trans Fail - CCF	2.57E-06	4.22E-05	17.41	C	Y
CSCCMLTLRW - RWST Level Trans Fail Low - CCF	2.47E-06	8.41E-04	339.25	C	Y
CSMM00RWST - Failure of RWST Flow	6.64E-06	2.29E-03	343.97	C	Y
CSMM896A/B - MOV 896A or B Transfer Closed	1.10E-05	2.16E-04	20.62	C	Y
CVCCMPFABC - Charging Pumps Fail to Run - CCF	8.49E-05	2.61E-03	31.79	C	Y
CVCVP00357 - Check Valve 357 Fails	1.17E-03	3.83E-03	4.28	C	Y
CVMMRCPAFP - CVCS to RCP A Seals Fails	4.88E-05	1.50E-03	31.79	C	Y
CVMMRCPALP - CVCS From RCP A Seals Fails	5.35E-05	1.65E-03	31.79	C	Y
CVMMRCPBFP - CVCS to RCP B Seals Fails	4.88E-05	1.50E-03	31.79	C	Y
CVMMRCPBLP - CVCS From RCP B Seals Fails	5.35E-05	1.65E-03	31.79	C	Y
CVMMRCPIFP - CVCS Filter to Both RCPs Plugs	1.91E-05	5.80E-04	31.41	C	Y
CVPPJCVCOM - Common CVCS Piping Rupture	1.33E-05	4.04E-04	31.41	C	Y
DCBDFAUXDA - DCPDPAB01A (Aux Bldg A)	5.78E-07	3.19E-06	6.52	C	Y

Table 9-6
Component Importance Measures

Event Name/EIN	Prob	Fus Ves	Ach W	Type[1]	Rank[2]
DCBDFFUSEA - DCPDPCB02A (Main Fuse A)	5.78E-07	6.38E-05	111.33	C	Y
DCBDFFUSEB - DCPDPCB02B (Main Fuse B)	5.78E-07	6.70E-05	116.8	C	Y
DCBDFMAINA - DCPDPCB03A (Main DC A)	5.78E-07	6.38E-05	111.33	C	Y
DCBDFMAINB - DCPDPCB03B (Main DC B)	5.78E-07	6.70E-05	116.8	C	Y
DCCC0BATTD - Batteries Fail - CCF	1.19E-06	5.95E-04	500.05	C	Y
DCMM0BATTB - Battery B fails	4.74E-05	5.94E-05	2.25	C	Y
DCMMAB01AB - DC Ckt to MCC C Fails	3.56E-05	1.96E-04	6.52	C	Y
DCMMAB01AD - DC Ctk to Bus 14 (Normal) Fails	1.60E-04	8.09E-04	6.06	C	Y
DCMMAB01BB - DC Ctk to Bus 16 (Emerg) Fails	3.56E-05	1.96E-04	6.52	C	Y
DCMMAB01BD - DC Ctk to Bus 16 (Normal) Fails	1.60E-04	8.03E-04	6.02	C	Y
DCMMAUX00A - DC Ctk to Aux Bldg A Fails	3.56E-05	5.24E-04	15.74	C	Y
DCMMAUX00B - DC Ctk to Aux Bldg B Fails	3.56E-05	2.01E-04	6.65	C	Y
DCMMMAIN1A - DC Ctk to Main DC Dist A Fails	3.56E-05	4.43E-03	125.58	C	Y
DCMMMAIN1B - DC Ctk to Main DC Dist B Fails	3.56E-05	4.72E-03	133.61	C	Y
DCMMMCB01B - DC Ctk to MCB A Fails	3.56E-05	4.13E-05	2.16	C	Y
DGCCCV5919 - Chk Vlvs 5919/20 Fail to Open - CCF	1.36E-05	3.58E-04	27.29	C	Y
DGCCCV5920 - Chk Vlvs 5919/20 Fail to Close - CCF	3.58E-05	9.79E-04	28.32	C	Y
DGCCCV5955 - Chk Vlvs 5955/56 Fail to Open - CCF	1.36E-05	3.58E-04	27.29	C	Y
DGCCCV5956 - Chk Vlvs 5955/56 Fail to Close - CCF	3.58E-05	9.79E-04	28.32	C	Y
DGCCCV5961 - Chk Vlvs 5961/62 Fail to Open - CCF	1.36E-05	3.58E-04	27.29	C	Y
DGCCFDP048 - DG Fuel Oil Strainers Fail - CCF	6.38E-05	2.72E-04	5.27	C	Y
DGCCFDP090 - DG Fuel Oil Foot Vlv Strainers - CCF	6.38E-05	2.72E-04	5.27	C	Y
DGCCPMA2AB - DG Fuel Oil Pmps Fail to Run - CCF	1.18E-04	3.36E-03	29.46	C	Y
DGCCPMF2AB - DG Fuel Oil Pmps Fail to Strt - CCF	1.78E-04	8.20E-04	5.6	C	Y
ESCC000BIN - ESFAS Instruments Fail - CCF	2.25E-08	6.80E-06	301.8	C	Y
ESCC000REB - ESFAS Relays Fail - CCF	7.65E-06	5.48E-04	72.55	C	Y
ESCC0SIAUX - ESFAS Aux Relays Fail - CCF	7.65E-06	4.01E-04	53.33	C	Y
ESCCMASTER - ESFAS Master Relays Fail - CCF	7.65E-06	5.48E-04	72.55	C	Y
ESCCMSIAGA - ESFAS Agastats Fail - CCF	7.65E-06	1.54E-04	21.1	C	Y
HVCCDG0RUN - DG Ventilation Fails to Run - CCF	1.88E-05	5.03E-04	27.79	C	Y
HVCCDGOPEN - DG Dampers Fail to Open - CCF	1.99E-05	5.33E-04	27.79	C	Y
HVCCDGSTRT - DG Ventilation Fails to Start - CCF	6.91E-05	1.94E-03	29.01	C	Y
MSCCARVAIR - ARVs Fail to Open - CCF	1.39E-03	3.90E-03	3.8	C	Y
MSCCCSGBLO - AOVs 5735/38 Fail to Close - CCF	5.56E-04	1.28E-03	3.3	C	Y
RCCC00430P - PORVs 430/431C Fail to Close - CCF	1.07E-04	2.16E-04	3.01	C	Y
RHCC697A/B - Chk Vlvs 697A/B Fail - CCF	4.42E-05	1.16E-03	27.23	C	Y
RHCC710A/B - Chk Vlvs 710A/B Fail - CCF	7.44E-06	1.17E-03	157.34	C	Y
RHCC852A/B - MOVs 852A/B Fail to Open - CCF	1.82E-04	3.91E-03	22.54	C	Y
RHCC853A/B - Chk Vlvs 853A/B Fail to Open - CCF	4.42E-05	9.27E-04	21.96	C	Y
RHCCPUMPBA - RHR Pumps A/B Fail to Start - CCF	1.64E-05	2.59E-03	158.63	C	Y
RHCVP00854 - Chk Valve 854 Fails	1.24E-04	2.59E-03	21.87	C	Y
RHHXPAC02A - RHR HX A Fails	4.97E-05	2.16E-04	5.35	C	Y
RHHXPAC02B - RHR HX B Fails	4.97E-05	2.14E-04	5.31	C	Y
RHMMAC01AF - RHR Pump A Fails to Run	1.49E-04	7.28E-04	5.89	C	Y
RHMMAC01BF - RHR Pump B Fails to Run	1.49E-04	7.25E-04	5.87	C	Y
RHMVK00856 - MOV 856 Fails Closed	3.74E-05	7.64E-04	21.41	C	Y

Table 9-6
Component Importance Measures

Event Name/EIN	*Prob*	*Fus Ves*	*Ach W*	*Type*[1]	*Rank*[2]
RHMVR0850A - MOV 850A Fails Open	2.14E-05	4.31E-04	21.1	C	Y
RHMVR0850B - MOV 850B Fails Open	2.14E-05	4.31E-04	21.1	C	Y
RHMVR0857B - MOV 857B Fails Open	2.14E-05	4.31E-04	21.1	C	Y
RHPPJINJLN - RHR Pipe Break	6.64E-06	1.33E-04	21.1	C	Y
RHXVK00714 - Valve 714 Fails Closed	1.84E-04	9.27E-04	6.04	C	Y
RHXVK00716 - Valve 716 Fails Closed	1.84E-04	9.22E-04	6.02	C	Y
RHXVK0694A - Valve 694A Fails Closed	1.84E-04	9.11E-04	5.96	C	Y
RHXVK0694B - Valve 694B Fails Closed	1.84E-04	9.06E-04	5.93	C	Y
RHXVK0696A - Valve 696A Fails Closed	1.84E-04	9.11E-04	5.96	C	Y
RHXVK0696B - Valve 696B Fails Closed	1.84E-04	9.06E-04	5.93	C	Y
RRBIF850AX - Bistable 850A-X Spuriously Operates	3.40E-03	3.74E-03	2.1	C	Y
RRBIF850BX - Bistable 850B-X Spuriously Operates	3.40E-03	3.74E-03	2.1	C	Y
RRCC697A/B - Chk Valves 697A/B Fail - CCF	2.21E-05	4.69E-04	22.17	C	Y
RRCC710A/B - Chk Valve 710A/B Fail - CCF	7.52E-06	1.51E-04	21.1	C	Y
RRCCM0857M - MOVs 857A/B Fail - CCF	3.08E-04	1.60E-03	6.19	C	Y
RRCCPUMPAB - RHR Pumps Fail to Start - CCF	4.16E-04	4.53E-03	11.88	C	Y
RRCCPUMPBA - RHR Pumps Fail to Run - CCF	3.27E-05	3.06E-04	10.33	C	Y
RRCVP0697B - Chk Valve 697B Fails	3.69E-04	1.92E-03	6.2	C	Y
RRCVP0710A - Chk Valve 710A Fails	1.25E-04	6.01E-04	5.8	C	Y
RRCVP0710B - Chk Valve 710B Fails	1.25E-04	6.01E-04	5.79	C	Y
RRHXFAC02A - RHR HX A Fails	1.55E-04	7.45E-04	5.8	C	Y
RRHXFAC02B - RHR HX B Fails	1.55E-04	7.42E-04	5.78	C	Y
RRHXPAC02A - RHR HX A Plugs	4.97E-05	2.16E-04	5.35	C	Y
RRHXPAC02B - RHR HX B Plugs	4.97E-05	2.14E-04	5.31	C	Y
RRMVR0857B - MOV 857B Fails to Open	2.14E-05	1.96E-04	10.17	C	Y
RRPPJINJLN - RHR Pipe Break	1.33E-05	1.20E-04	10.07	C	Y
RRSMP00A/B - CNMT Sump Screen Plugged	2.20E-05	3.66E-04	17.65	C	Y
RRTKG0SEAL - RHR Pump Seals Fail	1.32E-04	2.47E-03	19.66	C	Y
RRXVK00714 - Valve 714 Fails Closed	1.86E-04	9.35E-04	6.03	C	Y
RRXVK00716 - Valve 716 Fails Closed	1.86E-04	9.30E-04	6	C	Y
RRXVK0694A - Valve 694A Fails Closed	1.86E-04	9.16E-04	5.93	C	Y
RRXVK0694B - Valve 694B Fails Closed	1.86E-04	9.11E-04	5.9	C	Y
RRXVK0696A - Valve 696A Fails Closed	1.86E-04	9.16E-04	5.93	C	Y
RRXVK0696B - Valve 696B Fails Closed	1.86E-04	9.11E-04	5.9	C	Y
RRXVK0709A - Valve 709A Fails Closed	1.86E-04	9.35E-04	6.03	C	Y
RRXVK0709B - Valve 709B Fails Closed	1.86E-04	9.30E-04	6	C	Y
RRXVK0851A - Valve 851A Fails Closed	5.47E-04	8.65E-04	2.58	C	Y
RRXVK0851B - Valve 851B Fails Closed	5.47E-04	8.91E-04	2.63	C	Y
SICCM0842X - Chk Valve 842A/B Fail - CCF	3.79E-05	1.36E-04	4.58	C	Y
SICCM0867X - Chk Valve 867A/B Fail - CCF	3.79E-05	9.14E-04	25.08	C	Y
SICCM0878X - Chk Valve 878G/J Fail - CCF	3.79E-05	7.78E-04	21.5	C	Y
SICCM0889X - Chk Valve 889A/B Fail - CCF	6.38E-06	1.20E-04	19.74	C	Y
SRCCM0867X - Chk Valve 867A/B Fail - CCF	3.79E-05	1.90E-04	6.02	C	Y
SRCCM0878X - Chk Valve 878G/J Fail - CCF	3.79E-05	1.90E-04	6.02	C	Y
SRCCM0889X - Chk Valve 889A/B Fail - CCF	6.38E-06	3.10E-05	5.86	C	Y
SRCCMPSI1X - SI Pumps Fail to Start - CCF	2.64E-04	1.37E-03	6.19	C	Y

Table 9-6
Component Importance Measures

Event Name/EIN	*Prob*	*Fus Ves*	*Ach W*	*Type*[1]	*Rank*[2]
SRCCMPSI1Y - SI Pumps Fail to Run - CCF	8.38E-04	4.50E-03	6.36	C	Y
SWCCCHECKN - Chk Valves 4601/4604 Fail - CCF	7.26E-06	1.71E-04	24.58	C	Y
SWCCEXPANJ - SW Expansion Joints Fail - CCF	6.84E-08	5.92E-05	852.58	C	Y
SWCCPSWCVS - Chk Valve 9627A/B Fail - CCF	8.26E-06	2.59E-05	4.13	C	Y
SWCCPSWMVB - MOVs9629A/B Fail Open - CCF	1.02E-03	3.69E-03	4.63	C	Y
SWCCPUMPSR - SW Pumps Fail to Run - CCF	7.56E-07	1.25E-03	1.59E+03	C	Y
SWCCPUMPSS - SW Pumps Fail to Start - CCF	2.20E-05	1.07E-03	49.81	C	Y
SWMM0SWPAR - SW Pump A Fails to Run	7.50E-05	3.53E-04	5.7	C	Y
SWMM0SWPDR - SW Pump D Fails to Run	7.50E-05	3.53E-04	5.7	C	Y
SWXVK4739A - Valve 4739A Fails Closed	2.21E-06	8.97E-06	5.05	C	Y
TLCCFEATWS - RTS Signal Failure	1.40E-06	6.97E-06	5.98	C	Y
TLCCFMATWS - RTS Mechanical Failure	1.80E-06	3.15E-03	1.68E+03	C	Y
UVLCDBX114 - Relay 27BX1/14 Driver Fails	1.49E-03	1.66E-03	2.11	C	Y
UVLCDBX116 - Relay 27BX1/16 Driver Fails	1.49E-03	1.91E-03	2.27	C	Y
UVLCDBX117 - Relay 27BX1/17 Driver Fails	1.49E-03	2.01E-03	2.35	C	Y
UVLCDBX118 - Relay 27BX1/18 Driver Fails	1.49E-03	1.88E-03	2.26	C	Y
UVPXF12V14 - Relay 27X1/14 Fails	5.38E-04	6.03E-04	2.12	C	Y
UVPXF12V16 - Relay 27X1/16 Fails	5.38E-04	6.70E-04	2.25	C	Y
UVPXF12V17 - Relay 27X1/17 Fails	5.38E-04	6.70E-04	2.25	C	Y
UVPXF12V18 - Relay 27X1/18 Fails	5.38E-04	6.03E-04	2.12	C	Y

Notes:

1. Identifies that the basic event is associated with a component.

2. XY - High Risk Significant
X - Medium Risk Significant Due to RAW Only
Y - Medium Risk Significant Due to F-V Only

Figure 9-1
Truncation Evaluation

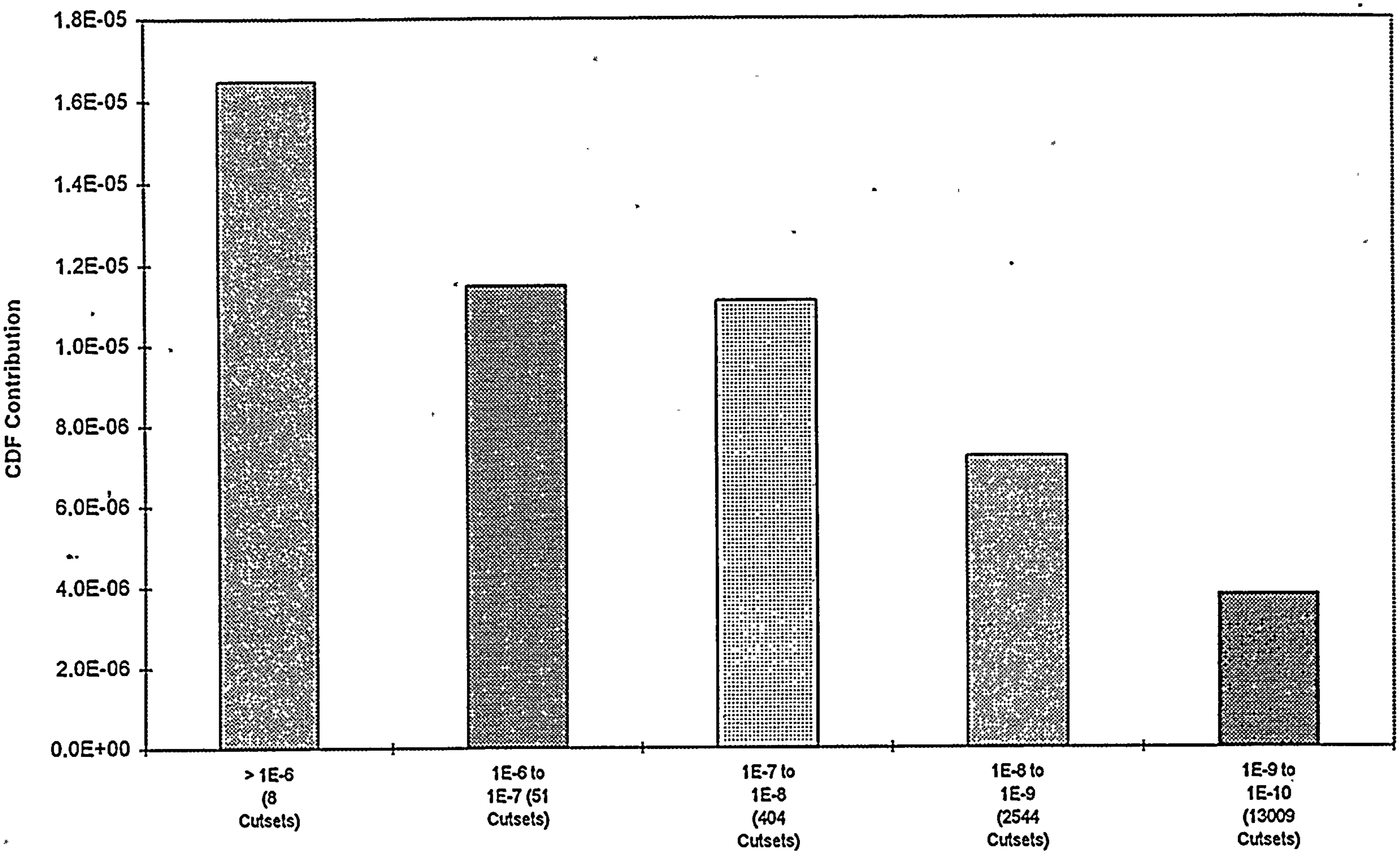


Figure 9-2
Initiating Events

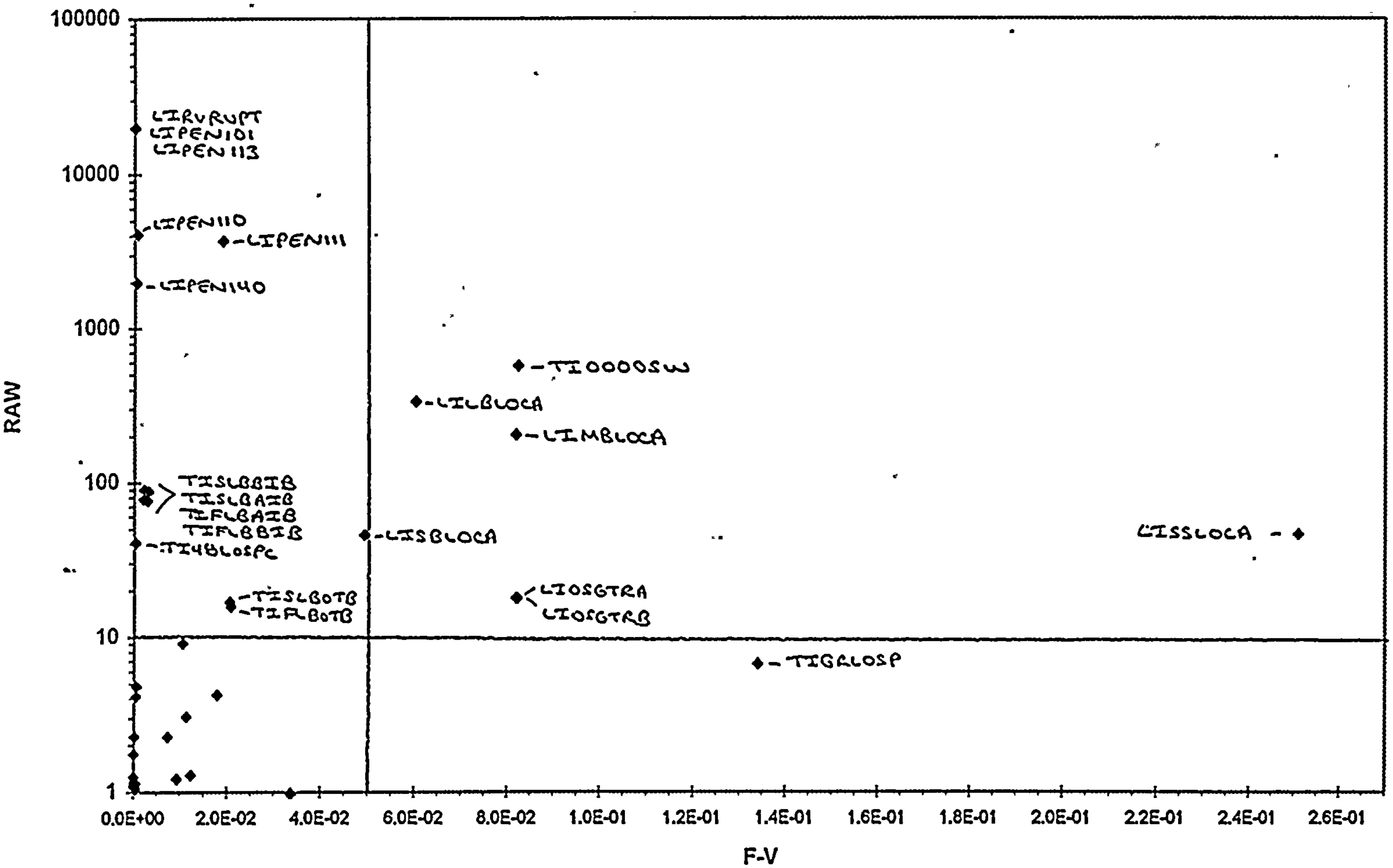


Figure 9-3
Human Error Events

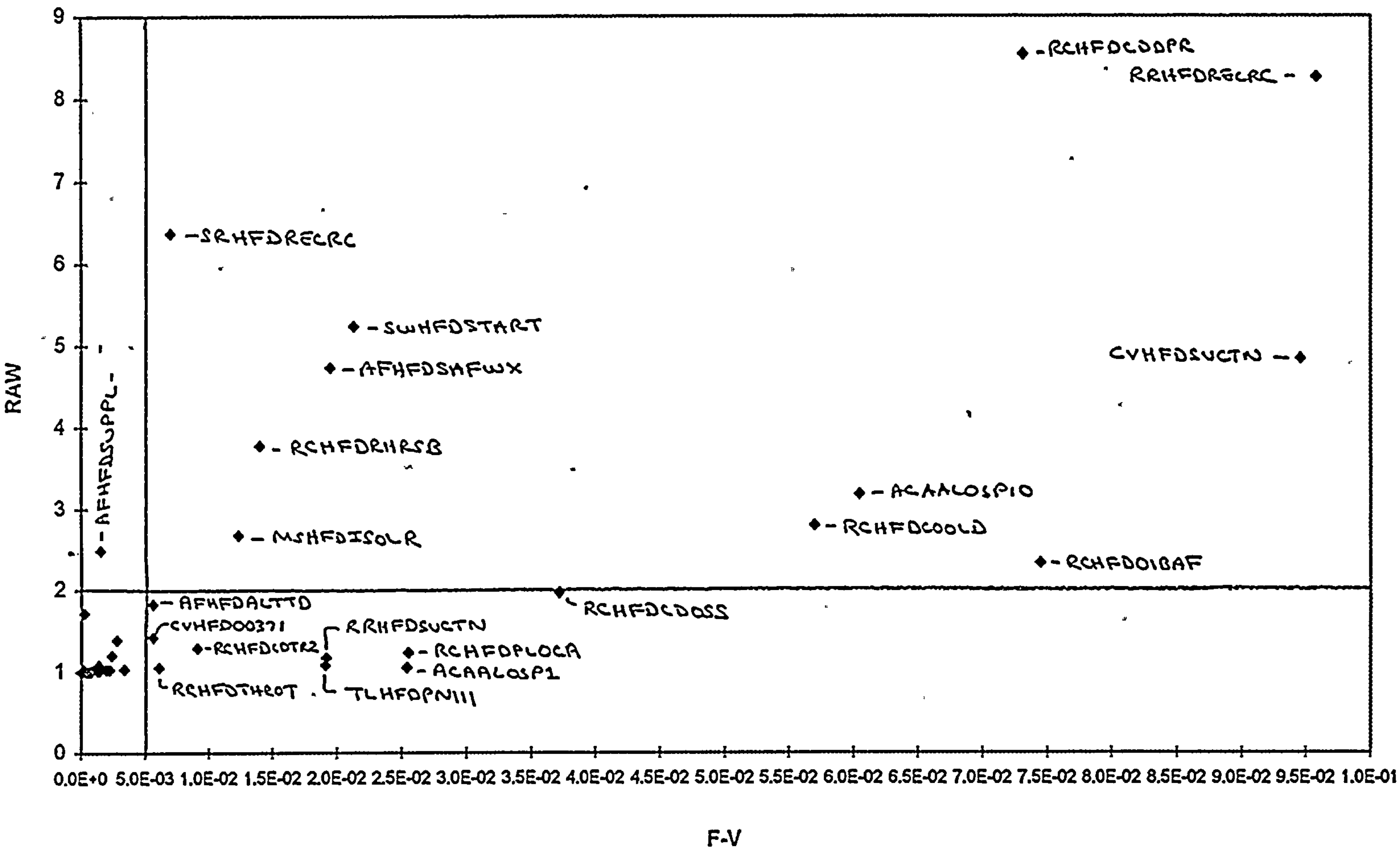


Figure 9-4
Test and Maintenance Events

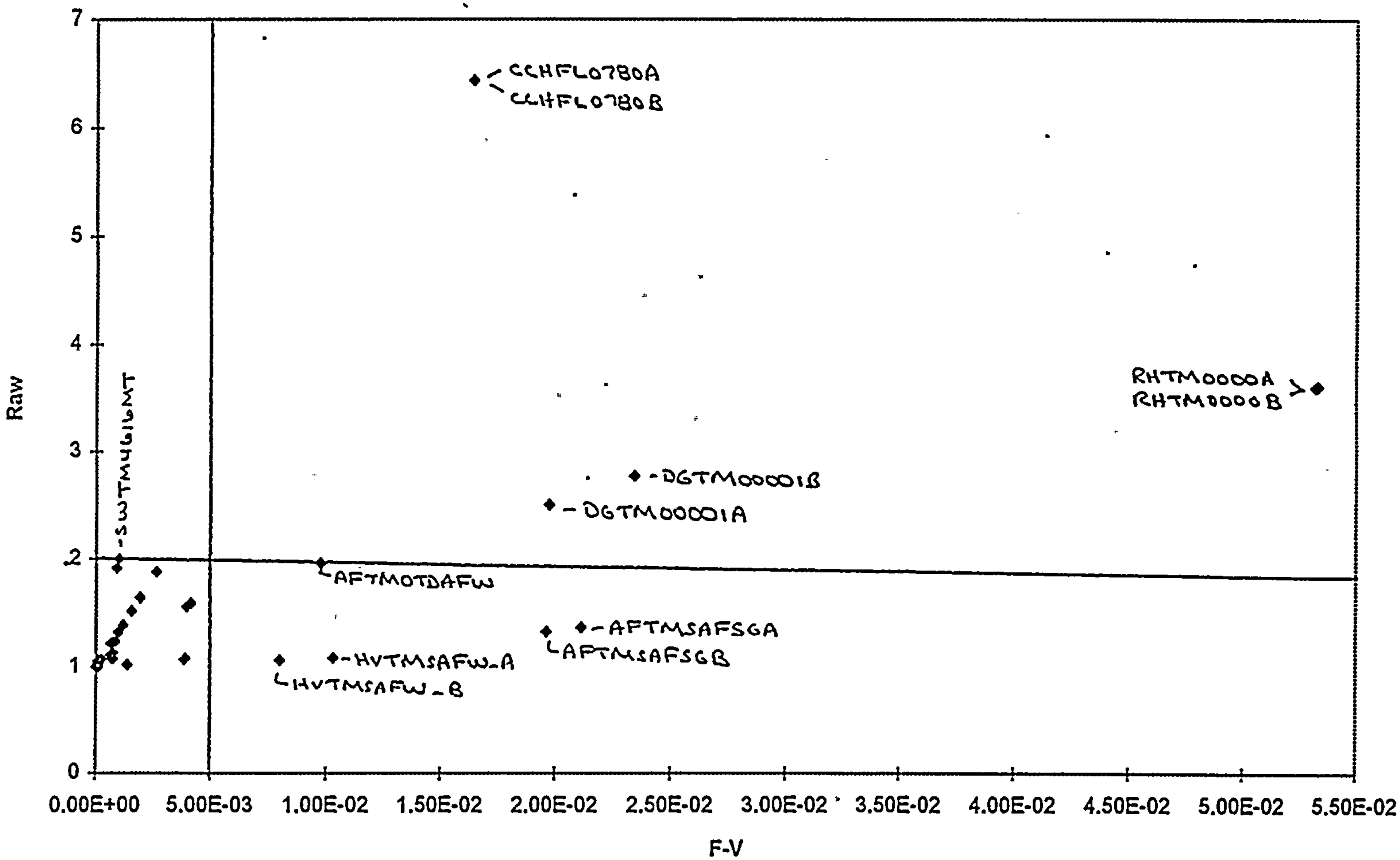


Figure 9-5
Systems

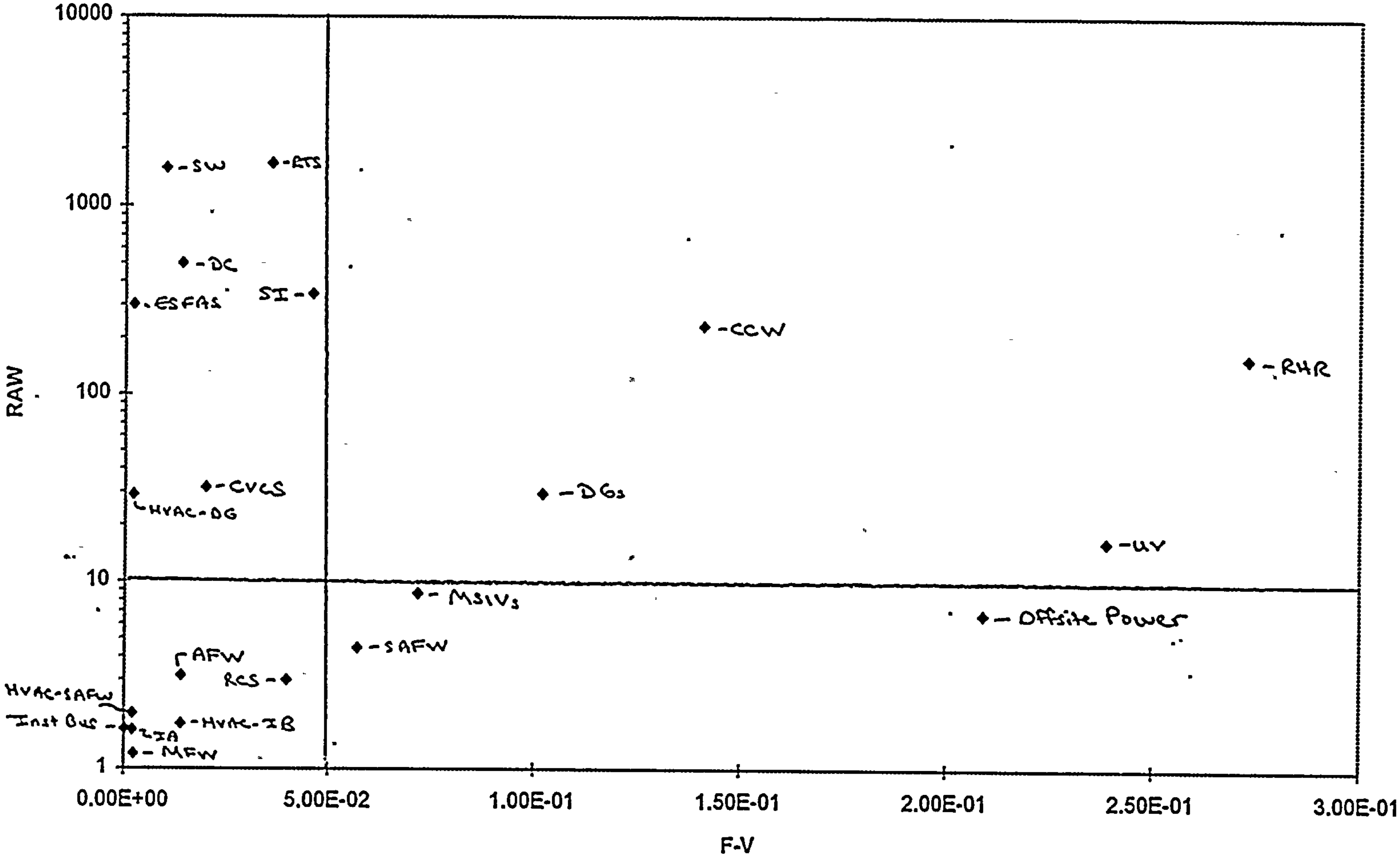
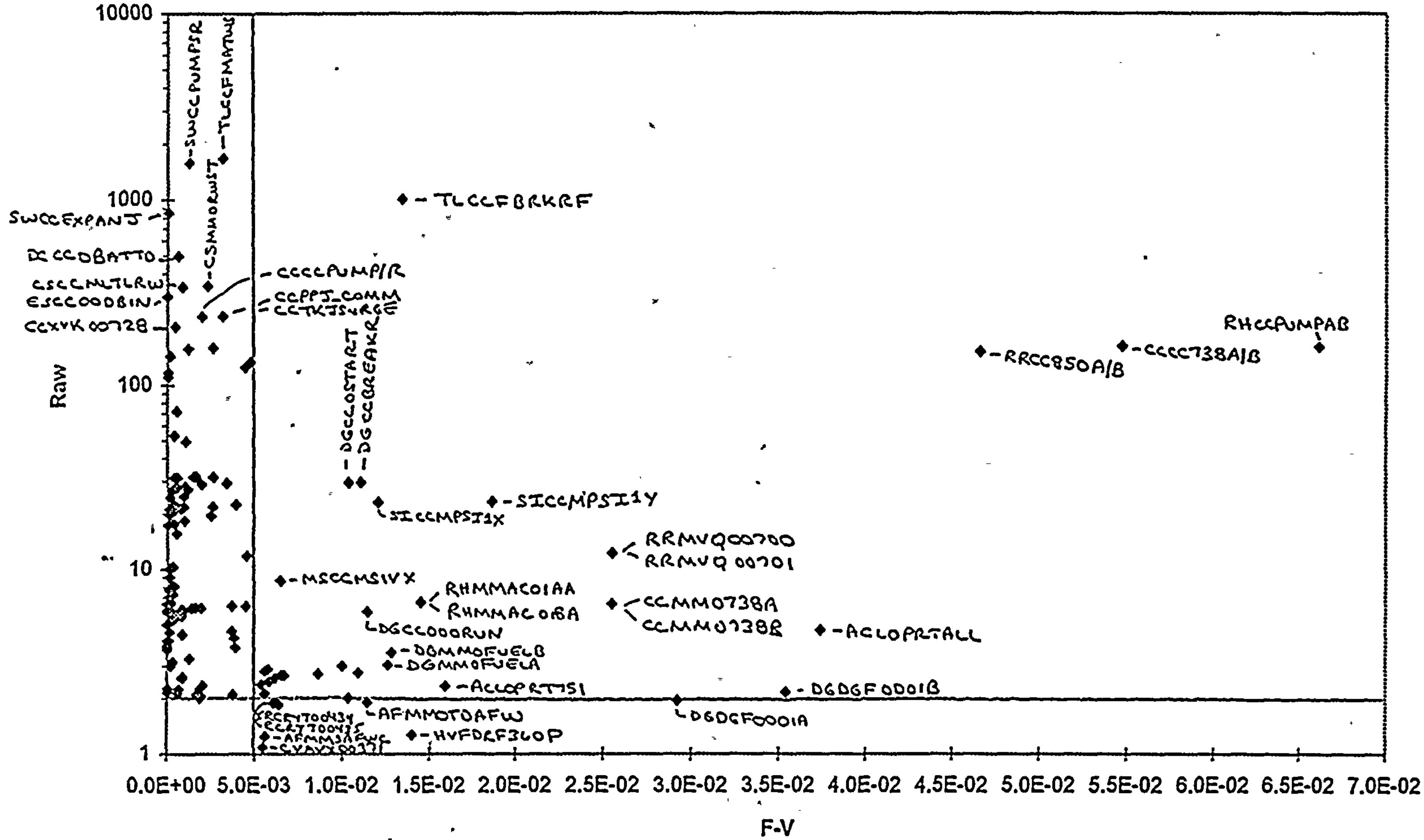


Figure 9-6
Components (Medium and High Risk Only)



10.0 LEVEL 2 ANALYSIS

[LATER]

11.0 SUMMARY AND CONCLUSIONS

Sections 9 and 10 discuss the results for the Level 1 and Level 2 PSA of Ginna Station, respectively. The major insights are summarized below along with a discussion of any vulnerabilities which were identified. For the purpose of the Ginna Station PSA, the vulnerability criteria which was used is as follows:

a. The total core damage frequency (CDF) must be less than 1.0E-04/ryr;

b. Are there any new or unusual means by which core damage or large early release from containment can occur than as identified in other relevant PSAs; and

c. Does any plant design, procedure, or training feature result in a contribution to core damage or large early release from containment greater than what is expected.

Following the summary of major insights is a discussion of the RG&E team and the independent review of the PSA which was performed.

11.1 Level 1 Summary

The final calculated CDF for Ginna Station is 5.021E-05/ryr. Figure 11-1 illustrates how each accident scenario contributes to this value while Figure 11-2 illustrates how each initiating event contributes to this value. As can be seen, LOCAs dominate the risk profile for Ginna Station (59%), followed by steam generator tube ruptures (SGTRs) (16%), station blackout (SBO) events (12%), and transients (9%). With respect to initiating events, the small-small LOCA (LISSLOCA) and grid related loss of offsite power (TIGRLOSP) contribute the most to the final CDF.

The LOCA contribution was primarily due to small-small LOCAs which were dominated by common cause failures related to the residual heat removal (RHR) pumps, containment sump B suction MOVs (850A and 850B), RHR injection valves to the reactor vessel (852A and 852B), and the component cooling water (CCW) MOVs to the RHR heat exchangers (738A and 738B). Operator actions also played a significant role in this accident (e.g., transfer to recirculation phase of an accident).

SGTRs were dominated by human actions related to terminating the break flow out the ruptured tube. This is a complex event which requires significant operator action in order to mitigate the consequences.

For SBO events, common cause failures of the diesel generators (DGs) to start and run, and failures of the associated 480 V safeguards bus breakers to open/close were significant with respect to causing the event. Steam generator (SG) cooling as provided by the turbine-driven auxiliary feedwater (TDAFW) pump was predominately lost by the failure to restore offsite power following depletion of the batteries and onset of core uncovery. Test and maintenance activities related to the TDAFW pump and the DGs were also important.

For transients, high energy line breaks (HELBs) in the Turbine Building along with loss of service water (SW) were the dominating initiators. The HELBs directly fail the main feedwater (MFW) and preferred Auxiliary Feedwater (AFW) systems such that only the Standby AFW (SAFW) system is available for SG cooling. Since this is a manually initiated system, operator errors with respect to successful implementation were important. It should be noted that leak-before-break considerations were not credited for any HELB frequencies or break locations as assumed in the Ginna Station licensing basis due to lack of available data. The loss of SW directly affects CCW, ventilation for SAFW, cooling to the DGs, and lube oil cooling to the preferred AFW pumps.

The primary systems of highest importance were related to core cooling (i.e., RHR and CCW for LOCAs). The support systems of high risk importance were those which support essentially all functions (undervoltage and DGs). It should be noted that while the Service Water (SW) system did not contribute as much to the final results as did CCW and the DGs due to its design (see Section 11.1.1 below), its failure would have the most impact on Ginna Station since it supports CCW, the DGs, AFW, and SAFW.

The most important operator actions were related to transferring to containment sump recirculation following a LOCA, terminating break flow following a SGTR, starting additional SW pumps when coincident undervoltage and safety injection signals do not exist, and initiating feed and bleed upon loss of all feedwater. The restoration of offsite power was also an important action during SBO sequences.

11.1.1 Unique and Important Safety Features

There are several unique and important safety features of Ginna Station which contributed to the calculated CDF. These include:

a. SAFW system;
b. Limited requirements for ventilation; and
c. Service Water (SW) system design.

The SAFW system is comprised of two 100% motor-driven pumps that are completely redundant to the preferred AFW system. This system was installed due to the potential common mode failures of the preferred AFW system (e.g., HELBs in the Intermediate Building). As such, there are four motor-driven AFW pumps and one TDAFW pump available at Ginna Station, any one of which can provide SG cooling. These pumps are in addition to the two motor-driven MFW pumps.

The Ginna Station layout typically does not include the use of compartments or rooms to protect various trains from one another. Instead, system components are generally grouped together on one floor level. While this makes the equipment susceptible to common mode failures (e.g., fire, HELB), it also eliminates the need for most equipment cooling due to the large air volumes and recirculation. The common mode failure issue is addressed by ensuring that multiple systems can be used to achieve the same function. The use of multiple systems for the same function also helps with respect to risk. This is demonstrated by the fact that the systems for which no redundancy is available identified are as being most risk significant (i.e., RHR and CCW post LOCA).

The SW system design is one of a large loop header that is supplied by four pumps. Two of the pumps are powered from each of the two electrical trains with in-series MOVs provided at various points to isolate non-critical loads on the loop header. As such, any SW pump can provide cooling water to any system load, no matter if the SW pump and system load are being supplied from the same electrical train or not. This design allows significant flexibility which reduced the SW contribution to the CDF. However, a failure of the SW system would have a significant impact on the final results as discussed in Section 11.1.

11.1.2 Changes Made to Facility

As a result of the insights obtained from the Ginna Station PSA, action reports were generated for all vulnerabilities listed in Section 11.1.3 below. This management tracking tool will ensure that all vulnerabilities are appropriately evaluated and provides a mechanism to initiate plant changes as required. It will also provide documentation of closure of these items. With respect to other issues, the following will be performed:

a. The Training Department will be provided with the listing of risk significant operator actions (see Section 9.3.2.2) to focus additional training and knowledge on these activities as necessary;

b. The Ginna Station Maintenance Rule Program will be updated as required with the new final results; and

c. Ginna Station personnel will be provided with an appropriate overview of the PSA results to support incorporation of risk insights into their daily activities.

There were no procedure changes or other plant modifications that were performed as a direct result of the Ginna Station PSA risk insights (nor credited in the PSA). However, it is noted that the PSA models identified a common mode DC electrical failure with respect to the pressurizer PORVs that was subsequently corrected during a recent outage (see LER 96-14). While the scenario was not risk significant due to the low probability of events which had to occur, it does demonstrate the capabilities of the PSA models.

11.1.3 Vulnerabilities

One of the primary objectives of Generic Letter 88-20 was to identify potential plant vulnerabilities. Using the definition of vulnerability in Section 11.0, the following items were identified by the Ginna Station PSA:

a. *Relays for SG Low-Low Level Actuation of AFW* - The three preferred AFW pumps each receive actuation signals based on SG low-low level. The relays for this signal (LLSGA and LLSGB) must energize in order to actuate; however, they are powered by non-safeguards Instrument Bus D which is unavailable upon loss of offsite power. Though other means exist to automatically start the pumps (e.g., opening of MFW pump breakers, SI signal) such that the total loss of automatic actuation is a very low probability event, this is a primary actuation signal. It is noted that SG cooling is not required to be initiated prior to 10 minutes for any current accident analysis scenario.

b. *ISLOCA Through Penetration 111* - A LOCA outside containment through Penetration 111 fails all RHR due to the low elevation of the RHR pump pits. There are two parallel sets of a single check valve and normally closed MOV associated with this penetration. An evaluation of the ISLOCA potential indicated that risk was dominated by inadvertent SI signals which opened the MOV (see Section 8.2.4.3). Though this event only contributes < 1% of the CDF, it is a potentially large offsite dose contributor. Therefore, this scenario must be evaluated in the Level 2 PSA.

c. *SAFW System Out-Of-Service Activities* - The SAFW system is specifically credited for providing SG cooling water in the event of a HELB in the Intermediate or Turbine Buildings. However, both trains of this system can be removed from service at the same time for extended periods of time (i.e., 7 days).

d. *Charging Pump Suction* - Upon loss of DC control power or instrument air, the letdown line will isolate removing the supply source to the volume control tank (VCT). In addition, the charging pump suction line will fail open to the VCT (and isolate other potential sources) such that an alternate source must be placed into service before the VCT empties. The need for charging is important with respect to ATWS events and preventing a reactor coolant pump seal LOCA.

e. *Intermediate Building Ventilation* - The preferred AFW pumps are all located in the basement of the Intermediate Building. There are two methods of accomplishing ventilation within the building: (1) natural circulation via Fire Door F36, and (2) forced ventilation by the Intermediate Building exhaust fans. However, only one train of the exhaust fans are DG backed such the three AFW pumps must rely on the passive fire door in the event the DG is inoperable.

11.2 Level 2 Summary

[LATER]

11.3 RG&E PSA Team

The original Ginna Station Level 2 PSA was completed in February 1994. This project was a joint effort between RG&E and Science Applications International Corporation (SAIC). The RG&E PSA team was comprised of three team members who, with various other station personnel, contributed over 20,000 man hours towards the completion of this project. Following this initial effort, RG&E elected to essentially re-perform the PSA utilizing two of the original team members along with two other newly trained personnel. This decision was based in part on the NRC questions and comments raised with respect to the original PSA effort [Ref. 74]. The new effort resulted in a complete review and update of the PSA including:

a. Re-evaluation of the initiating events that were considered along with a detailed review and documentation of the success criteria which was used;

b. Development of new event trees used for each accident sequence based on the review of the success criteria;

c. Verification of all system fault tree models to ensure they represented the current Ginna Station configuration;

d. Verification of all data used in the PSA (initiating event frequency, component failure rates, etc);

e. Re-evaluation of all human failure events and actions included within the models;

f. Re-quantification of the PSA models; and

g. [Level 2 Changes Later]

The new RG&E PSA team performed all of the above items except for the re-evaluation of the human failure events (item e) which was performed by an outside contractor (TENERA). However, the human reliability analysis was reviewed in depth by RG&E with the values generated for use in the Ginna Station PSA compared to other PSA studies [Refs. 3, 4, 5] as a further sanity check. Approximately 6,000 man-hours was spent by RG&E performing the new PSA study.

Finally, it should be noted that the Ginna Station PSA was comprised of a diverse skill base. First, the PSA project manager was a member of the original PSA study and has 10 years of related PSA experience. He was also the project manager for the recent conversion to Improved Standard Technical Specifications for Ginna Station such that he brought both a strong PSA background and an extensive accident analysis/systems knowledge to the team. The second member of the PSA team also participated in the original PSA study and has 6 years of related PSA experience. The third and fourth team members were recently trained in PSA techniques (e.g., 1 year of experience); however, they brought strong computer skills and plant knowledge to the PSA team (e.g., former I&C technician and quality assurance engineer).

11.4 Independent Review

The independent review of the Ginna Station PSA was comprised of two parts: (1) an internal review by RG&E personnel including operations, engineering, and management; and (2) an external review by a contractor (TENERA). The purpose of the first review was to ensure that the assumptions and results of the PSA were consistent with the Ginna Station design and operation practices. The review team members included:

Review Team Member		*SRO?*	*Yrs Experience*
a.	Manager, Nuclear Safety & Licensing	No	23
b.	Head Control Operator	Yes	15
c.	Licensed Operator Trainer	Yes	15

In addition, a detailed overview of the PSA inputs, techniques, and results were presented to Ginna Station PORC members.

The second review was focused on the PSA techniques which were utilized to ensure they were consistent with industry standards. Since TENERA had performed the PSA for a sister plant of Ginna Station (i.e., Prairie Island), the external review also focused on the results so that all significant differences were thoroughly examined.

All comments from both reviews were incorporated as necessary into the PSA; however, all comments were closed prior to release of this final report. As such, this report is considered to accurately reflect the risk profile of Ginna Station.

Figure 11-1
Ginna Station PSA Results

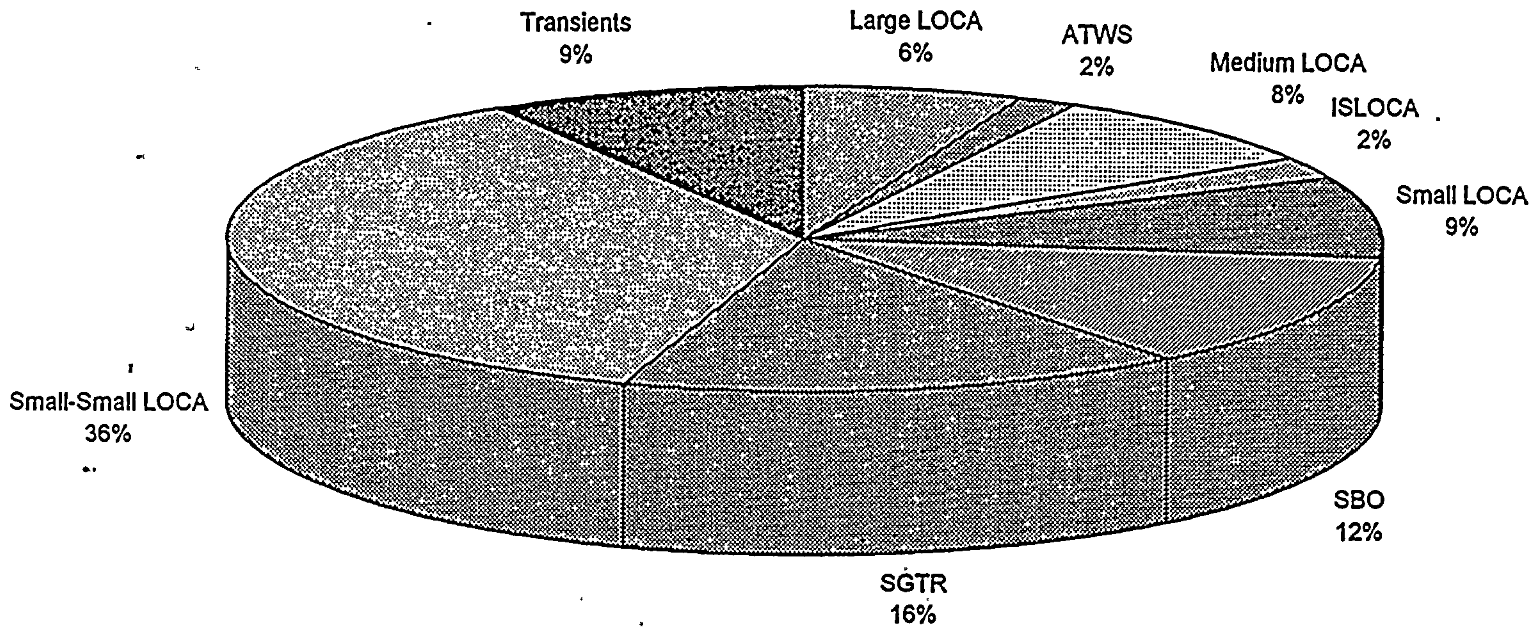
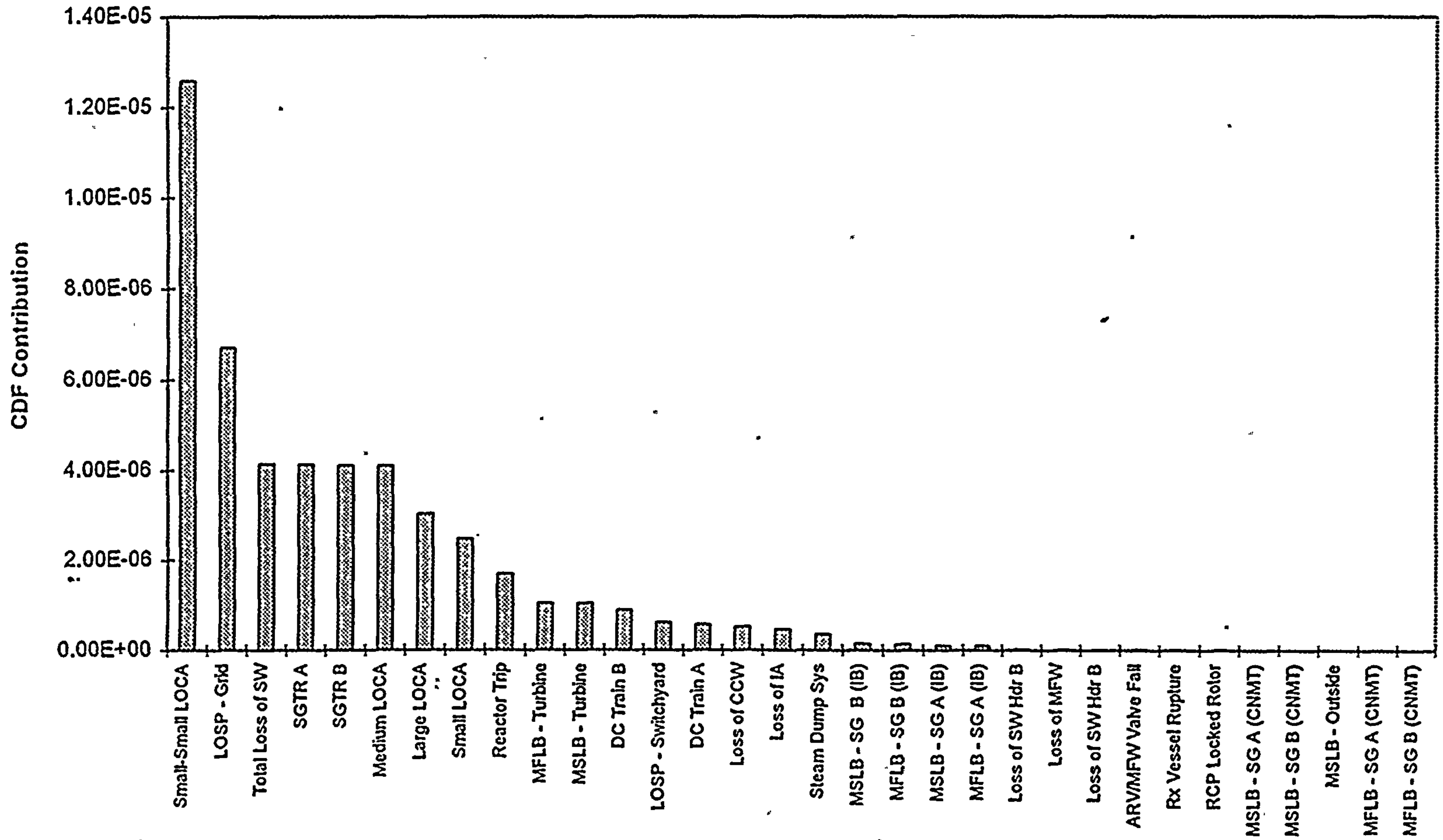


Figure 11-2
Initiating Event Ranking



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APPENDIX A

FINAL CUTSETS

A.0 FINAL CUTSETS

This appendix contains the top 50 cutsets for each of the eight sequences which were evaluated. The appendix is organized as follows:

a. ATWS
b. Large Loss-of-Coolant-Accident (LOCA)
c. Medium LOCA
d. Small LOCA
e. Small-Small LOCA
f. Steam Generator Tube Rupture (SGTR)
g. Transients
h. Station Blackout (SBO)

Only the top 50 cutsets are provided since the remaining cutsets are generally only a slightly different version of the same scenario (e.g., pump A failing versus pump B).

In addition to the cutsets, a listing of the core damage frequency with respect to each intiating event is provided (located prior to each cutset report).

Initiator Summary Report
ATWS = 8.30E-07 (Probability)

Name	Prob	%	Description
TIIALOSS	2.86E-07	34.5%	Loss of Instrument Air
TIGRLOSP	1.74E-07	21.0%	Loss of Offsite Power - Grid
TI000DCB	7.51E-08	9.1%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
LIOSGTRA	6.93E-08	8.4%	Steam Generator Tube Rupture in SG A
LIOSGTRB	6.93E-08	8.4%	Steam Generator Tube Rupture in SG B
TIOSLBSD	3.80E-08	4.6%	Steamline Break Through Steam Dump System
LISSLOCA	3.61E-08	4.3%	Small-Small LOCA (0-1")
TISLBSVA	1.83E-08	2.2%	Inadvertent Safety / FW Valve Operation for Both SGs
TIRXTRIP	1.75E-08	2.1%	Reactor Trip
TISLB0TB	9.18E-09	1.1%	Streamline Break in Turbine Building
TIFLB0TB	8.94E-09	1.1%	Feedlien Break in Turbine Building
TIFWLOSS	8.34E-09	1.0%	Loss of Main Feedwater
LISBLOCA	7.02E-09	0.8%	Small LOCA (1-1.5")
TISWLOSP	5.63E-09	0.7%	Loss of Offsite Power - Switchyard
LIMBLOCA	2.31E-09	0.3%	Medium LOCA (1.5" - 5.5")
TI0000SW	1.72E-09	0.2%	Total Loss of Service Water
TISLBBIB	4.65E-10	0.1%	Steamline Break in Line for SG B Inside Intermediate
TISLBACT	3.09E-10	0.0%	Steamline Break in Line for SG A Inside Containment
TISLBAIB	3.09E-10	0.0%	Steamline Break in Line for SG A Inside Intermediate
TISLBBCT	3.09E-10	0.0%	Steamline Break in Line for SG B Inside Containment
TIFLBBIB	3.07E-10	0.0%	Feedline Break in Line for SG B Inside Intermediate
TISLBSGB	2.84E-10	0.0%	Exterior Steam Line Break for SG B
TI000DCA	2.16E-10	0.0%	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TIRCPROT	1.80E-10	0.0%	Reactor Coolant Pump Locked Rotor Event
TIFLBAIB	1.30E-10	0.0%	Feedline Break in Line for SG A Inside Intermediate
TIFLBBCT	1.30E-10	0.0%	Feedline Break in Line for SG B Inside Containment
TIFLBACT	1.30E-10	0.0%	Feedline Break in Line for SG A Inside Containment
Total =	8.30E-07		

Report Summary:
Filename: C:\CAFTA-W\QUANT\ATWS.CUT
Print date: 1/13/97 11:05 AM
Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	2.10E-07
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
2	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.15E-07
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
3	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	3.03E-08
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
4	TIOSLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	2.92E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
5	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	2.80E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
6	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.78E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
7	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	2.45E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
8	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	2.45E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
9	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.66E-08
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
10	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.59E-08
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
11	TISLBSVA	Inadvertent Safety / FW Valve Operation for Both SGs		2.82E-03	2.82E-03	1.43E-08
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
12	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.39E-08
	TL00019DAY	Less Than or Equal to 19 Days into Cycle		1.92E-01	1.92E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
13	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.38E-08
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
14	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.38E-08
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
15	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.20E-08
	TL00019DAY	Less Than or Equal to 19 Days into Cycle		1.92E-01	1.92E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
16	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.20E-08
	TL00019DAY	Less Than or Equal to 19 Days into Cycle		1.92E-01	1.92E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
17	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.11E-08
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
18	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	1.02E-08
	TL00193DAY	Less Than or Equal to 193 Days into Cycle		1.37E-01	1.37E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
19	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	9.26E-09
	TL00139DAY	Less Than or Equal to 139 Days into Cycle		1.24E-01	1.24E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
20	TIFLBOTB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	7.08E-09
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
21	TISLBOTB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	6.52E-09
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
22	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	5.62E-09
	TL00193DAY	Less Than or Equal to 193 Days into Cycle		1.37E-01	1.37E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
23	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	5.56E-09
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
24	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	5.39E-09
	RP100	ATWS Mitigation System Actuation Circuitry (AMSAC) Fails		1.00E-02	1.00E-02	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
25	TIFWLOSS	Loss of Main Feedwater		7.20E-03	7.20E-03	5.25E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
26	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	5.09E-09
	TL00139DAY	Less Than or Equal to 139 Days into Cycle		1.24E-01	1.24E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
27	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	4.76E-09
	TL00111DAY	Time period RCS will always overpressurize		4.78E-01	4.78E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
28	TIOSLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	4.21E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
29	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	4.13E-09
	TL00111DAY	Time period RCS will always overpressurize		4.78E-01	4.78E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
30	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	4.13E-09
	TL00111DAY	Time period RCS will always overpressurize		4.78E-01	4.78E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
31	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	4.04E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
32	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.01E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
33	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	3.53E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
34	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	3.53E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
35	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	3.06E-09
	AFTMTDAFWB	TDAFW Pump Train injection line to S/G B out-of-service for maint		4.90E-02	4.90E-02	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
36	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	3.06E-09
	AFTMTDAFWA	TDAFW Pump Train injection line to S/G A out-of-service for maint		4.90E-02	4.90E-02	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	-MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
37	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.96E-09
	RP100	ATWS Mitigation System Actuation Circuitry (AMSAC) Fails		1.00E-02	1.00E-02	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
38	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	2.32E-09
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
39	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	2.29E-09
	-IAAAIAC02A	INSTRUMENT AIR COMPRESSOR A (CIA02A) RUNNING		2.26E-02	2.26E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	IATMCOMPRA	CIA02A COMPRESSOR IN MAINTENANCE		8.00E-02	8.00E-02	
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
40	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	2.18E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
	RCHFD00MRI	OPERATORS FAIL TO MANUALLY INSERT RODS		1.00E-02	1.00E-02	
41	TISLBSVA	Inadvertent Safety / FW Valve Operation for Both SGs		2.82E-03	2.82E-03	2.06E-09
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
42	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.02E-09
	TL00076DAY	Less Than or Equal to 76 Days into Cycle		3.89E-01	3.89E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
43	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.97E-09
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	2.40E+01	3.00E-02
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
44	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.97E-09
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	2.40E+01	3.00E-02
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
45	TIFWLOSS	Loss of Main Feedwater		7.20E-03	7.20E-03	1.78E-09
	TL00193DAY	Less Than or Equal to 193 Days into Cycle		1.37E-01	1.37E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
46	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.71E-09
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	2.40E+01	3.00E-02
	TL00019DAY	Less Than or Equal to 19 Days into Cycle		1.92E-01	1.92E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
47	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.71E-09
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	2.40E+01	3.00E-02
	TL00019DAY	Less Than or Equal to 19 Days into Cycle		1.92E-01	1.92E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
48	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.61E-09
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	TL00082DAY	Time period RCS will always overpressurize		4.05E-01	4.05E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	
49	TIIALOSS	Loss of Instrument Air		4.15E-02	4.15E-02	1.51E-09
	AFMMOTDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	TL00083DAY	Less Than or Equal to 83 Days into Cycle		2.21E-01	2.21E-01	
	TLCCFBRKRF	Electrical Scram Failure Probability (Breakers Only)		1.30E-05	1.30E-05	
50	TIOSLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	1.43E-09
	TL00193DAY	Less Than or Equal to 193 Days into Cycle		1.37E-01	1.37E-01	
	TLCCFMATWS	Mechanical Scram Failure Probability		1.80E-06	1.80E-06	

Report Summary:
Filename: C:\CAFTA-W\QUANT\ATWS.CUT
Print date: 1/15/97 2:44 PM
Not sorted
Printed the first 50

Initiator Summary Report

LLOCA = 3.03E-06 (Probability)

Name	Prob	%	Description
LILBLOCA	3.03E-06	100.0%	Large LOCA
Total =	3.03E-06		

Report Summary:

Filename: C:\CAFTA-W\QUANT\TL_A.CUT

Print date: 1/13/97 10:54 AM

Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.34E-06
	RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION		1.30E-02	1.30E-02	
2	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.35E-07
	CVAVX00371	AOV 371 FAILS TO CLOSE		2.60E-05	5.76E-02	
	CVHFD00371	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE)		1.30E-02	1.30E-02	
3	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	7.41E-08
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
4	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	6.07E-08
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
5	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	5.54E-08
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
6	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.27E-08
	RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <COMMON CAUSE EVENT>		1.82E-04	1.82E-04	
7	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.23E-08
	RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]		1.12E-07	1.24E-04	
8	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.67E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
9	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.67E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
10	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.08E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
11	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.08E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
12	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.08E-08
	RHHFL0000A	LATENT HUMAN FAILURE OF RHR TRAIN A		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
13	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.08E-08
	RHHFL0000B	LATENT HUMAN FAILURE OF RHR TRAIN B		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
14	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	9.21E-09
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
15	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	9.21E-09
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
16	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	7.96E-09
	RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <COMMON CAUSE EVENT>		4.42E-05	4.42E-05	
17	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	7.96E-09
	RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <COMMON CAUSE EVENT>		4.42E-05	4.42E-05	
18	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	6.83E-09
	SICCM0842X	COMMON CAUSE FAILURE TO OPEN OF CHECK VALVES 842A & 842B		3.79E-05	3.79E-05	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
19	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	6.83E-09
	SICCM0867X	COMMON CAUSE FAILURE TO OPEN OF CHECK VALVES 867A & 867B		3.79E-05	3.79E-05	
20	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	6.74E-09
	RHMVK00856	MOTOR-OPERATED VALVE 856 TRANSFERS CLOSED [INJECTION]		1.04E-06	3.74E-05	
21	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	4.22E-09
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
22	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	4.14E-09
	RHMVK0704A	MOV 704A TRANSFERS CLOSED (INJECTION)		1.04E-06	1.15E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
23	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	4.14E-09
	RHMVK0704B	MOV 704B TRANSFERS CLOSED (INJECTION)		1.04E-06	1.15E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
24	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.99E-09
	RRCC697A/B	CHECK VALVES 697A/B FAIL TO OPEN <COMMON CAUSE EVENT>		2.21E-05	2.21E-05	
25	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.96E-09
	RRSMP00A/B	CONTAINMENT SUMP SCREENS PLUGGED [RECIRC]		2.20E-05	2.20E-05	
26	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.93E-09
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RHXVK00715	MANUAL VALVE 715 TRANSFERS CLOSED [INJECTION]		1.66E-07	1.09E-03	
27	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.93E-09
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RHXVK00717	MANUAL VALVE 717 TRANSFERS CLOSED [INJECTION]		1.66E-07	1.09E-03	
28	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.89E-09
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
29	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.86E-09
	RHMVR0850A	MOTOR-OP VALVE 850A TRANSFERS OPEN [INJECTION]		5.95E-07	2.14E-05	
30	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.86E-09
	RHMVR0850B	MOTOR-OP VALVE 850B TRANSFERS OPEN [INJECTION]		5.95E-07	2.14E-05	
31	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.86E-09
	RHMVR0857B	MOTOR-OPERATED VALVE 857B TRANSFERS OPEN - LOSS OF FLOW		5.95E-07	2.14E-05	
32	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.43E-09
	SIPPJLBL0A	CONDITIONAL PROBABILITY OF LBLOCA IN THE "A" SI LINE		1.89E-02	1.89E-02	
	SIXVK00841	MOTOR OPERATED VALVE 841 TRANSFERS CLOSED		1.53E-07	1.01E-03	
33	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	3.43E-09
	SIPPJLBL0B	CONDITIONAL PROBABILITY OF LBLOCA IN THE "B" SI LINE		1.89E-02	1.89E-02	
	SIXVK00865	MOTOR OPERATED VALVE 865 TRANSFERS CLOSED		1.53E-07	1.01E-03	
34	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.99E-09
	IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE		1.94E-07	1.28E-03	
	CVHFD00371	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE)		1.30E-02	1.30E-02	
35	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.95E-09
	RHCCPUMPBA	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO RUN		1.64E-05	1.64E-05	
36	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.65E-09
	RHCVP0697A	CHECK VALVE 697A FAILS TO OPEN [INJECTION]		1.12E-07	7.37E-04	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
37	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.65E-09
	RHCVP0697B	CHECK VALVE 697B FAILS TO OPEN [INJECTION]		1.12E-07	7.37E-04	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
38	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.51E-09
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
39	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.51E-09
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
40	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.39E-09
	CCPPJ_COMM	PIPE RUPTURE IN THE COMMON CCW PIPING		5.53E-07	1.33E-05	
41	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.39E-09
	CCTKJSURGE	CCW SURGE TANK RUPTURE		5.53E-07	1.33E-05	
42	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.38E-09
	RRTKG0SEAL	RHR PUMP SEAL FAILURE FAILS BOTH PUMPS (LONG TERM)		5.52E-06	1.32E-04	
	RRHFDSEALX	FAILURE OF OPERATORS TO STOP RHR PUMP IF SEAL FAILS		1.00E-01	1.00E-01	
43	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.15E-09
	SICVP0842A	CHECK VALVE 842A FAILS TO OPEN		9.60E-08	6.32E-04	
	SIPPJLBL0A	CONDITIONAL PROBABILITY OF LBLOCA IN THE "A" SI LINE		1.89E-02	1.89E-02	
44	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.15E-09
	SICVP0842B	CHECK VALVE 842B FAILS TO OPEN		9.60E-08	6.32E-04	
	SIPPJLBL0B	CONDITIONAL PROBABILITY OF LBLOCA IN THE "B" SI LINE		1.89E-02	1.89E-02	
45	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.15E-09
	SICVP0867A	CHECK VALVE 867A FAILS TO OPEN		9.60E-08	6.32E-04	
	SIPPJLBL0A	CONDITIONAL PROBABILITY OF LBLOCA IN THE "A" SI LINE		1.89E-02	1.89E-02	
46	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.15E-09
	SICVP0867B	CHECK VALVE 867B FAILS TO OPEN		9.60E-08	6.32E-04	
	SIPPJLBL0B	CONDITIONAL PROBABILITY OF LBLOCA IN THE "B" SI LINE		1.89E-02	1.89E-02	
47	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.14E-09
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
48	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	2.14E-09
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
49	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.97E-09
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RRXVK00715	MANUAL VALVE 715 TRANSFERS CLOSED [RECIRC]		1.66E-07	5.47E-04	
50	LILBLOCA	Large LOCA		1.80E-04	1.80E-04	1.97E-09
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RRXVK00717	MANUAL VALVE 717 TRANSFERS CLOSED [RECIRC]		1.66E-07	5.47E-04	

Report Summary:

Filename: C:\CAFTA-W\QUANT\TL_A.CUT
Print date: 1/15/97 2:47 PM
Not sorted
Printed the first 50

Initiator Summary Report

MLOCA = 4.12E-06 (Probability)

Name	Prob	%	Description
LIMBLOCA	4.11E-06	99.8%	Medium LOCA (1.5"-5.5")
TIRXTRIP	4.74E-09	0.1%	Reactor Trip
TIIALOSS	5.14E-10	0.0%	Loss of Instrument Air
TISWLOSP	5.01E-10	0.0%	Loss of Offsite Power - Switchyard
TIGRLOSP	4.08E-10	0.0%	Loss of Offsite Power - Grid
TI0000SW	3.35E-10	0.0%	Total Loss of Service Water
TI000DCA	2.59E-10	0.0%	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TI000DCB	2.59E-10	0.0%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
Total =	4.12E-06		

Report Summary:

Filename: C:\CAFTA-W\QUANT\MLOCA.CUT

Print date: 1/13/97 10:41 AM

Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.12E-06
	RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION		1.30E-02	1.30E-02	
	MLOCRECIRC	MULTIPLIER FOR MEDIUM LOCA RECIRCULATION FAILURE RATE		4.08E-01	4.08E-01	
2	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	3.35E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO CCF		8.38E-04	8.38E-04	
3	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.18E-07
	SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO CCF		5.46E-04	5.46E-04	
4	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.65E-07
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
5	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.35E-07
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
6	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.23E-07
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
7	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.22E-07
	CVAVX00371	AOV 371 FAILS TO CLOSE		2.60E-05	5.76E-02	
	CVHFD00371	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE)		1.30E-02	1.30E-02	
	MLOCRECIRC	MULTIPLIER FOR MEDIUM LOCA RECIRCULATION FAILURE RATE		4.08E-01	4.08E-01	
8	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	7.26E-08
	RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <COMMON CAUSE EVENT>		1.82E-04	1.82E-04	
9	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.96E-08
	RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]		1.12E-07	1.24E-04	
10	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	3.72E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
11	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	3.72E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
12	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.40E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
13	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.40E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
14	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.40E-08
	RHHFL0000A	LATENT HUMAN FAILURE OF RHR TRAIN A		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
15	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.40E-08
	RHHFL0000B	LATENT HUMAN FAILURE OF RHR TRAIN B		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
16	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.05E-08
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
17	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	2.05E-08
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
18	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.77E-08
	RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <COMMON CAUSE EVENT>		4.42E-05	4.42E-05	
19	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.77E-08
	RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <COMMON CAUSE EVENT>		4.42E-05	4.42E-05	
20	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.52E-08
	SICCM0867X	COMMON CAUSE FAILURE TO OPEN OF CHECK VALVES 867A & 867B		3.79E-05	3.79E-05	
21	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.52E-08
	SICCM0878X	CHECK VALVES 878G AND 878J FAIL TO OPEN DUE TO COMMON CAUSE		3.79E-05	3.79E-05	
22	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	1.50E-08
	RHMVK00856	MOTOR-OPERATED VALVE 856 TRANSFERS CLOSED [INJECTION]		1.04E-06	3.74E-05	
23	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	9.37E-09
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
24	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	9.21E-09
	RHMVK0704A	MOV 704A TRANSFERS CLOSED (INJECTION)		1.04E-06	1.15E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
25	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	9.21E-09
	RHMVK0704B	MOV 704B TRANSFERS CLOSED (INJECTION)		1.04E-06	1.15E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
26	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.86E-09
	RRCC697A/B	CHECK VALVES 697A/B FAIL TO OPEN <COMMON CAUSE EVENT>		2.21E-05	2.21E-05	
27	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.80E-09
	RRSMP00A/B	CONTAINMENT SUMP SCREENS PLUGGED [RECIRC]		2.20E-05	2.20E-05	
28	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.74E-09
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RHXVK00715	MANUAL VALVE 715 TRANSFERS CLOSED [INJECTION]		1.66E-07	1.09E-03	
29	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.74E-09
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RHXVK00717	MANUAL VALVE 717 TRANSFERS CLOSED [INJECTION]		1.66E-07	1.09E-03	
30	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.65E-09
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
31	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.57E-09
	RHMVR0850A	MOTOR-OP VALVE 850A TRANSFERS OPEN [INJECTION]		5.95E-07	2.14E-05	
32	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.57E-09
	RHMVR0850B	MOTOR-OP VALVE 850B TRANSFERS OPEN [INJECTION]		5.95E-07	2.14E-05	
33	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.57E-09
	RHMVR0857B	MOTOR-OPERATED VALVE 857B TRANSFERS OPEN - LOSS OF FLOW		5.95E-07	2.14E-05	
34	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	8.11E-09
	RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE		5.20E-03	5.20E-03	
	RRPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE		3.90E-03	3.90E-03	
35	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	6.55E-09
	RHCCPUMPBA	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO RUN		1.64E-05	1.64E-05	
36	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.90E-09
	RHCVP0697A	CHECK VALVE 697A FAILS TO OPEN [INJECTION]		1.12E-07	7.37E-04	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
37	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.90E-09
	RHCVP0697B	CHECK VALVE 697B FAILS TO OPEN [INJECTION]		1.12E-07	7.37E-04	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
38	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.58E-09
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
39	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.58E-09
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
40	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.31E-09
	CCPPJ_COMM	PIPE RUPTURE IN THE COMMON CCW PIPING		5.53E-07	1.33E-05	
41	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.31E-09
	CCTKJSURGE	CCW SURGE TANK RUPTURE		5.53E-07	1.33E-05	
42	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	5.30E-09
	RRTKG0SEAL	RHR PUMP SEAL FAILURE FAILS BOTH PUMPS (LONG TERM)		5.52E-06	1.32E-04	
	RRHFDSEALX	FAILURE OF OPERATORS TO STOP RHR PUMP IF SEAL FAILS		1.00E-01	1.00E-01	
43	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.76E-09
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
44	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.76E-09
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
45	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.72E-09
	RHMVQ0852B	MOV 852B FAILS TO OPEN		2.27E-03	2.27E-03	
	RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE		5.20E-03	5.20E-03	
46	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.41E-09
	SIPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN THE "B" SI LINE		1.93E-03	1.93E-03	
	SITMTRAINB	SI TRAIN B DISCHARGE VALVES UNAVAILABLE DUE TO TEST OR MAINTENANCE		5.71E-03	5.71E-03	
47	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.41E-09
	CSMM896A/B	MOV 896A OR 896B TRANSFERS CLOSED (FAILS CS AND SI FROM RWST)		1.10E-05	1.10E-05	
48	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.38E-09
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RRXVK00715	MANUAL VALVE 715 TRANSFERS CLOSED [RECIRC]		1.66E-07	5.47E-04	
49	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	4.38E-09
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RRXVK00717	MANUAL VALVE 717 TRANSFERS CLOSED [RECIRC]		1.66E-07	5.47E-04	
50	LIMBLOCA	Medium LOCA (1.5"-5.5")		4.00E-04	4.00E-04	3.79E-09
	RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	
	RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	

Report Summary:
Filename: C:\CAFTA-W\QUANT\TL_M.CUT
Print date: 1/15/97 2:48 PM
Not sorted
Printed the first 50

Initiator Summary Report

SLOCA = 4.37E-06 (Probability)

Name	Prob	%	Description
LISBLOCA	2.46E-06	56.3%	Small LOCA (1-1.5")
TIRXTRIP	8.23E-07	18.8%	Reactor Trip
TI000DCB	2.20E-07	5.0%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
TI000DCA	2.19E-07	5.0%	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TISWLOSP	1.96E-07	4.5%	Loss of Offsite Power - Switchyard
TIGRLOSP	1.78E-07	4.1%	Loss of Offsite Power - Grid
TI0000SW	1.38E-07	3.2%	Total Loss of Service Water
TIIALOSS	1.11E-07	2.5%	Loss of Instrument Air
TIFWLOSS	1.14E-08	0.3%	Loss of Main Feedwater
TIFLB0TB	4.89E-09	0.1%	Feedline Break in Turbine Building
TISLB0TB	4.51E-09	0.1%	Steamline Break in Turbine Building
TIRCPROT	1.57E-09	0.0%	Reactor Coolant Pump Locked Rotor Event
TI000SWB	1.02E-09	0.0%	Loss of Service Water Header B
TI000SWA	9.58E-10	0.0%	Loss of Service Water Header A
Total =	4.37E-06		

Report Summary:

Filename: C:\CAFTA-W\QUANT\SLOCA.CUT
Print date: 1/13/97 10:33 AM
Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	4.53E-07
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
2	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	3.71E-07
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
3	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	3.39E-07
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
4	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.02E-07
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
5	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.02E-07
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
6	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	6.92E-08
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
7	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	6.92E-08
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
8	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	6.60E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
9	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	6.60E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
10	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	5.63E-08
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
11	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	5.63E-08
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
12	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)		5.54E-03	5.54E-03	5.36E-08
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
13	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)		5.54E-03	5.54E-03	5.36E-08
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
14	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	5.36E-08
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
15	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	5.36E-08
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
16	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	5.29E-08
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
	SRHFDRECRC	OPERATORS FAIL TO SHIFT SI SYSTEM TO RECIRCULATION		1.30E-03	1.30E-03	
17	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	4.88E-08
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
	RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION		1.30E-02	1.30E-02	
	SLOCRECIRC	MULTIPLIER FOR SLOCA AND SSLOCA RECIRCULATION FAILURE RATE		9.32E-02	9.23E-02	
18	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	3.41E-08
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
19	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	3.41E-08
	SRCCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN FOR RECIRC. DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
20	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	2.81E-08
	CRCCM0896X	COMMON CAUSE FAILURE OF MOVS 896A AND 896B TO CLOSE (RECIRC)		6.91E-04	6.91E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
21	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	2.38E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
22	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	2.22E-08
	SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO CCF		5.46E-04	5.46E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
23	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.81E-08
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
24	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.81E-08
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
25	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.80E-08
	RHCCPUMPBA	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO RUN		1.64E-05	1.64E-05	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
26	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.53E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
27	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.53E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
28	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.48E-08
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
29	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.48E-08
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
30	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.46E-08
	CCPPJ_COMM	PIPE RUPTURE IN THE COMMON CCW PIPING		5.53E-07	1.33E-05	
31	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.46E-08
	CCTKJSURGE	CCW SURGE TANK RUPTURE		5.53E-07	1.33E-05	
32	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.46E-08
	RRTKG0SEAL	RHR PUMP SEAL FAILURE FAILS BOTH PUMPS (LONG TERM)		5.52E-06	1.32E-04	
	RRHFDSEALX	FAILURE OF OPERATORS TO STOP RHR PUMP IF SEAL FAILS		1.00E-01	1.00E-01	
33	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.36E-08
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
34	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	1.36E-08
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
35	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.31E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
36	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.31E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
37	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.25E-08
	RRCCM0857M	MOVS 857A, 857B AND 857C FAIL TO OPEN DUE TO COMMON CAUSE		3.08E-04	3.08E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
38	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)		5.54E-03	5.54E-03	1.25E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
39	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)		5.54E-03	5.54E-03	1.25E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
40	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.25E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
41	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.25E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
42	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	1.17E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	-RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
43	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	1.17E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	-RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRZT00430	PORV PCV-430 Fails To Reseat After Steam Relief		5.00E-03	5.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RCHFDPLOCA	Operators Fail To Close PORV Block Valve (515/516)		1.00E-01	1.00E-01	
44	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.07E-08
	SRCCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR RECIRC. DUE TO CCF		2.64E-04	2.64E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
45	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	1.04E-08
	RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	
	RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	
46	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	9.90E-09
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
47	LISBLOCA	Small LOCA (1-1.5")		1.10E-03	1.10E-03	9.18E-09
	CCCCPUMP/R	COMMON CAUSE FAILURE OF CCW PUMPS TO RUN		8.35E-06	8.35E-06	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
48	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	9.10E-09
	RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose		7.45E-03	7.45E-03	
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
49	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	9.10E-09
	RCMVD00515	Motor-Operated Valve 515 Is Closed Due to PORV Leakage		3.26E-02	3.26E-02	
	RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose		7.45E-03	7.45E-03	
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	
50	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	9.10E-09
	RCMVD00516	Motor-Operated Valve 516 Is Closed Due To PORV Leakage		3.26E-02	3.26E-02	
	RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose		7.45E-03	7.45E-03	
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RXTRIPLL	PERCENTAGE OF RX TRIP DUE TO LOSS OF ELECTRIC LOAD		5.00E-02	5.00E-02	

Report Summary:
Filename: C:\CAFTA-W\QUANT\SLOCA.CUT
Print date: 1/15/97 2:45 PM
Not sorted
Printed the first 50

Initiator Summary Report

SSLOCA = 1.81E-05 (Probability)

Name	Prob	%	Description
LISSLOCA	1.25E-05	69.2%	Small-Small LOCA (0-1")
TI0000SW	3.69E-06	20.4%	Total Loss of Service Water
TIGRLOSP	5.38E-07	3.0%	Loss of Offsite Power - Grid
TI000CCW	5.30E-07	2.9%	Loss of Component Cooling Water
TIRXTRIP	3.64E-07	2.0%	Reactor Trip
TISWLOSP	3.15E-07	1.7%	Loss of Offsite Power - Switchyard
TIIALOSS	4.94E-08	0.3%	Loss of Instrument Air
TI000DCB	2.89E-08	0.2%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
TI000SWB	2.12E-08	0.1%	Loss of Service Water Header B
TI000DCA	1.92E-08	0.1%	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TI000SWA	1.68E-08	0.1%	Loss of Service Water Header A
TIOSLBSD	1.98E-09	0.0%	Steamline Break Through Steam Dump System
TIFLB0TB	1.67E-09	0.0%	Feedline Break in Turbine Building
TISLB0TB	1.54E-09	0.0%	Steamline Break in Turbine Building
TISLBSVA	6.89E-10	0.0%	Inadvertent Safety / FW Valve Operation for Both SGs
Total =	1.81E-05		

Report Summary:

Filename: C:\CAFTA-W\QUANT\SSLOCA.CUT

Print date: 1/13/97 10:09 AM

Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	3.41E-06
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
2	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.26E-06
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
3	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.85E-06
	CCCC738A/B	COMMON CAUSE FAILURE OF MOV'S 738A AND 738B TO OPEN		3.37E-04	3.37E-04	
4	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.69E-06
	RRCC850A/B	MOVS 850A/B FAIL TO OPEN <COMMON CAUSE EVENT>		3.08E-04	3.08E-04	
5	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	5.11E-07
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
6	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	5.11E-07
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
7	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	3.30E-07
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
8	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	3.30E-07
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
9	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.81E-07
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
10	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.81E-07
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
11	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.65E-07
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
	SRHFDRECRC	OPERATORS FAIL TO SHIFT SI SYSTEM TO RECIRCULATION		1.30E-03	1.30E-03	
12	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	2.44E-07
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
	RRHFDRECRC	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION		1.30E-02	1.30E-02	
	SLOCRECIRC	MULTIPLIER FOR SLOCA AND SSLOCA RECIRCULATION FAILURE RATE		9.32E-02	9.23E-02	
13	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.71E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
14	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.71E-07
	SRCCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN FOR RECIRC. DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
15	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	1.66E-07
	CVCVP00357	check valve 357 fails to open		1.77E-07	1.17E-03	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
16	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.41E-07
	CRCCM0896X	COMMON CAUSE FAILURE OF MOVS 896A AND 896B TO CLOSE (RECIRC)		6.91E-04	6.91E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
17	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.19E-07
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
18	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	1.11E-07
	SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO CCF		5.46E-04	5.46E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
19	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	1.10E-07
	CVCCMPFABC	COMMON CAUSE FAILURE OF THE CHARGING PUMPS TO RUN		8.49E-05	8.49E-05	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
20	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	9.00E-08
	RHCCPUMPBA	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO RUN		1.64E-05	1.64E-05	
21	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	7.67E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
22	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	7.67E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
23	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	7.30E-08
	CCPPJ_COMM	PIPE RUPTURE IN THE COMMON CCW PIPING		5.53E-07	1.33E-05	
24	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	7.30E-08
	CCTKJSURGE	CCW SURGE TANK RUPTURE		5.53E-07	1.33E-05	
25	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	7.29E-08
	RRTKG0SEAL	RHR PUMP SEAL FAILURE FAILS BOTH PUMPS (LONG TERM)		5.52E-06	1.32E-04	
	RRHFDSEALX	FAILURE OF OPERATORS TO STOP RHR PUMP IF SEAL FAILS		1.00E-01	1.00E-01	
26	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	6.95E-08
	CVMMRCPALP	NO FLOW THROUGH SEAL LEAKOFF PATH FROM RCP A TO COMMON HEADER		5.35E-05	5.35E-05	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
27	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	6.95E-08
	CVMMRCPBLP	SEAL LEAKOFF PATH FROM RCP B OBSTRUCTED		5.35E-05	5.35E-05	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
28	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	6.54E-08
	CCMM00738A	MOV 738A FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
29	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	6.54E-08
	CCMM00738B	MOV 738B FAILS TO OPEN		4.65E-03	4.65E-03	
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
30	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	6.34E-08
	CVMMRCPAFP	NO FLOW FROM SEAL INJECTION FILTER A TO RCP A SEAL		4.88E-05	4.88E-05	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
31	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	6.34E-08
	CVMMRCPBFP	NO FLOW PATH TO RCP B SEAL FROM SEAL INJECTION FILTER		4.88E-05	4.88E-05	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
32	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	6.27E-08
	RRCCM0857M	MOVS 857A, 857B AND 857C FAIL TO OPEN DUE TO COMMON CAUSE		3.08E-04	3.08E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
33	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	5.72E-08
	CCAACCPMPA	CCW PUMP A IS ALIGNED TO RUN <LOGIC FLAG>		5.00E-01	5.00E-01	
	CCTM_PUMPB	CCW PUMP B IS UNAVAILABLE DUE TO TESTING OR MAINTENANCE		7.00E-03	7.00E-03	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
34	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	5.72E-08
	CCAACCPMPB	CCW PUMP B IS ALIGNED TO RUN <LOGIC FLAG>		5.00E-01	5.00E-01	
	CCTM_PUMPA	CCW PUMP A IS UNAVAILABLE DUE TO TESTING OR MAINTENANCE		7.00E-03	7.00E-03	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
35	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	5.50E-08
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD00RCP	Operators Fail to Trip RCPs After Loss of Support Systems		1.61E-02	1.61E-02	
36	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	5.37E-08
	SRCCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR RECIRC. DUE TO CCF		2.64E-04	2.64E-04	
	RCHFDCD0SS	Operator Fails to Cooldown to RHR After SI Fails - SSLOCA		3.70E-02	3.70E-02	
37	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	5.22E-08
	RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	
	RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)		3.08E-03	3.08E-03	
38	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.95E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
39	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.59E-08
	CCCCPUMP/R	COMMON CAUSE FAILURE OF CCW PUMPS TO RUN		8.35E-06	8.35E-06	
40	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.22E-08
	CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED		3.00E-03	3.00E-03	
	RHMMAC01BA	RHR PUMP B (PAC01B) FAILS TO START		2.56E-03	2.56E-03	
41	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.22E-08
	CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED		3.00E-03	3.00E-03	
	RHMMAC01AA	RHR PUMP A (PAC01A) FAILS TO START		2.56E-03	2.56E-03	
42	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.09E-08
	RHCC710A/B	CHECK VALVES 710A, 710B FAIL TO OPEN <COMMON CAUSE EVENT>		7.44E-06	7.44E-06	
43	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	4.06E-08
	RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]		2.00E-02	2.00E-02	
	RRCVP0697B	CHECK VALVE 697B FAILS TO OPEN [RECIRC]		1.12E-07	3.69E-04	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
44	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	3.93E-08
	ACLOPRT751	Loss of Offsite Circuit 751 Following Reactor Trip		1.19E-02	1.19E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]		2.00E-02	2.00E-02	
45	TI000CCW	Loss of Component Cooling Water		1.30E-03	1.30E-03	3.76E-08
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
46	LISSLOCA	Small-Small LOCA (0-1")		5.50E-03	5.50E-03	3.65E-08
	CSMM00RWST	INSUFFICIENT FLOW AVAILABLE FROM TSI01 (RWST)		6.64E-06	6.64E-06	
47	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	3.62E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	SW026FX	NO UNDERVOLTAGE ON BUS 18		1.00E+00	1.00E+00	
	SWAASWP1BS	Service Water Pump PSW01B Is Selected In Standby		5.00E-01	5.00E-01	
	SWAASWP1CS	Service Water Pump PSW01C is selected in Standby		5.00E-01	5.00E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
	SWHFDSTART	OPERATORS FAIL TO START SW PUMP		5.00E-03	5.00E-03	
48	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	3.62E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	SW026FX	NO UNDERVOLTAGE ON BUS 18		1.00E+00	1.00E+00	
	SWAASWP1CS	Service Water Pump PSW01C is selected in Standby		5.00E-01	5.00E-01	
	SWAASWP1DS	Service Water Pump PSW01D in Standby		5.00E-01	5.00E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
	SWHFDSTART	OPERATORS FAIL TO START SW PUMP		5.00E-03	5.00E-03	
49	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	3.62E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	SWAASWP1AS	Service Water Pump PSW01A Is Selected In Standby		5.00E-01	5.00E-01	
	SWAASWP1BS	Service Water Pump PSW01B Is Selected In Standby		5.00E-01	5.00E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
	SWHFDSTART	OPERATORS FAIL TO START SW PUMP		5.00E-03	5.00E-03	
50	TISWLOSP	Loss of Offsite Power - Switchyard		4.04E-02	4.04E-02	3.62E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	IAAAIAC02C	IA COMPRESSOR CIA02C RUNNING		9.95E-01	9.95E-01	
	SWAASWP1AS	Service Water Pump PSW01A Is Selected In Standby		5.00E-01	5.00E-01	
	SWAASWP1DS	Service Water Pump PSW01D in Standby		5.00E-01	5.00E-01	
	CVHFDSUCTN	Operators Fail to Manually Open Suction Line Upon Loss of IA		2.40E-02	2.40E-02	
	RCHFD01RCP	OPERATORS FAIL TO RESTORE RCP SEAL COOLING WITHIN ONE HOUR		1.00E+00	1.00E+00	
	SWHFDSTART	OPERATORS FAIL TO START SW PUMP		5.00E-03	5.00E-03	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob

Report Summary:
Filename: C:\CAFTA-W\QUANT\SSLOCA.CUT
Print date: 1/15/97 2:46 PM
Not sorted
Printed the first 50

Initiator Summary Report

SGTR = 8.09E-06 (Probability)

Name	Prob	%	Description
LIOSGTRA	4.05E-06	50.1%	Steam Generator Tube Rupture in SG A
LIOSGTRB	4.04E-06	49.9%	Steam Generator Tube Rupture in SG B
Total =	8.09E-06		

Report Summary:

Filename: C:\CAFTA-W\QUANT\SGTR.CUT
Print date: 1/13/97 10:58 AM
Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.43E-06
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RCHFDCOOLD	Operators Fail to Rapidly Cooldown to RHR Conditions After ARV		3.07E-02	3.07E-02	
2	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.43E-06
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RCHFDCOOLD	Operators Fail to Rapidly Cooldown to RHR Conditions After ARV		3.07E-02	3.07E-02	
3	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.25E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR		3.07E-02	3.07E-02	
4	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.25E-07
	SICCMPSI1Y	PSI01A, PSI01B & PSI01C FAIL TO RUN DURING INJECTION DUE TO CCF		8.38E-04	8.38E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR		3.07E-02	3.07E-02	
5	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.06E-07
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
6	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.06E-07
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
7	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.06E-07
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
8	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.06E-07
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
9	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	8.11E-08
	SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO CCF		5.46E-04	5.46E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR		3.07E-02	3.07E-02	
10	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	8.11E-08
	SICCMPSI1X	PSI01A, PSI01B & PSI01C FAIL TO START FOR INJECTION DUE TO CCF		5.46E-04	5.46E-04	
	RCHFDCDTR2	Operator Fails to Cooldown to RHR After SI Fails - SGTR		3.07E-02	3.07E-02	
11	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.95E-08
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
12	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.95E-08
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
13	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.95E-08
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
14	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.95E-08
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
15	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
16	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
17	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
18	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
19	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release		6.00E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
20	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
21	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release		6.00E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
22	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	7.56E-08
	MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
23	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
24	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
25	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
26	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
27	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
28	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
29	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
30	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	7.56E-08
	MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
31	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	3.21E-08
	CSMM00RWST	INSUFFICIENT FLOW AVAILABLE FROM TSI01 (RWST)		6.64E-06	6.64E-06	
32	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	3.21E-08
	CSMM00RWST	INSUFFICIENT FLOW AVAILABLE FROM TSI01 (RWST)		6.64E-06	6.64E-06	
33	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	2.28E-08
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
34	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	2.28E-08
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
35	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.94E-08
	RRCCPUMPAB	PUMPS A/B FAIL TO START (RECIRC)<COMMON CAUSE EVENT>		4.16E-04	4.16E-04	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
36	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.94E-08
	RRCCPUMPAB	PUMPS A/B FAIL TO START (RECIRC)<COMMON CAUSE EVENT>		4.16E-04	4.16E-04	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
37	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.91E-08
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
38	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.91E-08
	RHCCPUMPAB	COMMON CAUSE FAILURE OF RHR PUMPS A AND B TO START		4.12E-04	4.12E-04	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
39	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.72E-08
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
40	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.72E-08
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	MSHFDISOLR	Operators Fail to Isolate ruptured S/G		7.24E-03	7.24E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
41	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.64E-08
	MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
42	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.64E-08
	MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
43	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.64E-08
	MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
44	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.64E-08
	MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
45	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.64E-08
	MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
46	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.64E-08
	MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
47	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.64E-08
	MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
48	LIOSGTRB	Steam Generator Tube Rupture in SG B		4.84E-03	4.84E-03	1.64E-08
	MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release		6.88E-03	6.88E-03	
	RRPTHPT420	PRESSURE TRANSMITTER PT-420 FAILS HIGH		1.49E-06	4.91E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
49	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.58E-08
	RRBIF850AX	BISTABLE 850A-X SPURIOUSLY OPERATES		1.03E-06	3.40E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	
50	LIOSGTRA	Steam Generator Tube Rupture in SG A		4.84E-03	4.84E-03	1.58E-08
	RRBIF850BX	BISTABLE 850B-X SPURIOUSLY OPERATES		1.03E-06	3.40E-03	
	RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR		9.61E-03	9.61E-03	
	RRHFDSUCTN	OPS FAILS TO MANUALLY OPEN RHR SUCTION VALVES		1.00E-01	1.00E-01	

Report Summary:
Filename: C:\CAFTA-W\QUANT\SGTR.CUT
Print date: 1/15/97 2:44 PM
Not sorted
Printed the first 50

Initiator Summary Report

TRANS = 4.43E-06 (Probability)

Name	Prob	%	Description
TIFLB0TB	1.03E-06	23.2%	Feedline Break in Turbine Building
TISLB0TB	1.02E-06	23.0%	Steamline Break in Turbine Building
TI000DCB	4.79E-07	10.8%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
TIGRLOSP	3.48E-07	7.9%	Loss of Offsite Power - Grid
TIOSLBSD	3.26E-07	7.4%	Steamline Break Through Steam Dump System
TI0000SW	2.99E-07	6.8%	Total Loss of Service Water
TI000DCA	2.41E-07	5.4%	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TISLBBIB	1.56E-07	3.5%	Steamline Break in Line for SG B Inside Intermediate Buildi ng
TIFLBBIB	1.47E-07	3.3%	Feedline Break in Line for SG B Inside Intermediate Building
TISLBAIB	1.06E-07	2.4%	Steamline Break in Line for SG A Inside Intermediate Buildi ng
TIFLBAIB	1.00E-07	2.3%	Feedline Break in Line for SG A Inside Intermediate Building
TISWLOSP	9.29E-08	2.1%	Loss of Offsite Power - Switchyard
TIRXTRIP	4.93E-08	1.1%	Reactor Trip
TIIALOSS	2.20E-08	0.5%	Loss of Instrument Air
TIRCPROT	4.73E-09	0.1%	Reactor Coolant Pump Locked Rotor Event
TIFWLOSS	3.10E-09	0.1%	Loss of Main Feedwater
TI000SWA	1.24E-09	0.0%	Loss of Service Water Header A
TI000SWB	1.03E-09	0.0%	Loss of Service Water Header B
Total =	4.43E-06		

Report Summary:

Filename: C:\CAFTA-W\QUANT\TRANS.CUT

Print date: 1/11/97 1:06 PM

Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	3.85E-07
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
2	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	3.55E-07
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
3	TI0SLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	2.58E-07
	MSCCCMSIVX	Common Cause Failure of MSIVs to Close		8.41E-04	8.41E-04	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
4	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	2.37E-07
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
5	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	2.18E-07
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
6	TI000DCA	Loss of Main DC Distribution Panel A (DCPDPCB03A)		5.54E-03	5.54E-03	1.97E-07
	DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)		3.56E-05	3.56E-05	
7	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.97E-07
	DCMMMAIN1A	Failure of Circuit E14 (To Main DC Distribution Panel 1A)		3.56E-05	3.56E-05	
8	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	1.50E-07
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F		1.67E-01	1.67E-01	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	HVTMSAFW_B	B SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
9	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	1.38E-07
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F		1.67E-01	1.67E-01	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	HVTMSAFW_B	B SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
10	TIFLBBIB	Feedline Break in Line for SG B Inside Intermediate Building		3.87E-05	3.87E-05	1.15E-07
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
11	TISLBBIB	Steamline Break in Line for SG B Inside Intermediate Building		3.58E-05	3.58E-05	1.06E-07
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
12	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	9.61E-08
	AFMM0TDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
13	TIFLBAIB	Feedline Break in Line for SG A Inside Intermediate Building		2.58E-05	2.58E-05	7.79E-08
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
14	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	7.62E-08
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
15	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	7.58E-08
	AFTM0TDAFW	TDAFW Pump Train out-of-service for maintenance		1.00E-02	1.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
16	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	7.55E-08
	SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open		1.02E-03	1.02E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
17	TISLBAIB	Steamline Break in Line for SG A Inside Intermediate Building		2.38E-05	2.38E-05	7.19E-08
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
18	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	6.95E-08
	SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open		1.02E-03	1.02E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
19	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	5.75E-08
	MSCCCMSIVX	Common Cause Failure of MSIVs to Close		8.41E-04	8.41E-04	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
20	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	5.08E-08
	AFHFDALTTD	OPERATORS FAIL TO PROVIDE COOLING TO TDAFW LUBE OIL FROM DIESEL		6.70E-03	6.70E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
21	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	4.69E-08
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
22	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.17E-08
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
23	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	3.93E-08
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	AFMMSAFWPD	Failure of SAFW Pump 1D Train		2.30E-02	2.30E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
24	TIOSLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	3.66E-08
	ESCC0MSFTD	COMMON CAUSE FAILURE TO RESPOND OF STEAM LINE FLOW TRANSMITTER		1.19E-03	1.19E-03	
	MSHFDMSIVX	Operators Fails to Close MSIV		1.00E-01	1.00E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
25	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	3.62E-08
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	AFMMSAFWPD	Failure of SAFW Pump 1D Train		2.30E-02	2.30E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
26	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.33E-08
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F		1.67E-01	1.67E-01	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
27	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	2.97E-08
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F		1.67E-01	1.67E-01	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	HVTMSAFW_B	B SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
28	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	2.27E-08
	AFHFLTDAFW	Failure to restore TDAFW pump train to service post test/maintenance		3.00E-03	3.00E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
29	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	1.86E-08
	AFCCDMOVNB	Common cause failure of MOVs 9701A and 9701B to throttle flow		2.51E-04	2.51E-04	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
30	TI0000SW	Total Loss of Service Water		1.43E-04	1.43E-04	1.82E-08
	AFTMTDAFWA	TDAFW Pump Train injection line to S/G A out-of-service for maint		4.90E-02	4.90E-02	
	AFTMTDAFWB	TDAFW Pump Train injection line to S/G B out-of-service for maint		4.90E-02	4.90E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
31	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.81E-08
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
32	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	1.72E-08
	AFCCDMOVNB	Common cause failure of MOVs 9701A and 9701B to throttle flow		2.51E-04	2.51E-04	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
33	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	1.49E-08
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open		1.02E-03	1.02E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
34	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.44E-08
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVAA>80DEG	OUTSIDE AIR TEMP IS GREATER THAN OR EQUAL TO 80 F		1.67E-01	1.67E-01	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE		1.10E-01	1.10E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
35	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	1.27E-08
	AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint		3.00E-03	3.00E-03	
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
36	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	1.25E-08
	AFHFLSAFWB	Failure to restore SAFW Pump Train 1D to service post test/maint		3.00E-03	3.00E-03	
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
37	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	1.17E-08
	AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint		3.00E-03	3.00E-03	
	AFTMSAFSGB	SAFW TRAIN D TO S/G B O.O.S. DUE TO T/M		5.70E-02	5.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
38	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	1.15E-08
	AFHFLSAFWB	Failure to restore SAFW Pump Train 1D to service post test/maint		3.00E-03	3.00E-03	
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
39	TIFLBBIB	Feedline Break in Line for SG B Inside Intermediate Building		3.87E-05	3.87E-05	1.06E-08
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
40	TIOSLBSD	Steamline Break Through Steam Dump System		5.78E-03	5.78E-03	1.02E-08
	MSAVX03516	MSIV 3516 Fails to Close		2.60E-06	5.76E-03	
	MSAVX03517	MSIV 3517 Fails to Close		2.60E-06	5.76E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
41	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.01E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
	RCHFDHEATR	OPERATORS FAIL TO LOAD PRESSURIZER HEATERS FOLLOWING A LOOP		3.10E-04	3.10E-04	
42	TIFLB0TB	Feedline Break in Turbine Building		1.40E-03	1.40E-03	9.98E-09
	AFMMSGBSAF	Failure of SAFW injection line to S/G B		2.40E-03	2.40E-03	
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
43	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	9.85E-09
	DCMMAUX00A	Failure of Circuit E53 (To Auxiliary Building DC Distribution Pnl A)		3.56E-05	3.56E-05	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
44	TISLBBIB	Steamline Break in Line for SG B Inside Intermediate Building		3.58E-05	3.58E-05	9.85E-09
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
45	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	9.41E-09
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
46	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	9.20E-09
	AFMMSGBSAF	Failure of SAFW injection line to S/G B		2.40E-03	2.40E-03	
	AFTMSAFSGA	SAFW TRAIN C TO S/G A O.O.S. DUE TO T/M		5.60E-02	5.60E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
47	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	8.54E-09
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	DGMM0FUELB	FAILURES OF FUEL TO D/G B		6.14E-03	6.14E-03	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
48	TISLB0TB	Steamline Break in Turbine Building		1.29E-03	1.29E-03	8.16E-09
	ESCC0MSFTD	COMMON CAUSE FAILURE TO RESPOND OF STEAM LINE FLOW TRANSMITTER		1.19E-03	1.19E-03	
	MSHFDMSIVX	Operators Fails to Close MSIV		1.00E-01	1.00E-01	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
49	TI000DCB	Loss of Main DC Distribution Panel B (DCPDPCB03B)		5.54E-03	5.54E-03	7.78E-09
	AFMMSAFWPC	Failure of SAFW Pump 1C train		2.30E-02	2.30E-02	
	AFMMSAFWPD	Failure of SAFW Pump 1D Train		2.30E-02	2.30E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVFDRF360P	ROLLING FIRE DOOR F36 IS SHUT		5.00E-02	5.00E-02	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	
50	TIFLBAIB	Feedline Break in Line for SG A Inside Intermediate Building		2.58E-05	2.58E-05	7.10E-09
	AFHFDSAFWX	OPERATORS FAIL TO CORRECTLY ALIGN SAFW		5.19E-03	5.19E-03	
	RCHFD01BAF	Operators Fail To Implement Feed And Bleed		5.30E-02	5.30E-02	

Report Summary:

Filename: C:\CAFTA-W\QUANT\TRANS.CUT

Print date: 1/15/97 2:48 PM

Not sorted

Printed the first 50

Initiator Summary Report
SBO = 6.22E-06 (Probability)

Name	Prob	%	Description
TIGRLOSP	5.48E-06	88.2%	Loss of Offsite Power - Grid
TIRXTRIP	4.31E-07	6.9%	Reactor Trip
TI000DCB	9.81E-08	1.6%	Loss of Main DC Distribution Panel B (DCPDPCB03B)
TI000DCA	9.41E-08	1.5%	Loss of Main DC Distribution Panel B (DCPDPCB03A)
LISSLOCA	3.51E-08	0.6%	Small-Small LOCA (0-1")
TISWLOSP	1.33E-08	0.2%	Loss of Offsite Power - Switchyard
LIOSGTRB	9.07E-09	0.1%	Steam Generator Tube Rupture in SG B
LIOSGTRA	9.07E-09	0.1%	Steam Generator Tube Rupture in SG A
TI0000SW	8.75E-09	0.1%	Total Loss of Service Water
LISBLOCA	4.75E-09	0.1%	Small LOCA (1-1.5")
TIOSLBSD	3.50E-09	0.1%	Steamline Break Through Steam Dump System
TI000CCW	3.19E-09	0.1%	Loss of Component Cooling Water
TIIALOSS	2.49E-09	0.0%	Loss of Instrument Air
TI000SWA	1.98E-09	0.0%	Loss of Service Water Header A
TI000SWB	1.98E-09	0.0%	Loss of Service Water Header B
TISLBSVA	1.04E-09	0.0%	Inadvertent Safety / FW Valve Operation for Both SGs
TIFLB0TB	4.29E-10	0.0%	Feedwater Break in Turbine Building
TISLB0TB	3.96E-10	0.0%	Steamline Break in Turbine Building
TIFWLOSS	0.00E+00	0.0%	Loss of Main Feedwater
TISLBBIB	0.00E+00	0.0%	Steamline Break in Line for SG B Inside Intermediate
TISLBACT	0.00E+00	0.0%	Steamline Break in Line for SG A Inside Containment
TISLBAIB	0.00E+00	0.0%	Steamline Break in Line for SG A Inside Intermediate
TISLBBCT	0.00E+00	0.0%	Steamline Break in Line for SG B Inside Containment
Total =	6.22E-06		

Report Summary:
Filename: C:\CAFTA-W\QUANT\SBO.CUT
Print date: 1/11/97 1:28 PM
Sorted by Probability

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
1	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.41E-07
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	
2	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.37E-07
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
3	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.21E-07
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
4	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.39E-07
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
5	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	7.26E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCCPMA2AB	FUEL OIL PUMPS PDG02A/02B FAIL TO START (COMMON CAUSE)		1.18E-04	1.18E-04	
6	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	6.00E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
7	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	6.00E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	DGTM00001A	DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
8	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.92E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0FUELA	FAILURES OF THE FUEL SUPPLY TO D/G A		6.14E-03	6.14E-03	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
9	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.92E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0FUELB	FAILURES OF FUEL TO D/G B		6.14E-03	6.14E-03	
	DGTM00001A	DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
10	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.46E-08
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	RCHFDRHRSB	Ops Fails to Rapidly Depressurize to RHR (or Use AFW Long-Term)		5.00E-03	5.00E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	
11	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.39E-08
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
	RCHFDRHRSB	Ops Fails to Rapidly Depressurize to RHR (or Use AFW Long-Term)		5.00E-03	5.00E-03	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
12	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.25E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	HV00LTFAIL	DUMMY EVENT FOR LONG TERM FAILURES DUE TO VENTILATION FAILURE		1.00E+00	1.00E+00	
	HVCCDGSTRT	FAN UNIT FOR DG FAILS TO START (COMMON CAUSE)		6.91E-05	6.91E-05	
13	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	4.10E-08
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
	RCHFDRHRSB	Ops Fails to Rapidly Depressurize to RHR (or Use AFW Long-Term)		5.00E-03	5.00E-03	
14	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.96E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMASTART	FAILURES OF D/G A TO START		4.94E-03	4.94E-03	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
15	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.96E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMBSTART	FAILURES OF D/G B TO START		4.94E-03	4.94E-03	
	DGTM00001A	DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
16	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.55E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFMM0TDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	
	SBOCORR007	CORRECTION FACTOR FOR AFMM0TDAFW FOR SBO		8.83E-01	8.83E-01	
17	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.49E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFMM0TDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
	SBOCORR007	CORRECTION FACTOR FOR AFMM0TDAFW FOR SBO		8.83E-01	8.83E-01	
18	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.26E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFMM0TDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
	SBOCORR007	CORRECTION FACTOR FOR AFMM0TDAFW FOR SBO		8.83E-01	8.83E-01	
19	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.17E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMBRKR14	FAILURES OF DG A SUPPLY BREAKER TO BUS 14 TO CLOSE		3.96E-03	3.96E-03	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
20	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.17E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMBRKR16	FAILURES OF DG B SUPPLY BREAKER TO BUS 16 TO CLOSE		3.96E-03	3.96E-03	
	DGTM00001A	DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
21	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.17E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFTM0TDAFW	TDAFW Pump Train out-of-service for maintenance		1.00E-02	1.00E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
22	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.12E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFTM0TDAFW	TDAFW Pump Train out-of-service for maintenance		1.00E-02	1.00E-02	
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
23	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.11E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMBRKR17	FAILURES OF DG B SUPPLY BREAKER TO BUS 17 TO CLOSE		3.88E-03	3.88E-03	
	DGTM00001A	DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
24	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.11E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMMBRKR18	FAILURES OF DG A SUPPLY BREAKER TO BUS 18 TO CLOSE		3.88E-03	3.88E-03	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
25	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	3.08E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0AAF04	AAF04 BREAKER 52/ABEF1G TO BUS 14 FAILS TO OPEN FOR LOAD SHED		3.85E-03	3.85E-03	
	DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE		1.30E-02	1.30E-02	
26	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.91E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFTM0TDAFW	TDAFW Pump Train out-of-service for maintenance		1.00E-02	1.00E-02	
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
27	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.84E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGMM0FUELB	FAILURES OF FUEL TO D/G B		6.14E-03	6.14E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
28	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.84E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	DGMM0FUELA	FAILURES OF THE FUEL SUPPLY TO D/G A		6.14E-03	6.14E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
29	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.71E-08
	DCCC0BATTD	Batteries A/B No Output on Demand <Common Cause>		1.19E-06	1.19E-06	
30	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.56E-08
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	RCHFDRHRSB	Ops Fails to Rapidly Depressurize to RHR (or Use AFW Long-Term)		5.00E-03	5.00E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
31	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	2.33E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
32	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.32E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0FUELA	FAILURES OF THE FUEL SUPPLY TO D/G A		6.14E-03	6.14E-03	
	DGMM0FUELB	FAILURES OF FUEL TO D/G B		6.14E-03	6.14E-03	
33	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	2.29E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
34	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.28E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGMMBSTART	FAILURES OF D/G B TO START		4.94E-03	4.94E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
35	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.28E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	DGMMASTART	FAILURES OF D/G A TO START		4.94E-03	4.94E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
36	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.20E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCCCV5920	COMMON CAUSE FAILURE OF FUEL OIL FOOT VALVES 5919 AND 5920 TO CLOSE		3.58E-05	3.58E-05	
37	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.20E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCCCV5956	COMMON CAUSE FAILURE OF FUEL OIL CHECK VALVES 5955 AND 5956 TO CLOSE		3.58E-05	3.58E-05	
38	TIRXTRIP	Reactor Trip		1.82E+00	1.82E+00	2.14E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	ACLOPNOSI2	CORRECTION FACTOR FOR NO SI CONDITION		1.21E-01	1.21E-01	
	ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip		1.00E-02	1.00E-02	
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
39	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.04E-08
	ACAADLOSP1	Failure to Restore Offsite Power Within 1 Hour		3.55E-01	3.55E-01	
	AFMM0TDAFW	Failure of TDAFW pump train components		1.27E-02	1.27E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
	SBOCORR007	CORRECTION FACTOR FOR AFMM0TDAFW FOR SBO		8.83E-01	8.83E-01	
40	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.02E-08
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	
41	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	2.02E-08
	DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)		2.34E-03	2.34E-03	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
	SBOCORR001	CORRECTION FACTOR FOR DGCC000RUN FOR SBO		1.67E-01	1.67E-01	

#	Inputs	Description	Rate	Exposure	Prob	Cutset Prob
42	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.99E-08
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
43	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.99E-08
	DGCCBREAKR	COMMON CAUSE FAILURE OF DIESEL GENERATOR OUTPUT BREAKERS TO CLOSE		3.85E-04	3.85E-04	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
44	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.87E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0FUELA	FAILURES OF THE FUEL SUPPLY TO D/G A		6.14E-03	6.14E-03	
	DGMMBSTART	FAILURES OF D/G B TO START		4.94E-03	4.94E-03	
45	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.87E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGMM0FUELB	FAILURES OF FUEL TO D/G B		6.14E-03	6.14E-03	
	DGMMASTART	FAILURES OF D/G A TO START		4.94E-03	4.94E-03	
46	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.86E-08
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
	RRMVQ00700	MOV 700 FAILS TO OPEN		2.27E-03	2.27E-03	
47	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.86E-08
	DGCC0START	DIESEL GENERATORS FAIL TO START (COMMON CAUSE)		3.60E-04	3.60E-04	
	RRMVQ00701	MOV 701 FAILS TO OPEN		2.27E-03	2.27E-03	
48	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.83E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGCCPMF2AB	FUEL OIL PUMPS PDG02A/02B FAIL TO RUN (COMMON CAUSE)		1.78E-04	1.78E-04	
	SBOCORR003	CORRECTION FACTOR FOR DGCCPMF2AB FOR SBO		1.67E-01	1.67E-01	
49	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.83E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN		1.25E-03	3.00E-02	
	DGMMBRKR16	FAILURES OF DG B SUPPLY BREAKER TO BUS 16 TO CLOSE		3.96E-03	3.96E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	
50	TIGRLOSP	Loss of Offsite Power - Grid		2.28E-02	2.28E-02	1.83E-08
	ACAALOSP10	Failure to Restore Offsite Power Within 10 Hours		2.70E-02	2.70E-02	
	DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN		1.25E-03	3.00E-02	
	DGMMBRKR14	FAILURES OF DG A SUPPLY BREAKER TO BUS 14 TO CLOSE		3.96E-03	3.96E-03	
	SBOCORR006	CORRECTION FACTOR FOR DGMM0VENTA AND DGMM0VENTB FOR SBO		2.50E-01	2.50E-01	

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APPENDIX B

STATION BLACKOUT TIMING EVALUATIONS

B.0 STATION BLACKOUT TIMING EVALUATIONS

This appendix contains the timing evaluations for station blackout (SBO) events. For the purpose of the Ginna Station PSA, a SBO event is one in which all AC power is lost to the 480 V safeguards buses. A SBO event is evaluated with respect to transients, small-small and small loss-of-coolant accidents (LOCAs), and steam generator tube ruptures (SGTRs). All remaining initiators (i.e., large break LOCA, medium break LOCA, and ATWS) are assumed to result in core damage given a SBO event. The appendix is organized into evaluating the following scenarios:

a. Loss of turbine-driven auxiliary feedwater (TDAFW) pump at time zero;

b. Run Time of TDAFW pump;

c. Loss of TDAFW pump at six hours;

d. Seal LOCA issues; and

e. Probability of restoring offsite power.

B.1 Loss of TDAFW Pump at Time Zero

All SBO events require some form of SG cooling for decay heat removal. However, only the TDAFW pump can provide this cooling until offsite power is restored since it is the only AC independent source of feedwater. Consequently, it must be determined how long the plant can survive without SG cooling following a SBO event (i.e., assume the TDAFW pump fails at time zero).

The basis for determining the maximum duration of no AFW was based on MAAP runs SLOCA32, RUH2J, and FW01X (see Table 4-2). The first MAAP run (SLOCA32) shows that for a 0.75 inch LOCA with one safety injection (SI) pump and no AFW, fuel damage does not occur until 2.5 hours. It is recognized that there would be no SI pump following a SBO; however, this run does provide some insights. The second MAAP run (RUH2J), shows that for a SGTR with 1 AFW pump and no SI, fuel damage does not occur until 5.5 hours due to the availability of core cooling. The last MAAP run (FW01X) shows that following a loss of MFW event, the SGs dry out at 45 minutes with fuel damage at 2.3 hours with no AFW. Given the uncertainties associated with the MAAP code, and the fact that a single event tree heading must address the loss of AFW for all transients and up to 1" LOCAs, it will be assumed that offsite power must be restored within 1 hour (in order to use the AFW and SAFW systems) if the TDAFW pump fails at the time of the SBO event.

B.2 Run Time of TDAFW Pump

The TDAFW pump has been shown to be AC independent; however, this is only for a short period of time since the station batteries begin to deplete and ventilation (i.e., cooling) potentially becomes a concern. Ginna Station has been evaluated with respect to a SBO event lasting for up to 4 hours [UFSAR, Section 8.1.4.4]. However, 4 hours is based on the battery end of the life calculations in the year 2009 and not existing capabilities. Electrical engineering estimates that the batteries should have sufficient capability to allow the TDAFW pump to run for 6 hours or more given the current loading and battery capacity (i.e., 8 hour batteries at constant loading). Consequently, it will be assumed that if offsite power is not available within 6 hours, the TDAFW pump will fail due to battery depletion.

In addition to battery depletion, successful TDAFW operation is also dependent upon adequate ventilation and lube oil cooling. As described in Section 6.2.3, a human action (AFHFDALTTD) has been added to the model for operators failing to restore lube oil cooling utilizing the diesel fire pump. This cooling must be provided within 2 hours based on previous testing experience [UFSAR, Section 10.5.4.2]. With respect to ventilation, Section 6.11 describes the Intermediate Building Ventilation system. Necessary cooling to the TDAFW pump can be provided by either a fan capable of being powered by DG B, or by natural convection within the building using Fire Door F36. Cooling by either means provides all required ventilation support to the TDAFW pump.

Therefore, based on the above, it can be concluded that the TDAFW pump can be assumed to operate up to 6 hours following a SBO event provided that the batteries are available, lube oil cooling is restored within 2 hours, and Fire Door F36 is open.

B.3 Loss of TDAFW Pump at Six Hours

Given that the TDAFW pump is assumed to fail at 6 hours per Section B.2, it must be determined: (1) how long the plant will survive without SG cooling after 6 hours of TDAFW pump operation, and (2) can the plant survive for up to 6 hours with no injection capability for LOCAs.

The calculation of time to fuel damage following 6 hours of TDAFW pump operation is essentially based on the fact whether operators have depressurized the primary system. This can occur naturally via a LOCA, or by using the ARVs and pressurizer PORVs (using the nitrogen system) for other transients. Several MAAP runs have been performed in an attempt to identify the appropriate time for the various scenarios as follows:

a. MAAP run FW01Z shows that with one AFW pump available for the first 6 hours of a loss of MFW transient, the SGs do not dry out until 8.5 hours with fuel damage occurring at 10.8 hours. Thus, having AFW for the first 6 hours delays SG dryout for an additional 2.5 hours (versus only 45 minutes if AFW was lost immediately post trip per MAAP run FW01X).

b. MAAP run RUH2J shows that following a SGTR (0.664 inch LOCA) with only one AFW pump available, the break flow is significantly reduced by primary and system pressures essentially equalizing. However, the SG inventory eventually begins to deplete due to the RCS heatup caused by the initial loss of inventory through the ruptured tube. This depletion continues until the SG dries out at 4 hours with fuel damage at 5 hours.

c. MAAP run SLOCA33 shows that for a 1" LOCA, core damage is expected to occur within 2.25 hours due to the lost RCS inventory. This time is extended up to 2.75 hours if it is only a 0.5" LOCA (MAAP run SLOCA34). Therefore, for all LOCAs other than SGTRs, offsite power restoration within 2.25 hours is required.

Based on the discussions above, the following will be assumed for the Ginna Station PSA:

a. For SBO related transients which do not lead to loss of RCS inventory, offsite power must be restored within 10 hours (or 4 hours after the TDAFW pump fails) in order to prevent core damage.

b. For SBO related SGTRs, offsite power must be restored within 5 hours (i.e., prior to the TDAFW pump failure) in order to prevent core damage.

b. For SBO related LOCAs, offsite power must be restored within 2.25 hours (i.e., prior to failure of the TDAFW pump) in order to prevent core damage.

B.4 Seal LOCA Issues

As described in Section 4.2.2.3.2, a reactor coolant pump (RCP) seal LOCA is assumed to result if: (1) operators fail to trip a running RCP within 2 minutes after the loss of all support system cooling (i.e., component cooling water (CCW) and chemical and volume control system (CVCS)), or (2) seal cooling is not restored within 1 hour following loss of all support system cooling due to long-term seal degradation issues. The first scenario results in a 482 gpm/pump leakage rate while the second scenario results in a 21 gpm/pump leakage rate. Since a SBO event can lead to either scenario, and both leakage rates are within the small-small LOCA category, it must be evaluated whether a seal LOCA falls within the 2, 4, or 10 hour offsite power restoration time per Section B.3 (i.e., LOCA versus non-LOCA) restoration time.

For the first scenario, the failure of operators to trip a RCP within 2 minutes upon loss of all seal cooling is defined by event RCHFD00RCP which has a failure probability of 1.61E-02 (see Table 7-15). Table B-1 identifies a failure probability of 0.208 and 0.027 for the operators to restore offsite power within 2 hours and 10 hours, respectively. Therefore, it is conservative to assume that a SBO induced seal LOCA can use the 10 hour non-LOCA offsite restoration time since:

$$f_{SBO} * \text{RCHFD00RCP} * \text{4 Hour Restoration} < f_{SBO} * \text{10 Hour Restoration}$$

$$f_{SBO} * (1.61\text{E-}02) * (0.208) < f_{SBO} * (2.7\text{E-}02)$$

For the second scenario, Section 4.2.2.3.2 states that with a leakage rate of 21 gpm/pump, core damage will not occur until approximately 20 hours for a 2-loop plant like Ginna Station. The use of the 10 hour restoration time bounds this value.

Based on the above assessment, all SBO induced seal LOCAs will be treated as non-LOCA transients with respect to offsite power restoration times.

B.5 Probability of Restoring Offsite Power

The probability of restoring offsite power is based on previous industry history with respect to actual loss of offsite power events. NSAC-203 [Ref. 1] was reviewed to determine which offsite power events were applicable to Ginna Station. Per Section 7.3.1.2, a total of 26 loss of offsite power events occurred at nuclear power plants in the U.S. between 1980 and 1993 that are applicable to Ginna Station. The time for which it took to restore offsite power for each of these events was then used to generate a curve fit for use in the Ginna Station PSA [Ref. 2]. Table B-1 presents the results along with the results provided in NSAC-147 [Ref. 3] which provides generic offsite power restoration probabilities based on data between 1975 and 1989.

Table B-1
Offsite Power Restoration Times

Recovery Time (Hrs)	*Ginna Station PSA*	*NSAC-147*
0.5	0.493	0.546
1	0.355	0.42
2	0.208	0.287
3	0.133	0.208
4	0.09	0.156
5	0.064	0.122
6	0.049	0.098
7	0.039	0.08
8	0.033	0.068
9	0.029	0.059
10	0.027	0.053
11	0.026	0.049
12	0.025	0.045
13	0.024	0.043
14	0.024	0.042
15	0.024	0.04
16	0.024	0.04
17	0.024	0.039
18	0.024	0.039
19	0.024	0.039
20	0.024	0.039
21	0.024	0.039
22	0.023	0.04
23	0.023	0.04
24	0.023	0.04

B.6 References

1. NSAC-203, *Losses of Offsite Power at U.S. Nuclear Power Plants Through 1993*, April 1994.

2. TENERA, *Determination of LOSP Cumulative Recovery Failure Probability*, November 13, 1996.

3. NSAC-147, *Losses of Offsite Power at U.S. Nuclear Power Plants Through 1989*, March 1990.

APPENDIX C

PLANT-SPECIFIC DATA ANALYSIS SUPPORTING DOCUMENTATION

C.0 PLANT SPECIFIC DATA ANALYSIS SUPPORTING DOCUMENTATION

This appendix contains the supporting analyses and documentation with respect to the plant-specific data collection activity. The summary of information contained within this appendix can be found in Section 7.

C.1 General Assumptions

The following assumptions have been made in developing the estimates of plant-specific reliability parameters:

a. All failure rates and failure-on-demand probabilities are constant over the data window. This assumption is commonly used in PSA data analysis work and is required since the plant-specific data collected is presented in terms of the total number of failures experienced over a specified population exposure (i.e., separate times-to-failure are not available).

b. Uncertainty estimates can be represented with a log-normal distribution. Martz [Ref. 1] has investigated the influence of various basic event probability distributions on system unavailability distributions, and concluded that gamma, log-gamma, log-normal, and log-uniform basic event distributions yield similar system unavailability distributions. The log-normal distribution assumption used in this work package has been selected for its computational ease.

C.2 Plant-Specific Data Base

The plant-specific data collection effort is described in detail in Section 7. This data collection effort met the needs of the data analysis task; however, a program was necessary to more easily organize the data. This program was required since the initial data was provided on a component level while the data analysis task required it on a system and component type basis. Therefore, a dBASE® program, RGEDATA.PRG, was developed to determine the total number of failures and total associated exposure for component types (e.g., motor-operated valves, etc.) and failure modes (e.g., "fails to open") on a system basis. Note that RGEDATA.PRG also provides summarized maintenance unavailability data (total out-of-service hours and total on-line hours). In RGEDATA.PRG, the total on-line time is assumed to be equal to the total number of reactor critical hours during the data window (64,054.35 hours), multiplied by the size of the associated component population.

The only information that was not easily retrievable from the initial data was the exposure hours for calculating standby failure rates. For the Ginna Station PSA project, standby failure rates are used in place of demand failure probabilities for components which are not continuously operating in order to better evaluate the impact of testing frequencies. Therefore, the following equation was used to determine the exposure hours for components that do not "transfer" to another position (e.g., pumps, diesel generators, etc.):

$$T_{stby} = (N_{pop} \times T_{dw}) - T_{op} - T_{repair} \tag{1}$$

where:

$$\begin{aligned} T_{stby} &= \text{total population standby exposure time} \\ N_{pop} &= \text{population size} \\ T_{dw} &= \text{calendar time in data window} \\ T_{op} &= \text{total population operating time} \\ T_{repair} &= \text{total population repair time} \end{aligned} \tag{2}$$

For the data window used to collect Ginna-specific data, the value of T_{dw} is given by:

$$\begin{aligned} T_{dw} &= 9\ yr \times 8760\ h/yr + 3\ leap\ yrs \times 24\ extra\ h/leap\ yr \\ &= 78912\ h \end{aligned} \tag{3}$$

For components that can "transfer" position (e.g., valves), standby exposure times were determined by finding the exposure time of a relevant associated failure mode. Table C-1 illustrates this concept. Table C-2 contains the output from RGEDATA.PRG.

C.3 Statistical Analysis of Plant-Specific Data

For constant failure rates (e.g., operating and standby failure rates), the following equations give the estimated mean value and 90% confidence bounds [Ref. 2]:

$$\begin{aligned} \bar{\lambda} &= \frac{n}{T} \\ \lambda_{0.05} &= \frac{\chi^2(2f,\ 0.05)}{2T} \\ \lambda_{0.95} &= \frac{\chi^2(2f+2,\ 0.95)}{2T} \end{aligned} \tag{4}$$

where:

$$
\begin{aligned}
n &= \text{number of observed failures}\\
T &= \text{time period over which failures were observed}\\
\bar{\lambda} &= \text{mean failure rate}\\
\lambda_{0.05} &= \text{5\% confidence bound on failure rate}\\
\lambda_{0.95} &= \text{95\% confidence bound on failure rate}\\
\chi^2(\nu, p) &= p\text{th percentile of a chi-squared distribution}\\
&\quad\ \text{with } \nu \text{ degrees of freedom}
\end{aligned}
\tag{5}
$$

For constant failure-on-demand probabilities, the following equations give the estimated mean value and 90% confidence bounds [Ref. 3]:

$$
\begin{aligned}
\bar{p} &= \frac{n}{D}\\
p_{0.05} &= \frac{n\,F_{0.05}(2n,\ 2D-2n+2)}{D - n + 1 + n\,F_{0.05}(2n,\ 2D-2n+2)}\\
p_{0.95} &= \frac{(n+1)\,F_{0.95}(2n+2,\ 2D-2n)}{D - n + (n+1)\,F_{0.95}(2n+2,\ 2D-2n)}
\end{aligned}
\tag{6}
$$

where:

$$
\begin{aligned}
n &= \text{number of observed failures}\\
D &= \text{number of demands}\\
\bar{p} &= \text{mean demand probability}\\
p_{0.05} &= \text{5\% confidence bound on demand probability}\\
p_{0.95} &= \text{95\% confidence bound on demand probability}\\
F_p(\nu_1, \nu_2) &= p\text{th percentile of an F-distribution}\\
&\quad\ \text{with } \nu_1 \text{ and } \nu_2 \text{ degrees of freedom}
\end{aligned}
\tag{7}
$$

The 90% confidence bounds may be mapped to a log-normal uncertainty bound by [Ref. 4]:

$$ef = \begin{cases} \sqrt{\dfrac{x_{0.95}}{\bar{x}}} & \text{for } x_{0.95} \geq 3.87\ \bar{x} \\ \exp\left[z_{0.95} \left(z_{0.95} - \sqrt{z_{0.95}^2 - 2 \ln\left(\dfrac{x_{0.95}}{\bar{x}}\right)} \right) \right] & \text{otherwise} \end{cases} \tag{8}$$

where:

$$\begin{aligned} ef &= \text{log-normal error factor} \\ z_{0.95} &= \text{95th percentile of the standard normal distribution } (\approx 1.645) \end{aligned} \tag{9}$$

Equations (4) through (9) are implemented in the CARP computer program [Ref. 5].

C.4 Final Reliability Parameters

In general, reliability parameters based on Ginna-specific experience were recommended for final integrated logic model quantification. For certain component types and/or failure modes, few (or no) occurrences have been observed at Ginna Station. Consequently, strict application of Equations (4) through (8) is questionable (or, in the case of no occurrences, impossible). In these cases, a Bayesian analysis was performed to combine the Ginna-specific experience with appropriate generic data. The Bayesian process has been implemented through the concept of conjugate prior distributions (i.e., gamma distributions for failure rates, and beta distributions for failure-on-demand probabilities). Specific calculational steps in the Bayesian analysis are shown in the following sections.

C.4.1 Development of Prior Distribution

The generic data supplied is expressed in terms of a log-normal distribution. To develop the prior distributions, the principle of moment matching was used:

$$\begin{aligned} \sigma &= \frac{\ln ef}{z_{0.95}} && \text{logarithmic standard deviation} \\ Var &= \bar{x}\ (e^{\sigma^2} - 1) && \text{variance} \end{aligned} \tag{10}$$

Then, for failure rates, the parameters of the prior gamma distribution in terms of the log-normal mean and variance are:

$$\alpha = \frac{\bar{x}^2}{Var}$$
$$\beta = \frac{\bar{x}}{Var} \tag{11}$$

For failure-on-demand probabilities, the parameters of the prior beta distribution in terms of the log-normal mean and variance are:

$$\alpha = \frac{\bar{x}^2\,(1 - \bar{x})}{Var} - \bar{x}$$
$$\beta = \frac{\bar{x}\,(1-\bar{x})}{Var} - 1 + \bar{x} \tag{12}$$

For failure rates, the parameters of the posterior gamma distribution are:

$$\alpha' = \alpha + n$$
$$\beta' = \beta + T \tag{13}$$

For failure-on-demand probabilities, the parameters of the posterior beta distribution are:

$$\alpha' = \alpha + n$$
$$\beta' = \beta + D - n \tag{14}$$

C.4.2 Development of Final Distribution

The principle of moment matching was used to convert the conjugate posterior distributions into a long-normal uncertainty distribution. For failure rates, the mean and variance of the posterior gamma distribution in terms of the gamma distribution parameters are:

$$\bar{x}' = \frac{\alpha'}{\beta'}$$
$$Var' = \frac{\alpha'}{\beta'^2} \tag{15}$$

For failure-on-demand probabilities, the mean and variance of the posterior beta distribution in terms of the beta distribution parameters are:

$$\bar{x}' = \frac{\alpha'}{\alpha' + \beta'}$$

$$Var' = \frac{\alpha'\beta'}{(\alpha' + \beta' + 1)(\alpha' + \beta')^2} \qquad (16)$$

The log-normal error factor in terms of the posterior mean and variance is:

$$ef' = \exp\left[z_{0.95}\sqrt{\ln\left(1 + \frac{Var'}{\bar{x}'^2}\right)}\right] \qquad (17)$$

Equations (10) through (17) are also implemented in the CARP computer program.

C.5 Plant-Specific Data Results

The following section contains the significant findings of the plant-specific data collection task. A summary report of all final reliability parameters (sorted by system, component type, and failure mode) is provided in Tables C-2 and C-3. Table C-2 contains the detailed plant-specific information while Table C-3 provides the plant-specific estimates from Equations (4) through (9), the relevant generic data, the results of any Bayesian analysis performed, and the final values. Note that the value contained in the row labeled *Final* and the column labeled *P1* is the final log-normal error factor for use in uncertainty analyses. Events for which additional plant-specific data and information was used (e.g., flags) are provided in Table C-4. Events which are not listed in Table C-3 or C-4 utilize generic data as described in Table 7-1.

The findings below are organized by system and include all major assumptions, significant events, and data trends or clarifications. All hard copies of MWRs, Running Hour Logs, and A-25.1, A-25.2, and A-52.4 forms are maintained by RG&E in the PSA Project Filing System for future reference. Included with these records are all original screening and analysis tables that were used in developing the data values. The system discussions are preceded by general notes which were used in the development of the data.

a. Components that have changed function, or been removed from service since 1988, were excluded from the data base (e.g., Main Feedwater Pump recirculation valves 4262 and 4263).

b. Obvious human errors are not considered as failure events; however, they are identified in the individual system comment sections for consideration by system modelers.

c. For PTs that have separate quarterly (Q) or monthly (M) sections, an estimate of the number of times each section has been performed was made using the total number of tests and ratioing it based on the relative frequencies of the different parts. For example, if PT-16 was performed 84 times, it is assumed that the quarterly and monthly steps were performed 28 times and just the monthly steps the remaining 56 times.

d. In the screening tables, a valve that fails to operate during a test due to a local switch failure, but which normally receives an automatic remote signal, was classified as a functional failure. These events can be screened out later through a detailed review of the elementary drawings, if desired.

e. If a pump control circuit is found to be inoperable (e.g., fuse burned out), the pump is assigned a failure to start.

f. Passive filters/strainers are considered to have functionally failed due to plugging if an obvious consequence is reported (e.g., substantially reduced flow, increased room temperatures, etc.).

g. A failure is assigned to a pump if either the pump or its breaker failed to function properly. However, only demands of the pump and breaker together are considered as valid pump demands (i.e., demands involving just the pump breaker are not included since the pump was not physically demanded).

h. For common cause failures, the subject components are not credited with a failure in this work package; however, all applicable demands are accounted for (i.e., both for the subject components and all interfacing components). This approach allows independent and common cause events to be treated separately.

i. For pumps, fans and air compressors, breaker events are included with the parent component consistent with [Ref. 6].

j. The review of A-25.2s was performed using the personal index maintained by the I&C PM analyst, the Central Records index (which is incomplete, especially for years 1987-88), and hardcopies of A-25.2 forms from 1987-88. However, some A-25.2s from 1984-86 have not been entered into the Central Records index. Hardcopies of A-25.2s between these dates were not collected since very few of the events identified on these forms were found to be significant (e.g., indicator out of calibration), and the I&C PM analyst index probably already included them. In addition, it was found that most events listed on A-25.2s were already identified on MWRs, A-25.1s or A-52.4s.

k. Demands are not considered for non-failure related corrective maintenance (i.e., incipient events) performed during shutdown. The only exception of this is those events associated with PM activities. This is a conservative approach.

l. For control valves, only the failure mode of "failing to control flow" was identified while the valve was operating. When the valve was not controlling flow, either "transfers closed" or "transfers open" was used depending on the valve's position. The valve transferring "open" or "closed" was not considered when the valve was controlling flow.

m. For valves which are either constantly open or closed (i.e., for the 9 year period), failure modes "transfers closed" and "transfers open" were applied for the entire 9 year period regardless of whether the valve had flow through it during the whole period. This is because the valve can transfer position whether it has flow through it or not.

C.5.1 *Reactor Coolant System (RCS)*

a. On April 18, 1985, failure of a pressure controller (PC-431K) caused inadvertent actuation of pressurizer spray valves 431A and 431B [ref. A-25.1, A-25.2]. These two valves were categorized as transferring open. Also, on two separate occasions (November 20, 1986 and February 27, 1987), a pressure controller (PC-431H) was out of calibration causing premature opening of pressurizer spray valve 431A [ref. A-25.2s]. Neither of these incidents were considered to be a functional failure of 431A, since the only effect in both cases was the valve opening at approximately 25 psia below the normal setpoint.

b. On December 11, 1986, AOV-508 failed its stroke test, opening in 44.89 seconds compared to the required 13 seconds [ref. MWR 86-4837]. This event was determined to be an incipient failure, since the valve could still close. As such, no functional failure was assigned to the valve.

c. PORV leaking events were considered to be non-failures, unless they resulted in a reactor transient.

d. There were several instances of equipment alarming due to high containment temperatures. These were resolved by starting another recirculation fan [ref. A-25.1 on 3/13/80, 5/30/80, and 7/25/85].

e. The Reactor Makeup Water (RMW) Pump is used to fill the Pressurizer Relief Tank to cover the spargers. This occurs approximately once or twice a year [16]. Therefore, it was assumed that there were 9 demands for a total of 1 hour.

f. The RCP standpipe is filled only 1-2 times a year [16]. Therefore, it was assumed that there were only 9 demands for components related to the standpipe for a total of 1 hour.

g. It was assumed that the RCS common header components were demanded 1/2 the total number of startups since the primary system may have been already heated up and operating (i.e., hot standby). This is equivalent to: 1/2 (22 trips + 9 refueling outages) = 15.

h. The Reactor Coolant Drain Tank flowpath was assumed to be used for 2 hours during each refueling outage for maintenance purposes.

i. Based on a review of the A-25.1 records, PORVs 430 and 431C were assumed to have opened a total of 2 and 5 times, respectively, following a plant transient. The majority of these events were attributed to the SGTR event.

C.5.2 *Emergency Safety Features Actuation System (ESFAS)*

a. ESFAS was only evaluated with respect to out of service time at power due to equipment failures since it is not normally removed from service for testing or PM activities (per C. Edgar of I&C/Electrical Maintenance). Also, functions such as containment isolation are included in their respective system (i.e., not ESFAS).

C.5.3 *Residual Heat Removal System (RHR)*

a. On May 1, 1983, RHR pump "B" Refueling Water Storage Tank suction valve 704B, was found in the closed position [ref. A-25.1 and LER 83-017]. The valve was apparently left shut following a refueling outage. Since this was a human error, no functional failure was assigned to the valve.

b. From January 1, 1980 through December 31, 1988, there were 13 instances of a MOV in the RHR system failing to open or close on demand. These failures resulted from a variety of causes, although torque switch and packing problems were predominant.

c. The new recirculation flowpaths for RHR were not added until the 1989 refueling outage. Prior to these flowpaths, recirculation was accomplished through FE628 which is now blanked off. This previous flowpath was evaluated for data analysis purposes.

d. During shutdown, the RHR pumps take suction through valves 700 and 701, and provide flow through valves 720 and 721. This was the configuration assumed during shutdown for demand and exposure counts.

e. It was assumed that 5% of the RHR pump's run time was due to testing, while the remaining time was due to shutdown conditions. For Pump A, this equals 7709 x 5% = 385 hours; for Pump B, this equals 5593 x 5% = 280 hours.

f. One RHR pump was assumed to be operating whenever the reactor was not critical, minus a 5% reduction for startup and immediate shutdown time periods. This equals 14,115 hours of at least one RHR pump operating.

g. There were two instances of small pipe leaks in the RHR system [Ref. A-25.1s on 11-25-80 and 1-13-82].

h. On September 23, 1982, the breaker for MOV-850A was found closed but not locked. Electricians taking current readings had inadvertently left the lock off [ref. A-25.1]. No failure was assigned since the valve could still perform its function.

i. On March 7, 1984, while shifting from the Reactor Coolant Drain Tank (RCDT) pump to the Low Pressure Purification Pump for draining the RCS, valves 851A and 851B were opened prior to shutting 850A. This caused loop levels to register zero, sump B indicating lights for the 8" level to display, and the pressurizer level to drop to 150". MOV 856 was then shut, the operating RHR pump was secured and containment was evacuated. No failure was assigned since this is an operator error at shutdown [ref. A-25.1].

C.5.4 *Diesel Generator (DG) System*

a. On January 18, 1980, DG "A" would not accept additional load after completing its 30 minute run at 1800 KW, thereby failing PT-12.1. The cause was an improper manual governor speed control setting [ref. A-25.1, A-52.4, MWR 80-224]. This event was classified as a failure to run.

b. On December 8, 1988, DG "A" tripped on overspeed while performing PT-12.1, due to air start solenoid valve 5933B failing to close [ref. A-25.1, A-52.4, MWR 88-8564]. This event was classified as a functional failure of DG "A" to start.

c. There were several instances where a DG started properly but failed to close onto its respective bus(es). These events, classified as DG output breaker failures, are included in the AC Electrical Distribution System.

d. On December 17, 1984, a "B" DG lube oil heater experienced a ground fault. The heater was jumpered out, leaving three of four heaters still in service [ref. A-25.1]. This resulted in an undesirable condition; however, neither DG "B" nor 480V buses 16 or 17 were made inoperable. Consequently, no failure was assigned.

e. On October 3, 1980, when starting DG "A," the barring device and pinion gear slipped and attempted to engage [ref. A-25.1]. On October 10, 1980, the barring device for DG "B" was found to be engaged [ref. A-25.1]. Neither event was considered to be a failure of the DG since the barring device is only used to "lock" the DG when being transported. If the DG attempted to start with the device engaged, the DG would tear up the device, but still operate (per Results and Tests).

f. On August 17, 1988, the DG "A" governor was not responsive and the governor control motor driver potentiometer was replaced [ref. MWR 88-5519]. No functional failure was assigned since the DG would still be able to accomplish its safety function (per Results and Tests).

g. Form A-52.4s written against the DGs for air compressor problems are not considered as DG failures or maintenance unavailability, since the compressors are not required for successful DG operation. Also, the repair of the compressors does not require the DG to be taken out of service. Consequently, only events which completely removed the DG air start function were considered.

h. DG fuel oil transfer pump run time is assumed to be 18 hours per year [16].

i. According to the Ginna Technical Specifications, each time one DG is taken out of service, the other DG must be tested. These demands are reflected in the column for "Interface Related" demands on Attachment 6.8.

j. On May 10, 1988, the Control Room received a high temperature alarm for "A" DG Oil Temperature. Operators started the exhaust fan for the room and the alarm subsequently cleared; therefore, no failure was assigned [ref. A-25.1].

k. Fuel Oil Transfer pump recirculation was assumed to not be required, and as such, was not included in the analysis of the DGs.

l. The DG starting air compressors were assumed to run for 2 minutes after each DG start [16].

m. Since the DG has only been used for testing purposes (besides a few bus undervoltage starts), the DG start attempts number obtained from the Official Record Log was set to zero and only demands from testing, PMs, failure events, and interface-related events were considered.

n. It was conservatively assumed that components associated with the fuel oil transfer system were only demanded during a test of the DG, not for failure or interface-related events.

C.5.5 *Chemical and Volume Control System (CVCS)*

a. Charging pump "B" and "C" discharge relief valves to the Volume Control Tank (284 and 283, respectively) experienced 13 excessive leakage failures over the nine year data period. In each case the subject valve was either replaced or rebuilt. No cause for these failures is provided in the data records.

b. The boric acid blender makeup control AOV to the Volume Control Tank, 110C, experienced eight functional failures over the data period considered. The failure modes included failure to close, transfer open, and failure to operate properly. The principal failure causes included seat leakage and switch failures. In the majority of cases, the corrective action involved replacing the valve diaphragm. Seven of the failures occurred within a three year period (June 1980 through June 1983) and only one failure occurred in the last five years of the data period (1984-88).

c. The Reactor Makeup Water AOV to the boric acid blender, 111, and the Loop "B" nonregenerative heat exchanger outlet AOV, 135, each experienced five functional failures. The principal cause was failure of the auto controller (FIC-111 and PC-135, respectively). Eight of the ten events occurred prior to 1985.

d. Broken or burned belts in the varidrive unit have consistently been a cause of failure for charging pumps "B" and "C." Overall, charging pumps "B" and "C" experienced 4 and 5 functional failures, respectively. There were no failures of charging pump "A" during the data period.

e. On October 27, 1988, while performing S-9W, "Blender Flushing," no boric acid flow was obtained [ref. A-25.1, A-52.4]. The cause was determined to be boron solidification in a small section of pipe downstream of check valve 355. The support on that section of pipe apparently acts as a heat sink for the heat trace system. This event also occurred on February 20, 1985 [ref. A-25.1 MWR 85-552]. In addition, on December 8, 1988, while performing RSSP-5.0, no flow was observed from vent valve 348C [ref. A-25.1, A-52.4]. Piping in the MOV-350 flow path was plugged and the line was heated to flush it.

f. Seat leakage of CVCS valves that results in increased T_{ave} (e.g., 110A, 110B, 110C, etc.) was considered to be a valve transfers open unless it was readily apparent that the valve was just operated, resulting in a failure to close.

g. Each pair of Boric Acid and Reactor Water Makeup pumps are started once for sampling each Monday, Wednesday and Friday, and started once for auto make-up each day of the week (per Operations).

h. AOV-110A failed to open twice due to mechanical binding [ref. A-25.1s and A-52.4s on September 24, 1985 and October 1, 1985].

i. On April 20, 1981, leaking relief valve 209 caused a Plant Radiation Emergency until it could be isolated by a plug [ref. A-25.1 and MWR 81-895].

j. There were seven piping leaks associated with the CVCS system. Most of these were minor leaks that were repaired by welding or using temporary patches. Only the event on May 6, 1983 was considered a failure since the pipe ruptured during a system hydro at only 140 psig [ref. A-25.1].

k. On January 15, 1981, the suction valve for the "A" Boric Acid Pump (267) was found to be partially closed resulting in low discharge pressure for the pump. No cause was listed [ref. A-25.1 and A-52.4].

l. On January 7, 1984, a suspected steam bubble in CVCS prevented boration of the Reactor Coolant System through the normal path (354). The emergency boration path through 350 had to be used [ref. A-25.1]. This event was included in the data as a pipe plugging failure.

m. There were three events related to erratic RCP seal leakoff and injection temperature indications due to high containment temperatures. Containment recirculation fans were started to adjust the air temperatures around the RCPs and the erratic parameters subsequently stabilized.

n. AOV-427 is used for the regenerative heat exchanger and was assumed to be demanded once every startup following a refueling outage (9).

o. The boric acid blender was assumed to be used approximately four times a day [16].

p. For AOVs 200A, 200B, and 202, typically only one or two valves are normally open at power [16]. Consequently, it was assumed that only one valve is open at a time so that each valve is open for a total of 21,351 hours (64,054 Rx Critical Hours/3 valves). They are not rotated at power so the number of demands per valve equals (22 reactor trips + 9 refueling outages)/3 valves = 10.

q. There were numerous failures of the BAST level transmitters which were caused by boric acid hardening in the sensing lines. These are the result of the design of the transmitter sensing lines in that boron tends to crystallize in the lines inside the tank. Attempts to heat trace these lines have not proven successful in resolving the problem.

C.5.6 *Safety Injection (SI) System*

a. SI pump "C" experienced six failures to start from 1980 through 1988, all of which involved 480V breaker problems. Four of the events were attributed to the Bus 16 breaker, while the other two events were caused by the failure to fully rack in the breaker following test and/or maintenance. Included with these latter two events was one common cause failure with SI pump "B". All of the events involving the Bus 16 breaker occurred over an 18 month period during 1980-1981. However, these events and three years of start demands for Pump C were eliminated from the data since a Engineering modification corrected this problem during the 1983 refueling outage.

b. The only SI pump run failure was related to SI pump "C." On March 3, 1981, a review of the previous day's test run revealed that the pump thrust bearing approached the procedural limit of 160°F after just 45 minutes of run time. The problem was attributed to excessive sediment in the pump cooling lines and most likely would have caused problems over an extended period of time.

c. There has been noticeable leakage through the SI system injection check valves on two occasions which caused system pressurization and accumulator dilution problems [ref. A-25.1s on June 5, 1988 and July 15, 1988].

d. The SI system can only be used for filling the accumulators or for a true actuation; however, only SI pumps "B" and "C" can be used for filling the accumulators. Since the total number of logged starts for pump "A" is 52, and there were only 3 SI actuations at power over the subject time period, it was assumed that 49 of the starts were test or post-maintenance related. Consequently, 49 start attempts were subtracted from the other two pumps normal start attempts values obtained from the Official Record Logs.

e. Only SI pumps "A" and "B" were assumed to have started on an SI signal. Also, each SI event was assumed to have only lasted 1 hour each (including the SGTR event) for a total of 3 hours. It was also assumed that there was no transfer to the RWST for any of the events.

f. The run time for testing, actuations, and accumulator fills was calculated as follows. It was assumed that the accumulator fill time was proportional to the number of demands.

Pump	Total Time from Logs	SI	Accumulator Filling	Test
A	33.25	3	0	30:25
B	140.00	3	(137 hrs/125 events)(125-49)=83	137-83=54
C	90.06	0	(90 hrs/156 events)(156-49)=62	90-62=28

g. The total number of start attempts for common components affected by accumulator fill activities was assumed to be the sum of start attempts for pumps "B" and "C" that were attributed to accumulator fill actions. This was done since only 1 pump is used at a time for this purpose. This approach was also used for run times for these common components.

h. Valve actuations for accumulator fill were taken from Procedure S-16.3, "RWST Water Makeup to Accumulators."

i. At the beginning of a test at shutdown, valve lineups were assumed to be those described in Procedure 0-2.2.

C.5.7 *Main Feedwater (MFW) System*

a. On January 8, 1981, the "B" main feed pump tripped on seal water low differential pressure. Cold outside air blew down through the exhaust fan duct and froze up one of the feed pump differential pressure switch sensing lines [ref. A-25.1].

b. On March 26, 1988, a "Feed Pump Seal Drain Tank Hi Level or Hi Temp" alarm was received in the control room. The "A" main feed pump seal drain tank was overflowing due to overheating of the inboard seal. The problem was found to be a structural (metal) failure of the impeller and categorized as a failure to run of the pump [ref. A-25.1].

c. On May 13, 1984, a "Feed Pump Seal Water Lo Differential Pressure" alarm was received in the control room, followed almost immediately by a trip of the "A" main feed pump. The condensate bypass valve was inadvertently left open during startup, causing the problem [ref. A-25.1]. This event is attributed to human error, and is not considered to be a failure of the pump. This same event also occurred on April 8, 1985 and resulted in a trip of the "B" main feed pump and subsequent reactor trip.

d. Components in the common header for MFW were assumed to be demanded every startup which is equivalent to 22 reactor trips and 9 refueling outages for a total of 31. They were also assumed to have flow through them for all periods when the reactor is critical (64,054 hours).

C.5.8 *DC Electrical Distribution System*

a. On December 3, 1985, battery charger "1A1" failed due to a control circuit card failure [ref. A-25.1, A-52.4, A-25.2, MWR 85-3396].

b. On February 24, 1987, battery charger "1A1" was found not functioning due to a blown fuse on the output side [ref. A-25.1, MWR 87-1144].

c. On July 6, 1981, invertor "1B" switched to its alternate power supply and could not be switched back [ref. MWR 81-1789]. The failure only involved the invertor switch, not the invertor itself. However, since the switch is a subcomponent of the invertor, this event was counted as an invertor failure. A similar event also occurred on February 11, 1986 [ref. A-25.1].

d. Operating hours for DC system components are assumed to be calendar time (i.e., 9 years).

e. On November 20, 1987, the Technical Support Center (TSC) invertor failed causing the loss of the plant computer and telephone system. The backup power source had been de-energized three days earlier due to computer transients it was causing [ref. A-25.1]. Consequently, when the normal power source failed, the invertor was lost.

f. On December 8, 1980, water from a spilled mop bucket in the relay room leaked through a bolt hole onto Battery Charger "1A1" causing it to fail [ref. A-25.1].

g. On June 26, 1981, water was discharged from the Relay Room Manual Deluge System causing various control room alarms such as "Battery Bank Ground" and "Safeguard DC Failure." The cause was later determined to be an undersized drain flow path in the deluge system which allowed water to flow to the spray nozzles during testing. Procedures were subsequently revised [ref. A-25.1].

h. On December 14, 1982, the control room received a "Battery Bank Ground" alarm on the main control board. Operations then found that a sprinkler system had frozen and ruptured and was dripping water onto the security DG. The sprinkler system was then isolated [ref. A-25.1].

i. On March 11, 1983, an individual climbing in the Battery Rooms stepped on breaker for Battery Charger "1A" and inadvertently opened it. Since it was discovered and corrected immediately, no failure was assigned, and there was only 10 minutes of maintenance out of service time [ref. A-25.1].

j. On May 11, 1983 during cold shutdown, a spurious battery ground caused two actual containment ventilation isolation signals in 5 minutes. No cause was found [ref. A-25.1].

C.5.9 *Auxiliary Feedwater (AFW) System*

a. There were several observed instances of AFW pump suction relief valves lifting and/or leaking. However, none of these events were attributed to failures of the relief valves for the reasons described below:

1. AOV-4294 frequently failed to regulate flow from the condensate pump discharge to AFW causing system pressure to increase to the relief valve setpoint. Therefore, this is a failure of AOV-4294, not the relief valves.

2. If check valves downstream of the pumps go closed prior to pumps reaching full stop, the relief valves will lift. This is a system design issue, not a failure of the relief valves.

b. In December 1983, insulators accidentally stepped on the TDAFW pump trip throttle valve and closed it. This was considered to be a failure of the pump to start since it was not observed for several days [ref. A-25.1].

c. Since there were many known failures of check valves in AFW, if an A-52.4 was written for "repair of check valve...," but no MWR was found, it was assumed that the check valve failed to close.

d. It was assumed that since there were MOVATS related A-52.4s for MOVs 4000A, 4000B, 4007 and 4008, it was not necessary to account for PMs listed on Attachment 6.4 since the number of MOVATS and PM events were essentially the same.

e. The motor-driven AFW pumps are used for many purposes. However, in some cases, bypass valves 4480 and 4481 are used in place of the main control valves 4007 and 4008. The following table shows this comparison (B - bypass, M - main):

Pump	Startup	Shutdown	PT-M	PT-Q	RSSP	Chemical	Trip
A	B	B	M	B/M	B/M	B	M
B	B	B	M	B/M	B/M	B	M

Since the startup, shutdown, and chemical addition configurations are expected to dominate the pump run times, it was assumed that the bypass valves were used 75% of the time. It was also assumed that for 25% of this time, recirculation valves 4304 and 4310 would have to be used in conjunction with the bypass valves due to limited flow conditions.

f. The operational time for components common to all three AFW pump trains was calculated as follows:

a. 4074 (4075) = (A Recirc) + (B Recirc) + (TDAFW)
= 361 + 315 + 87 = 763 hours

b. 4070 (4071) = (25% of time A and B operate together) + (75% of Pump A) + (75% of Pump B) + (TDAFW pump)
= .25[(1444 + 1260)/2] + .75(1444) + .75(1260) + 87 = 2453

g. During startup, shutdown, and chemical addition activities, typically only one AFW pump is used. For these cases, cross-tie valves 4000A and 4000B are opened and flow is provided to both steam generators. This configuration was assumed to occur 75% of the time (i.e., when the bypass control valves are used). Therefore, the following was assumed for component demands:

a. A Train Discharge Valves = .5[75%(B pump starts)] + A pump starts
= .5[.75(385)] + 450 = 594 demands

b. B Train Discharge Valves = .5[75%(A pump starts)] + B pump starts
= .5[.75(450)] + 385 = 554 demands

The demand values from the opposite trains were divided in half since operations is instructed to only run an AFW pump for two hours before switching. Consequently, it was assumed that for 50% of the time, the valves were already opened. For time calculations, the following was used:

c. A Train Discharge Valves = 75%(B pump time) + (A pump time)
= .75(1260) + 1444 = 2389 hours

d. B Train Discharge Valves = 75%(A pump time) + (B pump time)
= .75(1444) + 1260 = 2343 hours

e. 4000A/B = 75%(A pump time + B pump time) = .75(1444 + 1260) = 2028 hours

h. On April 21, 1988, a through wall leak was found upstream of 4001 (TDAFW to S/G "A"). The line was isolated and repair welds were made [ref. A-52.4 and MWR 88-3078].

i. On January 2, 1985, a faulty pressure switch for the TDAFW pump caused arcing and high voltage spikes in the DC Electrical System. This resulted in multiple alarm lights and the loss of the audible alarm in the control room [ref. A-25.1]. The same problem occurred again in June 1985 [ref. A-25.1s on June 7 and June 21].

C.5.10 *AC Electrical Distribution System*

a. On April 21, 1982, Bus 17 tripped out on undervoltage when the "B" RCP motor was started during startup operations. Operations could not duplicate the event [ref. MWR 82-1135 and A-25.1]. This event was not considered a failure since it occurred while operators were starting a RCP which would not be expected to occur following an accident.

b. In March 1988, the undervoltage relay device for Bus 11B failed to function properly (stuck). This was not considered a failure since the bus continued to operate and would have most likely tripped if power was lost to it [ref. A-52.4, MWRs 88-2396 and 88-2400].

c. On January 21, 1985, the offsite electrical distribution system was at 59.9 Hz causing both DGs to be started. The problem was caused outside the RG&E system, and as such, no failure was assigned [ref. A-25.1].

d. On July 16, 1988, a fault in Station 13A (switchyard) caused power to be lost to the 767 circuit to Aux Transformer 12B. All safeguards busses became de-energized and the DGs started [ref. A-25.1 and LER].

e. In 1987 and 1988, there were 4 failures of DC throwover relays related to safeguards busses. These switches enable transfer to another DC source for control power. Since there are two sources of DC control power, repair of one source does not disable the bus. All relays were subsequently replaced.

f. On September 3, 1988, a low voltage alarm was raised on Bus 16. The associated DG started but did not close in on the bus since the normal power to the bus was maintained in error. Bus 16 was then manually loaded onto the DG. The cause of the event was a bad solid state switchboard. This event was classified as a failure of Bus 16 since the board was considered to be a subcomponent of the bus [ref. A-25.1, A-25.2 and A-52.4].

g. In May 1982, it was discovered that during a modification, the wiring for Breaker 52/EG1B1 (DG to Bus 16) was incorrectly modified causing CCW Pump 1B to <u>not</u> initially trip off Bus 16 if a SI signal was received. It was determined that the DG could adequately handle this load; therefore, no failure was assigned [ref. A-25.1].

h. On September 10, 1980, while performing PT-12.2, the "B" DG failed to close onto Bus 16 (breaker 52/EG1B1). The failure was caused by a misaligned guide pin in the closing relay [ref. A-25.1, A-52.4, MWR 80-2394].

i. It was assumed that the Technical Support Center DG Day Tank Pump was used every time the DG was demanded. It was also assumed that the pump ran for 1/3 the time of the DG, which is consistent with the two main DGs. This equals 108 hours/3 = 36 hours.

j. There were several instances of the main Ginna transformer being doused by the fire water system. No real fire was ever discovered and the operability of the transformer was not affected.

k. On April 14, 1981, Breaker 767, normal feed to transformer #6 in the switchyard, was lost. This caused a loss of Busses 12A, 12B, 14, 16, 17 and 18. Both DGs started and loaded as required; however, the charging, SW, and condensate booster pumps, and containment recirculation fans were lost until the DGs fully loaded. Operations also received a Containment Isolation signal. The plant ranback ~10% but did not trip since Busses 11A and 11B were available [ref. A-25.1].

l. On July 23, 1982, an electrician inadvertently tripped the breaker for MCC A while troubleshooting Bus 13. He immediately reset the breaker. This was not considered as a failure of the MCC since it was of such short duration.

m. On March 30, 1985, while at cold shutdown, the door to RCP "B" breaker cabinet was closed causing the differential lockout for Bus 11B to activate, tripping the bus. The operator then tripped RCP "A" due to loss of pump instrumentation from Instrument Bus D. Power was restored by resetting the relay [ref. A-25.1]. This event was not classified as a failure since no personnel would be expected to be in this cabinet following an accident.

C.5.11 *Main Steam (MS) System*

a. A number of instances occurred where an MSIV failed to close completely during a test. However, these events were not considered to be failures since the MSIVs are not designed to fully close except under full flow conditions (i.e., they are flow assisted valves).

b. On May 7, 1982, the "B" MSIV solenoids failed to energize when actuated from the main control board [ref. MWR 82-1259]. The solenoid coils were replaced and the event was classified as a failure of the MSIV to open since the plant was at cold shutdown. In addition, two instances occurred whereby the "B" MSIV failed to close at power. The first occurred on June 9, 1983 and resulted from a failure of switch PC-946A [ref. A-25.1, MWR 83-1796], and the second occurred on February 7, 1987, with no root cause identified [ref. A-25.1].

c. On February 16, 1987, AOV-3410 failed to operate when manually stroked with its local handwheel. Investigation showed the valve seat to be steam cut [ref. A-25.1].

d. The TDAFW pump steam admission valve 3505A experienced two failures due to control switch problems. On October 3, 1980, 3505A failed to close due to a bad auxiliary switch [ref. A-25.1], and on March 10, 1988, the valve failed to open due to a faulty torque switch setting [ref. MWR 88-1941].

e. On May 23, 1988, TDAFW pump steam admission check valve 3504B was found to not be moving freely. The valve had a steam cut on the actuator shaft [ref. MWR 88-3786]. This event was classified as a failure of 3504B to close.

f. Main steam instrumentation events that could not be directly attributed to a specific component in the data base were excluded from the analysis.

g. Operating hours for main steam system components are assumed to be the reactor critical hours.

h. The main steam safety valves do not typically lift on a reactor trip unless there is an abnormal occurrence. Therefore, the safety valves were only assumed to have lifted during the SGTR event (per B. Eliasz of NS&L).

i. The MSIVs were assumed to be demanded once every other shutdown which is equivalent to 1/2 (22 reactor trips + 9 refueling outages) = 15. This value was used since the main steam system is not always isolated upon a reactor trip.

j. There were two events in 1980 where ARV-3411 was found to be sticking open. Manual isolation valve 3507 was closed until repairs were completed on the valve [ref. MWR 80-1856 and 80-2062].

k. There were several instances of indicating lights for ARV-3411 not working properly [ref. MWR 80-3253, 82-1609, and 88-1429]. A similar problem also occurred on the "A" MSIV [ref. MWR 88-0874].

C.5.12 *Containment Isolation (CI) System*

a. Containment process radiation monitor sample outlet isolation valve 1599 experienced five failures to close, four of them at power. The apparent cause of these failures is carbon/graphite from the sample pump building up in the valve. Since there have been no recurrences of this failure type since 1982, it appears the problem has been corrected.

b. The hydrogen pilot line solenoid-operated isolation valve to recombiner "A," 10205S1 or IV5A, experienced five failures to close. All five failures involved excessive valve leakage [ref. MWRs 81-1155, 82-610, 82-771, 82-981, and 84-817]. Four of the events occurred during 1981-82 and no events occurred after 1984.

c. The hydrogen main fuel line solenoid-operated isolation valve to recombiner "B", 10213S1 or IV3B, experienced three failures to open. It appears that these failures resulted from burned out solenoid coils and/or problems with the latching arm [ref. MWR 82-1380 and A-25.2s for 4/1/87 and 2/26/88].

d. On May 19, 1983, during testing, both LCVs 1003A and B failed to close upon generation of a CI signal. For the test, both valves had been opened using the Waste Disposal Panel control switch which apparently caused the CI signal contact to be bypassed. No failures were assigned to the valves since, during normal operation, the Waste Disposal Panel control switches are not in the open position.

e. On January 18, 1988, during PT-17.2, only the "A" train of containment ventilation isolation tripped when the high alarm was actuated. The relay K-850-R-12 contact pair associated with the "B" train failed to operate [ref. A-25.1]. The entire relay was replaced. No failure was assigned since the relay was not in the population.

f. AOV-539 is used to analyze the Pressurizer Relief Tank approximately once per shift, on a timer [16]. Therefore, the number of demands is (Rx Critical Hours)/8 = 64,054/8 = 8000. It was also assumed that AOV-539 opens for 5 minutes for each demand, or 5/60 x 8064 = 672 hours.

g. Valves 547 and 528 are used to place a nitrogen blanket on the Pressurizer Relief Tank once every startup which is equivalent to 22 reactor trips + 9 refueling outages = 31. (This also accounts for demands when nitrogen is leaking.) Also, it is assumed that the time is 10 minutes per demand or 10/60 x 31 = 5 hours.

h. On April 10, 1981, smoke was observed in Containment Isolation Relay Rack 1B and was soon determined to be from the relay associated with Purge Exhaust Fan 1B (ACF01B). The relay rack eventually tripped causing valves 313, 371, and 5392 to close. The plant was quickly stabilized [ref. A-25.1]. A second smoke related event occurred in the same cabinet on October 20, 1981. For this event, smoke was observed coming from the relay for 7443 causing valves 7443, 7444, 7445, 7971, and 7970 to close [ref. A-25.1].

i. It was assumed that 75% of the time that the SI pumps are running, valve 879 was open. This equals (33 + 140 + 90) x (.75) = 197 hours.

j. The accumulators are assumed to be filled once every week because of leakage problems [16]. Therefore, the number of demands for valves 846 and 8623 is equal to (Reactor Critical Hours)/(24 hours x 7 days) = 64,054/168 = 380. Also, it is assumed that the valves are open for 10 minutes for each demand or 10/60 x 380 = 63 hours.

k. Valves associated with the Reactor Coolant Drain Tank pumps are assumed to have flow through them 10% of the time. Valves associated with the RCDT gas analyzer are assumed to have flow through them 75% of the time.

l. The hot leg sample valves are assumed to be open for 30 minutes for each demand or [(63 + 65 + 61)/3] x 30/60 = 31 hours.

m. Containment isolation valves that are reported to have significant "seat leakage" are considered as failures.

n. Events involving containment pressure transmitters are really part of ESFAS (even though they appear in the Containment Isolation System screening tables). However, they are not considered for ESFAS unless they result in reactor trip or unavailability of an entire train of ESFAS (which none did).

o. Leakage rate information for containment isolation valves for the years 1988-90 was provided by Results and Test personnel. A review of this information showed that while there were several instances of a valve failing its Administrative limit, there was never a failure of the overall Containment Leakage criteria. Since the overall leakage criteria provides the basis for acceptable containment integrity, the failures with respect to Administrative limits are typically considered incipient. That is, the Administrative limits only provide the basis for determining poor performance, not necessarily the failure to isolate containment.

C.5.13 *Service Water (SW) System*

a. In evaluating functional failures of the traveling screens, the analysis only considers plugging or physical stopping of the screens. Any failures of the screens due to broken sections are only of concern to the downstream pumps, and are accounted for, if significant, with the applicable pump.

b. The SW strainer bypass SOVs for the TDAFW pump (4324) and motor-driven AFW pump "B" (4326) experienced six and four functional failures, respectively. The principal cause of these failures was problems with differential pressure switches DPS-2094 and DPS-2085.

c. Service Water MOVs 4614, 4664 and 4013 experienced 6, 4, and 2 functional failures, respectively. Virtually all of these failures were caused by torque switch problems.

d. The only SW pump functional failure occurred on July 6, 1984, when SW pump "D" failed to start. The cause was attributed to a faulty start switch [ref. A-52.4].

e. The four SW travelling screens experienced a total of 15 independent (i.e., non-common cause related) failures. The majority of the events involved drive chain (7) and shear pin (2) failures. The majority of the drive chain failures occurred in 1981-82.

f. On May 20, 1988, while performing M-37.85.4, "Restoration of "D" Standby Aux Feedwater Pump from Maintenance of CV-9627B," the Standby Auxiliary Feedwater pump room was sprayed down with service water. Per procedure, the supply valve was opened prior to closing the vent valve, causing the event [ref. A-25.1]. This event does not represent a component failure since it was a procedure deficiency, but it is an internal flooding concern.

g. On January 26, 1988, when attempting to open MOV-4027, the actuator would not stay in manual when the declutch lever was depressed. The tripper finger was subsequently adjusted [ref. MWR 88-0644]. The declutch lever is only used to manually open the MOV. Its failure only creates a nuisance since the operator would be required to constantly hold down the lever while manually opening the valve.

h. All four SW traveling screens are normally in the auto position. They are run sequentially, each for 20 minutes. Therefore, each screen (and its associated screenwash) is assumed to have experienced 59,184 demands.

i. It was conservatively assumed that there was never any SW flow through the AFW suction valves and the AFW pump lube oil coolers strainer bypass valves.

j. On May 19, 1982, an insulator drilled a 1/4 inch hole in a SW line while the plant was at cold shut down. It was quickly repaired [ref. A-25.1].

k. On January 20, 1983, operators received various screenhouse low level alarms. The water level eventually dropped to approximately 52 inches. Operations turned on all three intake heaters and opened the recirculation gate. Apparently, ice had prevented adequate flow [ref. A-25.1].

l. On May 20, 1983, divers found that heater cables had come loose in the intake structure tunnels blocking approximately 10% of the available flowpath. The cables were subsequently removed [ref. A-25.1].

m. There were a few instances of the expansion joints on the discharge of the SW pumps leaking; however, these were all minor and did not require any immediate repair.

C.5.14 *Containment Spray (CS) System*

a. On March 12, 1986, CS pump "B" was declared inoperable after failing a test. The pump discharge pressure was measured at 234.57 psi, below the acceptable limit of 240 psi. This was not considered to be a failure, however, since 235 psi was assumed to be adequate for the pump to perform its function due to system design margins.

b. On May 31, 1988, with CS pump "B" running during performance of PT-3, flames were observed emitting from the outboard pump bearing area. Apparently, the back-up packing gland and shaft sleeve were making contact resulting in excessive heat and galling, which caused the pump to seize up [ref. A-25.1, MWR 88-3897]. This event, which was the only CS pump failure from 1980-88, was classified as a failure to run.

c. The CS pump discharge isolation MOVs 860A, B, C, and D, experienced a total of 12 failures to open or close on demand. The principal failure cause was torque switch problems. Also during a two-month period in 1987 (i.e., April 10 - June 8), 860B experienced three failures to close. One event involved loose packing and the others had no root cause identified.

d. From July 1981 through November 1982, the CS pump "B" discharge check valve 862B experienced ten failures to close fully or promptly. The valve was then replaced during the 1983 refueling outage. Since that time, no additional failures of 862B to close have occurred. Consequently, these failures were not included in the data, and all exposure and demand counts for valve 862B between January 1980 and January 1983 were eliminated.

e. Spray additive tank air operated outlet isolation valves 836A and B, have experienced five functional failures. The failure causes principally involved controller components (ie., relays, switches, etc.). Four of the failures occurred in the last two years of the data collection period (1987-88).

f. On September 23, 1982, an auxiliary operator found the breaker for valve 860B to be unlocked but in the correct position (closed). The breaker was subsequently locked [ref. A-25.1]. No failure was assigned since the valve was in the closed (or desired) position.

C.5.15 *Standby Auxiliary Feedwater (SAFW) System*

a. On June 14, 1984, the "D" SAFW pump failed to trip both from the main control board and locally. The pump breaker at Bus 16 was then used to secure the pump. This was not considered a failure of the pump since no failure mode exists, but this is of concern for stripping the pump off of Bus 16 when a SI signal is generated. The cause was attributed to lack of lubrication for the breaker mechanical interlock.

b. On January 17, 1985, during performance of PT-36, it was discovered that the flow indicator for the "D" SAFW pump had its wires reversed and was reading zero. Since this did not affect the operation of the pump, no failure was assigned [ref. A-25.1].

c. In 1988, relief valves 9709A and 9709B were found to be lifting when the SAFW pumps were being shutdown due to system pressure oscillations [ref. MWR 88-4434]. Since this was during a test, the relief valves were assumed to lift 50% of the time following tests of the pumps. This was not assumed to be a failure of the relief valves.

d. Since the SAFW pumps have only been used for testing, the start demands obtained from the Official Record Logs were assumed to be related to testing or post maintenance activities and were subsequently ignored.

C.5.16 *Condensate System*

a. There were very few component failures in the system overall. In addition, most failures occurred in out-of-scope components.

b. There were several failures of condensate bypass valve 3959. Most of these events were attributed to MFW pump NPSH and heater drain tank problems. Plant transients which caused 3959 to open (and thus perform its intended function) were not considered as failures. The new digital feedwater system is expected to help correct these type of failures.

c. It is assumed that valves 3959, 4229, 3968, 3969 and 4230 receive one demand for each startup, which equals 22 trips + 9 refueling outages = 31.

d. On August 26, 1988, the condensate booster pumps were tripped due to high system pressure. Subsequently, they could not be started from the main control board, only locally due to a bad control board switch. No failure was assigned since the pumps could and did operate.

e. On December 5, 1980, a window was left open in the MFW pump room causing a sensing line in the NPSH cabinet to freeze. This in turn caused a plant transient and condensate bypass valve 3959 to open [ref. A-25.1]. This event was repeated in December 7, 1984 [ref. A-25.1].

f. On January 12, 1983, a roof fan in the Turbine Building was left open without the fan running causing a turbine oscillation which resulted in condensate bypass valve 3959 opening. The roof fans were closed and no explanation could be found [ref. A-25.1].

C.5.17 *Circulating Water System*

a. Circulating water pump "B" experienced three failures to run, one on January 7, 1981 [ref. A-25.1, MWR 81-031], a second on January 9, 1984 [ref. A-25.1, MWR 84-101], and a third on November 25, 1985 [ref. A-25.1]. The first two events were both attributed to problems with the power factor relay. Circulating water pump "B" also experienced two failures to start. On May 9, 1981 [ref. MWR 81-1165], the pump failed to start due to dust on secondary contacts in the excitation transformer compartment. On March 23, 1985, the pump failed to restart after tripping due to a Bus 11A undervoltage problem. A relay coil was found burnt out.

b. The cold weather recirculation MOV-3184, experienced two functional failures. On December 24, 1983, the valve failed to work electrically and the motor was replaced [ref. MWR 83-4058]. This event was assumed to be a failure to open. Also, the duration of the event (1632 hours) was estimated from the MWR dates (apparently the valve was not repaired until the plant shutdown for refueling). On November 12, 1984, MOV 3184 failed to close completely. The valve was cranked closed by hand [ref. MWR 84-3183].

c. On March 12, 1986, circulating water pump "A" tripped when the "A" RCP was started [ref. MWR 86-873]. The trip was caused by low bus voltage and the pump was successfully restarted. No functional failure was assigned to the pump.

d. MOV-3184 is used during the winter to prevent icing over of the water bay. It was assumed that this flowpath was needed 10% of the time and demanded once a year.

C.5.18 *Heating, Ventilation and Air Conditioning (HVAC) Systems*

a. MWR 86-4150 indicates that the fire system actuated in the Auxiliary Building prior to October 30, 1986, dousing a charcoal filter and requiring its replacement. No failure was assigned to this event.

b. The mini-purge fan was not installed until the 1988 outage. Therefore, it was assumed that the fan was started once for post installation testing purposes and run for five hours.

c. On February 7, 1985, the Service Water lines to the SAFW cooling units "ruptured" requiring the gaskets on both ends to be replaced [ref. MWR 25-437, A-25.1]. This was classified as a failure of the cooler.

d. Valves and dampers which act as containment isolation valves and which fail their <u>administrative</u> leakage rates are not considered to be failures. These administrative limits were established to be warning levels for repair and are much lower than Appendix J limits.

e. If the Containment Recirculation fan filters were saturated with water, they were still considered operable. These filters are designed to be flooded post-LOCA, and being flooded prior to this only presents long-term corrosion problems.

f. In November 1987, the breaker for the "B" SAFW cooling unit fan was found open. It was in this condition for approximately 12 days. It was also found open in January 1982 [ref. A-25.1s].

g. The two hydrogen recombiners were removed from service several times due to calibration problems related to air/gas flow monitors. The units could most likely operate with these indications out of tolerance [16].

h. For fans other than the Containment Recirculation and SAFW Pump cooling units, no components were assumed to be used to isolate the fan at power. The basis for this is that opening the breaker for the fan typically defeats the operating logic for the associated ventilation train and since the operating fluid is air, no isolation is necessary. However, for the two types of fans above, leaking water from the Service Water system was typically involved.

i. No isolation was assumed to be required for AAL03 (Auxiliary Building Charcoal Filter Damper) since none of the failures observed would require entering the ductwork barrier.

j. No isolation was assumed to be required for maintenance of the Hydrogen Recombiners since the air and hydrogen lines are normally locked closed.

k. No isolation was assumed to be required for 7970 and 7971 (mini-purge exhaust) since none of the maintenance activities observed would require entering the ductwork barrier.

l. No isolation was assumed to be required for AAD05 (charcoal damper 1G) since none of the maintenance activities observed would require entering the ductwork barrier.

m. It was conservatively assumed that the "A" and "C" Containment Recirculation Fans were already operating and the "B" and "D" fans stopped prior to conducting RSSP 2.1 since this test only starts the "A" and "C" fans if they are not already operating.

n. The Purge Supply Fans (ACF06A/B) receive a monthly PT only during shutdown. Consequently, a total of 15 PT-related demands was assigned to the fans [17]. The same number of demands was also assumed for the Containment Auxiliary Ventilation Fans (ACF02A/B).

o. The start attempts for many fan units are related to the demands placed on pumps which the fans are interlocked with. Therefore, the start attempts for the fans was based on the total number of demands placed on the pumps since the fan units were not included on the Attachments for the pumps. The start attempts for the fans was calculated as follows:

   a. AAF01A = Charging Pump A + 1/2 Charging Pump C = 217 + (225/2) = 329
   b. AAF01B = Charging Pump B + 1/2 Charging Pump C = 242 + (225/2) = 354
   c. AAF02A = RHR Pump A = 439
   d. AAF02B = RHR Pump B = 418
   e. AAF03A = SI Pump A + CS Pump A = 169 + 169 = 328
   f. AAF03B = SI Pump B + CS Pump B = 248 + 173 = 421
   g. AAF03C = SI Pump C = 439
   h. ADF01A/1B = DG A = 220
   i. ADF02A/2B = DG B = 190
   j. AEF22 = TSC DG = 108
   k. AFF01A = SAFW Pump A = 151
   l. AFF01B = SAFW Pump B = 158

p. On May 5, 1981, DG Supply Fan 1B-2 was found to be running continuously with the DG not running. A microswitch required adjustment [ref. MWR 81-1133]. No failure was assigned since the failure mode did not exist; however, this event is of concern with respect to freezing.

q. On May 19, 1988, the Battery Rooms were observed to be hot. The breaker for AKF02 was bound to be open. The breaker was subsequently closed and the room cooled off. No reason was listed for the breaker being open [ref. MWR 88-3728].

r. On March 3, 1988, the breaker for Reactor Compartment Cooling Fan B (ACF09B) was found to be open. The breaker was then closed. No reason was listed for the breaker being open [ref. MWR 88-1511].

s. On September 20, 1985, the control room ventilation spuriously isolated itself with no abnormal indications. The system was then successfully reset [ref. A-25.1].

t. There were two failures of SI Cooling Fan "C" (AAF03C) which were attributed to the control fuses for the "1C2" breaker [ref. MWRs 82-2121 and 84-3015].

u. There were two failures of SI Cooling Fan "B" (AAF03B) to run. The motor contactor required replacement in both cases [ref. MWRs 84-1659 and 84-2983].

v. There were numerous events associated with isolating the control room ventilation system. These events were not counted as failures against the ventilation system since the detection system was not included in the data analysis population. However, the types of isolation device failures are presented below:

	Radiation	Ammonia	Chlorine
Spurious Isolation of CR	6	6	5
Failure to Isolate CR	3	3	2

C.5.19 *Component Cooling Water (CCW) System*

a. MOV-738B was taken out of service twice to tighten torque switches. No failure was observed prior to performing this action.

b. CCW Pump "B" was removed from service twice at power to replace its main control board switch and to investigate a supposed breaker failure. The first event was not preceded by a failure. The second event came as the pump was shut off and both the run and stop lights remained lit. The breaker was cycled repeatedly, but no failure discovered; therefore, no failure was assigned.

c. There were 4 failures of MOV-814 to close in 1988 alone. These were attributed to stem lubrication and electrical problems.

d. The CCW Seal Drain Tank Pump was assumed to only operate for 100 hours and have 100 demands (approximately 1 demand per month for 1 hour).

e. On June 8, 1982, the control room received CCW Surge Tank low level alarms and eight actuations of the Auxiliary Building sump. Operators then found a leaking gasket on the Waste Evaporator Heat Exchanger which was isolated and repaired. No failure was assigned since these components are not within the system population and the leak did not appear to be serious (only one makeup to the CCW Surge Tank was required) [ref. A-25.1].

f. On July 24, 1984, high lake temperatures caused CCW to provide extra flow to the nonregenerative heat exchanger which resulted in low flow alarms associated with the RCPs. A second CCW pump was then started and SW flow was increased [ref. A-25.1]. No failure was assigned.

C.5.20 *Instrument and Service Air (IA and SA) Systems*

a. IA compressors were not considered failed if they were removed from service due to high temperature, since this is typically only a precautionary measure (or incipient failure). However, if the compressor trips off because of high temperature, this is considered a failure. High temperature on discharge from an air compressor will not automatically trip the compressor, but it will lock out the compressor such that if the compressor shuts down, it cannot be restarted.

b. On August 14, 1988, IA Compressor "C" tripped due to high <u>ambient</u> air temperature of approximately 113°F [ref. A-25.1]. This event occurred after placing a large portable fan in the area of the compressors (see MWR 88-4703).

c. If a solenoid valve for the air compressors was observed to be "leaking," no failure was considered since this condition was typically discovered by an auxiliary operator during his rounds and was not affecting its performance. However, if the air compressor "failed to operate properly," it was assumed that it was constantly loading and unloading. In this state, it is considered unlikely that the air compressor could provide adequate air for any period of time; therefore, it is assumed to be failed. The failure of an air compressor to unload is not considered a failure since relief valves would protect the system and air is being supplied.

d. If an Air Dryer failed to transfer, it was considered failed since, over time, the continuously operated Air Dryer would fail to perform its function.

e. On October 20, 1984, the IA line to the "2B" MSR steam admission valve ruptured (1/2 inch line). It was quickly isolated by an Auxiliary Operator [ref. A-25.1]. A second pipe break occurred on January 29, 1982, and was attributed to personnel stepping on the line [ref. A-25.1]. Two other pipe breaks occurred on September 4, 1981 and March 2, 1983 which were also attributed to personnel stepping on or bumping lines [ref. A-25.1s]. All events resulted in some degree of IA depressurization and required isolation.

f. On September 20, 1984, a fire occurred in the breaker for Air Compressor "C" [ref. A-25.1].

g. The electric SA compressor was deleted from the data analysis population since it was not installed until after 1988.

h. Two air compressors are usually run in CONSTANT; that is they run continuously, but load or unload due to system pressure. The third air compressor is run in STANDBY AUTO, which allows the compressor to start automatically when the pressure falls to a designated setpoint. If a compressor is in the CONSTANT mode, and its control solenoids are leaking, the compressor would tend to run continuously; therefore, it is still available. During shutdown, only one compressor is typically operated [16].

i. Since it is unknown whether or not a specific compressor was in AUTO or CONSTANT at the time of an event, it was usually assumed that the compressor was in CONSTANT (2 of 3 are in CONSTANT) and any failure was a failure to run.

j. Air Compressor "C" (CIA02C) was removed from service 3 times more often than the other two compressors for maintenance and other activities.

k. There are no isolation components in the IA population for the three air compressors. Therefore, there are no interface-related demands for the compressors.

l. It was assumed that for all RSSPs where the IA and SA systems were isolated by a SI signal, all air compressor check valves were demanded upon restart. It was also assumed that the AOVs for the Dryer Tanks were not demanded since the system loads are so minimal at this time.

m. It was assumed that the Dryer Tanks in each IA train were cycled once every day which is equivalent to 365 days x 9 years = 3285 days.

C.5.21 *Heat Tracing*

a. If the heat tracing failed high, it was not considered to be a failure unless there was a threat of boiling the water in the pipe. This was assumed since the heat tracing is installed to prevent crystallization of the boric acid contained in the pipe. Therefore, the purpose of the heat tracing is to heat the process line and too much heat is only a concern for boiling.

b. Any problems with the primary heat trace controller which required the secondary circuit to be energized were conservatively assumed to be functional failures of the heat tracing. This was done since these events required operator action to maintain the necessary temperature and it was unknown whether the failure to energize the secondary circuit would result in a failure. Consequently, a failure was assumed.

C.5.22 *Fire Protection System*

a. Data for this system was reviewed only for significant events and potential interface with the 21 systems included in the project scope.

b. The motor-driven fire pump is very sensitive to screenhouse level due to NPSH requirements. There were several instances whereby the fire pump was declared inoperable due to low screenhouse levels.

c. There were numerous events of false fire alarms due to dust, welding, grinding, bumping cabinets, etc.

d. The following are water/halon system actuations that were found during the observed time period:

1. On November 4, 1988, the cable tunnel sprinklers actuated and an unusual event was declared for a "fire greater than 10 minutes". No fire was found; personnel actuated a mechanical actuation device in the tunnel [ref. A-25.1, MWR 88-123]. The automatic fire suppression system for the cable tunnel also activated on November 6, 1985 due to an electrical "spike" in the system. An unusual event was declared [ref. A-25.1]. Finally, the cable tunnel actuation system was accidentally tripped by R&T personnel on November 12, 1982 [ref. A-25.1].

2. The #12B Transformer was doused by technician error on January 3, 1986 [ref. A-25.1]. On April 17, 1986, the deluge system was activated again for no apparent reason [ref. A-25.1]. Also, personnel bumping into the panel caused actuation of the system on November 14, 1980 and March 9, 1981 [ref. A-25.1s].

3. The auto deluge system for Condenser Pit was set off by someone hitting the manual "pull" system with lumber on February 16, 1986 [ref. A-25.1].

4. Operators inadvertently actuated the 1G Fan Filter Deluge system on April 11, 1986 [ref. A-25.1].

5. On January 23, 1985, a sprinkler head cracked and allowed water into the Rad Waste Storage Building [ref. A-25.1].

6. On March 23, 1984, the halon system in the relay room was actuated due to welding activities in Turbine Building combined with a lack of ventilation [ref. A-25.1].

7. On December 8, 1982, the control room was sprayed down due to a procedure error while conducting testing of the fire protection system [ref. A-25.1].

8. The telephone room halon system was activated twice by accident on May 5, 1986 and August 12, 1986 [ref. A-25.1s].

9. The #1 Generator Transformer deluge system was activated for unknown causes eight times. See A-25.1s on 11/21/81, 11/26/81, 11/26/81 (twice), 11/30/81, 10/10/80, 10/24/80, and 10/25/80.

10. A jackhammer penetrated the Fire SW system piping causing a small leak on January 14, 1980 [ref. A-25.1].

11. On June 26, 1981, water was sprayed into relay room during testing of a fire sprinkler due to a design error [ref. A-25.1].

e. The following is a listing of actual fires discovered during the observed time period:

1. A non-vital Security power panel caught fire on September 18, 1988. An unusual event declared and the fire was put out by isolating the power supply [ref. A-25.1 and MWR 88-103].

2. On August 27, 1987, a motor at the secondary sample sink caught fire after it broke and the overload relay failed to work. The fire was put out by isolating power to the motor [ref. A-25.1 and MWR 87-76].

3. A fire in the East Defense Position (Guard House) in an electrical box occurred on February 29, 1984. It was isolated electrically and extinguished [ref. A-25.1].

4. A fire in the computer room was found in the alternate computer transformer on February 25, 1983. The halon system was actuated in the relay room to extinguish the fire [ref. A-25.1].

5. A fire in the S/G Tent occurred from welding sparks during cold shutdown on May 18, 1983 [ref. A-25.1].

6. On January 8, 1981, a fire was found in the MFW Pump Room. A fire water booster pump froze and caught fire when it attempted to start [ref. A-25.1].

7. A smoldering rag was found in the relay room on February 23, 1981. It was removed and the fire was extinguished [ref. A-25.1].

8. A fire in the Reactor Seal Ring Storage Box was found on May 1, 1981. The fire was caused by grinding sparks and an unusual event was declared [ref. A-25.1].

9. A fire in the containment basement was found on December 1, 1980 from a small heat lamp gasket [ref. A-25.1].

10. On December 29, 1980, a fire was discovered in a MCC "A" breaker cubicle [ref. A-25.1].

11. A fire at the breaker for 1B EH Oil Pump was found on September 22, 1988. It was isolated electrically [ref. A-25.1].

C.5.23 *Turbine/EH System*

a. Data for this system was reviewed only for significant events and potential interface with the 21 systems included in the project scope.

b. There are several instances of turbine control problems. Control valves spuriously opening, turbine runbacks, and slight power oscillations were observed throughout period. This may be corrected by the new digital feedwater system. The turbine was typically placed in manual following these events.

C.5.24 *Steam Generator (SG)*

a. Data for this system was reviewed only for significant events and potential interface with the 21 systems included in the project scope.

b. Most events associated with the SG occurred during shutdown and were related to chemistry issues.

C.5.25 *Control Rods/Reactor Protection System*

a. Data for this system was reviewed only for significant events and potential interface with the 20 systems included in the project scope.

b. There were many cases of control rod position problems and various channels requiring calibration. Many of the control rod problems were related to a lack of ventilation in the area of the cabinets.

c. The Control Rod Drive MG Sets had several grounding problems as a result of previous inadvertent fire system actuations. See A-25.1s dated 12/25/81 and 1/8/82.

d. There were several instances where testing of RPS equipment resulted in small runbacks, alarms and misreadings on the control panels.

Table C-1
Calculation of Standby Exposures for Valves

Component Type and Failure Mode	*CAFTA Type Code*	*Exposure*	*Remarks*
MOV - transfers open	MV_R	T_{MV_R}	Obtained directly from RGEDATA.PRG, based on RG&E data input
MOV - fails to open (standby)	MV_P	T_{MV_R}	Failure mode can only happen if the MOV is closed; thus, use exposure time for Type Code MV_R
MOV - transfers closed	MV_K	T_{MV_K}	Obtained directly from RGEDATA.PRG, based on RG&E data input
MOV - fails to close (standby)	MV_X	T_{MV_K}	Failure mode can only happen if valve is open; thus, use exposure time for Type Code MV_K

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	AC	B1	*	4	0	0	H	256217.40	
Y	AC	B1	F	4	0	315648	H	0.00	
	AC	B2	*	25	2	17	H	1601358.75	
Y	AC	B2	F	25	2	1972783	H	0.00	
	AC	B4	*	6	0	0	H	384326.10	
Y	AC	B4	F	6	0	473472	H	0.00	
	AC	CB	*	55	7	34	H	3522989.25	
Y	AC	CB	D	55	3	779	N	0.00	
	AC	CB	K	17	0	1339882	H	0.00	
Y	AC	CB	O	55	3	4340140	H	0.00	Failures from AC_CB_D. Exposure from sum of AC_CB_K and AC_CB_R.
Y	AC	CB	R	42	4	3000258	H	0.00	
	AC	DG	*	1	0	0	H	64054.35	
	AC	DG	A	1	0	108	N	0.00	
	AC	DG	F	1	0	108	H	0.00	
	AC	MP	*	1	0	0	H	64054.35	
	AC	MP	A	1	0	108	N	0.00	
	AC	MP	F	1	0	36	H	0.00	
	AC	T1	*	3	1	5	H	192163.05	
Y	AC	T1	F	3	0	236731	H	0.00	
	AC	T2	*	6	0	0	H	384326.10	
	AC	T2	F	6	0	473472	H	0.00	
	AC	T6	*	3	0	0	H	192163.05	
Y	AC	T6	F	3	0	236736	H	0.00	
	AC	TK	*	1	0	0	H	64054.35	
	AC	TK	G	1	0	78912	H	0.00	
	AC	TK	J	1	0	78912	H	0.00	
M	AF	AV	*	10	9	59	H	640543.50	
	AF	AV	C	10	2	1530	N	0.00	
	AF	AV	F	10	1	67019	H	0.00	
Y	AF	AV	K	5	0	329877	H	0.00	
	AF	AV	N	10	1	1530	N	0.00	
Y	AF	AV	P	10	1	392165	H	0.00	Failures from AF_AV_N. Exposure from AF_AV_R.
	AF	AV	R	5	0	392165	H	0.00	
Y	AF	AV	X	10	2	329877	H	0.00	Failures from AF_AV_C. Exposure from AF_AV_K.
M	AF	CV	*	20	9	399	H	1281087.00	
Y	AF	CV	C	20	10	5349	N	0.00	
	AF	CV	K	20	0	10939	H	0.00	
	AF	CV	N	20	0	5349	N	0.00	
Y	AF	CV	P	20	0	1488947	H	0.00	Failures from AF_CV_N. Exposure from AF_CV_R.
	AF	CV	R	20	0	1488947	H	0.00	
	AF	LT	*	2	4	13	H	128108.70	
	AF	LT	L	2	4	157811	H	0.00	
M	AF	MP	*	4	20	398	H	256217.40	
	AF	MP	A	4	1	1473	N	0.00	
Y	AF	MP	F	4	0	2795	H	0.00	
Y	AF	MP	S	4	1	312455	H	0.00	Failures from AF_MP_A. Exposure = 4*78912 - 2795 - 398.
M	AF	MV	*	14	30	1616	H	896760.90	
Y	AF	MV	C	14	5	4211	N	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
Y	AF	MV	D	4	0	4823	H	0.00	
Y	AF	MV	K	10	0	634385	H	0.00	
	AF	MV	N	14	4	4211	N	0.00	
Y	AF	MV	P	14	4	470767	H	0.00	Failures from AF_MV_N. Exposure from AF_MV_R.
	AF	MV	R	6	0	470767	H	0.00	
Y	AF	MV	X	14	5	634385	H	0.00	Failures from AF_MV_C. Exposure from AF_MV_K.
	AF	PV	*	2	0	0	H	128108.70	
	AF	PV	C	2	0	0	N	0.00	
	AF	PV	F	2	0	91	H	0.00	
	AF	PV	N	2	0	0	N	0.00	
	AF	PV	R	2	0	157733	H	0.00	
	AF	RV	*	5	3	45	H	320271.75	
	AF	RV	C	5	3	136	N	0.00	
	AF	RV	N	5	0	136	N	0.00	
	AF	RV	R	5	0	394515	H	0.00	
	AF	TK	*	3	0	0	H	192163.05	
	AF	TK	G	3	0	236736	H	0.00	
Y	AF	TK	J	3	0	236736	H	0.00	
M	AF	TP	*	1	11	167	H	64054.35	
	AF	TP	A	1	2	222	N	0.00	
Y	AF	TP	F	1	0	87	H	0.00	
Y	AF	TP	S	1	2	78491	H	0.00	Failures from AT_TP_A. Exposure = 1*78912 - 87- 167.
M	AF	XV	*	46	5	1081	H	2946500.10	
	AF	XV	C	46	0	3396	N	0.00	
Y	AF	XV	K	39	0	3076484	H	0.00	
	AF	XV	N	46	0	3396	N	0.00	
Y	AF	XV	P	46	0	552384	H	0.00	Failures from AV_XV_N. Exposure from AF_XV_R.
	AF	XV	R	7	0	552384	H	0.00	
Y	AF	XV	X	46	0	3076484	H	0.00	Failures from AF_XV_C. Exposure from AF_XV_K.
M	CC	AV	*	5	1	55	H	320271.75	
	CC	AV	C	5	1	113	N	0.00	
	CC	AV	F	3	0	192162	H	0.00	
Y	CC	AV	K	1	0	78912	H	0.00	
	CC	AV	N	5	0	113	N	0.00	
	CC	AV	R	4	0	123431	H	0.00	
M	CC	CV	*	9	1	6	H	576489.15	
Y	CC	CV	C	9	2	519	N	0.00	
Y	CC	CV	K	9	0	562420	H	0.00	
	CC	CV	N	9	0	519	N	0.00	
	CC	CV	R	7	0	147782	H	0.00	
	CC	HX	*	14	4	48	H	896760.90	
Y	CC	HX	F	14	0	1075004	H	0.00	
Y	CC	HX	J	14	0	1075004	H	0.00	
Y	CC	HX	P	14	0	1075004	H	0.00	
M	CC	MP	*	3	3	39	H	192163.05	
Y	CC	MP	A	3	1	542	N	0.00	
Y	CC	MP	F	3	1	84432	H	0.00	
M	CC	MV	*	10	5	25	H	640543.50	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
Y	CC	MV	C	10	6	807	N	0.00	
Y	CC	MV	K	9	0	475873	H	0.00	
	CC	MV	N	10	4	807	N	0.00	
Y	CC	MV	P	10	4	313247	H	0.00	failures from CC_MV_N. Exposure from CC_MV_R.
	CC	MV	R	9	0	313247	H	0.00	
	CC	RV	*	12	0	0	H	768652.20	
	CC	RV	C	12	0	0	N	0.00	
	CC	RV	N	12	0	0	N	0.00	
	CC	RV	R	12	0	946944	H	0.00	
	CC	TK	*	1	0	0	H	64054.35	
	CC	TK	G	1	0	78912	H	0.00	
Y	CC	TK	J	1	0	78912	H	0.00	
M	CC	XV	*	57	0	0	H	3651097.95	
	CC	XV	C	57	0	638	N	0.00	
Y	CC	XV	K	57	0	4497984	H	0.00	
Y	CC	XV	N	57	0	638	N	0.00	
	CN	AV	*	3	10	23	H	192163.05	
	CN	AV	C	3	0	130	N	0.00	
	CN	AV	F	3	0	142966	H	0.00	
	CN	AV	N	3	0	130	N	0.00	
	CN	AV	R	3	10	93747	H	0.00	
	CN	CV	*	8	0	0	H	512434.80	
	CN	CV	C	8	0	560	N	0.00	
	CN	CV	K	8	0	378973	H	0.00	
	CN	CV	N	8	0	560	N	0.00	
	CN	CV	R	8	0	252283	H	0.00	
	CN	MP	*	6	10	13	H	384326.10	
	CN	MP	A	6	2	573	N	0.00	
	CN	MP	F	6	0	250865	H	0.00	
M	CS	AV	*	2	5	18	H	128108.70	
	CS	AV	C	2	1	321	N	0.00	
	CS	AV	N	2	2	321	N	0.00	
Y	CS	AV	P	2	2	157806	H	0.00	Failures from CS_AV_N. Exposure from CS_AV_R.
	CS	AV	R	2	2	157806	H	0.00	
M	CS	CV	*	6	0	0	H	384326.10	
Y	CS	CV	C	6	1	621	N	0.00	
	CS	CV	K	4	0	124	H	0.00	
	CS	CV	N	6	0	621	N	0.00	
Y	CS	CV	P	6	0	473181	H	0.00	Failures from CS_CV_N. Exposure from CS_CV_R.
	CS	CV	R	6	1	473181	H	0.00	
M	CS	MP	*	2	11	300	H	128108.70	
	CS	MP	A	2	0	342	N	0.00	
Y	CS	MP	F	2	1	67	H	0.00	
Y	CS	MP	S	2	0	157457	H	0.00	Failures from CS_MP_A. Exposure = 2*78912 - 67 - 300.
M	CS	MV	*	10	17	137	H	640543.50	
	CS	MV	C	10	9	1051	N	0.00	
Y	CS	MV	K	6	0	157958	H	0.00	
	CS	MV	N	10	7	1051	N	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
Y	CS	MV	P	10	7	631030	H	0.00	Failures from CS_MV_N. Exposure from CS_MV_R.
Y	CS	MV	R	8	0	631030	H	0.00	
Y	CS	MV	X	10	9	157958	H	0.00	Failure from CS_MV_C. Exposure from CS_MV_K.
	CS	RV	*	2	0	0	H	128108.70	
	CS	RV	C	2	0	0	N	0.00	
	CS	RV	N	2	0	0	N	0.00	
	CS	RV	R	2	0	157824	H	0.00	
M	CS	TK	*	2	0	0	H	128108.70	
	CS	TK	G	2	0	157824	H	0.00	
Y	CS	TK	J	2	0	157824	H	0.00	
M	CS	XV	*	21	1	3	H	1345141.35	
	CS	XV	C	21	0	1920	N	0.00	
Y	CS	XV	K	21	0	1026188	H	0.00	
Y	CS	XV	N	21	0	1920	N	0.00	
Y	CS	XV	R	10	0	630961	H	0.00	
	CT	AV	*	23	31	2235	H	1473250.05	
	CT	AV	C	23	10	11199	N	0.00	
	CT	AV	K	21	1	1203915	H	0.00	
	CT	AV	N	23	3	11199	N	0.00	
Y	CT	AV	R	11	1	610626	H	0.00	
	CT	BF	*	9	2	4	H	576489.15	
Y	CT	BF	F	9	1	577482	H	0.00	
	CT	CV	*	6	0	0	H	384326.10	
	CT	CV	C	6	0	411	N	0.00	
	CT	CV	K	2	0	68	H	0.00	
	CT	CV	N	6	0	411	N	0.00	
Y	CT	CV	R	6	0	473404	H	0.00	
	CT	SV	*	12	3	676	H	768652.20	
	CT	SV	C	12	2	584	N	0.00	
	CT	SV	K	4	0	314976	H	0.00	
	CT	SV	N	12	3	584	N	0.00	
	CT	SV	R	8	0	631292	H	0.00	
	CT	XV	*	27	0	0	H	1729467.45	
	CT	XV	C	27	0	248	N	0.00	
	CT	XV	K	2	0	202	H	0.00	
	CT	XV	N	27	0	248	N	0.00	
	CT	XV	R	27	0	2130422	H	0.00	
	CV	AV	*	27	20	71	H	1729467.45	
Y	CV	AV	C	27	7	20157	N	0.00	
	CV	AV	F	16	13	595778	H	0.00	
Y	CV	AV	K	7	0	268791	H	0.00	
Y	CV	AV	N	27	2	20157	N	0.00	
Y	CV	AV	P	27	2	1265985	H	0.00	Failures from CV_AV_N. Exposure from CV_AV_R.
	CV	AV	R	27	8	1265985	H	0.00	
	CV	CV	*	35	2	252	H	2241902.25	
	CV	CV	C	35	2	24640	N	0.00	
Y	CV	CV	K	20	0	873200	H	0.00	
Y	CV	CV	N	35	1	24640	N	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
Y	CV	CV	P	35	1	1888475	H	0.00	failures from CV_CV_N. Exposure from CV_CV_R.
	CV	CV	R	35	1	1888475	H	0.00	
	CV	HT	*	1	13	634	H	64054.35	
Y	CV	HT	F	1	10	64054	H	0.00	
	CV	HX	*	5	0	0	H	320271.75	
	CV	HX	F	5	0	320270	H	0.00	
	CV	HX	J	5	0	320270	H	0.00	
Y	CV	HX	P	5	0	320270	H	0.00	
	CV	LT	*	4	43	431	H	256217.40	
Y	CV	LT	D	4	4	315648	H	0.00	
Y	CV	LT	H	4	33	315648	H	0.00	
M	CV	MP	*	7	79	3423	H	448380.45	
Y	CV	MP	A	7	11	10179	N	0.00	
Y	CV	MP	F	7	4	147073	H	0.00	
	CV	MV	*	2	2	568	H	128108.70	
	CV	MV	C	2	1	127	N	0.00	
Y	CV	MV	K	1	0	64054	H	0.00	
Y	CV	MV	N	2	0	127	N	0.00	
	CV	MV	R	2	0	93203	H	0.00	
	CV	PP	*	1	5	175	H	64054.35	
Y	CV	PP	J	1	1	64054	H	0.00	
Y	CV	PP	P	1	4	64054	H	0.00	
M	CV	RV	*	7	12	210	H	448380.45	
	CV	RV	C	7	0	20	N	0.00	
Y	CV	RV	N	7	0	20	N	0.00	
Y	CV	RV	P	7	0	552174	H	0.00	Failures from CV_RV_N. Exposure from CV_RV_R.
Y	CV	RV	R	7	15	552174	H	0.00	
	CV	SU	*	6	3	24	H	384326.10	
	CV	SU	F	6	1	264085	H	0.00	
M	CV	TK	*	4	4	24	H	256217.40	
	CV	TK	G	4	0	315632	H	0.00	
Y	CV	TK	J	4	0	315632	H	0.00	
M	CV	XV	*	77	1	7	H	4932184.95	
	CV	XV	C	77	0	774	N	0.00	
Y	CV	XV	K	70	0	5366012	H	0.00	
	CV	XV	N	77	1	774	N	0.00	
Y	CV	XV	R	11	0	710208	H	0.00	
	CW	MP	*	2	3	9	H	128108.70	
	CW	MP	A	2	2	37	N	0.00	
	CW	MP	F	2	3	143604	H	0.00	
	CW	MV	*	11	2	1632	H	704597.85	
	CW	MV	C	11	1	54	N	0.00	
	CW	MV	K	11	0	663927	H	0.00	
	CW	MV	N	11	1	54	N	0.00	
	CW	MV	R	11	0	204105	H	0.00	
	DC	BC	*	4	19	77	H	256217.40	
	DC	BC	D	4	0	560	N	0.00	
Y	DC	BC	F	4	4	315571	H	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	DC	BD	*	33	0	0	H	2113793.55	
	DC	BD	D	2	0	218	N	0.00	
Y	DC	BD	F	33	0	2604096	H	0.00	
	DC	BT	*	3	2	4	H	192163.05	
Y	DC	BT	D	3	0	259	N	0.00	
Y	DC	BT	F	3	0	236732	H	0.00	
	DC	CF	*	55	0	0	H	3522989.25	
Y	DC	CF	R	55	0	4340160	H	0.00	
	DC	IN	*	3	3	10	H	192163.05	
Y	DC	IN	F	3	3	236728	H	0.00	
	DG	AM	*	2	0	0	H	128108.70	
	DG	AM	A	2	0	410	N	0.00	
	DG	AM	F	2	0	12	H	0.00	
	DG	CV	*	6	0	0	H	384326.10	
Y	DG	CV	C	6	0	698	N	0.00	
	DG	CV	K	4	0	648	H	0.00	
Y	DG	CV	N	6	0	698	N	0.00	
	DG	CV	R	6	0	472824	H	0.00	
M	DG	DG	*	2	29	182	H	128108.70	
Y	DG	DG	A	2	2	410	N	0.00	
Y	DG	DG	F	2	1	801	H	0.00	
	DG	MP	*	2	2	10	H	128108.70	
Y	DG	MP	A	2	0	352	N	0.00	
Y	DG	MP	F	2	0	324	H	0.00	
	DG	RV	*	2	0	0	H	128108.70	
	DG	RV	C	2	0	0	N	0.00	
	DG	RV	N	2	0	0	N	0.00	
Y	DG	RV	R	2	0	157824	H	0.00	
	DG	SV	*	4	0	0	H	256217.40	
	DG	SV	C	4	0	660	N	0.00	
	DG	SV	K	2	0	157824	H	0.00	
	DG	SV	N	4	1	660	N	0.00	
Y	DG	SV	P	4	1	157824	H	0.00	Failures from DG_SV_N. Exposure from DG_SV_R.
	DG	SV	R	2	0	157824	H	0.00	
Y	DG	SV	X	4	0	157824	H	0.00	Failures from DG_SV_C. Exposure from DG_SV_K.
	DG	TK	*	2	0	0	H	128108.70	
	DG	TK	G	2	0	157824	H	0.00	
Y	DG	TK	J	2	0	157824	H	0.00	
	DG	XV	*	8	0	0	H	512434.80	
	DG	XV	C	8	0	4	N	0.00	
Y	DG	XV	K	8	0	631296	H	0.00	
	DG	XV	N	8	0	4	N	0.00	
M	HV	AF	*	2	2	124	H	128108.70	
Y	HV	AF	F	2	1	136736	H	0.00	
	HV	HE	*	2	0	0	H	128108.70	
	HV	HE	A	2	0	2700	N	0.00	
Y	HV	HE	F	2	0	2700	H	0.00	
	HV	HR	*	2	10	52	H	128108.70	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	HV	HR	A	2	0	0	N	0.00	
	HV	HR	F	2	0	0	H	0.00	
M	HV	MC	*	52	5	943	H	3330826.20	
	HV	MC	C	52	4	10062	N	0.00	
Y	HV	MC	K	51	2	2177703	H	0.00	
Y	HV	MC	N	52	2	10062	N	0.00	
	HV	MC	R	35	0	1927785	H	0.00	
	HV	MD	*	7	0	0	H	448380.45	
	HV	MD	C	7	0	340	N	0.00	
	HV	MD	K	7	0	158474	H	0.00	
	HV	MD	N	7	0	340	N	0.00	
	HV	MD	R	5	0	393910	H	0.00	
M	HV	MF	*	45	95	2058	H	2882445.75	
Y	HV	MF	A	45	7	10127	N	0.00	
Y	HV	MF	F	45	11	1406947	H	0.00	
Y	HV	MF	S	45	7	2142035	H	0.00	Failures from HV_MF_A. Exposure = 45*78912 - 1406947 - 2058.
M	IA	AD	*	4	11	129	H	256217.40	
Y	IA	AD	F	4	10	157824	H	0.00	
M	IA	AF	*	5	0	0	H	320271.75	
Y	IA	AF	F	5	0	374659	H	0.00	
M	IA	AM	*	5	108	1364	H	320271.75	
Y	IA	AM	A	5	3	775	N	0.00	
Y	IA	AM	F	5	17	217069	H	0.00	
M	IA	AR	*	4	1	24	H	256217.40	
Y	IA	AR	F	4	1	217069	H	0.00	
M	IA	AV	*	9	2	4	H	576489.15	
	IA	AV	C	9	0	26331	N	0.00	
Y	IA	AV	K	9	0	394560	H	0.00	
Y	IA	AV	N	9	0	26331	N	0.00	
	IA	AV	R	8	0	315644	H	0.00	
M	IA	CV	*	12	0	0	H	768652.20	
	IA	CV	C	12	0	13977	N	0.00	
Y	IA	CV	K	8	0	394794	H	0.00	
Y	IA	CV	N	12	0	13977	N	0.00	
Y	IA	CV	P	12	0	552150	H	0.00	Failures from IA_CV_N. Exposure from IA_CV_R.
	IA	CV	R	11	0	552150	H	0.00	
	IA	PP	*	1	0	0	H	64054.35	
Y	IA	PP	J	1	4	78912	H	0.00	
	IA	RV	*	1	0	0	H	64054.35	
	IA	RV	C	1	0	0	N	0.00	
	IA	RV	N	1	0	0	N	0.00	
	IA	RV	R	1	0	78912	H	0.00	
	MF	AV	*	6	2	10	H	384326.10	
	MF	AV	C	6	2	475	N	0.00	
	MF	AV	F	4	2	256206	H	0.00	
	MF	AV	N	6	0	475	N	0.00	
	MF	AV	R	6	0	217256	H	0.00	
	MF	CV	*	4	1	1	H	256217.40	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	MF	CV	C	4	0	171	N	0.00	
	MF	CV	K	4	0	253375	H	0.00	
	MF	CV	N	4	1	171	N	0.00	
	MF	CV	R	4	0	62272	H	0.00	
	MF	MP	*	2	4	38	H	128108.70	
	MF	MP	A	2	0	146	N	0.00	
	MF	MP	F	2	2	125268	H	0.00	
	MF	RV	*	2	3	22	H	128108.70	
	MF	RV	C	2	1	3	N	0.00	
	MF	RV	N	2	0	3	N	0.00	
	MF	RV	R	2	1	157802	H	0.00	
	MF	SC	*	2	0	0	H	128108.70	
	MF	SC	C	2	0	62	N	0.00	
	MF	SC	K	2	0	128108	H	0.00	
	MF	SC	N	2	0	62	N	0.00	
	MF	SC	R	2	0	29716	H	0.00	
	MF	SD	*	2	0	0	H	128108.70	
	MF	SD	C	2	0	22	N	0.00	
	MF	SD	K	2	0	125267	H	0.00	
	MF	SD	N	2	0	22	N	0.00	
	MF	SD	R	2	0	32557	H	0.00	
	MF	XV	*	10	0	0	H	640543.50	
	MF	XV	C	10	0	49	N	0.00	
	MF	XV	K	10	0	789120	H	0.00	
	MF	XV	N	10	0	49	N	0.00	
M	MS	AV	*	2	0	0	H	128108.70	
Y	MS	AV	C	2	2	227	N	0.00	
Y	MS	AV	K	2	0	128108	H	0.00	
	MS	AV	N	2	1	227	N	0.00	
Y	MS	AV	P	2	1	29716	H	0.00	Failures from MS_AV_N. Exposure from MS_AV_R.
	MS	AV	R	2	0	29716	H	0.00	
M	MS	CV	*	2	1	103	H	128108.70	
Y	MS	CV	C	2	1	379	N	0.00	
	MS	CV	K	2	0	174	H	0.00	
	MS	CV	N	2	0	379	N	0.00	
Y	MS	CV	P	2	0	157547	H	0.00	Failures from MS_CV_N. Exposure from MS_CV_R.
	MS	CV	R	2	0	157547	H	0.00	
	MS	MV	*	2	6	129	H	128108.70	
Y	MS	MV	C	2	1	438	N	0.00	
	MS	MV	K	2	0	174	H	0.00	
	MS	MV	N	2	1	438	N	0.00	
Y	MS	MV	P	2	1	157521	H	0.00	Failures from MS_MV_N. Exposure from MS_MV_R.
Y	MS	MV	R	2	0	157521	H	0.00	
	MS	RV	*	2	2	48	H	128108.70	
Y	MS	RV	C	2	0	83	N	0.00	
	MS	RV	N	2	1	83	N	0.00	
Y	MS	RV	P	2	1	157776	H	0.00	Failures from MS_RV_N. Exposure from MS_RV_R.
	MS	RV	R	2	2	157776	H	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	MS	RY	*	8	0	0	H	512434.80	
	MS	RY	N	8	0	80	N	0.00	
	MS	RY	R	8	0	631296	H	0.00	
Y	MS	RY	T	8	0	8	N	0.00	
M	MS	XV	*	4	2	6	H	256217.40	
Y	MS	XV	C	4	0	26	N	0.00	
Y	MS	XV	K	4	0	315642	H	0.00	
	MS	XV	N	4	0	26	N	0.00	
Y	MS	XV	P	4	0	0	H	0.00	Failures from MS_XV_N. Exposure = 4*78912 - 315642 - 6.
	RC	AV	*	8	5	10	H	512434.80	
	RC	AV	C	8	1	254	N	0.00	
	RC	AV	F	2	2	128101	H	0.00	
Y	RC	AV	K	5	0	64058	H	0.00	
Y	RC	AV	N	8	1	254	N	0.00	
Y	RC	AV	P	8	1	439127	H	0.00	Failures from RC_AV_N. Exposure from RC_AV_R.
	RC	AV	R	8	0	439127	H	0.00	
	RC	CV	*	3	0	0	H	192163.05	
	RC	CV	C	3	0	61	N	0.00	
	RC	CV	K	3	0	3	H	0.00	
Y	RC	CV	N	3	0	61	N	0.00	
	RC	CV	R	3	0	236733	H	0.00	
	RC	MP	*	2	0	0	H	128108.70	
	RC	MP	A	2	0	275	N	0.00	
Y	RC	MP	F	2	0	132807	H	0.00	
	RC	MV	*	2	3	35	H	128108.70	
	RC	MV	C	2	0	153	N	0.00	
Y	RC	MV	K	2	0	157789	H	0.00	
	RC	MV	N	2	0	153	N	0.00	
Y	RC	MV	P	2	0	0	H	0.00	Failures from RC_MV_N. Exposure = 2*78912 - 157789 - 35.
Y	RC	MV	X	2	0	157789	H	0.00	Failures from RC_MV_C. Exposure from RC_MV_K.
	RC	RV	*	2	0	0	H	128108.70	
	RC	RV	C	2	0	7	N	0.00	
	RC	RV	N	2	0	7	N	0.00	
Y	RC	RV	R	2	0	157824	H	0.00	
	RC	RZ	*	2	9	4178	H	128108.70	
	RC	RZ	N	2	0	206	N	0.00	
Y	RC	RZ	P	2	0	153646	H	0.00	Failures from RC_RZ_N. Exposure from RC_RZ_R.
	RC	RZ	Q	2	1	206	N	0.00	
	RC	RZ	R	2	0	153646	H	0.00	
	RC	SV	*	4	0	0	H	256217.40	
	RC	SV	C	4	2	53	N	0.00	
	RC	SV	N	4	0	53	N	0.00	
Y	RC	SV	P	4	0	315648	H	0.00	Failures from RC_SV_N. Exposure from RC_SV_R.
	RC	SV	R	4	0	315648	H	0.00	
	RC	TK	*	2	0	0	H	128108.70	
	RC	TK	G	2	0	142966	H	0.00	
	RC	TK	J	2	0	142966	H	0.00	
	RC	XV	*	16	0	0	H	1024869.60	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	RC	XV	C	16	0	42	N	0.00	
Y	RC	XV	K	11	0	710244	H	0.00	
	RC	XV	N	16	0	42	N	0.00	
	RC	XV	R	7	0	552348	H	0.00	
M	RH	AV	*	3	8	40	H	192163.05	
	RH	AV	C	3	0	196	N	0.00	
Y	RH	AV	F	1	0	7324	H	0.00	
Y	RH	AV	K	2	0	157798	H	0.00	
	RH	AV	N	3	0	196	N	0.00	
Y	RH	AV	R	1	0	71585	H	0.00	
M	RH	CV	*	9	0	0	H	576489.15	
Y	RH	CV	C	9	0	2038	N	0.00	
	RH	CV	K	5	0	27269	H	0.00	
	RH	CV	N	9	0	2038	N	0.00	
Y	RH	CV	P	9	0	682939	H	0.00	Failures from RH_CV_N. Exposure from RH_CV_R.
	RH	CV	R	9	0	682939	H	0.00	
	RH	HX	*	2	1	13	H	128108.70	
Y	RH	HX	F	2	0	13302	H	0.00	
	RH	HX	J	2	0	13302	H	0.00	
Y	RH	HX	P	2	0	13302	H	0.00	
	RH	LT	*	2	3	6	H	128108.70	
	RH	LT	D	2	0	157818	H	0.00	
M	RH	MP	*	2	14	268	H	128108.70	
	RH	MP	A	2	1	857	N	0.00	
Y	RH	MP	F	2	0	13301	H	0.00	
Y	RH	MP	S	2	1	144255	H	0.00	Failures from RH_MP_A. Exposure = 2*78912 - 13301 - 268.
M	RH	MV	*	18	13	148	H	1152978.30	
	RH	MV	C	18	3	2969	N	0.00	
Y	RH	MV	K	9	0	450935	H	0.00	
	RH	MV	N	18	10	2969	N	0.00	
Y	RH	MV	P	18	10	918651	H	0.00	Failures from RH_MV_N. Exposure from RH_MV_R.
Y	RH	MV	R	13	0	918651	H	0.00	
Y	RH	MV	X	18	3	450935	H	0.00	Failures from RH_XV_C. Exposure from RH_MV_K.
M	RH	XV	*	18	0	0	H	1152978.30	
	RH	XV	C	18	0	150	N	0.00	
Y	RH	XV	K	14	0	645944	H	0.00	
	RH	XV	N	18	0	150	N	0.00	
Y	RH	XV	P	18	0	301000	H	0.00	Failures from RH_XV_N. Exposure from RH_XV_R.
Y	RH	XV	R	6	0	458824	H	0.00	
	SI	AV	*	6	1	1	H	384326.10	
	SI	AV	C	6	0	495	N	0.00	
	SI	AV	K	2	0	290	H	0.00	
	SI	AV	N	6	0	495	N	0.00	
	SI	AV	R	6	0	473182	H	0.00	
M	SI	CV	*	18	1	13	H	1152978.30	
Y	SI	CV	C	18	5	2618	N	0.00	
	SI	CV	K	11	0	680	H	0.00	
	SI	CV	N	18	0	2618	N	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
Y	SI	CV	P	18	0	1419721	H	0.00	Failures from SI_CV_N. Exposure from SI_CV_R.
Y	SI	CV	R	18	1	1419721	H	0.00	
M	SI	MP	*	3	26	451	H	192163.05	
	SI	MP	A	3	1	657	N	0.00	
Y	SI	MP	F	3	1	263	H	0.00	
Y	SI	MP	S	3	1	210167	H	0.00	Failures from SI_MP_A. Exposure = 3*78912-263-451-3 yrs C PP
M	SI	MV	*	18	24	252	H	1088923.95	
Y	SI	MV	C	18	7	2615	N	0.00	
Y	SI	MV	K	14	0	789098	H	0.00	
	SI	MV	N	18	6	2615	N	0.00	
Y	SI	MV	P	18	6	631066	H	0.00	Failures from SI_MV_N. Exposure from SI_MV_R.
	SI	MV	R	12	0	631066	H	0.00	
Y	SI	MV	X	18	7	789098	H	0.00	Failures from SI_MV_C. Exposure from SI_MV_K.
	SI	RV	*	4	0	0	H	256217.40	
	SI	RV	C	4	0	6	N	0.00	
	SI	RV	N	4	0	6	N	0.00	
	SI	RV	R	4	0	315648	H	0.00	
	SI	TK	*	2	0	0	H	128108.70	
	SI	TK	G	2	1	157824	H	0.00	
	SI	TK	J	2	0	157824	H	0.00	
M	SI	XV	*	13	0	0	H	832706.55	
	SI	XV	C	13	1	232	N	0.00	
Y	SI	XV	K	13	0	1025856	H	0.00	
	SI	XV	N	13	0	232	N	0.00	
M	SW	AV	*	11	3	14	H	704597.85	
	SW	AV	C	11	2	233770	N	0.00	
	SW	AV	F	3	3	236734	H	0.00	
Y	SW	AV	K	7	0	221022	H	0.00	
	SW	AV	M	1	0	359	N	0.00	
Y	SW	AV	N	10	0	233411	N	0.00	
	SW	AV	R	7	0	410262	H	0.00	
M	SW	CV	*	6	3	850	H	384326.10	
Y	SW	CV	C	6	1	2064	N	0.00	
Y	SW	CV	K	6	0	183118	H	0.00	
Y	SW	CV	N	6	0	2064	N	0.00	
Y	SW	CV	P	6	0	290342	H	0.00	Failures from SW_CV_N. Exposure from SW_CV_R.
	SW	CV	R	6	0	290342	H	0.00	
M	SW	MP	*	4	77	6355	H	256217.40	
Y	SW	MP	A	4	0	1366	N	0.00	
Y	SW	MP	F	4	0	183027	H	0.00	
M	SW	MV	*	15	32	478	H	960815.25	
Y	SW	MV	C	15	12	2053	N	0.00	
Y	SW	MV	K	12	2	946768	H	0.00	
Y	SW	MV	N	15	9	2053	N	0.00	
Y	SW	MV	P	15	9	236446	H	0.00	Failures from SW_MV_N. Exposure from SW_MV_R.
	SW	MV	R	3	0	236446	H	0.00	
	SW	RV	*	29	0	0	H	1857576.15	
	SW	RV	C	29	0	0	N	0.00	

TABLE C-2
PLANT-SPECIFIC DATA SUMMARY

IN PSA MODEL	SYSTEM	COMPONENT TYPE	FAILURE MODE	POP SIZE	FAILURE COUNT	EXPOSURE	EXPOSURE BASIS	ON-LINE HOURS	NOTES
	SW	RV	N	29	0	0	N	0.00	
	SW	RV	R	29	0	2288448	H	0.00	
	SW	SC	*	2	0	0	H	128108.70	
	SW	SC	C	2	0	646	N	0.00	
	SW	SC	K	2	0	91	H	0.00	
	SW	SC	N	2	0	646	N	0.00	
	SW	SC	R	2	0	157733	H	0.00	
M	SW	SV	*	15	14	127	H	960815.25	
	SW	SV	C	15	6	913	N	0.00	
Y	SW	SV	K	12	0	749785	H	0.00	
	SW	SV	N	15	7	913	N	0.00	
Y	SW	SV	P	15	7	433772	H	0.00	Failures from SW_SV_N. Exposure from SW_SV_R.
	SW	SV	R	11	1	433772	H	0.00	
	SW	TN	*	4	23	143	H	256217.40	
	SW	TN	A	4	2	236813	N	0.00	
	SW	TN	F	4	13	142019	H	0.00	
M	SW	XV	*	112	6	84	H	7174087.20	
Y	SW	XV	C	112	1	3114	N	0.00	
Y	SW	XV	K	104	0	8206764	H	0.00	
	SW	XV	N	112	0	3114	N	0.00	
Y	SW	XV	P	112	0	631296	H	0.00	Failures from SW_XV_N. Exposure from SW_XV_R.
	SW	XV	R	8	0	631296	H	0.00	

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AC	B1 F	>4 KV BUS	FAULT	H								
			Plant						9.49-06			
			Aggregated		L	4.50-08	1.41-09	1.55-08	1.71-07	1.10+01		
			Updated		L	4.07-08	1.28-09	1.41-08	1.55-07	1.10+01	1.22-14	
			Final		L	4.07-08	1.28-09	1.41-08	1.55-07	1.10+01	1.22-14	B
AC	B2 F	<4 KV BUS	FAULT	H								
			Plant			1.01-06	1.80-07		3.19-06			
			Aggregated		L	1.19-07	2.31-09	3.26-08	4.60-07	1.41+01		
			Updated		L	7.84-07	2.30-07	6.44-07	1.80-06	2.80+00	2.95-13	
			Final		L	7.84-07	2.30-07	6.44-07	1.80-06	2.80+00	2.95-13	B
AC	B4 F	120 V BUS	FAULT	H								
			Plant						6.33-06			
			Aggregated		L	1.19-07	2.31-09	3.26-08	4.60-07	1.41+01		
			Updated		L	7.03-08	1.37-09	1.93-08	2.72-07	1.41+01	6.08-14	
			Final		L	7.03-08	1.37-09	1.93-08	2.72-07	1.41+01	6.08-14	B
AC	CB D	AC BREAKER	FAILS TO OPERATE	N								
			Plant			3.85-03	1.05-03		9.95-03			
			Aggregated		L	1.16-03	2.04-04	8.14-04	3.25-03	3.99+00		
			Updated									
			Final		L	3.85-03	8.53-04	2.91-03	9.95-03	3.42+00		P
AC	CB O	AC BREAKER	STANDBY FAILS TO OPERATE	H								
			Plant			6.91-07	1.88-07		1.79-06			
			Aggregated		L	1.06-06	1.86-07	7.44-07	2.97-06	3.99+00		
			Updated									
			Final		L	6.91-07	1.53-07	5.23-07	1.79-06	3.42+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AC	CB R	AC BREAKER	TRANSFERS OPEN	H								
			Plant			1.33-06	4.55-07		3.05-06			
			Aggregated		L	1.87-06	1.90-07	1.07-06	6.07-06	5.66+00		
			Updated									
			Final		L	1.33-06	3.97-07	1.10-06	3.05-06	2.77+00		P
AC	T1 F	KV TRANSFORMERS	FAULT	H								
			Plant						1.27-05			
			Aggregated		L	2.08-06	1.51-07	1.04-06	7.21-06	6.92+00		
			Updated		L	8.42-07	6.09-08	4.22-07	2.92-06	6.92+00	2.12-12	
			Final		L	8.42-07	6.09-08	4.22-07	2.92-06	6.92+00	2.12-12	B
AC	T6 F	480V-240V TRANS	FAULT	H								
			Plant						1.27-05			
			Aggregated		L	1.90-06	8.99-08	7.92-07	6.98-06	8.81+00		
			Updated		L	6.05-07	2.86-08	2.52-07	2.22-06	8.81+00	1.74-12	
			Final		L	6.05-07	2.86-08	2.52-07	2.22-06	8.81+00	1.74-12	B
AF	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						9.08-06			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	1.01-06	9.62-08	5.66-07	3.33-06	5.88+00	2.24-12	
			Final		L	1.01-06	9.62-08	5.66-07	3.33-06	5.88+00	2.24-12	B
AF	AV P	AIR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			8.50-07	4.36-08		4.03-06			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	8.50-07	3.43-08	3.30-07	3.17-06	9.62+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AF	AV X	AIR-OP VALVE	STANDBY FAILS TO CLOSE	H								
			Plant			2.02-06	3.59-07		6.36-06			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	2.02-06	2.35-07	1.22-06	6.36-06	5.21+00		P
AF	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant			1.87-03	1.01-03		3.17-03			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated									
			Final		L	1.87-03	9.68-04	1.75-03	3.17-03	1.81+00		P
AF	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						6.71-07			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	9.48-08	2.27-08	7.34-08	2.38-07	3.24+00	5.99-15	
			Final		L	9.48-08	2.27-08	7.34-08	2.38-07	3.24+00	5.99-15	B
AF	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant						1.07-03			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	3.81-05	1.67-06	1.54-05	1.41-04	9.18+00	7.49-09	
			Final		L	3.81-05	1.67-06	1.54-05	1.41-04	9.18+00	7.49-09	B
AF	MP S	MOTOR-DRIVEN PUMP	STANDBY FAILS TO START	H								
			Plant			1.07-06	5.47-08		5.06-06			
			Aggregated		L	4.42-06	4.99-07	2.64-06	1.40-05	5.30+00		
			Updated									
			Final		L	1.07-06	4.30-08	4.14-07	3.98-06	9.62+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AF	MV C	MOTOR-OP VALVE	FAILS TO CLOSE	H								
			Plant			1.19-03	4.68-04		2.50-03			
			Aggregated		L	6.01-03	6.72-04	3.58-03	1.91-02	5.33+00		
			Updated									
			Final		L	1.19-03	4.22-04	1.03-03	2.50-03	2.43+00		P
AF	MV D	MOTOR-OP VALVE	FAILS TO THROTTLE	H								
			Plant						6.21-04			
			Aggregated		L	2.25-06	1.13-06	2.10-06	3.90-06	1.86+00		
			Updated		L	2.25-06	1.12-06	2.09-06	3.89-06	1.86+00	7.72-13	
			Final		L	2.25-06	1.12-06	2.09-06	3.89-06	1.86+00	7.72-13	B
AF	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						4.72-06			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated		L	9.23-07	2.20-07	7.14-07	2.32-06	3.25+00	5.72-13	
			Final		L	9.23-07	2.20-07	7.14-07	2.32-06	3.25+00	5.72-13	B
AF	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			2.83-06	9.67-07		6.48-06			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated									
			Final		L	2.83-06	8.42-07	2.34-06	6.48-06	2.77+00		P
AF	MV X	MOTOR-OP VALVE	STANDBY FAILS TO CLOSE	H								
			Plant			2.63-06	1.04-06		5.52-06			
			Aggregated		L	5.49-06	6.14-07	3.27-06	1.74-05	5.33+00		
			Updated									
			Final		L	2.63-06	9.33-07	2.27-06	5.52-06	2.43+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AF	TK J	TANK	LEAKAGE	H								
			Plant						1.27-05			
			Aggregated		L	5.52-06	2.51-06	5.04-06	1.01-05	2.01+00		
			Updated		L	4.39-06	2.00-06	4.01-06	8.06-06	2.01+00	3.80-12	
			Final		L	4.39-06	2.00-06	4.01-06	8.06-06	2.01+00	3.80-12	B
AF	TP F	TURBINE PUMP	FAILS TO RUN	H								
			Plant						3.44-02			
			Aggregated		L	8.91-05	1.08-05	5.48-05	2.77-04	5.06+00		
			Updated		L	8.80-05	1.07-05	5.41-05	2.74-04	5.06+00	1.27-08	
			Final		L	8.80-05	1.07-05	5.41-05	2.74-04	5.06+00	1.27-08	B
AF	TP S	TURBINE PUMP	STANDBY FAILS TO START	H								
			Plant			8.49-06	1.51-06		2.67-05			
			Aggregated		L	2.39-05	3.81-06	1.62-05	6.91-05	4.26+00		
			Updated									
			Final		L	8.49-06	9.87-07	5.14-06	2.67-05	5.21+00		P
AF	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						9.74-07			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.07-07	1.53-08	7.00-08	3.20-07	4.58+00	1.56-14	
			Final		L	1.07-07	1.53-08	7.00-08	3.20-07	4.58+00	1.56-14	B
AF	XV P	MANUAL VALVE	STANDBY FAILS TO OPEN	H								
			Plant						5.42-06			
			Aggregated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00		
			Updated		L	3.77-07	2.78-08	1.90-07	1.30-06	6.84+00	4.15-13	
			Final		L	3.77-07	2.78-08	1.90-07	1.30-06	6.84+00	4.15-13	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
AF	XV X	MANUAL VALVE	STANDBY FAILS TO CLOSE	H								
			Plant						9.74-07			
			Aggregated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00		
			Updated		L	9.97-08	7.36-09	5.04-08	3.44-07	6.84+00	2.91-14	
			Final		L	9.97-08	7.36-09	5.04-08	3.44-07	6.84+00	2.91-14	B
CC	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						3.80-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	2.27-06	2.16-07	1.27-06	7.48-06	5.88+00	1.13-11	
			Final		L	2.27-06	2.16-07	1.27-06	7.48-06	5.88+00	1.13-11	B
CC	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant			3.85-03	6.85-04		1.21-02			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated									
			Final		L	3.85-03	4.48-04	2.33-03	1.21-02	5.21+00		P
CC	CV K	CHECK VALVE	TRANSFERS CLOSED	H								
			Plant						5.33-06			
			Aggregated		L	1.69-06	4.32-07	1.34-06	4.13-06	3.09+00		
			Updated		L	1.08-06	2.75-07	8.50-07	2.63-06	3.09+00	6.95-13	
			Final		L	1.08-06	2.75-07	8.50-07	2.63-06	3.09+00	6.95-13	B
CC	HX F	HEAT EXCHANGER	COOLING CAPABILITY FAILS	H								
			Plant						2.79-06			
			Aggregated		L	1.95-05	5.82-07	6.58-06	7.43-05	1.13+01		
			Updated		L	1.19-07	3.55-09	4.01-08	4.53-07	1.13+01	1.10-13	
			Final		L	1.19-07	3.55-09	4.01-08	4.53-07	1.13+01	1.10-13	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CC	HX J	HEAT EXCHANGER	TUBE RUPTURE	H								
			Plant						2.79-06			
			Aggregated		L	2.61-05	1.80-06	1.28-05	9.12-05	7.12+00		
			Updated		L	2.92-07	2.01-08	1.43-07	1.02-06	7.12+00	2.68-13	
			Final		L	2.92-07	2.01-08	1.43-07	1.02-06	7.12+00	2.68-13	B
CC	HX P	HEAT EXCHANGER	PLUGS	H								
			Plant						2.79-06			
			Aggregated		L	2.20-06	2.16-07	1.25-06	7.20-06	5.78+00		
			Updated		L	3.66-07	3.58-08	2.07-07	1.20-06	5.78+00	2.84-13	
			Final		L	3.66-07	3.58-08	2.07-07	1.20-06	5.78+00	2.84-13	B
CC	MP A	MOTOR-DRIVEN PUMP	FAILS TO START	N								
			Plant			1.85-03	9.46-05		8.75-03			
			Aggregated		L	4.84-03	5.46-04	2.89-03	1.53-02	5.30+00		
			Updated									
			Final		L	1.85-03	7.44-05	7.16-04	6.88-03	9.62+00		P
CC	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant			1.18-05	6.08-07		5.62-05			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated									
			Final		L	1.18-05	4.78-07	4.59-06	4.42-05	9.62+00		P
CC	MV C	MOTOR-OP VALVE	FAILS TO CLOSE	H								
			Plant			7.43-03	3.24-03		1.47-02			
			Aggregated		L	6.01-03	6.72-04	3.58-03	1.91-02	5.33+00		
			Updated									
			Final		L	7.43-03	2.98-03	6.61-03	1.47-02	2.22+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CC	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						6.30-06			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated		L	1.02-06	2.44-07	7.92-07	2.57-06	3.25+00	7.03-13	
			Final		L	1.02-06	2.44-07	7.92-07	2.57-06	3.25+00	7.03-13	B
CC	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			4.26-06	1.45-06		9.74-06			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated									
			Final		L	4.26-06	1.27-06	3.51-06	9.74-06	2.77+00		P
CC	TK J	TANK	LEAKAGE	H								
			Plant						3.80-05			
			Aggregated		L	5.52-06	2.51-06	5.04-06	1.01-05	2.01+00		
			Updated		L	5.08-06	2.31-06	4.65-06	9.34-06	2.01+00	5.10-12	
			Final		L	5.08-06	2.31-06	4.65-06	9.34-06	2.01+00	5.10-12	B
CC	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						6.66-07			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	8.90-08	1.27-08	5.80-08	2.66-07	4.58+00	1.07-14	
			Final		L	8.90-08	1.27-08	5.80-08	2.66-07	4.58+00	1.07-14	B
CC	XV N	MANUAL VALVE	FAILS TO OPEN	N								
			Plant						4.70-03			
			Aggregated		L	3.47-04	2.56-05	1.75-04	1.20-03	6.84+00		
			Updated		L	2.11-04	1.55-05	1.06-04	7.27-04	6.84+00	1.30-07	
			Final		L	2.11-04	1.55-05	1.06-04	7.27-04	6.84+00	1.30-07	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CR CS	AV P	AIR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			4.22-06	7.51-07		1.33-05			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	4.22-06	4.91-07	2.55-06	1.33-05	5.21+00		P
CR CS	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant			1.61-03	8.26-05		7.64-03			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated									
			Final		L	1.61-03	6.50-05	6.25-04	6.01-03	9.62+00		P
CR CS	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						2.11-06			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	1.17-07	2.81-08	9.09-08	2.94-07	3.24+00	9.18-15	
			Final		L	1.17-07	2.81-08	9.09-08	2.94-07	3.24+00	9.18-15	B
CR CS	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant			1.49-02	7.66-04		7.08-02			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	5.05-04	1.03-04	3.73-04	1.34-03	3.61+00	2.14-07	
			Final		L	5.05-04	1.03-04	3.73-04	1.34-03	3.61+00	2.14-07	B
CR CS	MP S	MOTOR-DRIVEN PUMP	STANDBY FAILS TO START	H								
			Plant						6.34-06			
			Aggregated		L	4.42-06	4.99-07	2.64-06	1.40-05	5.30+00		
			Updated		L	9.31-07	1.05-07	5.57-07	2.95-06	5.30+00	1.56-12	
			Final		L	9.31-07	1.05-07	5.57-07	2.95-06	5.30+00	1.56-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CR CS MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
		Plant						1.90-05			
		Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
		Updated		L	1.31-06	3.12-07	1.01-06	3.29-06	3.25+00	1.15-12	
		Final		L	1.31-06	3.12-07	1.01-06	3.29-06	3.25+00	1.15-12	B
CR CS MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
		Plant			3.70-06	1.74-06		6.95-06			
		Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
		Updated									
		Final		L	3.70-06	1.62-06	3.35-06	6.95-06	2.07+00		P
CR CS MV R	MOTOR-OP VALVE	TRANSFERS OPEN	H								
		Plant						4.75-06			
		Aggregated		L	1.36-06	2.39-07	9.55-07	3.81-06	3.99+00		
		Updated		L	7.22-07	1.27-07	5.07-07	2.02-06	3.99+00	5.37-13	
		Final		L	7.22-07	1.27-07	5.07-07	2.02-06	3.99+00	5.37-13	B
CR CS MV X	MOTOR-OP VALVE	STANDBY FAILS TO CLOSE	H								
		Plant			1.90-05	9.91-06		3.31-05			
		Aggregated		L	5.49-06	6.14-07	3.27-06	1.74-05	5.33+00		
		Updated									
		Final		L	1.90-05	9.40-06	1.76-05	3.31-05	1.88+00		P
CR CS TK J	TANK	LEAKAGE	H								
		Plant						1.90-05			
		Aggregated		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		
		Updated									
		Final		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		G

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CR CS	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						2.92-06			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.53-07	2.18-08	9.96-08	4.56-07	4.58+00	3.16-14	
			Final		L	1.53-07	2.18-08	9.96-08	4.56-07	4.58+00	3.16-14	B
CR CS	XV N	MANUAL VALVE	FAILS TO OPEN	N								
			Plant						1.56-03			
			Aggregated		L	3.47-04	2.56-05	1.75-04	1.20-03	6.84+00		
			Updated		L	1.18-04	8.68-06	5.94-05	4.06-04	6.84+00	4.05-08	
			Final		L	1.18-04	8.68-06	5.94-05	4.06-04	6.84+00	4.05-08	B
CR CS	XV R	MANUAL VALVE	TRANSFERS OPEN	H								
			Plant						4.75-06			
			Aggregated		L	1.30-07	1.50-08	7.84-08	4.10-07	5.23+00		
			Updated		L	1.14-07	1.31-08	6.85-08	3.59-07	5.23+00	2.26-14	
			Final		L	1.14-07	1.31-08	6.85-08	3.59-07	5.23+00	2.26-14	B
CT	AV R	AIR-OP VALVE	TRANSFERS OPEN	H								
			Plant			1.64-06	8.40-08		7.77-06			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated									
			Final		L	1.64-06	6.61-08	6.35-07	6.11-06	9.62+00		P
CT	BF F	BLIND FLANGE	FAILURE	H								
			Plant			1.73-06	8.88-08		8.21-06			
			Aggregated		L							
			Updated									
			Final		L	1.73-06	6.99-08	6.72-07	6.46-06	9.62+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CT	CV R	CHECK VALVE	TRANSFERS OPEN	H								
			Plant						6.33-06			
			Aggregated		L	9.46-07	4.96-08	4.13-07	3.43-06	8.32+00		
			Updated		L	3.26-07	1.71-08	1.42-07	1.18-06	8.32+00	4.51-13	
			Final		L	3.26-07	1.71-08	1.42-07	1.18-06	8.32+00	4.51-13	B
CV	AV C	AIR-OP VALVE	FAILS TO CLOSE	N								
			Plant			3.47-04	1.63-04		6.52-04			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated									
			Final		L	3.47-04	1.52-04	3.15-04	6.52-04	2.07+00		P
CV	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						1.11-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	1.17-06	1.11-07	6.54-07	3.85-06	5.88+00	2.99-12	
			Final		L	1.17-06	1.11-07	6.54-07	3.85-06	5.88+00	2.99-12	B
CV	AV N	AIR-OP VALVE	FAILS TO OPEN	N								
			Plant			9.92-05	1.76-05		3.12-04			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated									
			Final		L	9.92-05	1.25-05	6.00-05	3.12-04	5.21+00		P
CV	AV P	AIR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			5.27-07	9.36-08		1.66-06			
			Aggregated		L	1.98-06.	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	5.27-07	6.12-08	3.18-07	1.66-06	5.21+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CV	CV K	CHECK VALVE	TRANSFERS CLOSED	H								
			Plant						3.43-06			
			Aggregated		L	1.69-06	4.32-07	1.34-06	4.13-06	3.09+00		
			Updated		L	8.96-07	2.29-07	7.08-07	2.19-06	3.09+00	4.82-13	
			Final		L	8.96-07	2.29-07	7.08-07	2.19-06	3.09+00	4.82-13	B
CV	CV N	CHECK VALVE	FAILS TO OPEN	N								
			Plant			4.06-05	2.08-06		1.93-04			
			Aggregated		L	1.45-04	3.47-05	1.12-04	3.64-04	3.24+00		
			Updated									
			Final		L	4.06-05	1.64-06	1.57-05	1.51-04	9.62+00		P
CV	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant			1.77-07	9.05-09		8.37-07			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated									
			Final		L	1.77-07	7.12-09	6.85-08	6.59-07	9.62+00		P
CV	HT F	HEAT TRACE	FAILS	H								
			Plant			1.56-04	8.47-05		2.65-04			
			Aggregated		L							
			Updated									
			Final		L	1.56-04	8.08-05	1.46-04	2.65-04	1.81+00		P
CV	HX P	HEAT EXCHANGER	PLUGS	H								
			Plant						9.35-06			
			Aggregated		L	2.20-06	2.16-07	1.25-06	7.20-06	5.78+00		
			Updated		L	8.82-07	8.64-08	5.00-07	2.89-06	5.78+00	1.65-12	
			Final		L	8.82-07	8.64-08	5.00-07	2.89-06	5.78+00	1.65-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CV	LT D	LEVEL TRANSMITTER	FAILS TO RESPOND	H								
			Plant			1.27-05	4.33-06		2.90-05			
			Aggregated		L	2.14-06	4.63-07	1.61-06	5.58-06	3.47+00		
			Updated									
			Final		L	1.27-05	3.77-06	1.05-05	2.90-05	2.77+00		P
CV	LT H	LEVEL TRANSMITTER	FAILS HIGH	H								
			Plant			1.05-04	7.65-05		1.40-04			
			Aggregated		L	2.02-06	3.72-07	1.44-06	5.57-06	3.87+00		
			Updated									
			Final		L	1.05-04	7.55-05	1.03-04	1.40-04	1.36+00		P
CV	MP A	MOTOR-DRIVEN PUMP	FAILS TO START	N								
			Plant			1.08-03	6.06-04		1.79-03			
			Aggregated		L	4.84-03	5.46-04	2.89-03	1.53-02	5.30+00		
			Updated									
			Final		L	1.08-03	5.81-04	1.02-03	1.79-03	1.75+00		P
CV	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant			2.72-05	9.29-06		6.22-05			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated									
			Final		L	2.72-05	8.09-06	2.24-05	6.22-05	2.77+00		P
CV	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						4.68-05			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated		L	1.43-06	3.40-07	1.10-06	3.59-06	3.25+00	1.37-12	
			Final		L	1.43-06	3.40-07	1.10-06	3.59-06	3.25+00	1.37-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CV	MV N	MOTOR-OP VALVE	FAILS TO OPEN	N								
			Plant						2.36-02			
			Aggregated		L	5.07-03	1.39-03	4.09-03	1.20-02	2.94+00		
			Updated		L	3.76-03	1.03-03	3.03-03	8.92-03	2.94+00	7.61-06	
			Final		L	3.76-03	1.03-03	3.03-03	8.92-03	2.94+00	7.61-06	B
CV	PP J	PIPING	LEAKAGE	H								
			Plant						4.68-05			
			Aggregated		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		
			Updated									
			Final		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		G
CV	PP P	PIPING	PLUGS	H								
			Plant			6.24-05	2.13-05		1.43-04			
			Aggregated		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		
			Updated									
			Final		L	6.24-05	1.86-05	5.15-05	1.43-04	2.77+00		P
CV	RV N	RELIEF VALVE	FAILS TO OPEN	N								
			Plant						2.07-01			
			Aggregated		L	2.12-04	7.96-06	7.96-05	7.96-04	****+00		
			Updated		L	2.07-04	7.76-06	7.76-05	7.76-04	1.00+01	2.60-07	
			Final		L	2.07-04	7.76-06	7.76-05	7.76-04	1.00+01	2.60-07	B
CV	RV P	RELIEF VALVE	STANDBY FAILS TO OPEN	H								
			Plant						1.81-06			
			Aggregated		L	1.94-07	7.28-09	7.28-08	7.28-07	****+00		
			Updated		L	6.56-08	2.46-09	2.46-08	2.46-07	****+00	2.62-14	
			Final		L	6.56-08	2.46-09	2.46-08	2.46-07	****+00	2.62-14	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
CV	RV R	RELIEF VALVE	SPURIOUS OPEN	H								
			Plant			2.72-05	1.67-05		4.18-05			
			Aggregated		L	1.69-06	2.84-07	1.17-06	4.80-06	4.11+00		
			Updated									
			Final		L	2.72-05	1.62-05	2.61-05	4.18-05	1.60+00		P
CV	TK J	TANK	LEAKAGE	H								
			Plant						9.49-06			
			Aggregated		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		
			Updated		L	3.65-07	2.67-08	1.83-07	1.26-06	6.88+00	3.93-13	
			Final		L	3.65-07	2.67-08	1.83-07	1.26-06	6.88+00	3.93-13	B
CV	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						5.58-07			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	8.05-08	1.15-08	5.25-08	2.40-07	4.58+00	8.78-15	
			Final		L	8.05-08	1.15-08	5.25-08	2.40-07	4.58+00	8.78-15	B
CV	XV R	MANUAL VALVE	TRANSFERS OPEN	H								
			Plant						4.22-06			
			Aggregated		L	1.30-07	1.50-08	7.84-08	4.10-07	5.23+00		
			Updated		L	1.12-07	1.29-08	6.75-08	3.53-07	5.23+00	2.19-14	
			Final		L	1.12-07	1.29-08	6.75-08	3.53-07	5.23+00	2.19-14	B
DC	BC F	BATTERY CHARGER	NO OUTPUT	H								
			Plant			1.27-05	4.33-06		2.90-05			
			Aggregated		L	7.78-06	3.51-07	3.18-06	2.87-05	9.04+00		
			Updated									
			Final		L	1.27-05	3.77-06	1.05-05	2.90-05	2.77+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
DC	BD F	DC BUS	FAULT	H								
			Plant						1.15-06			
			Aggregated		L	4.50-08	1.41-09	1.55-08	1.71-07	1.10+01		
			Updated		L	2.41-08	7.58-10	8.34-09	9.18-08	1.10+01	4.30-15	
			Final		L	2.41-08	7.58-10	8.34-09	9.18-08	1.10+01	4.30-15	B
DC	BT D	BATTERY	NO OUTPUT (DEMAND)	N								
			Plant						1.16-02			
			Aggregated		L	6.61-03	7.13-04	3.89-03	2.12-02	5.45+00		
			Updated		L	1.54-03	1.63-04	8.98-04	4.93-03	5.49+00	4.53-06	
			Final		L	1.54-03	1.63-04	8.98-04	4.93-03	5.49+00	4.53-06	B
DC	BT F	BATTERY	NO OUTPUT (HOURLY)	H								
			Plant						1.27-05			
			Aggregated		L	1.93-06	1.75-07	1.06-06	6.42-06	6.05+00		
			Updated		L	9.39-07	8.52-08	5.16-07	3.12-06	6.05+00	2.04-12	
			Final		L	9.39-07	8.52-08	5.16-07	3.12-06	6.05+00	2.04-12	B
DC	CF R	FUSE	FAILS OPEN	H								
			Plant						6.90-07			
			Aggregated		L	6.38-07	2.40-08	2.40-07	2.39-06	9.98+00		
			Updated		L	3.58-08	1.35-09	1.35-08	1.34-07	9.98+00	7.79-15	
			Final		L	3.58-08	1.35-09	1.35-08	1.34-07	9.98+00	7.79-15	B
DC	IN F	INVERTER	NO OUTPUT	H								
			Plant			1.27-05	3.45-06		3.28-05			
			Aggregated		L	2.87-05	9.67-07	1.02-05	1.09-04	1.06+01		
			Updated									
			Final		L	1.27-05	2.81-06	9.59-06	3.28-05	3.42+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
DG	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant						4.29-03			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated		L	3.58-04	2.49-05	1.76-04	1.25-03	7.08+00	4.00-07	
			Final		L	3.58-04	2.49-05	1.76-04	1.25-03	7.08+00	4.00-07	B
DG	CV N	CHECK VALVE	FAILS TO OPEN	N								
			Plant						4.29-03			
			Aggregated		L	1.45-04	3.47-05	1.12-04	3.64-04	3.24+00		
			Updated		L	1.36-04	3.25-05	1.05-04	3.41-04	3.24+00	1.23-08	
			Final		L	1.36-04	3.25-05	1.05-04	3.41-04	3.24+00	1.23-08	B
DG	DG A	DIESEL GENERATOR	FAILS TO START	N								
			Plant			4.88-03	8.67-04		1.54-02			
			Aggregated		L	1.76-02	2.21-03	1.10-02	5.43-02	4.96+00		
			Updated									
			Final		L	4.88-03	5.67-04	2.95-03	1.54-02	5.21+00		P
DG	DG F	DIESEL GENERATOR	FAILS TO RUN	H								
			Plant			1.25-03	6.40-05		5.92-03			
			Aggregated		L	2.25-03	1.72-04	1.15-03	7.72-03	6.70+00		
			Updated									
			Final		L	1.25-03	5.04-05	4.84-04	4.66-03	9.62+00		P
DG	MP A	MOTOR-DRIVEN PUMP	FAILS TO START	N								
			Plant						8.51-03			
			Aggregated		L	4.84-03	5.46-04	2.89-03	1.53-02	5.30+00		
			Updated		L	1.18-03	1.32-04	7.04-04	3.75-03	5.33+00	2.53-06	
			Final		L	1.18-03	1.32-04	7.04-04	3.75-03	5.33+00	2.53-06	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
DG	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant						9.25-03			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	7.41-05	3.25-06	2.99-05	2.74-04	9.18+00	2.83-08	
			Final		L	7.41-05	3.25-06	2.99-05	2.74-04	9.18+00	2.83-08	B
DG	RV R	RELIEF VALVE	SPURIOUS OPEN	H								
			Plant						1.90-05			
			Aggregated		L	1.69-06	2.84-07	1.17-06	4.80-06	4.11+00		
			Updated		L	1.31-06	2.20-07	9.05-07	3.72-06	4.11+00	1.87-12	
			Final		L	1.31-06	2.20-07	9.05-07	3.72-06	4.11+00	1.87-12	B
DG	SV P	SOLENOID-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			2.11-06	1.08-07		1.00-05			
			Aggregated		L	2.58-06	1.62-07	1.22-06	9.14-06	7.51+00		
			Updated									
			Final		L	2.11-06	8.52-08	8.19-07	7.88-06	9.62+00		P
DG	SV X	SOLENOID-OP VALVE	STANDBY FAILS TO CLOSE	H								
			Plant						6.33-06			
			Aggregated		L	2.58-06	1.62-07	1.22-06	9.14-06	7.51+00		
			Updated		L	4.90-07	3.08-08	2.31-07	1.74-06	7.51+00	8.38-13	
			Final		L	4.90-07	3.08-08	2.31-07	1.74-06	7.51+00	8.38-13	B
DG	TK J	TANK	LEAKAGE	H								
			Plant						1.90-05			
			Aggregated		L	5.52-06	2.51-06	5.04-06	1.01-05	2.01+00		
			Updated		L	4.71-06	2.14-06	4.30-06	8.65-06	2.01+00	4.38-12	
			Final		L	4.71-06	2.14-06	4.30-06	8.65-06	2.01+00	4.38-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
DG	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						4.75-06			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.66-07	2.37-08	1.08-07	4.97-07	4.58+00	3.75-14	
			Final		L	1.66-07	2.37-08	1.08-07	4.97-07	4.58+00	3.75-14	B
HV	AF F	AIR FILTER	FAILS TO DELIVER FLOW	H								
			Plant			7.31-06	3.75-07		3.47-05			
			Aggregated		L	7.23-06	1.16-06	4.92-06	2.08-05	4.24+00		
			Updated									
			Final		L	7.31-06	2.95-07	2.84-06	2.73-05	9.62+00		P
HV	HE F	ROOM HEATER	FAILS TO OPERATE	H								
			Plant						1.11-03			
			Aggregated		L	1.16-06	6.66-07	1.11-06	1.84-06	1.66+00		
			Updated		L	1.16-06	6.66-07	1.11-06	1.84-06	1.66+00	1.34-13	
			Final		L	1.16-06	6.66-07	1.11-06	1.84-06	1.66+00	1.34-13	B
HV	MC K	AIR-OP DAMPER	TRANSFERS CLOSED	H								
			Plant			9.18-07	1.63-07		2.89-06			
			Aggregated		L	5.09-06	2.24-07	2.06-06	1.88-05	9.16+00		
			Updated									
			Final		L	9.18-07	1.07-07	5.55-07	2.89-06	5.21+00		P
HV	MC N	AIR-OP DAMPER	FAILS TO OPEN	N								
			Plant			1.99-04	3.53-05		6.26-04			
			Aggregated		L	2.18-03	6.10-04	1.77-03	5.13-03	2.90+00		
			Updated									
			Final		L	1.99-04	2.31-05	1.20-04	6.26-04	5.21+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
HV	MF A	MOTOR-DRIVEN FAN	FAILS TO START	H								
			Plant			6.91-04	3.24-04		1.30-03			
			Aggregated		L	2.08-04	9.43-06	8.51-05	7.67-04	9.02+00		
			Updated									
			Final		L	6.91-04	3.02-04	6.27-04	1.30-03	2.07+00		P
HV	MF F	MOTOR-DRIVEN FAN	FAILS TO RUN	H								
			Plant			7.82-06	4.38-06		1.29-05			
			Aggregated		L	1.24-05	4.61-06	1.08-05	2.55-05	2.35+00		
			Updated									
			Final		L	7.82-06	4.20-06	7.37-06	1.29-05	1.75+00		P
HV	MF S	MOTOR-DRIVEN FAN	STANDBY FAILS TO START	H								
			Plant			1.09-06	5.11-07		2.05-06			
			Aggregated		L	1.90-07	8.62-09	7.77-08	7.01-07	9.02+00		
			Updated									
			Final		L	1.09-06	4.77-07	9.88-07	2.05-06	2.07+00		P
IA	AD F	AIR DRYER	FAILS TO DELIVER FLOW	H								
			Plant			6.34-05	3.44-05		1.07-04			
			Aggregated		L	5.23-07	3.38-07	5.07-07	7.61-07	1.50+00		
			Updated									
			Final		L	6.34-05	3.28-05	5.94-05	1.07-04	1.81+00		P
IA	AF F	AIR FILTER	FAILS TO DELIVER FLOW	H								
			Plant						8.00-06			
			Aggregated		L	7.23-06	1.16-06	4.92-06	2.08-05	4.24+00		
			Updated		L	1.74-06	2.79-07	1.18-06	5.02-06	4.24+00	3.53-12	
			Final		L	1.74-06	2.79-07	1.18-06	5.02-06	4.24+00	3.53-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
IA	AM A	AIR COMPRESSOR	FAILS TO START	N								
			Plant			3.87-03	1.06-03		1.00-02			
			Aggregated		L	1.27-01	9.65-02	1.25-01	1.63-01	1.30+00		
			Updated									
			Final		L	3.87-03	8.57-04	2.93-03	1.00-02	3.42+00		P
IA	AM F	AIR COMPRESSOR	FAILS TO RUN	H								
			Plant			7.83-05	4.99-05		1.17-04			
			Aggregated		L	2.48-03	6.56-05	7.90-04	9.51-03	1.20+01		
			Updated									
			Final		L	7.83-05	4.86-05	7.55-05	1.17-04	1.55+00		P
IA	AR F	AIR RECEIVER	LOCAL FAULTS	H								
			Plant			4.61-06	2.36-07		2.19-05			
			Aggregated		L	6.00-07	1.05-08	1.56-07	2.32-06	1.49+01		
			Updated									
			Final		L	4.61-06	1.86-07	1.79-06	1.72-05	9.62+00		P
IA	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						7.59-06			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	8.84-07	8.42-08	4.95-07	2.91-06	5.88+00	1.71-12	
			Final		L	8.84-07	8.42-08	4.95-07	2.91-06	5.88+00	1.71-12	B
IA	AV N	AIR-OP VALVE	FAILS TO OPEN	N								
			Plant						1.14-04			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated		L	2.79-05	4.00-06	1.82-05	8.32-05	4.56+00	1.05-09	
			Final		L	2.79-05	4.00-06	1.82-05	8.32-05	4.56+00	1.05-09	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
IA	CV K	CHECK VALVE	TRANSFERS CLOSED	H								
			Plant						7.59-06			
			Aggregated		L	1.69-06	4.32-07	1.34-06	4.13-06	3.09+00		
			Updated		L	1.21-06	3.09-07	9.54-07	2.95-06	3.09+00	8.74-13	
			Final		L	1.21-06	3.09-07	9.54-07	2.95-06	3.09+00	8.74-13	B
IA	CV N	CHECK VALVE	FAILS TO OPEN	N								
			Plant						2.14-04			
			Aggregated		L	1.45-04	3.47-05	1.12-04	3.64-04	3.24+00		
			Updated		L	6.17-05	1.47-05	4.78-05	1.55-04	3.24+00	2.54-09	
			Final		L	6.17-05	1.47-05	4.78-05	1.55-04	3.24+00	2.54-09	B
IA	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						1.81-06			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	1.15-07	2.75-08	8.92-08	2.89-07	3.24+00	8.85-15	
			Final		L	1.15-07	2.75-08	8.92-08	2.89-07	3.24+00	8.85-15	B
IA.	PP J	PIPING	LEAKAGE	H								
			Plant			5.07-05	1.73-05		1.16-04			
			Aggregated		L	5.53-07	4.04-08	2.78-07	1.91-06	6.88+00		
			Updated									
			Final		L	5.07-05	1.51-05	4.18-05	1.16-04	2.77+00		P
IA	SV P	IA SOLENOID VALVE	FAILS TO OPEN (STANDBY)									
			Plant									
			Aggregated		L	4.31-07	2.71-08	2.03-07	1.53-06	7.51+00		
			Updated									
			Final		L	4.31-07	2.71-08	2.03-07	1.53-06	7.51+00		G

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
MS	AV C	MSIV VALVE	FAILS TO CLOSE	N								
			Plant			8.81-03	1.57-03		2.77-02			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated									
			Final		L	8.81-03	1.02-03	5.33-03	2.77-02	5.21+00		P
MS	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						2.34-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	1.83-06	1.74-07	1.02-06	6.01-06	5.88+00	7.29-12	
			Final		L	1.83-06	1.74-07	1.02-06	6.01-06	5.88+00	7.29-12	B
MS	AV P	AIR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			1.12-05	5.75-07		5.32-05			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	1.12-05	4.53-07	4.35-06	4.19-05	9.62+00		P
MS	AV X	MAIN STEAM AOV	FAILS TO OPEN (STANDBY)									
			Plant			2.60-06	1.33-07		1.23-05			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	2.60-06	1.05-07	1.01-06	9.71-06	9.62+00		P
MS	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant			2.64-03	1.35-04		1.25-02			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated									
			Final		L	2.64-03	1.06-04	1.02-03	9.84-03	9.62+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
MS	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						6.34-06			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	1.27-07	3.03-08	9.82-08	3.18-07	3.24+00	1.07-14	
			Final		L	1.27-07	3.03-08	9.82-08	3.18-07	3.24+00	1.07-14	B
MS	MV C	MOTOR-OP VALVE	FAILS TO CLOSE	N								
			Plant			2.28-03	1.17-04		1.08-02			
			Aggregated		L	6.01-03	6.72-04	3.58-03	1.91-02	5.33+00		
			Updated									
			Final		L	2.28-03	9.21-05	8.86-04	8.52-03	9.62+00		P
MS	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			2.12-06	1.09-07		1.00-05			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated									
			Final		L	2.12-06	8.54-08	8.21-07	7.90-06	9.62+00		P
MS	MV R	MOTOR-OP VALVE	TRNASFERS OPEN	H								
			Plant						1.90-05			
			Aggregated		L	1.36-06	2.39-07	9.55-07	3.81-06	3.99+00		
			Updated		L	1.11-06	1.96-07	7.82-07	3.12-06	3.99+00	1.28-12	
			Final		L	1.11-06	1.96-07	7.82-07	3.12-06	3.99+00	1.28-12	B
MS	RV C	RELIEF VALVE	FAILS TO CLOSE	N								
			Plant						5.52-02			
			Aggregated		L	5.18-03	1.11-04	1.49-03	2.00-02	1.34+01		
			Updated		L	8.53-04	1.74-05	2.40-04	3.30-03	1.37+01	8.50-06	
			Final		L	8.53-04	1.74-05	2.40-04	3.30-03	1.37+01	8.50-06	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
MS	RV P	RELIEF VALVE	STANDBY FAILS TO OPEN	H								
			Plant			2.11-06	1.08-07		1.00-05			
			Aggregated		L	1.94-07	7.28-09	7.28-08	7.28-07	****+00		
			Updated									
			Final		L	2.11-06	8.52-08	8.20-07	7.88-06	9.62+00		P
MS	RY T	PSV, SG SAFETY VLV	FAILS TO RESEAT AFTER STEAM	N								
			Plant						4.29-01			
			Aggregated		L	7.45-03	1.05-03	4.83-03	2.23-02	4.62+00		
			Updated		L	6.88-03	9.64-04	4.46-03	2.06-02	4.62+00	6.52-05	
			Final		L	6.88-03	9.64-04	4.46-03	2.06-02	4.62+00	6.52-05	B
MS	XV C	MANUAL VALVE	FAILS TO CLOSE	N								
			Plant						1.64-01			
			Aggregated		L	3.47-04	2.56-05	1.75-04	1.20-03	6.84+00		
			Updated		L	3.38-04	2.50-05	1.71-04	1.17-03	6.84+00	3.34-07	
			Final		L	3.38-04	2.50-05	1.71-04	1.17-03	6.84+00	3.34-07	B
MS	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						9.49-06			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.79-07	2.55-08	1.17-07	5 35-07	4.58+00	4.34-14	
			Final		L	1.79-07	2.55-08	1.17-07	5.35-07	4.58+00	4.34-14	B
MS	XV P	MANUAL VALVE	STANDBY FAILS TO OPEN	H								
			Plant									
			Aggregated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00		
			Updated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00	2.71-12	
			Final		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00	2.71-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
RC	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						4.68-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	2.45-06	2.34-07	1.37-06	8.08-06	5.88+00	1.32-11	
			Final		L	2.45-06	2.34-07	1.37-06	8.08-06	5.88+00	1.32-11	B
RC	AV N	AIR-OP VALVE	FAILS TO OPEN	N								
			Plant			3.94-03	2.02-04		1.87-02			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated									
			Final		L	3.94-03	1.59-04	1.53-03	1.47-02	9.62+00		P
RC	AV P	AIR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			7.59-07	3.89-08		3.60-06			
			Aggregated		L	1.98-06	2.85-07	1.30-06	5.89-06	4.55+00		
			Updated									
			Final		L	7.59-07	3.06-08	2.94-07	2.83-06	9.62+00		P
RC	CV N	CHECK VALVE	FAILS TO OPEN	N								
			Plant						7.42-02			
			Aggregated		L	1.45-04	3.47-05	1.12-04	3.64-04	3.24+00		
			Updated		L	1.44-04	3.45-05	1.12-04	3.62-04	3.24+00	1.39-08	
			Final		L	1.44-04	3.45-05	1.12-04	3.62-04	3.24+00	1.39-08	B
RC	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant						2.26-05			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	1.44-06	6.31-08	5.79-07	5.32-06	9.18+00	1.06-11	
			Final		L	1.44-06	6.31-08	5.79-07	5.32-06	9.18+00	1.06-11	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
RC	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						1.90-05			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated		L	1.31-06	3.12-07	1.01-06	3.29-06	3.25+00	1.15-12	
			Final		L	1.31-06	3.12-07	1.01-06	3.29-06	3.25+00	1.15-12	B
RC	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant						6.33-06			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated		L	2.13-06	5.83-07	1.72-06	5.04-06	2.94+00	2.43-12	
			Final		L	2.13-06	5.83-07	1.72-06	5.04-06	2.94+00	2.43-12	B
RC	MV X	MOTOR-OP VALVE	STANDBY FAILS TO CLOSE	H								
			Plant						6.33-06			
			Aggregated		L	5.49-06	6.14-07	3.27-06	1.74-05	5.33+00		
			Updated		L	9.60-07	1.07-07	5.72-07	3.05-06	5.33+00	1.67-12	
			Final		L	9.60-07	1.07-07	5.72-07	3.05-06	5.33+00	1.67-12	B
RC	RV R	RELIEF VALVE	SPURIOUS OPEN	H								
			Plant						1.90-05			
			Aggregated		L	1.69-06	2.84-07	1.17-06	4.80-06	4.11+00		
			Updated		L	1.31-06	2.20-07	9.05-07	3.72-06	4.11+00	1.87-12	
			Final		L	1.31-06	2.20-07	9.05-07	3.72-06	4.11+00	1.87-12	B
RC	RZ P	PORV	STANDBY FAILS TO OPEN	H								
			Plant						1.08-06			
			Aggregated		L	6.32-07	7.67-08	3.89-07	1.97-06	5.06+00		
			Updated		L	1.63-07	1.98-08	1.00-07	5.08-07	5.06+00	4.37-14	
			Final		L	1.63-07	1.98-08	1.00-07	5.08-07	5.06+00	4.37-14	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis.
RC	SV P	SOLENOID-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant						3.16-06			
			Aggregated		L	2.58-06	1.62-07	1.22-06	9.14-06	7.51+00		
			Updated		L	2.71-07	1.70-08	1.28-07	9.59-07	7.51+00	2.56-13	
			Final		L	2.71-07	1.70-08	1.28-07	9.59-07	7.51+00	2.56-13	B
RC	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						4.22-06			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.64-07	2.33-08	1.07-07	4.88-07	4.58+00	3.62-14	
			Final		L	1.64-07	2.33-08	1.07-07	4.88-07	4.58+00	3.62-14	B
RH RR	AV F	AIR-OP VALVE	FAILS TO THROTTLE	H								
			Plant						4.09-04			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	3.53-06	3.36-07	1.98-06	1.16-05	5.88+00	2.73-11	
			Final		L	3.53-06	3.36-07	1.98-06	1.16-05	5.88+00	2.73-11	B
RH RR	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						1.90-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	1.63-06	1.55-07	9.13-07	5.37-06	5.88+00	5.83-12	
			Final		L	1.63-06	1.55-07	9.13-07	5.37-06	5.88+00	5.83-12	B
RH RR	AV R	AIR-OP VALVE	TRANSFERS OPEN	H								
			Plant						4.18-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	2.36-06	2.25-07	1.32-06	7.76-06	5.88+00	1.22-11	
			Final		L	2.36-06	2.25-07	1.32-06	7.76-06	5.88+00	1.22-11	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
RH RR	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant						1.47-03			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated		L	1.43-04	9.96-06	7.05-05	5.00-04	7.08+00	6.41-08	
			Final		L	1.43-04	9.96-06	7.05-05	5.00-04	7.08+00	6.41-08	B
RH RR	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						1.46-06			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	1.12-07	2.67-08	8.66-08	2.81-07	3.24+00	8.34-15	
			Final		L	1.12-07	2.67-08	8.66-08	2.81-07	3.24+00	8.34-15	B
RH RR	HX F	HEAT EXCHANGER	COOLING CAPABILITY FAILS	H								
			Plant						2.25-04			
			Aggregated		L	1.95-05	5.82-07	6.58-06	7.43-05	1.13+01		
			Updated		L	6.46-06	1.93-07	2.18-06	2.46-05	1.13+01	3.25-10	
			Final		L	6.46-06	1.93-07	2.18-06	2.46-05	1.13+01	3.25-10	B
RH RR	HX P	HEAT EXCHANGER	PLUGS	H								
			Plant						2.25-04			
			Aggregated		L	2.20-06	2.16-07	1.25-06	7.20-06	5.78+00		
			Updated		L	2.07-06	2.03-07	1.17-06	6.78-06	5.78+00	9.09-12	
			Final		L	2.07-06	2.03-07	1.17-06	6.78-06	5.78+00	9.09-12	B
RH RR	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant						2.25-04			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	1.24-05	5.47-07	5.02-06	4.61-05	9.18+00	7.98-10	
			Final		L	1.24-05	5.47-07	5.02-06	4.61-05	9.18+00	7.98-10	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
RH RR MP S	MOTOR-DRIVEN PUMP	STANDBY FAILS TO START	H								
		Plant			2.31-06	1.19-07		1.10-05			
		Aggregated		L	4.42-06	4.99-07	2.64-06	1.40-05	5.30+00		
		Updated									
		Final		L	2.31-06	9.32-08	8.96-07	8.62-06	9.62+00		P
RH RR MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
		Plant						6.64-06			
		Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
		Updated		L	1.04-06	2.48-07	8.05-07	2.62-06	3.25+00	7.27-13	
		Final		L	1.04-06	2.48-07	8.05-07	2.62-06	3.25+00	7.27-13	B
RH RR MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
		Plant			3.63-06	1.97-06		6.15-06			
		Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
		Updated									
		Final		L	3.63-06	1.88-06	3.40-06	6.15-06	1.81+00		P
RH RR MV Q	MOTOR-OP VALVE	FAILS TO OPEN (RCS ISOL VLVS)	N								
		Plant			2.27-03	8.93-04		4.76-03			
		Aggregated		L	5.07+00	1.39+00	4.09+00	1.20+01	2.94+00		
		Updated									
		Final		L	2.27-03	8.04-04	1.96-03	4.76-03	2.43+00		P
RH RR MV R	MOTOR-OP VALVE	TRANSFERS OPEN	H								
		Plant						3.26-06			
		Aggregated		L	1.36-06	2.39-07	9.55-07	3.81-06	3.99+00		
		Updated		L	5.95-07	1.05-07	4.18-07	1.67-06	3.99+00	3.64-13	
		Final		L	5.95-07	1.05-07	4.18-07	1.67-06	3.99+00	3.64-13	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
RH RR MV X	MOTOR-OP VALVE	STANDBY FAILS TO CLOSE	H								
		Plant			2.22-06	6.04-07		5.73-06			
		Aggregated		L	5.49-06	6.14-07	3.27-06	1.74-05	5.33+00		
		Updated									
		Final		L	2.22-06	4.91-07	1.68-06	5.73-06	3.42+00		P
RH RR XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
		Plant						4.64-06			
		Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
		Updated		L	1.66-07	2.36-08	1.08-07	4.95-07	4.58+00	3.72-14	
		Final		L	1.66-07	2.36-08	1.08-07	4.95-07	4.58+00	3.72-14	B
RH RR XV P	MANUAL VALVE	STANDBY FAILS TO OPEN	H								
		Plant						9.95-06			
		Aggregated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00		
		Updated		L	5.21-07	3.85-08	2.63-07	1.80-06	6.84+00	7.94-13	
		Final		L	5.21-07	3.85-08	2.63-07	1.80-06	6.84+00	7.94-13	B
RH RR XV R	MANUAL VALVE	TRANSFERS OPEN	H								
		Plant						6.53-06			
		Aggregated		L	1.30-07	1.50-08	7.84-08	4.10-07	5.23+00		
		Updated		L	1.18-07	1.36-08	7.10-08	3.71-07	5.23+00	2.43-14	
		Final		L	1.18-07	1.36-08	7.10-08	3.71-07	5.23+00	2.43-14	B
SI SR CV C	CHECK VALVE	FAILS TO CLOSE	N								
		Plant			1.91-03	7.53-04		4.02-03			
		Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
		Updated									
		Final		L	1.91-03	6.78-04	1.65-03	4.02-03	2.43+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SI SR	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						7.03-07			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	9.60-08	2.30-08	7.44-08	2.41-07	3.24+00	6.15-15	
			Final		L	9.60-08	2.30-08	7.44-08	2.41-07	3.24+00	6.15-15	B
SI SR	CV R	CHECK VALVE	TRANSFERS OPEN	H								
			Plant			7.04-07	3.61-08		3.34-06			
			Aggregated		L	9.46-07	4.96-08	4.13-07	3.43-06	8.32+00		
			Updated									
			Final		L	7.04-07	2.84-08	2.73-07	2.63-06	9.62+00		P
SI SR	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant			3.80-03	1.95-04		1.80-02			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	4.66-04	9.54-05	3.44-04	1.24-03	3.61+00	1.82-07	
			Final		L	4.66-04	9.54-05	3.44-04	1.24-03	3.61+00	1.82-07	B
SI SR	MP S	MOTOR-DRIVEN PUMP	STANDBY FAILS TO START	H								
			Plant			1.59-06	8.14-08		7.52-06			
			Aggregated		L	4.42-06	4.99-07	2.64-06	1.40-05	5.30+00		
			Updated									
			Final		L	1.59-06	6.40-08	6.15-07	5.92-06	9.62+00		P
SI SR	MV C	MOTOR-OP VALVE	FAILS TO CLOSE	N								
			Plant			2.68-03	1.26-03		5.03-03			
			Aggregated		L	6.01-03	6.72-04	3.58-03	1.91-02	5.33+00		
			Updated									
			Final		L	2.68-03	1.17-03	2.43-03	5.03-03	2.07+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SI SR	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						3.80-06			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated		L	8.42-07	2.00-07	6.51-07	2.12-06	3.25+00	4.76-13	
			Final		L	8.42-07	2.00-07	6.51-07	2.12-06	3.25+00	4.76-13	B
SI SR	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			3.17-06	1.38-06		6.26-06			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated									
			Final		L	3.17-06	1.27-06	2.82-06	6.26-06	2.22+00		P
SI SR	MV X	MOTOR-OP VALVE	STANDBY FAILS TO CLOSE	H								
			Plant			2.96-06	1.39-06		5.55-06			
			Aggregated		L	5.49-06	6.14-07	3.27-06	1.74-05	5.33+00		
			Updated									
			Final		L	2.96-06	1.29-06	2.68-06	5.55-06	2.07+00		P
SI SR	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						2.92-06			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	1.53-07	2.18-08	9.96-08	4.56-07	4.58+00	3.16-14	
			Final		L	1.53-07	2.18-08	9.96-08	4.56-07	4.58+00	3.16-14	B
SH	AV K	AIR-OP VALVE	TRANSFERS CLOSED	H								
			Plant						1.36-05			
			Aggregated		L	3.74-06	3.56-07	2.09-06	1.23-05	5.88+00		
			Updated		L	1.33-06	1.27-07	7.45-07	4.38-06	5.88+00	3.88-12	
			Final		L	1.33-06	1.27-07	7.45-07	4.38-06	5.88+00	3.88-12	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SW	AV N	AIR-OP VALVE	FAILS TO OPEN	N								
			Plant						1.28-05			
			Aggregated		L	2.17-03	3.12-04	1.42-03	6.46-03	4.55+00		
			Updated		L	3.19-06	4.56-07	2.08-06	9.49-06	4.56+00	1.36-11	
			Final		L	3.19-06	4.56-07	2.08-06	9.49-06	4.56+00	1.36-11	B
SW	CV C	CHECK VALVE	FAILS TO CLOSE	N								
			Plant			4.84-04	2.49-05		2.30-03			
			Aggregated		L	1.63-03	1.14-04	8.05-04	5.68-03	7.06+00		
			Updated									
			Final		L	4.84-04	1.95-05	1.88-04	1.81-03	9.62+00		P
SW	CV K	CHECK VALVE	TRANSFERS CLOSED	H								
			Plant						1.64-05			
			Aggregated		L	1.69-06	4.32-07	1.34-06	4.13-06	3.09+00		
			Updated		L	1.43-06	3.65-07	1.13-06	3.48-06	3.09+00	1.22-12	
			Final		L	1.43-06	3.65-07	1.13-06	3.48-06	3.09+00	1.22-12	B
SW	CV N	CHECK VALVE	FAILS TO OPEN	N								
			Plant						1.45-03			
			Aggregated		L	1.45-04	3.47-05	1.12-04	3.64-04	3.24+00		
			Updated		L	1.21-04	2.89-05	9.36-05	3.03-04	3.24+00	9.74-09	
			Final		L	1.21-04	2.89-05	9.36-05	3.03-04	3.24+00	9.74-09	B
SW	CV P	CHECK VALVE	STANDBY FAILS TO OPEN	H								
			Plant						3.44-06			
			Aggregated		L	1.32-07	3.16-08	1.02-07	3.31-07	3.24+00		
			Updated		L	1.23-07	2.93-08	9.50-08	3.08-07	3.24+00	1.00-14	
			Final		L	1.23-07	2.93-08	9.50-08	3.08-07	3.24+00	1.00-14	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SW	MP A	MOTOR-DRIVEN PUMP	FAILS TO START	N								
			Plant						2.19-03			
			Aggregated		L	4.84-03	5.46-04	2.89-03	1.53-02	5.30+00		
			Updated		L	3.71-04	4.15-05	2.21-04	1.18-03	5.33+00	2.51-07	
			Final		L	3.71-04	4.15-05	2.21-04	1.18-03	5.33+00	2.51-07	B
SW	MP F	MOTOR-DRIVEN PUMP	FAILS TO RUN	H								
			Plant						1.64-05			
			Aggregated		L	8.45-05	3.71-06	3.41-05	3.13-04	9.18+00		
			Updated		L	1.05-06	4.60-08	4.22-07	3.88-06	9.18+00	5.65-12	
			Final		L	1.05-06	4.60-08	4.22-07	3.88-06	9.18+00	5.65-12	B
SW	MV C	MOTOR-OP VALVE	FAILS TO CLOSE	N								
			Plant			5.85-03	3.37-03		9.47-03			
			Aggregated		L	6.01-03	6.72-04	3.58-03	1.91-02	5.33+00		
			Updated									
			Final		L	5.85-03	3.24-03	5.54-03	9.47-03	1.71+00		P
SW	MV K	MOTOR-OP VALVE	TRANSFERS CLOSED	H								
			Plant			2.11-06	3.75-07		6.65-06			
			Aggregated		L	1.52-06	3.62-07	1.18-06	3.82-06	3.25+00		
			Updated									
			Final		L	2.11-06	2.45-07	1.28-06	6.65-06	5.21+00		P
SW	MV N	MOTOR-OP VALVE	FAILS TO OPEN	N								
			Plant			4.38-03	2.29-03		7.65-03			
			Aggregated		L	5.07-03	1.39-03	4.09-03	1.20-02	2.94+00		
			Updated									
			Final		L	4.38-03	2.17-03	4.07-03	7.65-03	1.88+00		P

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SW	MV P	MOTOR-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			1.27-05	6.62-06		2.21-05			
			Aggregated		L	4.63-06	1.27-06	3.73-06	1.10-05	2.94+00		
			Updated									
			Final		L	1.27-05	6.28-06	1.18-05	2.21-05	1.88+00		P
SW	SV K	SOLENOID-OP VALVE	TRANSFERS CLOSED	H								
			Plant						4.00-06			
			Aggregated		L	4.09-07	1.08-07	3.26-07	9.86-07	3.02+00		
			Updated		L	3.48-07	9.20-08	2.78-07	8.39-07	3.02+00	6.91-14	
			Final		L	3.48-07	9.20-08	2.78-07	8.39-07	3.02+00	6.91-14	B
SW	SV P	SOLENOID-OP VALVE	STANDBY FAILS TO OPEN	H								
			Plant			5.38-06	2.52-06		1.01-05			
			Aggregated		L	2.58-06	1.62-07	1.22-06	9.14-06	7.51+00		
			Updated									
			Final		L	5.38-06	2.35-06	4.88-06	1.01-05	2.07+00		P
SW	XV C	MANUAL VALVE	FAILS TO CLOSE	N								
			Plant			3.21-04	1.65-05		1.52-03			
			Aggregated		L	3.47-04	2.56-05	1.75-04	1.20-03	6.84+00		
			Updated									
			Final		L	3.21-04	1.30-05	1.25-04	1.20-03	9.62+00		P
SW	XV K	MANUAL VALVE	TRANSFERS CLOSED	H								
			Plant						3.65-07			
			Aggregated		L	1.94-07	2.76-08	1.26-07	5.79-07	4.58+00		
			Updated		L	6.15-08	8.75-09	4.01-08	1.84-07	4.58+00	5.12-15	
			Final		L	6.15-08	8.75-09	4.01-08	1.84-07	4.58+00	5.12-15	B

CARP -- DATA ANALYSIS SUMMARY REPORT

Type	Code	Component	Failure Mode	Unit	Dist	Mean	Lower	Median	Upper	P1	P2	Basis
SW	XV P	MANUAL VALVE	STANDBY FAILS TO OPEN	H								
			Plant						4.75-06			
			Aggregated		L	9.63-07	7.11-08	4.86-07	3.33-06	6.84+00		
			Updated		L	3.47-07	2.56-08	1.75-07	1.20-06	6.84+00	3.52-13	
			Final		L	3.47-07	2.56-08	1.75-07	1.20-06	6.84+00	3.52-13	B

Table C-4
Additional Plant-Specific Data

Event Name	*Value*	*Description of Event and Basis for Value*
ACAA50_50N	1.0E-01	*Offsite Power in 50/50 Mode (Normal)* - This offsite power configuration has Ckt 751 supplying Bus 12A with Ckt 767 supplying Bus 12B which is the normally configuration. However, during severe storms, the station may go to a 100/0 configuration where Ckt 767 supplies both buses. Therefore, it will be assumed that the station is always in the 50/50 Mode to allow sensitivity studies to be performed for other configurations.
ACAA50_50A	0.0	*Offsite Power in 50/50 Mode (Alternate)* - See discussion for event AAAA50_50N.
ACAA100_0X	0.0	*Offsite Power in 100/0 Mode* - See discussion for event AAAA50_50N.
ACAA0_100X	0.0	*Offsite Power in 0/100 Mode* - See discussion for event AAAA50_50N.
ACAAMCCG18	5.00E-01	*480 VAC MCC G Being Powered From 480 VAC Bus 18* - Operators normally select either Bus 17 or Bus 18 to power MCC G prior to startup from the refueling outage and leave it for the entire cycle. The source for MCC G may then change at the next outage. Since there is no preference for the power source, each source was given an equal probability (i.e., 0.5).
CCBREAK001	1.0	*CCW Line To RCP A Breaks Due To Damage During A LOCA* - Since the CCW line is outside the missile barrier in containment and is therefore not protected, a value of 1.0 is conservatively used.
CCBREAK002	1.0	*CCW Line To RCP B Breaks Due To Damage During A LOCA* - Since the CCW line is outside the missile barrier in containment and is therefore not protected, a value of 1.0 is conservatively assigned.
CTAACT0202 CTAACT200A CTAACT200B	5.77E-01	*AOV 202 (200A, 200B) In Service (2/3 Orifice Valves Typically in Service)* - Given that any combination of two valves can be used, the following is true: 202*200A + 202*200B + 200A*200B = 1.0, or $3*202^2 = 1.0$, or the probability that any given valve is in service is 5.77E-01.
CTAACTMINI	2.74E-02	*Conditional Probability That Mini-Purge System in Use* - The mini-purge system is used to maintain containment pressure and air quality within acceptable limits during power operation. Its use is strictly controlled by plant procedures since it provides a direct path from containment to the outside environment during power operation. Depressurization of containment typically takes less than 20 minutes due to the small allowed pressure window (-2.5 to 1.0 psig). Air "cleanup" takes approximately one 8 hour shift based on the 2000 cfm system flowrate and 1,000,000 ft^3 containment free volume with containment entries typically occurring once per month. Consequently, it will be assumed that the mini-purge system is used 20 hours per month. This equates to a probability of 20 hrs *12 months / 8760 hrs or 2.74E-02.
CTAACTPIPE	1.00	*Conditional Probability That Piping Inside Missile Barrier is Ruptured* - Conservatively assumed to be 1.00.

Table C-4
Additional Plant-Specific Data

Event Name	*Value*	*Description of Event and Basis for Value*
CVAACCPMPA CVAACCPMPB CVAACHPMPC	5.77E-01	*Charging Pump A (B,C) Running* - Two charging pumps are normally running during power operation. Given that any combination of pumps can be used, the following is true: A*B + A*C + B*C = 1.0, or $3A^2 = 1.0$, or the probability that any given pump is in service is 5.77E-01.
DG0RUNTRIP	1.00E-01	*DG Trips Following SI or LOOP Event Given That It Was Running* - Conservative estimate based on sudden loading of DG even though it is designed to meet these requirements.
DG1ANOTRUN DG1BNOTRUN	9.97E-01	*DG 1A Is Not Running and Tied To Buses 14 and 18 While Reactor Is Critical* - Each DG is tested monthly and run for approximately 2 hours. In addition, an operable DG may have to be run if its redundant DG is declared inoperable for more than 24 hours by the technical specifications. The P-S data did not show that either DG was inoperable for more than 24 hours during the 9 year data collection window; however, it will be assumed to be one event lasting for 1 hour. Therefore, the probability the DG is running is [(2 hrs/month * 12 months) + (1 DG run/9 yrs * 1 hr)] / [8760 hrs * .81] = 3.40E-03. The probability a DG is <u>not</u> running is 1 - 3.40E-03 = 9.97E-01.
DGCWINTAKE	3.75E-01	*CW Intake Heaters Energized (Oct 1 to May 1)* - Using the same approach as described above for AAAA<40DEG since its assumed that the outside air temperature must average below 32°F for water to freeze and thus require the intake heaters and 40°F is a conservative estimate.
HVAAHVCT_A HVAAHVCT_B HVAAHVCT_C HVAAHVCT_D	9.53E-01	*Containment Fan Cooler Train A (B, C, D) Running* - Four fans typically operate while three fans may be used during winter months. Therefore, the following will be assumed: a. 4 fans are operated 90% of the time and 3 fans 10%. b. Each fan has an equal probability of being in service, or 0.9(A*B*C*D) + 0.1(A*B*C + A*B*D + A*C*D). As such, each fan has a probability of 95.3% of being in service.
HVAAHVCWPA HVAAHVCWPB	5.00E-01	*Chilled Water Pump Loop A (B) Running* - One loop is normally running; therefore, it was assumed that each loop had an equal probability of being in service since no maintenance information was collected against this system.
HVAA<30DEG	3.33E-01	*Average Outside Air Temperature Is Below 30 Degrees* - Based on UFSAR Figure 2.3-1, there are 8 months where the <u>minimum</u> temperature is < 30°F; however, there are only 4 months where the <u>average</u> temperature is < 30°F. Therefore, assume 4/12 months or 3.33E-01.
HVAA<40DEG	3.75E-01	*Average Air Temperature Less Than Or Equal To 40 Degrees* - Based on UFSAR Figure 2.3-1, there are 10 months where the <u>minimum</u> temperature is < 40°F; however, there are only 4.5 months where the <u>average</u> temperature is < 40°F. Therefore, assume 4.5/12 months or 3.75E-01.

Table C-4
Additional Plant-Specific Data

Event Name	*Value*	*Description of Event and Basis for Value*
HVAA<45DEG	4.17E-01	*Outdoor Temperature Less Than 45 Degrees* - Based on UFSAR Figure 2.3-1, there are 8 months where the minimum temperature is < 45°F; however, there are only 5 months where the average temperature is < 45°F. Therefore, assume 5/12 months or 4.17E-01.
HVAA>80DEG	1.67E-01	*Outside Air Temperature Is Greater Than or Equal To 80 Degrees* - Based on UFSAR Figure 2.3-1, there are 8 months where the maximum temperature is > 80°F; however, there are no months where the average temperature is >80°F. Therefore, assume 2/12 months or 1.67E-01.
HVFDRF360P	5.00E-02	*Rolling Fire Door F36 Is Shut* - This door is only shut if welding or other potential fire hazards exist. Therefore, it was assumed that the door is open 95% of the time.
IAAAIAC02A IAAAIAC02B	2.26E-02	*Instrument Air Compressor A (B) Running* - IA Compressor C is normally running with Compressors A and B in standby since the new Compressor C can handle the entire system load. Therefore, based on the test and maintenance probability for Compressor C (4.51E-03), assume that Compressor C would be in service for all periods except test and maintenance (9.95E-01) while Compressors A and B would be in service for 1/2 of the remaining time (2.26E-03).
IAAAIAC02C	9.95E-01	*Instrument Air Compressor C Running* - See above discussion for AAAAIAC02A and AAAAIAC02B.
RCMVD00515	3.26E-02	*Motor-Operated Valve 515 is Closed Due To PORV Leakage* - The plant-specific data for PORV 431C shows that the valve was isolated due to leakage for a total of 4,142.7 hours. Therefore, the probability that block valve 515 is closed at power is 6.47E-02 (4,142.7/64,054 Rx Critical Hours). However, due to limited data, the value to be used is an average of the two block valves or 3.26E-02.
RCMVD00516	3.26E-04	*Motor-Operated Valve 516 is Closed Due To PORV Leakage* - The plant-specific data for PORV 430 shows that the valve was isolated due to leakage for a total of 34.1 hours. Therefore, the probability that block valve 516 is closed at power is 5.32E-04 (3.41/64,054 Rx Critical Hours). However, due to limited data, the value to be used is an average of the two block valves or 3.26E-02.
RRPPJMBLOA	5.20E-03	*Conditional Probability of Medium LOCA in A RHR Line* - Generated using methods described in [EPRI TR-100380].
RRPPJMBLOB	3.90E-03	*Conditional Probability of Medium LOCA in B RHR Line* - Generated using methods described in [EPRI TR-100380].
RRPPJSBLOA	3.47E-04	*Conditional Probability of Small LOCA in A RHR Line* - Generated using methods described in [EPRI TR-100380].

Table C-4
Additional Plant-Specific Data

Event Name	*Value*	*Description of Event and Basis for Value*
RRPPJSBLOB	3.13E-04	*Conditional Probability of Small LOCA in B RHR Line* - Generated using methods described in [EPRI TR-100380].
SIPPJLBLOA	1.89E-02	*Conditional Probability That Large LOCA Occurs In RCS Loop A* - Generated using methods described in [EPRI TR-100380].
SIPPJLBLOB	1.89E-02	*Conditional Probability That Large LOCA Occurs In RCS Loop B* - Generated using methods described in [EPRI TR-100380].
SIPPJMBLOA	1.45E-03	*Conditional Probability That Medium LOCA Occurs In RCS Loop A* - Generated using methods described in [EPRI TR-100380].
SIPPJMBLOB	1.93E-03	*Conditional Probability That Medium LOCA Occurs In RCS Loop B* - Generated using methods described in [EPRI TR-100380].
SIPPJSBLOA	6.25E-04	*Conditional Probability That Small LOCA Occurs In RCS Loop A* - Generated using methods described in [EPRI TR-100380].
SIPPJSBLOB	6.94E-04	*Conditional Probability That Small LOCA Occurs In RCS Loop B* - Generated using methods described in [EPRI TR-100380].
SWAASW3OF4	3.15E-01	*Three of Four SW Pumps Initially Running* - In 1994, three SW pumps were used 32.5% of the time while two SW pumps were used for the remainder 67.5%. In 1995, the values were 30.4% and 69.6% respectively. An average between the two years yields 31.5% and 68.5%.
SWAASWP1AR SWAASWP1BR SWAASWP1CR SWAASWP1DR	6.27E-01	*Service Water Pump A (B,C, D) Is In Operation* - Based on the discussion for AAAASW3OF4, the following was assumed. a. 31.5% of the time, two SW pumps were in operation, one from each electrical train. Assuming each pump had an equal chance of being in service, this equates to $A*B + A*D + C*B + C*D = 4A^2$. b. 68.5% of the time, three SW pumps were in operation, with at least one pump from each electrical train. Assuming that each pump had an equal chance of being in service, this equates to $A*B*C + A*B*D + B*C*D = 3A^3$. c. The total probability of any given SW pump being in service is $0.315*4A^2 + 0.685*3A^3 = 1.0$, or $1.26A^2 + 2.06A^3 = 1.0$, or 0.627.
SWAASWP1AS SWAASWP1BS SWAASWP1CS SWAASWP1DS	5.00E-01	*Service Water Pump A (B)(C)(D) Is In Standby* - There are two SW pumps per electrical train; one pump on each train must be selected in standby. Each pump generally has an equal probability of being selected (i.e., 50%).

C.6 References

1. H.F. Martz and R.A. Waller, *Bayesian Reliability Analysis*, 1991.

2. NUREG/CR-2300, *PRA Procedures Guide: A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants*, January 1983.

3. John Neter, William Wasserman, and G.A. Whitmore, *Applied Statistics*, 1988.

4. SAIC, *Ginna Nuclear Power Plant Probabilistic Risk Assessment Generic Data Work Package*, Revision 1, July 24, 1992.

5. SAIC, *CARP - Computerized Assessment of Reliability Parameters*, Version 1.1, March 1992.

6. RG&E Design Analysis, NSL-4976-DA001, *Probabilistic Risk Assessment Determination of Component Boundaries.*

APPENDIX D

COMMON CAUSE FAILURE ANALYSIS SUPPORTING DOCUMENTATION

D.0 CCF ANALYSIS SUPPORTING DOCUMENTATION

This appendix contains the CCF related information as found by the plant-specific data collection effort. This information supplements that found in Section 7.

D.1 *Reactor Coolant System (RCS)*

No common cause failure events were identified.

D.2 *Emergency Safety Features Actuation System (ESFAS)*

No common cause failure events were identified.

D.3 *Residual Heat Removal (RHR) System*

a. On April 12, 1983, RHR flow was lost due to air in the RHR pump suction lines. During cold shutdown, while draining water out of SG B due to excessive "boot" leakage, air leaked by the boot and caused both RHR pumps to become air bound. The system was quickly vented and both pumps were restored to operability (ref. A-25.1). This event is not considered applicable during power operations due to the system configuration (i.e., draining the steam generators) and was therefore excluded from consideration.

b. On December 21, 1987, RHR pump B failed to start during PT-2.2. One contributing factor to the event was insufficient amptector actuator arm clearance (ref. A-25.1, A-52.4, MWR 87-6657). This event has potential common cause failure implications, since new amptector devices had been installed throughout the plant only a few months earlier. Apparently the problem of insufficient arm clearance was incapable of causing the equipment failure by itself; however the attempted start of RHR pump B described above occurred during a battery equalizing charge, which most likely combined with the arm clearance problem to cause the actual failure. Amptector actuator arm clearances were inspected and adjusted as necessary for all affected equipment (see various MWRs in 1988 with respect to pumps). During this inspection, Safety Injection Pump "B" also failed to start due to the same problem (ref. LER 87-008). Consequently, this event was conservatively assumed to be a common cause failure both for SI and RHR.

D.4 *Diesel Generator (DG) System*

a. On June 17, 1981, while performing PT 12.1 and 12.2 on DGs A and B, respectively, DG A was sluggish for several minutes before attaining the minimum acceptable test load and DG B failed the PT (ref. A-25.1). Post-maintenance testing revealed improper governor settings for both DGs. This was considered a common cause failure since it is unknown whether DG A would have been able to maintain the necessary load.

b. On February 20, 1987, while Transformer 12A was being modified and both DGs supplying their respective buses, a low fuel oil day tank level alarm was received for DG B (ref. A-25.1). Shortly thereafter, the same problem occurred with DG A. A portable pump was used to transfer fuel oil from the fuel oil storage tanks to the diesel generators. This event can be attributed to common cause plugging of the fuel oil suction strainers for both DGs. Also, on May 15, 1987, the DG B fuel oil transfer pump again exhibited very low discharge pressure due to plugging of the fuel oil suction strainer (ref. A-52.4, MWR 87-2846). The severity of both these events is curtained by the time and recovery options available. Also, these strainers can now be cleaned in-service due to a modification of the fuel oil transfer system in 1988. Consequently, these events were not be considered as CCFs of the DGs. In addition, no independent failures were assigned to the DGs since they continued to operate during both events.

D.5 *Chemical and Volume Control System (CVCS)*

a. On March 11, 1981, both Boric Acid Feed Pumps (PCH03A and PCH03B) failed to start and were subsequently replaced (ref. MWR 81-639). No information was given as to the cause of these failures, although it appears likely that they were due to the same reason. Consequently, it was conservatively assumed to be a common cause failure.

b. There were numerous failures of Boric Acid Storage Tank (BAST) level transmitters LT-102, LT-106, LT-171, and LT-172. These were primarily caused by boric acid hardening in the sensing lines and would often occur at the same time (ref. A-25.1s, especially in 1988). Attempts to heat trace these lines have not proven successful in resolving this problem; however, the safety-related function of the BAST is currently being assessed and their classification may be downgraded. The following table shows the combination of events which occurred during the observed data window.

Transmitters	Failed High	Failed Low
106 and 172	2	0
106 and 171	1	1
102, 171, and 172	1	0

D.6 *Safety Injection (SI) System*

a. On May 5, 1980, during performance of RSSP-2.2 (DG Safeguards Sequence Test) for B train logic, SI pumps B and C failed to start on simulated loss of voltage coincident with a SI signal. The pump breakers were subsequently found to not be fully inserted (ref. A-25.1) which can be considered a failure to restore equipment to service after maintenance or testing. As such, this is a human induced common cause failure event.

b. On October 13, 1987, the locking devices for valves 897 and 898 were found to be off; however, the valves were in their required position. The devices were successfully re-installed (ref. A-25.1). Since the valves were in their correct position, this was not considered as a common cause event.

c. See discussion related to RHR Pump B and SI Pump B.

D.7 *Main Feedwater (MFW) System*

No common cause failure events were identified.

D.8 *DC Electrical Distribution System*

No common cause failure events were identified.

D.9 *Auxiliary Feedwater (AFW) System*

a. On October 26, 1988, check valves 4003 and 4004 (TDAFW discharge lines) were found to be leaking by. This resulted in air entering the discharge lines causing the three TDAFW pump flow transmitters to read erratically (ref. MWR 88-7453). The check valves were subsequently repaired. Operators now inspect the AFW discharge lines once every shift to ensure that the check valves are not leaking by. Consequently, this failure mode was not modeled and this event was not considered.

D.10 *AC Electrical Distribution System*

a. On March 1, 1988, during performance of PT-12.2, the breakers from DG B to Buses 16 and 17 (52/EG1B1 and 52/EG1B2) were found to be in the TEST versus NORMAL position. This would have prevented the DG from automatically tying into these two buses. No reason for this event is given, but they were most likely related to a human failure to restore the breakers following test or maintenance (ref. A-25.1). As such, this event is considered a human induced common cause failure.

D.11 *Main Steam (MS) System*

No common cause failure events were identified.

D.12 *Containment Isolation (CI) System*

a. On June 18, 1985, during an operational check of the SG blowdown monitor, SG sample valves 5735 and 5736 both failed to shut (ref. A-25.1). The auto/open switches for both valves had been left in the open position. This event qualifies as a human induced common cause failure. A trouble card was submitted to provide a sign-off adjacent to the auto/open switches to leave them in the auto position.

b. On October 26, 1983, fuses for valves 1787 and 1728 were found to be blown. The valves had failed closed which is their fail-safe position. Three other non-PRA components had blown fuses also. Since no common cause could be identified and the containment isolation valves performed their safety-related function, this event was not considered a common cause failure (ref. A-25.1).

D.13 *Service Water (SW) System*

a. On December 13, 1982, both travelling screens B and D were found to be not working due to frozen valve lines (ref. MWR 82-3820). This had been preceded by icing on the travelling screens on November 19, 1982 (ref. A-25.1). In addition, on February 7, 1988, all four travelling screens failed due to freezing. A PCN to A-54.4.1 was subsequently issued requiring that the screens should be operated in manual whenever the turbine is off-line and the lake temperature is below 35°F (ref. A-25.1). These are obvious CCF events; however, the changes to plant procedures is expected to correct this problem. Also, the events were partially due to the fact that the plant was shutdown with minimal plant heat being generated.

b. On February 18, 1987, manual valve 4641 was physically unable to closed during performance of RSSP-2.4. The other three SW isolation valves to the Containment Recirculation Fans were also "believed to have the same situation". All four valves were removed and the retainer ring surface was polished smooth (ref. A-25.1). It was assumed that this was a CCF of the valves to close.

D.14 *Containment Spray (CS) System*

a. On December 22, 1981, MOVs 876A and 876B both failed to open during their respective stroke test (PT-2.3). The failure cause for 876A was slack in the wires interfering with the proper operation of the torque switch (ref. A-25.1, MWR 81-3732). The failure cause for 876B was the valve sticking in the closed position until manual operation freed it up (ref. A-25.1, MWR 81-3722). Even though both valves failed to open during the same PT, there does not appear to be any evidence of a common cause failure and the failures were therefore treated independently.

b. On June 8, 1987, MOVs 860A and 860B both failed to go completely closed during their respective stroke tests (PT-2.3). Valve 860A apparently failed to close due to the presence of metal chips in and around the stem and stem nut area (ref. A-25.1, MWR 87-3280). No cause was identified for the failure of valve 860B (ref. MWR 87-3279). Consequently, this was conservatively assumed to be a CCF event.

c. On June 13, 1983, after leaving cold shutdown, both CS pumps were found to be in the pull-stop position. Both pumps were immediately placed in the auto position (ref. A-25.1). This event represents a human induced CCF. However, since this event could only occur following a plant startup, and the CS pump breakers are verified during startup with monthly testing thereafter, this event was ignored.

D.15 *Standby Auxiliary Feedwater (SAFW) System*

No common cause failure events were identified.

D.16 *Condensate System*

No common cause failure events were identified.

D.17 *Circulating Water System*

No common cause failure events were identified.

D.18 *Heating, Ventilation and Air Conditioning (HVAC) Systems*

No common cause failure events were identified.

D.19 *Component Cooling Water System (CCW)*

No common cause failure events were identified.

D.20 *Instrument and Service Air Systems (IA and SA)*

No common cause failure events were identified.

D.21 *Heat Tracing*

No common cause failure events were identified.

APPENDIX E

TEST AND MAINTENANCE DATA
SUPPORTING DOCUMENTATION

E.0 TEST AND MAINTENANCE DATA SUPPORTING DOCUMENTATION

This appendix contains the test and maintenance (T/M) related information as found by the plant-specific data collection effort. While the data is not used by the Ginna Station PSA Project for reasons discussed in Section 7, it is provided for potential future uses and to demonstrate that the values used in the PSA are conservative.

E.1 PLANT-SPECIFIC RESULTS

Table E-1 provides a summary of the plant-specific maintenance unavailability results on a component type code basis while Table E-2 provides a listing of the periodic tests which were determined to cause component unavailability. This information was used to generate the final T/M values as provided in Table E-3. This table contains the boundary definition of each T/M event and applies the appropriate value(s) from Tables E-1 and E-2 for each component type. As can be seen, all T/M values are lower than 1.00E-02 and are generally consistent with data given in NUREG/CR-4550 [14]. The only exception to this are the service water pumps which have a calculated test and maintenance unavailability of 2.70E-02. This high value is due to routine, scheduled maintenance and that Technical Specifications do not limit the amount of time that a single SW pump can be out-of-service. General notes are provided below while specific notes on each system follow:

a. Maintenance events for components which are required to close was ignored since the valve would be either closed or otherwise isolated during its out-of-service period.

b. Out-of-service time related to instrumentation was not included since no plant-specific data was collected. However, this out-of-service time was typically assigned to the associated valve, pump, etc., during the data collection effort.

E.1.1 Uncertainty Assessment

The average T/M event probabilities are uncertain due to several factors:

a. Statistical confidence

The equation provided in Section 7 for calculating T/M probabilities is the long-term average maintenance unavailability of various components. Uncertainty in the estimate of component-level maintenance unavailabilities is due, in part, to the fact that T/M data has only been collected over nine years. Statistical confidence can be improved by increasing the length of the data window.

b. Data tolerance

When using plant-specific maintenance experience to estimate T/M event probabilities, it is assumed that the factors which govern maintenance (e.g., the rate of maintenance, the duration of maintenance, plant policies, etc.) have remained constant over the data window. In reality, the summarized maintenance data reflects a mixture of governing factors that have varied during the data window. Since one of the goals of PRA is to predict future risks associated with plant operation, it is possible to reduce data tolerance issues by shortening the length of the data window (i.e., by using only the most recent experience). Note that the reduction of data tolerance concerns is counter to the improvement of statistical confidence, and that the selection of the data window length involves a compromise between these two competing sources of uncertainty.

c. Input estimation errors

The values used to calculate testing unavailability are based on engineering estimates. Test frequencies have generally been obtained through review of relevant procedures; however, the actual times between tests may vary somewhat, depending on the plant status and the test planning policies used by RG&E. Test durations have been obtained through interviews with knowledgeable plant personnel and, thus, represent a mixture of individual opinions. No estimate of the spread among the individual opinions is available.

As a result, uncertainty estimates for the average T/M event probabilities have been made by assuming a log-normal error factor of 10.0 [14, Table 8.2-4].

E.1.2 Summary of the Significant Findings From the Plant-Specific Data Collection Task

The following provides the specific findings of the RG&E data collection activities with respect to T/M events. The information is organized by system and includes all major assumptions, significant events, and data trends or clarifications. All hard copies of MWRs, Running Hour Logs, and A-25.1, A-25.2, and A-52.2 forms have been maintained by RG&E. Included with these records are all original screening and analysis tables that were used in developing the data values.

E.1.2.1 *Reactor Coolant System (RCS)*

a. On September 22, 1980, power operated relief valve, PCV-431C, was isolated by its associated block valve due to excessive leakage (ref. A-25.1). This valve remained out-of-service for more than a month until the next outage. A similar event occurred on September 25, 1987, with PCV-431C being left isolated for over four months, until the next scheduled refueling outage (ref. A-52.4). These two events resulted in over 4100 hours of unavailability for PCV-431C. Even though PORV block valve 515 was declared inoperable for this time period, the maintenance unavailability was attributed to PCV-431C since this is the valve that experienced the leakage.

b. On May 5, 1980, the RCS Overpressurization System was inadvertently de-energized by Results and Test personnel for approximately an hour during performance of a test at shutdown. This is not included in the data base since the Overpressurization System is not included in the model.

E.1.2.2 *Emergency Safety Features Actuation System (ESFAS)*

a. ESFAS was only evaluated with respect to out-of-service time at power due to equipment failures since it is not normally removed from service for testing or PM activities (per C. Edgar of I&C/Electrical Maintenance). Also, functions such as containment isolation are included in their respective system (i.e., not ESFAS).

b. On October 20, 1987, the power supply to containment pressure transmitter PT-950 failed (ref. A-25.2). However, due to the presence of redundant transmitters, this did not cause a spurious SI signal nor unavailability of the ESFAS.

E.1.2.3 *Residual Heat Removal (RHR) System*

a. On April 22, 1985, while reviewing post maintenance procedure PT-2.2 for the "A" RHR pump, a calculation error was discovered for the test performed on April 20, 1985. This error, when corrected, resulted in the differential pressure for the pump to be outside the Technical Specification limit of 140 psid (ref. A-25.1). The proper reading was 139.98 psid which required that the "A" pump be declared inoperable until satisfactory data was obtained. As such, an A-52.4 was written and the pump declared inoperable from the time of the original test until the time of the satisfactory retest (on April 23, 1985). However, since the pump was available to perform its function over the entire period and the pressure difference was only 0.02 psid, no maintenance unavailability was assigned.

E.1.2.4 *Diesel Generator (DG) System*

a. On November 18, 1983, the prelube pump for D/G "B" did not stop once the diesel started running. The motor contactor was replaced (ref. MWR 83-3737). Since the D/G is not typically taken out-of-service for this type of work (per Results and Tests), no maintenance unavailability was assigned to D/G "B." Also, since the prelube pump is a subcomponent of the D/G, the failure of the prelube pump to trip was not considered a failure of the D/G.

b. Form A-52.4s written against the D/Gs for air compressor problems are not considered as D/G failures or maintenance unavailability, since the compressors are not required for successful D/G operation. Also, the repair of the compressors does not require the D/G to be taken out-of-service. Consequently, only events which completely removed the D/G air start function were considered.

E.1.2.5 *Chemical and Volume Control System (CVCS)*

a. On March 25, 1981, MOV-350 was declared inoperable in order to repair a flange near flow transmitter FT-113 (ref. A-52.4). The valve was out-of-service for 567 hours, until the reactor was shut down for refueling.

b. On June 30, 1988, charging pump "B" was taken out-of-service for lubrication and remained out-of-service for 701.6 hours. The return of charging pump "B" to service was not rushed since Technical Specifications only require operability of two of the three charging pumps.

c. On July 11, 1980, the boric acid concentration in both boric acid storage tanks was found to be below the minimum acceptable level, necessitating a power reduction (ref. A-25.1). Similar events also occurred on July 14, 1980, November 24, 1980, October 13, 1982, March 27, 1985, October 13, 1985, November 24, 1985, and June 1, 1988 (ref. A-25.1s). In addition, on September 28, 1988, the concentration was found to be too high (ref. A-25.1). These events were not classified as failures since no failure mode existed; however, out-of-service time was applied to the tanks. This time was calculated based on the time required to bring the tanks back into acceptable levels with an additional 4 hours added (i.e., one-half time since last test).

d. For seat leakage of CVCS valves, maintenance unavailability was only assigned if maintenance work was actually performed on the valve, not for isolating the valve for other activities.

E.1.2.6 *Safety Injection (SI) System*

a. On March 31, 1980, it was discovered that the accumulators had not been sampled within the required two months ±15 day time period due to confusion with the surveillance testing procedure. No out-of-service time was assigned since the accumulators were found to be within acceptable limits.

E.1.2.7 *Main Feedwater (MFW) System*

No significant unavailability information.

E.1.2.8 *DC Electrical Distribution System*

a. On March 11, 1983, an individual climbing in the Battery Rooms stepped on the breaker for Battery Charger "1A" and inadvertently opened it. Since it was discovered and corrected immediately, no failure was assigned, only 10 minutes of maintenance out-of-service time (ref. A-25.1).

E.1.2.9 *Auxiliary Feedwater (AFW) System*

a. Several MOVs exhibited extensive out-of-service times for MOVATS testing. However, discussions with operations indicates that they would attempt to use these valves during an emergency if needed. The extensive length of out-of-service time is attributed to the older, more lenient Technical Specifications; consequently, these out-of-service times may be conservative.

b. There were several instances where a component was removed from service multiple times over a short period of time (<1 month) to perform testing, etc. However, there was never any indication of a failure in the records. As such, only out-of-service time was considered and no failures were assigned.

c. The cleaning of SW strainers in the flowpath for the AFW pump bearing coolers was not considered to render the pump inoperable since there is an alternate flowpath available.

d. Form A-52.4s written against the failure to perform a PT was not considered a maintenance or a failure event since the equipment was in no way failed, and testing did not render it inoperable.

e. In cases where equipment was found to be inoperable from a human error (e.g., breaker open; stepping on trip valve), the out-of-service hours were calculated as one-half the time between discovery and latest operation. Any maintenance time required to repair the component was subsequently added on.

f. There were many fire and seismic modifications related to the AFW system. However, since these were a "one-time only" modification that was not expected to be duplicated in the future, they were not included in the calculated maintenance out-of-service times.

g. Summing together the out-of-service times for all components in a given AFW train yields:

Pump A (PFW02A, 4009, 4007) = 97.9 hours
Pump B (PFW02B, 4010, 4310, 4008, 4022) = 514.3 hours
TDAFW Pump (PFW04, 4004, 4003, 4291, 3996, 4297) = 1,240.2 hours

These values are essentially the time for which the components are out-of-service and either prevented operation of the pump train or required significant operator action to recover.

h. There were a significant number of calibration related A-52.4s and A-25.1s. Over the time period of interest, the declaration of components being out-of-service for calibration varied greatly. In some cases, the pump train was declared inoperable, while in others, only the indicator or transmitter. These differences were mainly caused by different interpretations of the Technical Specifications. However, the current calibration procedures call for the entire train to be declared inoperable. Discussions with plant personnel indicate that for components declared out-of-service for calibration events, operators would attempt to use the equipment if it was needed. Therefore, calibration events were identified separately and assumed to take the entire train out-of-service. This affects the out-of-service times calculated above as follows:

Pump A = 97.9 + 367.1 = 465.0 hours (1%)
Pump B = 514.3 + 295.5 = 809.8 hours (1.3%)
TDAFW Pump = 1,240.2 + 2,418.0 = 3,658.2 hours (5.7%)

The percentage of time that each pump train was out-of-service at power is listed next to the final numbers. These values are high as compared to other systems due to the Technical Specifications in existence at this time which allowed individual trains to be out-of-service for 7 days <u>before</u> entering the LCO. This has since been changed. In addition, the TDAFW train values are higher due to there being two flowpaths versus only one for the two motor driven pumps. Taken together, one train of AFW was declared out-of-service 7.7% of the time (4,933.0 hours) at power. However, the calibration events were <u>not</u> included in the data supplied by RG&E.

i. Since PMs related to the pumps are no longer performed at power, these events were included with the calibration events and are not included.

j. There were 105 A-52.4s written against the AFW system from 1980 through 1988 indicating that system components were removed from service very frequency.

k. Level transmitters LT-2022A and LT-2022B are isolated by components in the AFW data population. Therefore, the associated out-of-service time related to these transmitters was collected.

E.1.2.10 *AC Electrical Distribution System*

a. PM related work is performed on bus tie breakers at power; however, these activities were not considered to be maintenance, and as such, no out-of-service time was calculated. The basis for this is that an auxiliary operator is stationed at the test site and is in contact with the control room during the test. Also, the PM activities do not physically disable the breaker (per G. Joss of Results and Tests).

E.1.2.11 *Main Steam (MS) System*

No significant unavailability information.

E.1.2.12 *Containment Isolation (CI) System*

a. On May 9, 1988, AOV-1789 was declared inoperable due to modifications being performed on the gas analyzer. The valve remained out-of-service for nearly two and one-half months; however, the valve remained in its fail safe position (closed).

b. On June 26, 1985, solenoid valves 923 and 924 were held for isolation so that maintenance work could be performed on the hydrogen analyzer. Both valves were held out-of-service (i.e., closed) for two weeks. Therefore, no out-of-service time was assigned.

E.1.2.13 *Service Water (SW) System*

a. All of the SW pumps have experienced substantial amounts of maintenance downtime, especially SW pumps "A", "C", and "D." Most of the pump maintenance unavailability was due to routine, scheduled maintenance (major pump overhauls have ranged from about 400 to 1300 hours). Extended SW pump maintenance outages were common since Technical Specifications do not limit the amount of time a single SW pump can be out-of-service.

E.1.2.14 *Containment Spray (CS) System*

No significant unavailability information.

E.1.2.15 *Standby Auxiliary Feedwater (SAFW) System*

a. The ventilation system for the SAFW pumps was taken out-of-service several times for maintenance over this time period. Consequently, operations declared the associated SAFW pump out-of-service; however, these events were not assigned to the SAFW pumps, and instead are found in the HVAC system.

b. In April and November 1985, several supports related to the "D" SAFW pump were found to be loose. However, the only action performed was to tighten the loose bolts. Consequently, no failure was assigned and since the maintenance was minor, no out-of-service time was considered.

c. Summing together the out-of-service times for all components in a given SAFW train yields:

Pump C (PFW03A, 9710A, 9629A, 9701A, 9704A) = 280.2 hours
Pump D (PFW03B, 9629B, 9710B, 9709B, 9701B, 9704B) = 338 hours

These values are essentially the time for which the components are out-of-service and either prevented operation of the pump train or required significant operator action to recover.

d. The majority of out-of-service time related to the SAFW pumps was related to modifications (e.g., seismic, fire, etc.). These events were separated from corrective maintenance activities since they would not accurately reflect future performance.

e. There were a significant number of events related to calibration and PM activities. Similar to AFW, these out-of-service times were calculated separately since PMs are no longer performed at power and calibration events do not physically prevent the train from operating. However, adding these out-of-service times to those calculated above yields:

Pump C = 280.0 + 285.3 = 565.5 hours (<1%)
Pump D = 331.0 + 330.1 = 668.1 hours (1%)

The percentage of time that each pump train was out-of-service at power is listed next to the final numbers. Again, these numbers are relatively high as compared to other systems due to the previous Technical Specifications which allowed extensive out-of-service durations at power. Calibration and PM events are not included in the data base supplied by RG&E.

E.1.2.16 *Condensate System*

a. PMs related to the pump breakers were not considered to be maintenance and as such, no out-of-service time was counted. This is because there is an auxiliary operator stationed at the test who is in contact with the control room. Also, the PM only involves using an ampmeter and placing the breaker in the TEST position. It does not physically disable the breaker (per G. Joss of Results and Tests).

E.1.2.17 *Circulation Water System*

a. No significant unavailability information.

E.1.2.18 *Heating, Ventilation, and Air Conditioning (HVAC) Systems*

a. For failure events described only by MWRs, the maintenance out-of-service time was taken to be the number of days from the Request Date to the Completed Date as shown on the MWR. For non-failure events, the maintenance out-of-service time is related to the number of manhours required to perform the task.

b. There were four PM related events with respect to AKF03 (Control Room Air Handling Unit) found in the plant records. Since Attachment 6.4 for AKF03 showed there to be nine PM events, the out-of-service time was taken to be the average of the three lowest known times (the fourth time was considered to be unrepresentative).

c. A duration of three hours was used for PM related out-of-service time for AKF04 (Battery Room DC Fan), AAF04 (Auxiliary Building Exhaust Fan G), and ACF01A and ACF01B (Purge Exhaust Fans).

d. PM activities related to AKF08 (Control Room Air Handling Unit Exhaust fan) were assumed to be performed at the same time as that for AKF03. Therefore, no out-of-service time was allocated for AKF08.

e. A duration of four hours was used for PM related out-of-service time for AKF01A and AKF01B (Battery Room Exhaust Fans A and B).

f. PMs related to Auxiliary Building Charcoal Filter Fan G were not considered to be maintenance and, as such, no out-of-service time was counted. This is because there is an auxiliary operator stationed at the test who is in contact with the control room, and the test does not physically disable the breaker (per G. Joss of Results and Tests).

E.1.2.19 *Component Cooling Water (CCW) System*

a. CCW Heat Exchanger "B" was declared out-of-service mainly due to MOVATS testing of SW valve 4615.

E.1.2.20 *Instrument and Service Air (IA & SA) Systems*

a. For failure events described only by MWRs, the maintenance out-of-service time was taken to be the number of days from the Request Date to the Completed Date as shown on the MWR. For non-failure events, the maintenance out-of-service time is related to the number of manhours required to perform the task, unless the equipment is expected to be removed from service immediately (e.g., compressors).

b. For PM activities, it was unsure whether the PMs were performed at the same time that a repair was performed. Consequently, the PMs were separated out. In addition, the major PMs related to the air compressors were assumed to be done in place of the minor PMs whenever they coincide. Therefore, even though a minor PM could expect to be performed every 6 months, the analysis assumes only every 12 months. Adding together the failure related events and PMs results in the following out-of-service hours:

CIA02A - 121.0 + 252.0 = 373.0
CIA02B - 120.9 + 252.0 = 372.9
CIA02C - 142.7 + 252.0 = 394.7
CSA02 - 7.0 + 216.0 = 223.0

c. PMs related to the air compressor breakers were not considered to be maintenance and, as such, no out-of-service time was counted. This is because there is an auxiliary operator stationed at the test who is in contact with the control room. Also, the PM does not physically disable the breakers (per G. Joss of Results and Tests).

Table E-1
Summarized Maintenance Unavailability Data

CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
AF AV	AFW air-operated valve	9.21E-05	59	640543.50
AF CV	AFW check valve	3.11E-04	399	1281087.00
AF MP	AFW motor-driven pump	1.55E-03	398	256217.40
AF MV	AFW motor-operated valve	1.80E-03	1616	896760.90
AF TP	AFW turbine-driven pump	2.61E-03	167	64054.35
AF XV	AFW manual valve	3.67E-04	1081	2946500.10
CC CV	CCW check valve	1.04E-05	6	576489.15
CC MP	CCW motor-driven pump	2.03E-04	39	192163.05
CC MV	CCW motor-operated valve	3.90E-05	25	640543.50
CC XV	CCW manual valve	0.00	0	3651097.95
CS AV	CS air-operated valve	1.41E-04	18	128108.70
CS CV	CS check valve	0.00	0	384326.10
CS MP	CS motor-driven pump	2.34E-03	300	128108.70
CS MV	CS motor-operated valve	2.14E-04	137	640543.50
CS TK	CS tank	0.00	0	128108.70
CS XV	CS manual valve	2.23E-06	3	1345141.35
CV MP	CVCS motor-driven pump	7.63E-03	3423	448380.45
CV RV	CVCS relief valve	4.68E-04	210	448380.45
CV XV	CVCS manual valve	1.42E-06	7	4932184.95
DG DG	Diesel Generator	1.42E-03	182	128108.70
HV AF	HVAC air filter	9.68E-04	124	128108.70
HV MC	HVAC air-operated damper	2.83E-04	943	3330826.20

Table E-1
Summarized Maintenance Unavailability Data

CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
HV MF	HVAC motor-driven fan	7.14E-04	2058	2882445.75
IA AM	IA compressor	4.26E-03	1364	320271.75
IA AR	IA receiver	9.37E-05	24	256217.40
IA CV	IA check valve	0.00	0	768652.20
MS AV	Main Steam air-operated valve	0.00	0	128108.70
MS CV	Main Steam check valve	8.04E-04	103	128108.70
MS MV	Main Steam motor-operated valve	1.01E-03	129	128108.70
MS RV	Main Steam relief valve	3.75E-04	48	128108.70
MS XV	Main Steam manual valve	2.34E-05	6	256217.40
RH AV	RHR air-operated valve	2.08E-04	40	192163.05
RH CV	RHR check valve	0.00	0	576489.15
RH HX	RHR heat exchanger	1.01E-04	13	128108.70
RH MP	RHR motor-driven pump	2.09E-03	268	128108.70
RH MV	RHR motor-operated valve	1.28E-04	148	1152978.30
RH XV	RHR manual valve	0.00	0	1152978.30
SI CV	SI check valve	1.13E-05	13	1152978.30
SI MP	SI motor-driven pump	2.35E-03	451	192163.05
SI MV	SI motor-operated valve	2.31E-04	252	1088923.95
SI XV	SI manual valve	0.00	0	832706.55
SW AV	SW air-operated valve	1.99E-05	14	704597.85
SW CV	SW check valve	2.21E-03	850	384326.10
SW MP	SW motor-driven pump	2.48E-02	6355	256217.40

Table E-1
Summarized Maintenance Unavailability Data

CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
SW MV	SW motor-operated valve	4.97E-04	478	960815.25

Table E-1
Summarized Maintenance Unavailability Data

CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
SW SV	SW solenoid valve	1.32E-04	127	960815.25
SW XV	SW manual valve	1.17E-05	84	7174087.20

Table E-2
Survey of Periodic Tests Causing Equipment Unavailability

System	PT	Remarks	Test Frequency	Test Duration (Source)	$\overline{a}_T$
AC AC power	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
AF Auxiliary Feedwater	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
CC Component Cooling Water	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
CI Containment Isolation	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
CS Containment Spray	PT-3M PT-3Q	Each pump injection path to the spray ring headers is isolated for half of the test duration.	monthly	1 h / train (1)	1.11E-03
CV Chemical and Volume Control	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
CW Circulating Water	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
DC DC power	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
DG Diesel Generator	CP-64	Calibration and/or maintenance of DG instrumentation.	monthly	1 h (13)	1.11E-03
	PT-12.1 PT-12.2	There is a caution statement in this procedure which notes that if a SI or LOOP signal occurs, the normal bus source breakers will open. T-27.4 cautions that the possibility of an overvoltage or undercurrent trip exists in this situation.	monthly	2 h (1)	2.78E-03
	PT-12.6	Fuel oil transfer system check valve testing; procedure contains a caution that fuel oil is unavailable until realigned.	monthly	1 h (13)	1.11E-03
ES Safeguards Actuation	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
HV Heating, Ventilation, and Air Conditioning	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
IA Instrument Air	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
MF Main Feedwater	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A

Table E-2
Survey of Periodic Tests Causing Equipment Unavailability

System	PT	Remarks	Test Frequency	Test Duration (Source)	$\overline{\alpha}_T$
MS Main Steam	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
RC Primary Pressure Control	PT-2.3	Stroke test of MOV-515 and MOV-516.	quarterly	1 h / valve (1)	3.71E-04
RH Residual Heat Removal	PT-2.3	Stroke test of MOV-704A, MOV-704B, MOV-850A, and MOV-850B.	quarterly	1 h / valve (1)	3.71E-04
SI Safety Injection	PT-2.1M	Test of Pumps A and C (B and C).	monthly	2 h (1 h) (1)	2.22E-03 (1.11E-03)
	PT-2.1M	Closes MOV-871A while SI Pump C is tested.	monthly	2 h (1)	2.22E-03
	PT-2.1Q	Test of Pumps A and C (B and C).	quarterly	2.5 h (2.5 h) (1)	9.27E-04 (9.27E-04)
	PT-2.1Q	Closes MOV-871A for half the time that SI Pump C is tested, and MOV-871B for the other half.	quarterly	2 h (1)	7.41E-04
SW Service Water	N/A	There are no PTs which affect this system as modeled	N/A	N/A	N/A

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
AFTM004048	Alternate Suction Source For AFW Pumps	AF XV	4048	3.67E-04	1.10E-03	1
		AF XV	4070A	3.67E-04		
		AF XV	4071A	3.67E-04		
AFTM0AFWAB	Motor-Driven AFW Pumps Cross-Connect Line	AF MV	4000A	1.80E-03	4.33E-03	
		AF MV	4000B	1.80E-03		
		AF XV	4356	3.67E-04		
		AF XV	4357	3.67E-04		
AFTM0AFWIA	Motor-Driven AFW Pumps Injection Line to S/G A	AF CV	4000C	3.11E-04	2.48E-03	
		AF MV	4007	1.80E-03		
		AF XV	4011	3.67E-04		
AFTM0AFWIB	Motor-Driven AFW Pumps Injection Line to S/G B	AF CV	4000D	3.11E-04	2.48E-03	
		AF MV	4008	1.80E-03		
		AF XV	4012	3.67E-04		
AFTM0AFWPA	Motor-Driven AFW Pump Train 1A	AF AV	4304	9.21E-05	3.19E-03	2
		AF CV	4009	3.11E-04		
		AF CV	4017	3.11E-04		
		AF MP	PAF01A	1.55E-03		
		AF XV	4019	3.67E-04		
		AF XV	4081	3.67E-04		
		SW FD	NFW02	-		
		SW SV	4325	1.32E-04		
		SW XV	4029	1.17E-05		
		SW XV	4031	1.17E-05		
		SW XV	4091	1.17E-05		
		SW XV	4093	1.17E-05		
		SW XV	4095	1.17E-05		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
AFTM0AFWPB	Motor-Driven AFW Pump Train 1B	AF AV	4310	9.21E-05	3.19E-03	2
		AF CV	4010	3.11E-04		
		AF CV	4016	3.11E-04		
		AF MP	PAF01B	1.55E-03		
		AF XV	4018	3.67E-04		
		AF XV	4082	3.67E-04		
		SW FD	NFW04	-		
		SW SV	4326	1.32E-04		
		SW XV	4030	1.17E-05		
		SW XV	4032	1.17E-05		
		SW XV	4090	1.17E-05		
		SW XV	4092	1.17E-05		
		SW XV	4094	1.17E-05		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
AFTM0TDAFW	Turbine-Driven AFW Pump Train	AF AV	4291	9.21E-05	9.04E-03	2
		AF CV	3998	3.11E-04		
		AF CV	4023	3.11E-04		
		AF MV	3996	1.80E-03		
		AF TP	PAF03	2.61E-03		
		MS CV	3504B	8.04E-04		
		MS CV	3505B	8.04E-04		
		MS MV	3505A	1.01E-03		
		MS MV	3505B	1.01E-03		
		MS XV	3504	2.34E-05		
		MS XV	3505	2.34E-05		
		MS XV	3570E	2.34E-05		
		SW FD	NFW03	-		
		SW SV	4324	1.32E-04		
		SW XV	4085	1.17E-05		
		SW XV	4087	1.17E-05		
		SW XV	4088	1.17E-05		
		SW XV	4089	1.17E-05		
		SW XV	4087B	1.17E-05		
		SW XV	4087C	1.17E-05		
		SW XV	4088B	1.17E-05		
AFTMCONDPP	Condensate Transfer Pump (PCD04)	AF CV	4045	3.11E-04	2.91E-03	
		AF CV	4049	3.11E-04		
		AF MP	PCD04	1.55E-03		
		AF XV	4046	3.67E-04		
		AF XV	4047	3.67E-04		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
AFTMOUTCON	Outside Condensate Storage Tank Valves	AF XV	9501B	3.67E-04	1.10E-03	3
		AF XV	9509C	3.67E-04		
		AF XV	9509E	3.67E-04		
AFTMSAFWAB	SAFW Cross-Connect Line	AF MV	9703A	1.80E-03	4.33E-03	
		AF MV	9703B	1.80E-03		
		AF XV	9702C	3.67E-04		
		AF XV	9702D	3.67E-04		
AFTMSAFWIA	SAFW Injection Line to S/G A	AF CV	9705A	3.11E-04	2.85E-03	
		AF MV	9704A	1.80E-03		
		AF XV	9702A	3.67E-04		
		AF XV	9706A	3.67E-04		
AFTMSAFWIB	SAFW Injection Line to S/G B	AF CV	9705B	3.11E-04	4.65E-03	
		AF MV	9746	1.80E-03		
		AF MV	9704B	1.80E-03		
		AF XV	9702B	3.67E-04		
		AF XV	9706B	3.67E-04		
AFTMSAFWPC	SAFW Pump Train 1C	AF AV	9710A	9.21E-05	5.55E-03	
		AF CV	9700A	3.11E-04		
		AF MP	PSF01A	1.55E-03		
		AF MV	9629A	1.80E-03		
		AF MV	9701A	1.80E-03		
AFTMSAFWPD	SAFW Pump Train 1D	AF AV	9710B	9.21E-05	5.55E-03	
		AF CV	9700B	3.11E-04		
		AF MP	PSF01B	1.55E-03		
		AF MV	9629B	1.80E-03		
		AF MV	9701B	1.80E-03		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	*Description*	*CAFTA Type Code*	*EIN*	*Component Mean*	*T/M Event Mean*	*Notes*
AFTMTDAFWA	TDAFW Pump Train Injection Line to S/G A	AF AV	4297	9.21E-05	1.50E-03	
		AF CV	4003	3.11E-04		
		AF XV	3999	3.67E-04		
		AF XV	4001	3.67E-04		
		AF XV	4005	3.67E-04		
AFTMTDAFWB	TDAFW Pump Train Injection Line to S/G B	AF AV	4298	9.21E-05	1.50E-03	
		AF CV	4004	3.11E-04		
		AF XV	4000	3.67E-04		
		AF XV	4002	3.67E-04		
		AF XV	4006	3.67E-04		
CCTM_PUMPA	CCW Pump Train A	CC CV	723A	1.04E-05	2.13E-04	4
		CC MP	PAC02A	2.03E-04		
		CC XV	722A	0.00		
		CC XV	724A	0.00		
CCTM_PUMPB	CCW Pump Train B	CC CV	723B	1.04E-05	2.13E-04	4
		CC MP	PAC02B	2.03E-04		
		CC XV	722B	0.00		
		CC XV	724B	0.00		
CSTM00NAOH	CS Additive Train	CS AV	836A	1.41E-04	2.89E-04	
		CS AV	836B	1.41E-04		
		CS CV	847A	0.00		
		CS CV	847B	0.00		
		CS TK	TSI02	0.00		
		CS XV	873A	2.23E-06		
		CS XV	873B	2.23E-06		
		CS XV	881B	2.23E-06		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	*Description*	*CAFTA Type Code*	*EIN*	*Component Mean*	*T/M Event Mean*	*Notes*
CSTMTRAINA	CS Pump Train A	CS CV	862A	0.00	3.89E-03	
		CS MP	PSI02A	2.34E-03		
		CS MV	860A	2.14E-04		
		CS MV	860B	2.14E-04		
		CS XV	2860	2.23E-06		
		CS XV	831A	2.23E-06		
		CS XV	858A	2.23E-06		
		CS XV	868A	2.23E-06		
		CS XV	881D	2.23E-06		
		PT-3M, PT-3Q	860A, 860B	1.11E-03		
CSTMTRAINB	CS Pump Train B	CS CV	862B	0.00	3.89E-03	
		CS MP	PSI02B	2.34E-03		
		CS MV	860C	2.14E-04		
		CS MV	860D	2.14E-04		
		CS XV	2665	2.23E-06		
		CS XV	831B	2.23E-06		
		CS XV	858B	2.23E-06		
		CS XV	868B	2.23E-06		
		CS XV	881C	2.23E-06		
		PT-3M, PT-3Q	860C, 860D	1.11E-03		
CVTMCHPMPA	CVCS Pump A	CV MP	PCH01A	7.63E-03	8.57E-03	
		CV RV	285	4.68E-04		
		CV RV	287	4.68E-04		
		CV XV	267	1.42E-06		
CVTMCHPMPB	CVCS Pump B	CV MP	PCH01B	7.63E-03	8.10E-03	
		CV RV	284	4.68E-04		
		CV XV	269	1.42E-06		
		CV XV	288	1.42E-06		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
CVTMCHPMPC	CVCS Pump C	CV MP	PCH01C	7.63E-03	8.10E-03	
		CV RV	291	4.68E-04		
		CV XV	291	1.42E-06		
		CV XV	399	1.42E-06		
DGTM00001A	D/G 1A	CP-64	KDG01A	1.11E-03	5.86E-03	5
		DG DG	KDG01A	1.42E-03		
		PT-12.1	KDG01A	2.22E-03		
		PT-12.6	KDG01A	1.11E-03		
DGTM00001B	D/G 1B	CP-64	KDG01B	1.11E-03	5.86E-03	5
		DG DG	KDG01B	1.42E-03		
		PT-12.2	KDG01B	2.22E-03		
		PT-12.6	KDG01B	1.11E-03		
HVTMAAIF02	IB exhaust Fan AAIF02	HV MB	AID04A	2.83E-04	1.56E-03	6
		HV MB	AID04B	2.83E-04		
		HV MB	AID05H	2.83E-04		
		HV MF	AIF02	7.14E-04		
HVTMABSTRA	IB Exhaust Fan AAIF08A	HV MC	AAD08A	2.83E-04	1.28E-03	
		HV MC	AAD09A	2.83E-04		
		HV MF	AAF08A	7.14E-04		
HVTMABSTRB	IB Exhaust Fan AAIF08B	HV MC	AAD08B	2.83E-04	1.28e-03	
		HV MC	AAD09B	2.83E-04		
		HV MF	AAF08B	7.14E-04		
HVTMAIF01A	IB Exhaust Fan AIF01A	HV MC	AID01A	2.83E-04	1.28E-03	
		HV MC	AID02A	2.83E-04		
		HV MF	AIF01A	7.14E-04		
HVTMAIF01B	IB Exhaust Fan AIF01B	HV MC	AID01B	2.83E-04	1.28E-03	
		HV MC	AID02B	2.83E-04		
		HV MF	AIF01B	7.14E-04		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	*Description*	*CAFTA Type Code*	*EIN*	*Component Mean*	*T/M Event Mean*	*Notes*
HVTMCHARGA	Charging Pump Room HVAC Train A	HV MB	CP-13-P/A	2.83E-04	1.03E-03	6
		HV MF	AAF01A	7.14E-04		
		SW XV	4750	1.17E-05		
		SW XV	4751	1.17E-05		
		SW XV	4767	1.17E-05		
HVTMCHARGB	Charging Pump Room HVAC Train B	HV MB	CP-13-P/B	2.83E-04	1.03E-03	6
		HV MF	AAF01B	7.14E-04		
		SW XV	4752	1.17E-05		
		SW XV	4753	1.17E-05		
		SW XV	4768	1.17E-05		
HVTMCTMT_A	CTMT HVAC Train A	HV AF	ACL07A	9.68E-04	3.24E-03	
		HV AF	ACL08A	9.68E-04		
		HV MC	5871	2.83E-04		
		HV MC	5872	2.83E-04		
		HV MF	ACF08A	7.14E-04		
		SW XV	4627	1.17E-05		
		SW XV	4629	1.17E-05		
HVTMCTMT_B	CTMT HVAC Train B	HV MC	5880	2.83E-04	1.02E-03	
		HV MF	ACF08B	7.14E-04		
		SW XV	4628	1.17E-05		
		SW XV	4630	1.17E-05		
HVTMCTMT_C	CTMT HVAC Train C	HV AF	ACL07B	9.68E-04	3.24E-03	
		HV AF	ACL08B	9.68E-04		
		HV MC	5874	2.83E-04		
		HV MC	5876	2.83E-04		
		HV MF	ACF08C	7.14E-04		
		SW XV	4641	1.17E-05		
		SW XV	4643	1.17E-05		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	*Description*	*CAFTA Type Code*	*EIN*	*Component Mean*	*T/M Event Mean*	*Notes*
HVTMCTMT_D	CTMT HVAC Train D	HV MC	5877	2.83E-04	1.02E-03	
		HV MF	ACF08D	7.14E-04		
		SW XV	4642	1.17E-05		
		SW XV	4644	1.17E-05		
HVTMCTRLRM	Control Rm HVAC	HV MC	AKD06	2.83E-04	2.28E-03	
		HV MC	AKD13	2.83E-04		
		HV MC	AKD14	2.83E-04		
		HV MF	AKF03	7.14E-04		
		HV MF	AKF08	7.14E-04		
HVTMRELAYA	A Relay Room HVAC	HV MF	AKF01A	7.14E-04	9.05E-04	
		SW SV	4761E	1.32E-04		
		SW XV	4761H	1.17E-05		
		SW XV	4761N	1.17E-05		
		SW XV	4761P	1.17E-05		
		SW XV	4761Q	1.17E-05		
		SW XV	4761V	1.17E-05		
HVTMRELAYB	B Relay Room HVAC	HV MF	AKF01B	7.14E-04	8.93E-04	
		SW SV	4761K	1.32E-04		
		SW XV	4761B	1.17E-05		
		SW XV	4761C	1.17E-05		
		SW XV	4761J	1.17E-05		
		SW XV	4761L	1.17E-05		
HVTMSAFW_A	SAFW Room Fan Cooler A	HV MB	Return A1	2.83E-04	3.80E-03	6
		HV MB	Return A2	2.83E-04		
		HV MB	Return A3	2.83E-04		
		HV MF	AFF01A	7.14E-04		
		SW AV	9632A	1.99E-05		
		SW CV	9633A	2.21E-03		
		SW XV	9631A	1.17E-05		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
HVTMSAFW_B	SAFW Room Fan Cooler B	HV MB	Return B1	2.83E-04	3.80E-03	6
		HV MB	Return B2	2.83E-04		
		HV MB	Return B3	2.83E-04		
		HV MF	AFF01B	7.14E-04		
		SW AV	9632B	1.99E-05		
		SW CV	9633B	2.21E-03		
		SW XV	9631B	1.17E-05		
IATMCOMPRA	IA - A Compressor	IA AM	CIA02A	4.26E-03	6.74E-03	7
		IA AR	TIA04A	9.37E-05		
		IA CV	5301	0.00		
		IA XV	5303	-		
		SW CV	5333	2.1E-03		
		SW SV	5261	1.32E-04		
		SW XV	5300	1.17E-05		
		SW XV	5325	1.17E-05		
		SW XV	5331	1.17E-05		
		SW XV	5337	1.17E-05		
IATMCOMPRB	IA - B Compressor	IA AM	CIA02B	4.26E-03	6.74E-03	7
		IA AR	TIA04B	9.37E-05		
		IA CV	5302	0.00		
		IA XV	5304	-		
		SW CV	5334	2.21E-03		
		SW SV	5262	1.32E-04		
		SW XV	5332	1.17E-05		
		SW XV	5334	1.17E-05		
		SW XV	5338	1.17E-05		
		SW XV	8314	1.17E-05		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	*Description*	*CAFTA Type Code*	*EIN*	*Component Mean*	*T/M Event Mean*	*Notes*
IATMCOMPRC	IA - C Compressor	IA AM	CIA02C	4.26E-03	4.51E-03	7
		IA AR	TIA04C	9.37E-05		
		IA CV	8216	0.00		
		IA XV	8217	-		
		SW SV	8242	1.32E-04		
		SW XV	8311	1.17E-05		
		SW XV	4787B	1.17E-05		
IATMSACOMP	SA Compressor	IA AM	CSA02	4.26E-03	6.74E-03	7
		IA AR	TSA01	9.37E-05		
		IA XV	5357	-		
		SW CV	5370	2.1E-03		
		SW SV	5272	1.2E-04		
		SW XV	5366	1.17E-05		
		SW XV	5369	1.17E-05		
		SW XV	5373	1.17E-05		
		SW XV	5379	1.17E-05		
MSTM003410	ARV B	MS RV	3410	3.75E-04	3.98E-04	
		MS XV	3506	2.34E-05		
MSTM003411	ARV A	MS RV	3411	3.75E-04	3.98E-04	
		MS XV	3507	2.34E-05		
RCTM000515	MOV-515 Closed Due to Stroke Test	PT-2.3	515	3.71E-04	3.71E-04	
RCTM000516	MOV-516 Closed Due to Stroke Test	PT-2.3	516	3.71E-04	3.71E-04	

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
RHTM00000A	RHR Injection Train "A"	PT-2.3	704A	3.71E-04	2.90E-03	
		RH AV	625	2.08E-04		
		RH CV	697A	0.00		
		RH CV	710A	0.00		
		RH HX	EAC02A	1.01E-04		
		RH MP	PAC01A	2.09E-03		
		RH MV	704A	1.28E-04		
		RH XV	714	0.00		
		RH XV	717	0.00		
		RH XV	694A	0.00		
		RH XV	696A	0.00		
		RH XV	709A	0.00		
RHTM00000B	RHR Injection Train "B"	PT-2.3	704B	3.71E-04	2.90E-03	
		RH AV	624	2.08E-04		
		RH CV	697B	0.00		
		RH CV	710B	0.00		
		RH HX	EAC02B	1.01E-04		
		RH MP	PAC01B	2.09E-03		
		RH MV	704B	1.28E-04		
		RH XV	715	0.00		
		RH XV	716	0.00		
		RH XV	694B	0.00		
		RH XV	696B	0.00		
		RH XV	709B	0.00		
SITM00825A	MOV 825A	SI MV	825A	2.31E-04	2.31E-04	
SITM00825B	MOV 825B	SI MV	825B	2.31E-04	2.31E-04	

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
SITM00871A	MOV-871A Closed Due to Monthly or Quarterly Test of PSI01C; or Maintenance Event	PT-2.1M; PT-2.1Q	871A	2.96E-03	3.20E-03	
		SI CV	870A	1.13E-05		
		SI MV	871A	2.31E-04		
SITM00871B	MOV-871B Closed Due to Quarterly Test of PSI01C	PT-2.1Q	871B	7.42E-04	9.84E-04	
		SI CV	870B	1.13E-05		
		SI MV	871B	2.31E-04		
SITM0PSI1A	SI Pump A	SI CV	889A	1.13E-05	2.37E-03	
		SI CV	891A	1.13E-05		
		SI MP	PSI01A	2.35E-03		
		SI XV	1820A	0.00		
		SI XV	888A	0.00		
		SI XV	890A	0.00		
SITM0PSI1B	SI Pump B	SI CV	889B	1.13E-05	2.37E-03	
		SI CV	891C	1.13E-05		
		SI MP	PSI01B	2.35E-03		
		SI XV	1820C	0.00		
		SI XV	888B	0.00		
		SI XV	890B	0.00		
SITM0PSI1C	SI Pump C	SI CV	891B	1.13E-05	2.82E-03	
		SI MP	PSI01C	2.35E-03		
		SI MV	1815A	2.31E-04		
		SI MV	1815B	2.31E-04		
		SI XV	1820B	0.00		

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
SITMTRAINA	SI Train A Discharge Valves	PT-2.1M, PT-2.1Q	PSI01A, 1/2 PSI01C	3.15E-03	3.65E-03	8
		SI CV	842A	1.13E-05		
		SI CV	867A	1.13E-05		
		SI CV	878G	1.13E-05		
		SI MV	841	2.31E-04		
		SI MV	878B	2.31E-04		
SITMTRAINB	SI Train B Discharge Valves	PT-2.1M, PT-2.1Q	PSI01B, 1/2 PSI01C	2.04E-03	2.54E-03	8
		SI CV	842B	1.13E-05		
		SI CV	867B	1.13E-05		
		SI CV	878J	1.13E-05		
		SI MV	841	2.31E-04		
		SI MV	878D	2.31E-04		
		SI XV	878E	0.00		
SWTM1AMAIN	SW Pump A Maintenance	SW CV	4601	2.21E-03	2.70E-02	
		SW MP	PSW01A	2.48E-02		
		SW XV	4605	1.17E-05		
SWTM1BMAIN	SW Pump B Maintenance	SW CV	4602	2.21E-03	2.70E-02	
		SW MP	PSW01B	2.48E-02		
		SW XV	4606	1.17E-05		
SWTM1CMAIN	SW Pump C Maintenance	SW CV	4603	2.21E-03	2.70E-02	
		SW MP	PSW01C	2.48E-02		
		SW XV	4607	1.17E-05		
SWTM1DMAIN	SW Pump D Maintenance	SW CV	4604	2.21E-03	2.70E-02	
		SW MP	PSW01D	2.48E-02		
		SW XV	4608	1.17E-05		
SWTM4613MT	MOV 4613 Maintenance	SW MV	4613	4.97E-04	4.97E-04	
SWTM4614MT	MOV 4614 Maintenance	SW MV	4614	4.97E-04	4.97E-04	
SWTM4615MT	MOV 4615 Maintenance	SW MV	4615	4.97E-04	4.97E-04	
SWTM4616MT	MOV 4616 Maintenance	SW MV	4616	4.97E-04	4.97E-04	

Table E-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
SWTM4664MT	MOV 4664 Maintenance	SW MV	4664	4.97E-04	4.97E-04	
SWTM4670MT	MOV 4670 Maintenance	SW MV	4670	4.97E-04	4.97E-04	
SWTM4734MT	MOV 4734 Maintenance	SW MV	4734	4.97E-04	4.97E-04	
SWTM4735MT	MOV 4735 Maintenance	SW MV	4735	4.97E-04	4.97E-04	
SWTM9627AM	SW Header To SAFW Train A	SW CV	9627A	2.21E-03	2.22E-03	
		SW XV	9626A	1.17E-05		
SWTM9627BM	SW Header To SAFW Train B	SW CV	9627B	2.21E-03	2.22E-03	
		SW XV	9626B	1.17E-05		

Notes:

(1) These manual valves were not included in the plant-specific data collection task. Therefore, the valves use the plant-specific maintenance history for other AFW manual valves which was considered to be a representative population.

(2) The service water filters (SW FD) were not included in the plant-specific data collection task. Since these are passive components, any maintenance on the filters should have resulted in either the associated solenoid valve or even AFW pump being declared inoperable. Therefore, no maintenance out-of-service time was assigned to the filters.

(3) Only valves in the common flowpath for this block of components was considered. That is, the probability of having both Sluice Pump trains inoperable due to maintenance was considered very unlikely given the frequency that the pumps are operated. In addition, since this T/M event applies to recovery action, the human error associated with aligning the system should dominate the results.

(4) The CCW surge tank was not included in this T/M event since this would fail both CCW pumps which is not allowed by Ginna Technical Specifications during power operation.

(5) The boundaries for the diesel generators (D/Gs) was limited to the diesels themselves. This was done on the basis that if any ventilation or fuel system component was inoperable, and that component rendered the respective DG inoperable, then the out-of-service time would be assigned to the D/G in the data collection task. In addition, a review of the out-of-service times for the ventilation and fuel system components showed them to be negligible.

(6) Backdraft dampers were not included in the plant-specific data collection task. Consequently, maintenance data associated with air-operated dampers was used. This is conservative since an air-operated damper is more likely to require maintenance due to the additional parts, etc.

(7) Instrument air manual valves were not included in the plant-specific data collection task. However, the manual valves on the discharge of the air compressors was included within the component boundary for the air compressors. Consequently, no maintenance out-of-service time is assigned to these valves.

(8) PT-2.1M/Q both require use of the Safety Injection test line; consequently, operations declares the affected pump trains inoperable. Since SI Pump C must provide flow through one of the two injection lines, Pumps A and B are also affected. Therefore, for PT-2.1M, two-thirds of the test time is assigned to SITMTRAINA since Pump C is only used through 871A. For PT-2.1Q, one-half of the test time is assigned to both SITMTRAINA and SITMTRAINB.

APPENDIX F

HUMAN ERROR EVALUATIONS

F.0 HUMAN ERROR EVALUATIONS

This appendix contains detailed information used to generate human error probabilities for use in the Ginna Station PSA. The appendix is organized into several tables as follows:

a. LOCA sump recirculation timing (residual heat removal);
b. LOCA sump recirculation timing (safety injection and containment spray);
c. Pre-initiator human errors; and
d. Post-initiator human errors.

The final calculation of human errors is provided in [Ref. 1]. Please note that Tables F-3 and F-4 only address human errors included in the final integrated PSA model (i.e., all human errors described in Section 6 may not be in these tables if the event was not included in the integrated model).

Table F-1
Sump Recirculation Timing

Background:

1. Per procedure ES-1.3, transferring to containment sump recirculation consists of the following general steps after the RWST level has reached 28%:

   a. Verify CNMT Sump B Level is > 113 inches.
   b. Establish SW to the CCW heat exchangers and CCW to the RHR heat exchangers as required.
   c. Stop SI Pump C, one CS pump, and both RHR pumps.
   d. Reconfigure the RHR system by isolating the suction line from the RWST (MOV 856) and opening the suction line from CNMT Sump B (MOVs 850A and 850B).
   e. Start both RHR pumps.

2. Once the RWST level reaches 15%, operators are instructed to perform the following additional steps:

   a. Stop all remaining SI, CVCS, and CS pumps.
   b. Reconfigure the SI and CS systems for high head recirculation by isolating the suction line from the RWST (MOVs 897 and 898) and opening the suction lines from the RHR system (MOVs 857A and 857C for one line and MOV 857B for the second line).
   c. Starting one SI or CS pump based on core exit thermocouple indication and CNMT pressure, respectively.

Analysis:

For the purpose of modeling human recovery actions, it is desirable to know how fast the RWST will deplete to the 28% and 15% level indications for each size LOCA. To calculate these values, MAAP runs were made assuming that all SI, CS, and RHR pumps were available since this provides the most conservative results. Also, the largest LOCA size for each of the four LOCA initiators was used for the same reason. The calculated results are provided below:

MAAP Identifier	LOCA Size	Time to 28%	Time to 15%	Δ For 28% to 15%
RWST1A	1"	349 min	432 min	83 min
RWST2A	2"	176 min	224 min	48 min
RWST6A	6"	69 min	82 min	13 min
RWST14A	14"	46 min	59 min	13 min

It should be noted that MAAP cannot address LOCAs larger than 1/2 the piping diameter (hence the 14" run). As such, the large LOCA timing will be reduced by 1/3 to compensate for this difference, resulting in the following:

MAAP Identifier	LOCA Size	Time to 28%	Time to 15%	Δ For 28% to 15%
N/A	Large	30 min	39 min	9 min

Table F-2
High-Head Recirculation Timing

Assumptions:

a. The time available to operators is the time required to "remove" the available water above the active fuel. Per RG&E Design Analysis DA-NS-93-096-00, Revision 0, the RCS total volume at hot zero power is 5,551.5 ft^3 with 1,219.9 ft^3 located below the active fuel. Assuming that 4,331.7 ft^3 of water is available is appropriate since in order to reach high-head recirculation conditions, the LOCA size must be relatively small (on the order of 1" or less). For LOCAs within this class size, operators would reach SI termination criteria since the flow from 2/3 SI pumps would rapidly overcome flow rate out the break. This is consistent with the steam generator tube rupture accident for an equivalent 3/4" guillotine break of one tube. However, for conservatism, only 50% of the water volume will be assumed available (i.e., 2,165 ft^3).

b. There are two available means of losing RCS inventory: (1) flow out the break, and (2) decay heat. The flow out the break will be assumed to be 500 gpm which is the approximate flow out of a SG tube following a guillotine break at full RCS pressure. Decay heat at 7 hours (Table F-1 for 1" LOCA) is approximately 1% of RTP, or 15.80 MWt.

c. RCS is assumed to be at saturation at 500 psia.

Calculation:

Since there are two methods of losing RCS inventory, the following equation is used to determine the time to boil off:

$$(\text{Loss Due to Decay Heat Boil Off}) + (\text{Loss Due to Break Flow}) = 2{,}165.85 \text{ ft}^3$$

where:

a. Loss Due to Decay Heat Boil Off can be defined as t * Q which can be calculated as:

$$t\,Q = m\,(h_g - h_f)$$

or, solving to determine the mass which is lost due to decay heat:

$$m = (t\,Q)/(h_g - h_f)$$

$$\text{volume} = (t\,Q\,v)/(h_g - h_f)$$

$$= t\,(15.80 \text{ MWt})(3.4129 \text{ Btu/hr/W})(1.0E6 \text{ W/MW})(0.01975 \text{ft}^3/\text{lb}) \,/\, (1204.7 - 449.5)\text{Btu/lb}$$

$$= 1410.22 \text{ ft}^3/\text{hr} * t$$

b. Loss Due to Break Flow can be defined as 500 gpm * t or:

$$(500 \text{ gal/min})(0.1337 \text{ ft}^3/\text{gal})(60 \text{ min/hr}) * t = 4{,}011 \text{ ft}^3/\text{hr} * t$$

Solving the original equation yields:

$$1410.22 \text{ ft}^3/\text{hr} * t + 4{,}011 \text{ ft}^3/\text{hr} * t = 2{,}165.85 \text{ ft}^3$$

$$t = 0.40 \text{ hrs or 24 minutes to complete transfer}$$

TABLE F-3 Human Reliability Events - Pre Initiators					
System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
AFW	AFHFL0AFWA	PRE	FAILURE TO RESTORE AFW MOTOR-DRIVEN PUMP TRAIN A TO SERVICE POST TEST/MAINT. Event represents failure to properly restore MDAFW pump train A to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on SR equipment is controlled by work package and EIN specific procedure (e.g., M-11.5c). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-16Q-A) be performed to verify proper equipment operation following maintenance or testing. Operators take the following actions and/ or have the following visual cues to indicate that AFW is restored to service: Annunciators J-25, H-9, and H-10. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
AFW	AFHFL0AFWB	PRE	FAILURE TO RESTORE AFW MOTOR-DRIVEN PUMP TRAIN B TO SERVICE POST TEST/MAINT. Event represents failure to properly restore MDAFW pump train B to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on SR equipment is controlled by work package and EIN specific procedure (e.g., M-11.5e). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-16Q-B) be performed to verify proper equipment operation following maintenance or testing. Operators take the following actions and/ or have the following visual cues to indicate that AFW is restored to service: Annunciators J-25, H-9, and H-10. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
AFW	AFHFLS5737	PRE	OPERATOR LEAVES SWITCH 1S1/5737 IN THE DEF OR AUX POSITION. This switch bypasses the SG blowdown isolation function on MDAFW start. Switch 1S1/5737 allows AOV 5737 to be opened to provide blowdown flow from SG B during periods of low feedwater flow. Failure to properly operate these switches could result in inability to maintain SG B water inventory, as the flow rate through the blowdown valves is normally 100 gpm. Annunciator K-13 alarms when switch 1S1/5737 is in an off normal position. Operators are directed to place the switch in normal by procedure 0-1, MFW Pump A or MFW Pump B attachments during the MFW pump startup sequence.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
AFW	AFHFLS5738	PRE	OPERATOR LEAVES SWITCH 1S1/5738 IN THE DEF OR AUX POSITION. This switch bypasses the SG blowdown isolation function on MDAFW start. Switch 1S1/5738 allows AOV 5738 to be opened to provide blowdown flow from SG A during periods of low feedwater flow. Failure to properly operate these switches could result in inability to maintain SG A water inventory, as the flow rate through the blowdown valves is normally 100 gpm. Annunciator K-13 alarms when switch 1S1/5738 is in an off normal position. Operators are directed to place the switch in normal by procedure 0-1, MFW Pump A or MFW Pump B attachments during the MFW pump startup sequence.	3.00E-03	3.00E-03
AFW	AFHFLSAFWA	PRE	FAILURE TO RESTORE SAFW PUMP TRAIN C TO SERVICE POST TEST/MAINT. Event represents failure to properly restore SAFW pump train C to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on SR equipment is controlled by work package and EIN specific procedure (e.g., M-11.14). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-36M-C) be performed to verify proper equipment operation following maintenance or testing. Operators take the following actions and/ or have the following visual cues to indicate that SAFW is restored to service: Annunciator AA-5. O-6.13 pump switch positions and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
AFW	AFHFLSAFWB	PRE	FAILURE TO RESTORE SAFW PUMP TRAIN D TO SERVICE POST TEST/MAINT. Event represents failure to properly restore SAFW pump train D to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on SR equipment is controlled by work package and EIN specific procedure (e.g., M-1015). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-36M-D) be performed to verify proper equipment operation following maintenance or testing. Operators take the following actions and/ or have the following visual cues to indicate that SAFW is restored to service: Annunciator AA-5. O-6.13 pump switch positions and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
AFW	AFHFLTDAFW	PRE	FAILURE TO RESTORE TDAFW PUMP TRAIN TO SERVICE POST TEST/MAINT. Event represents failure to properly restore the TDAFW pump to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on SR equipment is controlled by work package and EIN specific procedure (e.g., M-11.5K). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-16M-T) be performed to verify proper equipment operation following maintenance or testing. Operators take the following actions and/ or have the following visual cues to indicate that the TDAFW pump is restored to service: O-6.13 pump switch positions and verifies valve position (dot check) each shift. AC Oil pump power available light. Steam admission valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
CCW	CCHFL0780A	PRE	CCW THROTTLING VALVE 780A MISPOSITIONED. Manual valve 780A is the outlet valve for CCW heat exchanger A. The valve is required to be in service to support RHR operation within 22.4 minutes following a large break LOCA (recirc phase of an accident). Initial positioning of valve 780A per procedure S-8A, step 5.12.8 before reactor startup. Position of 780A verified every 31 days per procedure S-30.2, step 5.2.22.	3.00E-03	3.00E-03
CCW	CCHFL0780B	PRE	CCW THROTTLING VALVE 780B MISPOSITIONED. Manual valve 780B is the outlet valve for CCW heat exchanger B. The valve is required to be in service to support RHR operation within 22.4 minutes following a large break LOCA (recirc phase of an accident). Initial positioning of valve 780B per procedure S-8A, step 5.12.10 before reactor startup. Position of 780B verified every 31 days per procedure S-30.2, step 5.2.24.	3.00E-03	3.00E-03
CS	CSHFL0896A	PRE	MOV 896A LEFT UNAVAILABLE AFTER TESTING OR MAINTENANCE. Event represents failure to restore MOV 896A, "Refueling Water Storage Tank(RWST) Outlet to CS and SI Pumps" to service following maintenance and/or testing. MOV 896A is used to isolate the CS and SI pump suction from the RWST during the shift to recirculation. Failure of this valve combined with failure of MOV 896B would result in loss of SI and CS functions when the RWST empties. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 896A is controlled by work package and EIN specific procedures (e.g., CMP-37-01-03A, M-64.1.2). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.4) be performed to verify proper equipment operation following maintenance or testing. Breaker position is verified per S-30.1. Operators take the following actions and/ or have the following visual cues to indicate that MOV 896A is restored to service: O-6.13 verifies valve position (dot check) each shift. White breaker disagreement light indicates that beaker position differs from switch position. Valve position indication indicates that DC control power is available to the valve.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
CS	CSHFL0896B	PRE	MOV 896B LEFT UNAVAILABLE AFTER TESTING OR MAINTENANCE. Event represents failure to restore MOV 896B, "Refueling Water Storage Tank(RWST) Outlet to CS and SI Pumps" to service following maintenance and/or testing. MOV 896B is used to isolate the CS and SI pump suction from the RWST during the shift to recirculation. Failure of this valve combined with failure of MOV 896A would result in loss of SI and CS functions when the RWST empties. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 896A is controlled by work package and EIN specific procedures (e.g., CMP-37-01-03A, M-64.1.2). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.4) be performed to verify proper equipment operation following maintenance or testing. Breaker position is verified monthly per S-30.1. Operators take the following actions and/ or have the following visual cues to indicate that MOV 896B is restored to service: O-6.13 verifies valve position (dot check) each shift. White breaker disagreement light indicates that beaker position differs from switch position. Valve position indication indicates that DC control power is available to the valve.	3.00E-03	3.00E-03
CS	CSHFLTRANA	PRE	OPERATORS FAIL TO RESTORE CS TRAIN A EQUIPMENT AFTER TESTING OR MAINTENANCE. Event represents failure to restore CS Train A to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on CS Train A equipment is controlled by work package and specific procedures (e.g., M-11.14 for CS pump A). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-3M) be performed to verify proper equipment operation following maintenance or testing. Breaker position is verified monthly per S-30.3. Operators take the following actions and/ or have the following visual cues to indicate that CS is restored to service: Annunciators B-8, B-16, B-24, A-27 and A-28. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
CS	CSHFLTRANB	PRE	OPERATORS FAIL TO RESTORE CS TRAIN B EQUIPMENT AFTER TESTING OR MAINTENANCE. This basic event represent failure to restore CS Train B to service following maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on CS Train A equipment is controlled by work package and specific procedures (e.g., M-11.14 for CS pump B). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-3M) be performed to verify proper equipment operation following maintenance or testing. Breaker position is verified monthly per S-30.3. Operators take the following actions and/ or have the following visual cues to indicate that CS is restored to service: Annunciators B-8, B-16, B-24, A-27 and A-28. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
ESFAS	ESHFLCPH1A	PRE	TEST SWITCH FOR RELAY PC-945A-X1, PC-947A-X1 OR PC949A-X1 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the Hi containment pressure train A logic circuit from the master SI relay when placed in test. This, if a high pressure condition occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLCPH1B	PRE	TEST SWITCH FOR RELAY PC-945A-X2, PC-947A-X2 OR PC-949A-X2 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the Hi containment pressure train B logic circuit from the master SI relay when placed in test. This, if a high pressure condition occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03

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Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLCPH2A	PRE	TEST SWITCH FOR RELAY PC-946A-X1, PC-948A-X1 OR PC-950A-X1 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the Hi containment pressure train A logic circuit from the master SI relay when placed in test. This, if a high pressure condition occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLCPH2B	PRE	TEST SWITCH FOR RELAY PC-946A-X2, PC-948A-X2 OR PC-950A-X2 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the Hi containment pressure train B logic circuit from the master SI relay when placed in test. This, if a high pressure condition occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLCPH3A	PRE	1 OR MORE CNMT HI PRES TRAIN A RELAY TEST SWITCH LEFT IN TEST POSITION POST TEST. This basic event represents failure to restore test switches for relays PC-945B-X1, PC-946B-X1, PC-947B-X1, PC-948B-X1, PC-949B-X1 or PC-950-X1 to normal position after testing. Each of these switches disconnects containment spray master relay S1 from the high pressure train A logic circuitry when placed in the test position. Thus, if a Hi pressure condition occurred CS would not occur. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03

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Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLCPH3B	PRE	1 OR MORE CNMT HI PRES TRAIN B RELAY TEST SWITCH LEFT IN TEST POSITION POST TEST. This basic event represents failure to restore test switches for relays PC-945B-X2, PC-946B-X2, PC-947B-X2, PC-948B-X2, PC-949B-X2 or PC-950-X2 to normal position after testing. Each of these switches disconnects containment spray master relay S1 from the high pressure train B logic circuitry when placed in the test position. Thus, if a Hi pressure condition occurred CS would not occur. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLF/464	PRE	FAILURE TO RESTORE SWITCH TIS-F/464 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-F/464 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high steam flow would be sensed. Operation of TIS-F/464 is controlled by procedure (ex. CPI-FLO-464) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in steam flow indication (FI-464) differing from other steam flow indications available to the operators. Also annunciator B-6 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLF/465	PRE	FAILURE TO RESTORE SWITCH TIS-F/465 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-F/465 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high steam flow would be sensed. Operation of TIS-F/465 is controlled by procedure (ex. CPI-FLO-465) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in steam flow indication (FI-464) differing from other steam flow indications available to the operators. Also annunciator B-14 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLP/945	PRE	FAILURE TO RESTORE SWITCH TIS-P/945 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/945 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/945 is controlled by procedure (ex. CPI-PRES-945) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-945) differing from other containment pressure indications available to the operators. Also annunciator B-6 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	Event Name	Pre or Post Init	Description Of Event	Screening Value	Final Value
ESFAS	ESHFLP/946	PRE	FAILURE TO RESTORE SWITCH TIS-P/946 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/946 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/946 is controlled by procedure (ex. CPI-PRES-946) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-946) differing from other containment pressure indications available to the operators. Also annunciator B-14 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLP/947	PRE	FAILURE TO RESTORE SWITCH TIS-P/947 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/947 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/947 is controlled by procedure (ex. CPI-PRES-947) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-947) differing from other containment pressure indications available to the operators. Also annunciator B-22 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLP/948	PRE	FAILURE TO RESTORE SWITCH TIS-P/948 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/948 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/948 is controlled by procedure (ex. CPI-PRES-948) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-948) differing from other containment pressure indications available to the operators. Also annunciator B-22 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03

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Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLP/949	PRE	FAILURE TO RESTORE SWITCH TIS-P/949 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/949 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/949 is controlled by procedure (ex. CPI-PRES-949) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-949) differing from other containment pressure indications available to the operators. Also annunciator B-14 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLP/950	PRE	FAILURE TO RESTORE SWITCH TIS-P/950 TO NORMAL POSITION AFTER TESTING. This basic event represents failure to restore test injection switch TIS-P/950 to normal following testing or maintenance. When the test injection switch is in test, the loop flow transmitter is removed from the instrument loop, therefore no actual high containment pressure would be sensed. Operation of TIS-P/950 is controlled by procedure (ex. CPI-PRES-950) which has steps to have independent verification of the test switch's return to normal. Leaving the test injection in test would result in containment pressure indication (PI-950) differing from other containment pressure indications available to the operators. Also annunciator B-30 would alarm because it is impossible to close the test injection panel cover without placing the test injection switches in normal.	3.00E-03	3.00E-03
ESFAS	ESHFLPPL1A	PRE	PRZR LOW PRES RELAY PC-431G-1X1 OR PC-429C-X1 TEST SWITCH LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train A logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03

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Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLPPL1B	PRE	PRZR LOW PRES RELAY PC-431G-1X2 OR PC-429C-X2 TEST SWITCH LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train B logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLPPL2A	PRE	PRZR LOW PRES RELAY PC-430E-X1 OR PC-429C-1X1 TEST SWITCH LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train A logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLPPL2B	PRE	PRZR LOW PRES RELAY PC-430E-X2 OR PC-429C-1X2 TEST SWITCH LEFT IN TEST. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train B logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test. POSITION	3.00E-03	3.00E-03

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Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLPPL3A	PRE	PRZR LOW PRES RELAY PC-431G-X1 OR PC-430E-1X1 TEST SWITCH LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train A logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLPPL3B	PRE	PRZR LOW PRES RELAY PC-431G-X2 OR PC-430E-1X2 TEST SWITCH LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low pressurizer pressure train B logic circuit from the master SI relay when placed in test. Thus, if a low pressurizer pressure occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLSAPLA	PRE	TEST SWITCH FOR RELAY PC-468A-X1, PC-469A-X1 OR PC-482A-X1 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low steam generator A pressure train A logic circuit from the master SI relay when placed in test. Thus, if a steam generator pressure occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
ESFAS	ESHFLSAPLB	PRE	TEST SWITCH FOR RELAY PC-468A-X2, PC-469A-X2 OR PC-482A-X2 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low steam generator A pressure train B logic circuit from the master SI relay when placed in test. Thus, if a steam generator pressure occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLSBPLA	PRE	TEST SWITCH FOR RELAY PC-478A-X1, PC-479A-X1 OR PC-483A-X1 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low steam generator pressure train A logic circuit from the master SI relay when placed in test. Thus, if a steam generator B pressure occurred with the switches test, the SI train A master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
ESFAS	ESHFLSBPLB	PRE	TEST SWITCH FOR RELAY PC-478A-X2, PC-479A-X2 OR PC-483A-X2 LEFT IN TEST POSITION. This basic event represent failure to return individual relay test switches for the above relays to normal following safeguards logic testing (PT-32.1). Each of these switches disconnects the low steam generator B pressure train B logic circuit from the master SI relay when placed in test. Thus, if a steam generator pressure occurred with the switches test, the SI train B master relay would not receive a signal. Operators have the following indications and/or take the following actions to verify that each test switch is returned to normal: Annunciator L-30 would be lit any time a test switch is in test. Testing of each relay is controlled by procedure PT-32.1, which has single action steps that verify each test switch returned to normal and all annunciators are clear at the end of a test.	3.00E-03	3.00E-03
HVAC	HVHFLSAFWA	PRE	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION. This basic event represent failure to restore SAFW Train C to service following maintenance and/or testing. The switch specifically mentioned would disable the auto start feature of SAFW HVAC unit A upon start of SAFW pump C. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-36Q-C) be performed to verify equipment operability following maintenance or testing. Position of Switch-A is verified by the auxiliary operators during each shift's SAFW room tour (O-6.1).	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
HVAC	HVHFLSAFWB	PRE	LATENT HUMAN ERRORS IN SAFW-B COOLING INCL. SWITCH-B POSITION. This basic event represent failure to restore SAFW Train D to service following maintenance and/or testing. The switch specifically mentioned would disable the auto start feature of SAFW HVAC unit B upon start of SAFW pump D. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-36Q-D) be performed to verify equipment operability following maintenance or testing. Position of Switch-B is verified by the auxiliary operators during each shift's SAFW room tour (O-6.1).	3.00E-03	3.00E-03
HVAC	HVHFL_SAFW	PRE	OPERATOR FAILS TO DISCOVER ROOM HEATING FAILURE IN SAFW ROOM. This basic event represents operator failure to discover a heater failure in the SAFW room. SAFW room heaters are powered from the same non- Class 1E power supply. The SAFW room is susceptible to freezing if heaters are lost. Operators check the SAFW room once per shift (O-6.1). MCB annunciator AA-4 is received upon low temperature in the room.	3.00E-03	3.00E-03
MS	MSHFLARV-A	PRE	LATENT HUMAN ERROR DISABLES ARV 3411. This basic event represents failure of the SG A ARV due to improper maintenance, testing or restoration to service. This includes valve position errors, miscalibration of electronic or pneumatic control loops, and improper control switch settings. Functional operability of the ARV is verified each refueling cycle by performance of PT-2.6.1. Calibration of the valve and control circuitry is performed per procedure CPI-ARV-3411. Valve maintenance is performed per CMP-37-14. AOV MCB switch setting for normal operation is performed during startup per O-1.2, step 5.4.3.15. Operators have the following visual cues to indicate that ARV 3411 is restored to service: Valve position indication indicates that DC control power is available to the valve. Hand controller in auto, setpoint and control signal available indicating light.	3.00E-03	3.00E-03
MS	MSHFLARV-B	PRE	LATENT HUMAN ERROR DISABLES ARV 3410 This basic event represents failure of the SG B ARV due to improper maintenance, testing or restoration to service. This includes valve position errors, miscalibration of electronic or pneumatic control loops, and improper control switch settings. Functional operability of the ARV is verified each refueling cycle by performance of PT-2.6.1. Calibration of the valve and control circuitry is performed per procedure CPI-ARV-3410. Valve maintenance is performed per CMP-37-14. AOV MCB switch setting for normal operation is performed during startup per O-1.2, step 5.4.3.15. Operators have the following visual cues to indicate that ARV 3410 is restored to service: Valve position indication indicates that DC control power is available to the valve. Hand controller in auto, setpoint and control signal available indicating light.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
RCS	RCHFL0431K	PRE	CONTROLLER PC-431K MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure controller PC-431K which fails automatic of PZR spray valves. Failure could be due to human or procedure error. Calibration of PC-431K is performed per procedure CPI-PRESS-MOD-11.1 by individuals qualified to that specific procedure. Operators could receive annunciator F-2 if PC-431K were improperly calibrated.	3.00E-03	3.00E-03
RCS	RCHFLC429B	PRE	ALARM BISTABLE PC-429B MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure duplex alarm to PORV 430 (i.e., PC-429B). Failure could be due to human or procedure error. Calibration of PC-429B is performed per procedure CPI-PRESS-429 by individuals qualified to that specific procedure. Operators could receive annunciator F-10 if PC-429B were improperly calibrated.	3.00E-03	3.00E-03
RCS	RCHFLC430B	PRE	ALARM BISTABLE PC-430B MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure duplex alarm to PORV 430 (i.e., PC-430B). Failure could be due to human or procedure error. Calibration of PC-430B is performed per procedure CPI-PRESS-MOD-11.1 by individuals qualified to that specific procedure. No alarm or indication available to inform operators of possible calibration problems.	3.00E-03	3.00E-03
RCS	RCHFLC431B	PRE	ALARM PC-431B MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure duplex alarm to PORV 431C (i.e., PC-431B). Failure could be due to human or procedure error. Calibration of PC-431B is performed per procedure CPI-PRESS-MOD-11.1 by individuals qualified to that specific procedure. No alarm or indication available to inform operators of possible calibration problems.	3.00E-03	3.00E-03
RCS	RCHFLC431F	PRE	ALARM BISTABLE PC-431F MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure duplex alarm to PORV 431C (i.e., PC-431F). Failure could be due to human or procedure error. Calibration of PC-431F is performed per procedure CPI-PRESS-431 by individuals qualified to that specific procedure. Operators could receive annunciator F-10 if PC-431F were improperly calibrated.	3.00E-03	3.00E-03
RCS	RCHFLLT427	PRE	PRESSURIZER LEVEL TRANSMITTER LT-427 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer level transmitter LT-427. Failure could be due to human or procedure error. Calibration of LT-427 is performed per procedure CPI-LT-427 by individuals qualified to that specific procedure. Operators have the following cues to indicate that LT-427 has been miscalibrated: Difference between LT-427 indication and other pressurizer level channels. Possible annunciator F-28 and status light White, PZR HI LEVEL LC427A	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
RCS	RCHFLLT428	PRE	PRESSURIZER LEVEL TRANSMITTER LT-428 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer level transmitter LT-428. Failure could be due to human or procedure error. Calibration of LT-428 is performed per procedure CPI-LT-428 by individuals qualified to that specific procedure. Operators have the following cues to indicate that LT-427 has been miscalibrated: Difference between LT-428 indication and other pressurizer level channels. Possible annunciator F-28 and status light Blue, PZR HI LEVEL LC428A	3.00E-03	3.00E-03
RCS	RCHFLPC450	PRE	ALARM PC-450 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection alarm PC-450 which fails LTOP nitrogen supply to PORVs. Failure could be due to human or procedure error. Calibration of PC-450 is performed per procedure CPI-PRESS-450 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PC-450 has been miscalibrated: Possible annunciator AA-22.	3.00E-03	3.00E-03
RCS	RCHFLPC451	PRE	ALARM PC-451 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection alarm PC-451 which fails LTOP nitrogen supply to PORVs. Failure could be due to human or procedure error. Calibration of PC-451 is performed per procedure CPI-PRESS-451 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PC-451 has been miscalibrated: Possible annunciator AA-23.	3.00E-03	3.00E-03
RCS	RCHFLPC452	PRE	ALARM PC-452 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection alarm PC-452 which fails LTOP nitrogen supply to the PORVs. Failure could be due to human or procedure error. Calibration of PC-452 is performed per procedure CPI-PRESS-452 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PC-452 has been miscalibrated: Possible annunciator AA-31.	3.00E-03	3.00E-03
RCS	RCHFLPL451	PRE	PRESSURE TRANSMITTER PT-451 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection alarm PC-451. Failure could be due to human or procedure error. Calibration of PC-451 is performed per procedure CPI-PRESS-451 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-451 has been miscalibrated: Possible annunciator AA-23.	3.00E-03	3.00E-03
RCS	RCHFLPT429	PRE	PRESSURE TRANSMITTER PT-429 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure transmitter PT-429. Failure could be due to human or procedure error. Calibration of PT-429 is performed per procedure CPI-PRESS-429 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-429 has been miscalibrated: Possible annunciators F-27, F-26, C-27 and C-28. Difference in indication when compared to other pressurizer pressure channels.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
RCS	RCHFLPT430	PRE	PRESSURE TRANSMITTER PT-430 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure transmitter PT-430. Failure could be due to human or procedure error. Calibration of PT-430 is performed per procedure CPI-PRESS-430 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-430 has been miscalibrated: Possible annunciators F-27, F-26, C-27 and C-28. Difference in indication when compared to other pressurizer pressure channels.	3.00E-03	3.00E-03
RCS	RCHFLPT431	PRE	PRESSURE TRANSMITTER PT-431 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure transmitter PT-431. Failure could be due to human or procedure error. Calibration of PT-431 is performed per procedure CPI-PRESS-431 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-431 has been miscalibrated: Possible annunciators F-27, F-26, C-27 and C-28. Difference in indication when compared to other pressurizer pressure channels.	3.00E-03	3.00E-03
RCS	RCHFLPT449	PRE	PRESSURE TRANSMITTER PT-449 MISCALIBRATED. This basic event represents failure to properly calibrate pressurizer pressure transmitter PT-449. Failure could be due to human or procedure error. Calibration of PT-449 is performed per procedure CPI-PRESS-449 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-449 has been miscalibrated: Possible annunciator F-27. Difference in indication when compared to other pressurizer pressure channels. Status light Yellow, PZR LO PRESS PC449A may be lit.	3.00E-03	3.00E-03
RCS	RCHFLPT450	PRE	PRESSURE TRANSMITTER PT-450 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection pressure transmitter PT-450 which fails LTOP nitrogen supply to the PORVs. Failure could be due to human or procedure error. Calibration of PT-450 is performed per procedure CPI-PRESS-450 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-450 has been miscalibrated: Possible annunciator AA-22.	3.00E-03	3.00E-03
RCS	RCHFLPT452	PRE	PRESSURE TRANSMITTER PT-452 MISCALIBRATED. This basic event represents failure to properly calibrate reactor coolant over pressure protection pressure transmitter PT-452 which fails LTOP nitrogen supply to the PORVs. Failure could be due to human or procedure error. Calibration of PT-452 is performed per procedure CPI-PRESS-452 by individuals qualified to that specific procedure. Operators have the following cues to indicate that PT-452 has been miscalibrated: Possible annunciator AA-31.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
RHR	RHHFL0000A	PRE	LATENT HUMAN FAILURE OF RHR TRAIN A. This basic event represents failure of RHR Train A due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on RHR Train A components is controlled by work package and specific procedures. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.2Q) be performed to verify proper equipment operation following maintenance or testing. Proper operation of RHR Train A components are verified quarterly by scheduled performance of PT-2.2Q. Critical valve positions are verified every 12 hours (T.S. SR 3.5.2.1). Other RHR Train A and breaker positions are verified every 31 days per procedure S-30.2.	3.00E-03	3.00E-03
RHR	RHHFL0000B	PRE	LATENT HUMAN FAILURE OF RHR TRAIN B. This basic event represents failure of RHR Train B due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on RHR Train B components is controlled by work package and specific procedures. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.2Q) be performed to verify proper equipment operation following maintenance or testing. Proper operation of RHR Train B components are verified quarterly by scheduled performance of PT-2.2Q. Critical valve positions are verified every 12 hours (T.S. SR 3.5.2.1). Other RHR Train B and breaker positions are verified every 31 days per procedure S-30.2.	3.00E-03	3.00E-03
RHR	RRHFL00856	PRE	LATENT HUMAN FAILURE ON MOV 856. This basic event represents failure of RHR pump motor operated suction from the RWST valve 856 due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on RHR components is controlled by work package and specific procedures (e.g., CMP-37-03-856). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.4) be performed to verify proper equipment operation following maintenance or testing. Proper operations of RHR Train B components are verified quarterly by scheduled performance of PT-2.4. Valve position is verified every 12 hours (T.S. SR 3.5.2.1).	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
SI	SIHFL0857B	PRE	LATENT HUMAN FAILURE ON MOV 857B. This basic event represents failure of RHR discharge to SI pump suction MOV 857B due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 857B is controlled by work package and specific procedures (e.g., CMP-37-03-857B). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.3) be performed to verify proper equipment operation following maintenance or testing. Proper operation of MOV 857B is verified quarterly by scheduled performance of PT-2.3. Valve position is verified every 31 days per procedure S-30.2.	3.00E-03	3.00E-03
SI	SIHFL0871A	PRE	LATENT HUMAN FAILURE ON MOV 871A. This basic event represents failure of SI pump discharge to loop B MOV 871A due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 871A is controlled by work package and specific procedures (e.g., CMP-37-02-03A). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.3) be performed to verify proper equipment operation following maintenance or testing. Proper operation of MOV 871A is verified quarterly by scheduled performance of PT-2.3. Operators take the following actions and/ or have the following visual cues to indicate that MOV 871A is restored to service: O-6.13 verifies valve position (dot check) each shift. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
SI	SIHFL0871B	PRE	LATENT HUMAN FAILURE ON MOV 871B. This basic event represents failure of SI pump discharge to loop A MOV 871B due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 871A is controlled by work package and specific procedures. (Example CMP-37-02-03A) Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.3) be performed to verify proper equipment operation following maintenance or testing. Proper operation of MOV 871A is verified quarterly by scheduled performance of PT-2.3. Operators take the following actions and/ or have the following visual cues to indicate that MOV 871B is restored to service: O-6.13 verifies valve position (dot check) each shift. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
SI	SIHFL0857AC	PRE	LATENT HUMAN FAILURE ON MOV 857A OR 857C. This basic event represents failure of RHR motor operated discharge to SI pump suction MOVs 857A or 857C due to improper maintenance, testing, or alignment. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Performance of maintenance on MOV 857A and 857C is controlled by work package and specific procedures (e.g., 857A, CMP-37-03-02A). Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.3) be performed to verify proper equipment operation following maintenance or testing. Proper operations of MOV 857A and 857C is verified quarterly by scheduled performance of PT-2.3. Valve positions are verified every 31 days per procedure S-30.2. Operators take the following actions and/ or have the following visual cues to indicate that MOVs 857A and 867C are restored to service: O-6.13 verifies valve position (dot check) each shift. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker. Possible annunciator J-25.	3.00E-03	3.00E-03
SI	SIHFLPSI1A	PRE	OPERATORS FAIL TO RESTORE SI PUMP A EQUIPMENT AFTER TEST OR MAINTENANCE. This basic event represents failure to restore SI pump A to service after maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.1 series) be performed to verify proper equipment operation following maintenance or testing. Pump is tested quarterly per PT-2.1A. Operators take the following actions and/ or have the following visual cues to indicate that SI is restored to service: Annunciator J-25. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03

TABLE F-3
Human Reliability Events - Pre Initiators

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
SI	SIHFLPSI1B	PRE	OPERATORS FAIL TO RESTORE SI PUMP B EQUIPMENT AFTER TEST OR MAINTENANCE. This basic event represents failure to restore SI pump B to service after maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.1 series) be performed to verify proper equipment operation following maintenance or testing. Pump is tested quarterly per PT-2.1B. Operators take the following actions and/ or have the following visual cues to indicate that SI is restored to service: Annunciator J-25. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03
SI	SIHFLPSI1C	PRE	OPERATORS FAIL TO RESTORE SI PUMP C EQUIPMENT AFTER TEST OR MAINTENANCE This basic event represents failure to restore SI pump C to service after maintenance and/or testing. Maintenance on Safety Related (SR) and Safety Significant (SS) components is controlled by the work control system. Tracking documents (A-52.4) are initiated to track equipment inoperability and ensures steps are taken to restore equipment function and perform operability testing. The work control system requires that operability testing (PT-2.1 series) be performed to verify proper equipment operation following maintenance or testing. Pump is tested quarterly per PT-2.1C. Operators take the following actions and/ or have the following visual cues to indicate that SI is restored to service: Annunciator J-25. O-6.13 checks pump switch position and verifies valve position (dot check) each shift. White breaker disagreement light (valves and pumps) indicates that beaker position differs from switch position. Valve position indication and pump breaker position status lights also verify that DC control power is available to each component breaker.	3.00E-03	3.00E-03

TABLE F-4
Human Reliability Events - Post Initiator

System	Event Name	Pre or Post Init	Description Of Event	Screening Value	Final Value
AC	ACHFDIR751	POST	OPERATORS FAIL TO REALIGN OFFSITE POWER SUPPLY TO CIRCUIT 751. This event represents the failure of operators to align the offsite power feed from CKT 767 to CKT751. This event is used in station blackout sequences where the plant is initially being supplied entirely from CKT 767 which fails following an initiating event. Procedure ECA-0.0, step 7, instructs operators to consult Power Contol to determine if either offsite circuit is available, and if so, to restore offsite power per procedure ER-ELEC.1.	1.00E-01	1.00E-01
AC	ACHFDIR767	POST	OPERATORS FAIL TO REALIGN OFFSITE POWER SUPPLY TO CIRCUIT 767. This event represents the failure of operators to align the offsite power feed from CKT 751 to CKT767. This event is used in station blackout sequences where the plant is initially being supplied entirely from CKT 751 which fails following an initiating event. Procedure ECA-0.0, step 7, instructs operators to consult Power Contol to determine if either offsite circuit is available, and if so, to restore offsite power per procedure ER-ELEC.1.	1.00E-01	1.00E-01
AFW	AFHFDALTTD	POST	OPERATORS FAIL TO PROVIDE COOLING TO TDAFW LUBE OIL FROM DIESEL FIRE PUMP. This event represents to the failure of operators to align the diesel driven fire water pump to supply cooling water to the TDAFW pump lube oil cooler during a station blackout event. Actual testing of TDAFW pump has shown that it can run for 2 hours without cooling water to the lube oil coolers. Procedure ECA-0.0, step 8.b, directs operators to align backup cooling water to the TDAFW pump using Attachment FIRE WATER COOLING TO TDAFW PUMP.	1.00E-01	6.7E-03
AFW	AFHFDSAFWX	POST	OPERATORS FAIL TO CORRECTLY ALIGN SAFW. This event represents the failure of operators to align and start the SAFW system for events which result in a loss of all three AFW trains and MFW (e.g., HELB or SLB events). SAFW must be aligned prior to steam generator dryout which occurs at 45 minutes following a loss of MFW event. Procedure FR-H.1, step 7, directs operators to align the SAFW system for operation per Attachment SAFW.	1.00E-01	5.19E-03
AFW	AFHFDSUPPL	POST	OPERATORS FAIL TO SUPPLY ALTERNATE SOURCES OF WATER TO AFW. This event represents the failure of operators to provide alternate sources of water to the suction of the AFW pumps after the CST inventory is exhausted. One CST provides sufficient volume for a minimum of 2 hrs of decay heat removal. Assuming that two tanks are available, four hours would be available prior to exhausting inventory in the CSTs. Annunciator H-13, CONDENSATE STORAGE TANK HI-LO LEVEL ALARM sounds at 18' 4". Alarm response procedure AR-H-13 directs the operators on receipt of a low level alarm to "Check Hotwell Level Controller LC-107 is operating properly, and start transferring water in." Procedure ER-AFW.1 provides directions for operators to transfer water in or to provide alternate sources of water to the AFW pumps. This event specifically includes the options available in steps 4.1, 4.4, 4.7, and 4.8. Steps 4.2 and 4.3 were assumed to be unavailable and steps 4.5 and 4.6 are included in the event for the operators failing to align SAFW (AFHFDSAFWX, above).	1.00E-01	1.00E-03

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
AFW	AFHFDTDAFW	POST	OPERATORS FAIL TO MANUALLY START TDAFW PUMP DURING SBO. This event represents the failure of operators to manually start a TDAFW pump during a SBO when the start signal to the pump fails. Procedure ECA-0.0, Step 4 requires operators to verify that the TDAFW pump is running.	1.00E-01	1.00E-01
CCW	CCHFDCCWAB	POST	OPERATORS FAIL TO START STANDBY CCW PUMP IF AUTO START FAILS. This event represents failure to start the standby CCW pump given that the running pump fails and the auto start signal on low header pressure fails. This event is used for seal LOCA modeling only, not for CCW failure for recirculation sequences. Operators would have 1 hour to start the standby pump prior to long-term RCP seal failure. Operators have the following cues to indicate the need for starting the standby CCW pump: Annunciators A-17, and A-31. Direction for recovery found in AR-A-17 and AR-A-31. AR-A-17, step 3. directs the operators to procedure AP-CCW.2, while AR-A-31 instructs the operators to insure a CCW pump is running and also refers them to procedure AP-CCW.3. Both these procedures direct operators to start the standby pump.	1.00E-01	7.0E-03
CCW	CCHFDSTART	POST	OPERATORS FAIL TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI. This event occurs during a loss of offsite power coincident with an SI signal which trips the CCW pumps such that they must be manually restarted. This event is used for seal LOCA modeling only (i.e. not for CCW failure for recirculation). Operators would have 1 hour to start the standby pump prior to long-term RCP seal failure. Procedure E-0, step 13 directs operators to verify that at least one CCW pump is running, and if not, to start a pump.	1.00E-01	7.0E-03
CVCS	CVHFD00313	POST	OPERATORS FAIL TO MANUALLY ISOLATE MOV 313 (SEAL RETURN LINE). This event represents the failure of operators to manually isolate containment isolation MOV 313 given that it fails to close upon a CI signal following a seal LOCA. This action is necessary to prevent a potential ISLOCA event. Procedure E-0, step 12 instructs operators to verify all containment isolation valve status lights are lit. If not, they are directed to locally close alternate isolation valves per Attachment CI/CVI.	1.00E-01	1.20E-03
CVCS	CVHFD00371	POST	OPERATORS FAIL TO MANUALLY ISOLATE AOV 371 (LETDOWN LINE). This event represents the failure of operators to manually isolate containment isolation AOV 371 given that it fails to close upon a CI signal. This event is applicable to sump recirculation sequences, and must be completed prior to going on recirc. Therefore, the timing of this event is different for the different LOCA sequences. Procedure E-0, step 12 instructs operators to verify all containment isolation valve status lights are lit. If not, they are directed to locally close alternate isolation valves per Attachment CI/CVI.	1.00E-01	1.3E-02 (L) 5.3E-03 (M) 1.2E-03 (S) 1.2E-03 (SS)

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
CVCS	CVHFDBORAT	POST	OPERATORS FAIL TO IMPLEMENT EMERGENCY BORATION. This event represents failure of operators to provide emergency boration to the RCS during an ATWS event within 10 minutes. Failure to do so results in a failure to achieve long-term shutdown reactivity margin. Final value taken from WCAP-11993, page B-25. Operators are directed to initiate emergency boration per FR-S.1, step 4.	1.00E-02	1.00E-02
CVCS	CVHFDPMPST	POST	OPERATORS FAIL TO MANUALLY LOAD CHARGING PUMP. This event represents failure of operators to manually start charging pumps following an undervoltage signal or an SI signal, since the pumps are shed from the bus on either signal. Operators have 1 hour to start a charging pump prior to long-term RCP seal failure. Procedures E-0, step 19 RNO d (for SI conditions) or ES-0.1, step 7 (for non-SI conditions) provide the necessary operator direction.	1.00E-01	7.0E-03
CVCS	CVHFDSUCTN	POST	OPERATORS FAIL TO MANUALLY OPEN SUCTION LINE TO CHARGING PUMPS. This event represents the failure of operators to open the alternate suction valve to the RWST, and to isolate the VCT, upon a loss of support systems for the normal valves, which would cause them to go closed (i.e. loss of IA or DC power). Operators would have 30 minutes to complete the task prior to the VCT draining down to the point where there could be air entrainment in the charging pumps, failing the pumps. Procedure ES-0.1, step 6 RNO, provides directions for operators to locally open manual charging pump suction valve to the RWST and close the isolation valve to the VCT.	1.00E-01	2.4E-02
HVAC	HVHFDABVLP	POST	OPERATORS FAIL TO RESTART AB EXHAUST VENT FOLLOWING A LOOP. This event represents operator failure of the operators to restart the Auxiliary Building exhaust fans following a loss of offsite power. Intermediate building (AFW pump area) ventilation fans exhaust to the inlet plenum of the Auxiliary Building exhaust fans. Failure to restart the fans combined with a loss of natural air circulation cooling in the Intermediate Building could result in a loss of AFW due to high ambient temperatures. There is no specific procedural guidance for restoring power to Auxiliary Building fan; however, ER-ELEC.1 provides guidance for the MCCs.	1.00E-01	1.00E-01
HVAC	HVHFDIBVEN	POST	OPERATORS FAILS TO RESTART IB EXHAUST FANS FOLLOWING A LOOP. This event represents failure of the operators to restart the Intermediate Building exhaust fans following a loss of offsite poewr. Failure to restart the Intermediate Building exhaust fans combined with a loss of natural air circulation cooling in the Intermediate Building could result in a loss of AFW due to high ambient temperatures. There is no specific procedural guidance for restoring power to Auxiliary Building fan; however, ER-ELEC.1 provides guidance for the MCCs.	1.00E-01	1.00E-01

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
HVAC	HVHFD_CTMT	POST	OPERATORS FAIL TO RE-START CONTAINMENT COOLING. This event represents the failure of operators to re-start Containment Recirculation Fan Coolers (CRFCs). The CRFCs combined with the containment spray system work to limit post accident pressure and temperature. If the CRFCs fail to start due to ESFAS signal failure and less than 2 CRFCs are initially running, operators must restart containment fan coolers to prevent exceeding the ultimate containment pressure of ~ 140 psig. Operators are directed to start or verify CRFCs are running when required by ECA-0.2, step 4d and E-0, step 6.	1.00E-01	1.00E-01
IA	IAHFDCSA03	POST	OPERATORS FAIL TO PLACE CNMT BREATHING AIR COMPRESSOR IN SERVICE. The containment breathing air compressor provides manual backup to the IA compressors. This event represents failure to place this portable air compressor into service when needed as backup to the IA compressors (e.g., attempt to use IA supply to PORVs). On receipt of annunciator H-8 or other indication of loss of IA, operators are directed to go to AP-IA.1, Step 3 which directs the portable air compressors be started per procedure T-2F.	1.00E-01	1.00E-01
IA	IAHFDCSA04	POST	OPERATORS FAIL TO PLACE THE DIESEL AIR COMPRESSOR IN SERVICE. The diesel air compressor provides manual backup to the IA compressors. This event represents failure to place the portable air compressor into service when needed as backup to the IA compressors (e.g., attempt to use IA supply to PORVs). On receipt of annunciator H-8 or other indication of loss of IA, operators are directed to go to AP-IA.1, Step 3 which directs the portable air compressors be started per procedure T-2F.	1.00E-01	1.00E-01
MF	MFHFDMF100	POST	OPERATORS FAIL TO REESTABLISH MFW FLOW. This event represents failure of the operators to reinitiate MFW flow post reactor trip, given that AFW cannot be established or is insufficient (<200 gpm). MFW must be established prior to steam generator dryout which occurs at 45 minutes following a loss of MFW. E-0 step 15 directs the operators to FR-H.1. After trying to establish AFW flow, FR-H-1, step 6 directs operators to try and establish MFW flow to at least one steam generator. Two values are generated due to the complexity of a potential SI signal.	1.00E-01	1.2E-02 (SI) 9.3E-3 -noSI
MS	MSHFDISOLA	POST	OPERATORS FAIL TO ISOLATE A RUPTURED SG GIVEN A FAILURE OF NORMAL ISOLATION VALVES. This event represents the failure of the operators to use an alternate method to isolate the ruptured SG given that normal isolation valve fails to close. Procedure E-3, steps 3, 4 and 5, and Attachment RUPTURED SG, give specific guidance as to how ruptured SG is to be isolated. The RNO section for these steps gives alternate means to isolate. Based on MAAP runs, operators have 45 minutes to complete this task.	1.00E-01	1.00E-01

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
MS	MSHFDISOLR	POST	OPERATORS FAIL TO ISOLATE A RUPTURED SG. This event represents operator failure to isolate feedwater flow to, and steam flow from, a ruptured SG during a steam generator tube rupture event. E-0 step 25 has operators verify that SG U-tubes are intact. If SG primary is not intact, then operators are directed to go to procedure E-3. E-3, steps 3, 4 and 5, and Attachment RUPTURED SG, give specific guidance as to how ruptured SG is to be isolated. Based on MAAP runs, operators have 45 minutes to complete this task.	1.00E-01	7.24E-03
MS	MSHFDMSIVX	POST	OPERATORS FAIL TO MANUALLY CLOSE MSIVS GIVEN THAT THEY FAIL TO CLOSE FOLLOWING A STEAM LINE BREAK. This event represents the failure of the operators to close the MSIV on the faulted SG. Procedure E-2, step 1, instructs the operators to check that the MSIV on the faulted SG is closed. If it is not closed, they are directed to manually close the MSIV. This event is only applicable if it is an instrumentation failure (i.e. MSIV must remain capable of closing from the control room). Timing is assumed to be a few minutes (1-2).	1.00E-01	1.00E-01
Top Logic	RCHFD00MRI	POST	OPERATORS FAIL TO MANUALLY INSERT RODS - ATWS EVENT. This event represents the failure of the operators to manually insert the control rods given that they have failed to insert due to non-mechanical failures (i.e. failure of the trip signal but the rods are still capable of being inserted). The value is based on WCAP-11993, page B-7.	1.00E-02	1.00E-02
Top Logic	RCHFD00RCP	POST	OPERATORS FAIL TO TRIP RCPs AFTER LOSS OF SUPPORT SYSTEMS. This event represents failure of the operators to trip the RCPs after cooling is lost to the RCP seals. Operators have 2 minutes to trip the RCPs prior to seal failure. Operators are directed by procedure E-0, step 19 verify CCW flow to the RCP thermal barriers. If CCW flow is lost, E-0, step 19 directs the operators to stop the affected RCPs.	1.00E-01	1.61E-02
Top Logic	RCHFD01BAF	POST	OPERATORS FAIL TO IMPLEMENT BLEED AND FEED. This event represents failure of the operators to recognize or initiate bleed and feed of the RCS for decay heat removal. Bleed and Feed must be initiated within 45 minutes per Section 4.2.2.4. Operators are directed by failure to achieve adequate AFW flow (≥ 200gpm) and SG low levels, or CSFST (F-0.3) Heat Sink Red Path to procedure FR-H.1. FR-H.1, step 14 provides guidance to the operators in performing bleed and feed of the RCS. Different values are provided for multiple human events in same cutset and for SI versus non-SI events.	1.00E-01	5.3E-2, SI,1 4.07E-1,SI,+ 2.9E-2, noSI 6.2E-2,noSI
Top Logic	RCHFDCD0SS	POST	OPERATORS FAIL TO COOLDOWN TO RHR AFTER SI FAILS - LOCAs. This event represents failure of the operators to take actions to rapidly cooldown the RCS to RHR conditions in the event that core cooling is inadequate following a small break LOCA. This must be initiated within 45 minutes per Section 4.2.2.3.3. In this scenario, SI flow fails or is inadequate to provide core cooling such that CSFST (F-0.2) Core Cooling Path is Red. Operators are then directed to FR-C.1 to cool down the RCS to RHR conditions using the ARVs.	1.00E-01	3.7E-02

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
Top Logic	RCHFDCDDPR	POST	OPERATORS FAIL TO COOLDOWN AND DEPRESSURIZE RCS PRIOR TO SG OVERFILL. This event represents failure of the operators to take actions to cooldown and depressurize the RCS and then terminate SI following a SGTR. Using the ARVs and PORVs, operators are instructed to perform these activities by E-3, steps 14 and 22. The accident analysis assumes that the ARVs will be opened within 20 minutes of isolating the ruptured S/G (or 30 minutes total) with the PORVs opened 2 minutes later and SI terminated thereafter (see Section 4.2.2.3.3). MAAP runs suggest that opening the ARV could be delayed 45 to 60 minutes.	1.00E-01	9.6E-03
Top Logic	RCHFDCDOVR	POST	OPERATORS FAIL TO COOLDOWN TO RHR CONDITIONS AFTER SG OVERFILL OCCURS. This event represents failure of the operators to cooldown to RHR conditions in the event that a ruptured SG is overfilled. The danger of overfilling the SG is lifting an ARV or S/G safety valve due to solid water conditions thereby having a primary leak outside of containment. Overfilling could be caused by failure to equalize pressure between the primary and secondary, or failure to properly isolate feedwater to the ruptured SG. Operators would have the following cues indicating the need to cooldown to RHR conditions. SG levels rapidly increasing or out of sight high, pressurizer level decreasing.	1.00E-01	3.07E-02
Top Logic	RCHFDCDTR2	POST	OPERATOR FAILS TO COOLDOWN TO RHR AFTER SI FAILS DURING SGTR. This event represents failure of the operators to take actions to rapidly cooldown the RCS to RHR conditions in the event that SI fails following a SGTR. This must be initiated within 45 minutes per Section 3.2.2.3.3. In this scenario, SI flow fails or is inadequate to provide core cooling such that CSFST (F-0.2) Core Cooling Path is Red. Operators are then directed to FR-C.1 to cool down the RCS to RHR conditions using the ARVs.	1.00E-01	3.07E-02
Top Logic	RCHFDCOOLD	POST	OPERATORS FAIL TO COOLDOWN TO RHR AFTER ARV STICKS OPEN. This event represents failure of the operators to cooldown to RHR conditions in the event that the ARV sticks open preventing the capability to terminate the SGTR break flow. In this scenario, the ARV fails such that an overcooling event occurs requiring entry into RHR conditions. Operators are directed by procedure ECA-3.1 to perform the depressurization. This is assumed to be initiated within 45 minutes per Section 4.2.2.3.3.	1.00E-01	7.2E-02
PPC	RCHFDHEATR	POST	OPERATORS FAIL TO LOAD PRESSURIZER HEATERS FOLLOWING A LOOP OR SI SIGNAL. This event represents operator failure to re-energize pressurizer heaters following a loss of offsite power or a safety injection signal. Failing to re-energize heaters could result in a loss of primary plant pressure control and subcooling margin necessary for natural circulation. For LOOP events, either procedure ES-0, step 7.e, or ECA-0.1, step 20, instructs operators to reset the heaters. For SI events, after the SI is terminated, operators are directed by ES-1.1, step 3 to reset the heaters. Required within 6 hours per Section 4.2.2.2.2.	1.00E-01	3.1E-04

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event**	*Screening Value*	*Final Value*
Top Logic	RCHFDPLOCA	POST	OPERATORS FAIL TO CLOSE PORV BLOCK VALVE (515/516) TO TERMINATE LOCA. This event represents operator failure to close the PORV block valves assuming a PORV lifts and cannot be closed. Procedural guidance is given by E-0, step 22 and E-1 step 5. The operators are directed to manually close the open PORV. If this fails they are directed to manually close its associated block valve. Operators have approximately 3 minutes to perform this action before a small break LOCA results. (Note - this was done in 3 minutes following 1982 SGTR)	1.00E-01	1.00E-01
Top Logic	RCHFDRHRSB	POST	OPERATORS FAIL TO RAPIDLY DEPRESSURIZE TO RHR (OR USE AFW LONG-TERM). This event represents the failure of operators to depressurize the primary system down to RHR conditions or continue to use AFW following restoration of power after an SBO event.	1.00E-01	5.00E-03
Top Logic	RCHFDSCRAM	POST	OPERATORS FAIL TO TRIP ROD DRIVE MG SETS DURING ATWS. This event represents operator failure to trip the reactor by deenergizing the rod drive motor generator sets during an ATWS event. Deenergizing the motor generator sets would cause the control rod assemblies to drop, shutting down the reactor. Once an ATWS event is identified by the operators, procedure FR-S.1 is used. FR-S.1, step 5 directs that an auxiliary operator be dispatched to trip the rod drive motor generator sets. Failure probability based on WCAP-11993, page B-7.	1.00E-02	1.00E-02
RHR	RRHFDSEALX	POST	OPERATORS FAIL TO SHUT DOWN AN RHR PUMP GIVEN THAT THE PUMP SEAL HAS FAILED. This event represents the failure of the operators to shut down a running RHR pump, given that its seal has failed. Failure to shut down the pump would eventually flood the RHR pit, failing both pumps. Annunciators L-9 (Aux Bldg Sump Hi Level) and L-10 (Aux Bldg Sump Pump Auto Start), would give operators indications of pump seal failure. Alarm response procedures AR-L-9 and AR-L-10 direct operators to check for leakage in the RHR pit upon a high level alarm or repeated sump pump starts. Worst case scenario of no sump pump operation would require operators to shut down the running pump within 2 hours (UFSAR Section 5.4.5.3.5).	1.00E-01	1.00E-01
RHR	RRHFDRECRC	POST	OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION. This event represents operator failure to shift the RHR system to the recirculation mode prior to the RWST level dropping below 15%, including necessary manipulations within RHR, CCW, and SW systems. Decision point to transfer to recirculation is found in E-1, step 21, and is based on the level in the RWST reaching 28%. E-1 step 21 directs that the shift to recirculation be made per ES-1.3, steps 1-8. Table F-1 provides timing information where RHR is shutoff at 28% RWST level. Since the time available is different for each of the LOCA initiators, different values are used. Note that steps 9-12 of procedure ES-1.3 are included in event SRHFDRECRC and are not considered here.	1.00E-01	1.3E-02 (L) 5.3E-03 (M) 1.2E-03 (S) 1.2E-03 (SS)

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
RHR	RRHFDSUCTN	POST	OPERATORS FAIL TO MANUALLY OPEN RHR SUCTION VALVES. This event represents the failure of operators to manually open the RHR suction valves from the RCS loop "A" hot leg for long-term recirculation in the event that they are prevented from opening automatically due to a failure of instrumentation.. Since these valves are inside containment, operators would have to potentially jumper the control circuit at the MCB and open the valves.	1.00E-01	1.00E-01
RHR	RRHFDTHROT	POST	OPERATORS FAIL TO THROTTLE RHR FLOW WHEN REQUIRED. This basic event represents operator failure to manually throttle RHR flow during recirculation. Manual positioning of valves 715 and/or 717 to throttle RHR pump flow to less than 1500 gpm per pump would be required if AOVs 624 and/or 625 fail to throttle flow, and only one sump B RHR suction valve is open. Consequences of failing to limit flow through each RHR pump to less than 1500 gpm with one suction valve open would be pump failure due to loss of pump net positive suction head (NPSH). Prior to initiating recirculation flow, procedure ES-1.3, step 5 directs the operators to check each RHR pump flow less than 1500 gpm. If flow is not less than 1500 gpm, operators are directed to dispatch an AO to manually throttle 715 and 717. Operators must complete these action prior to going into recirculation.	1.00E-01	1.00E-01
SI	SIHFDSTRTP	POST	OPERATORS FAIL TO START AN SI OR RHR PUMP IF START SIGNAL FAILS. This event represents the failure of the operators to start an SI pump or RHR pump, given that the pump has not received a start signal due to a failure of relays in the ESFAS circuitry. Procedure E-0, step 5 instructs the operators to verify that all SI pumps, and both RHR pumps are running. If not, they are instructed to manually start the pumps.	1.00E-01	1.00E-01
SI	SRHFDRECRC	POST	OPERATORS FAIL TO ALIGN AND INITIATE HIGH HEAD RECIRCULATION. This event represents operator failure to identify, align and initiate high head recirculation using the SI pumps. Specifically failure to complete steps 9 through 12 of ES-1.3. Event assumes that operators have successfully aligned the RHR system for sump recirculation (see event RRHFDRECRC). Timing information is provided in Table F-2.	1.00E-01	1.30E-03
SW	SWHFDSTART	POST	OPERATORS FAIL TO START A SERVICE WATER PUMP. This event represents the failure of the operators to start a service water pump if two pumps are not running. This event is used for cases where pumps have tripped due to undervoltage on the bus and have not received a start signal either due to failure of the signal or because they are not aligned in standby. Procedure E-0, step 1 (SI conditions), and procedure ES-0.1, step 5 (no SI conditions), direct operators to verify that two service water pumps are running. If not they are instructed to start the pumps. Event includes hardware faults	1.00E-01	5.00E-03
Top Logic	TLHFDPN110	Post	OPERATOR FAILS TO RECOVER ISLOCA THROUGH PENETRATION 110. See Section 8.2.4.	2.07E-01	2.07E-01
Top Logic	TLHFDPN140	Post	OPERATOR FAILS TO RECOVER ISLOCA THROUGH PENETRATION 111. See Section 8.2.4.	1.88E-01	1.88E-01

TABLE F-4
Human Reliability Events - Post Initiator

System	*Event Name*	*Pre or Post Init*	*Description Of Event*	*Screening Value*	*Final Value*
Top Logic	TLHFDPN140	Post	OPERATOR FAILS TO RECOVER ISLOCA THROUGH PENETRATION 140. See Section 8.2.4.	1.90E-01	1.90E-01

F.1 References:

1. TENERA, *RG&E Ginna Nuclear Power Plant Detailed Human Error Probability Calculation*, January 1997.