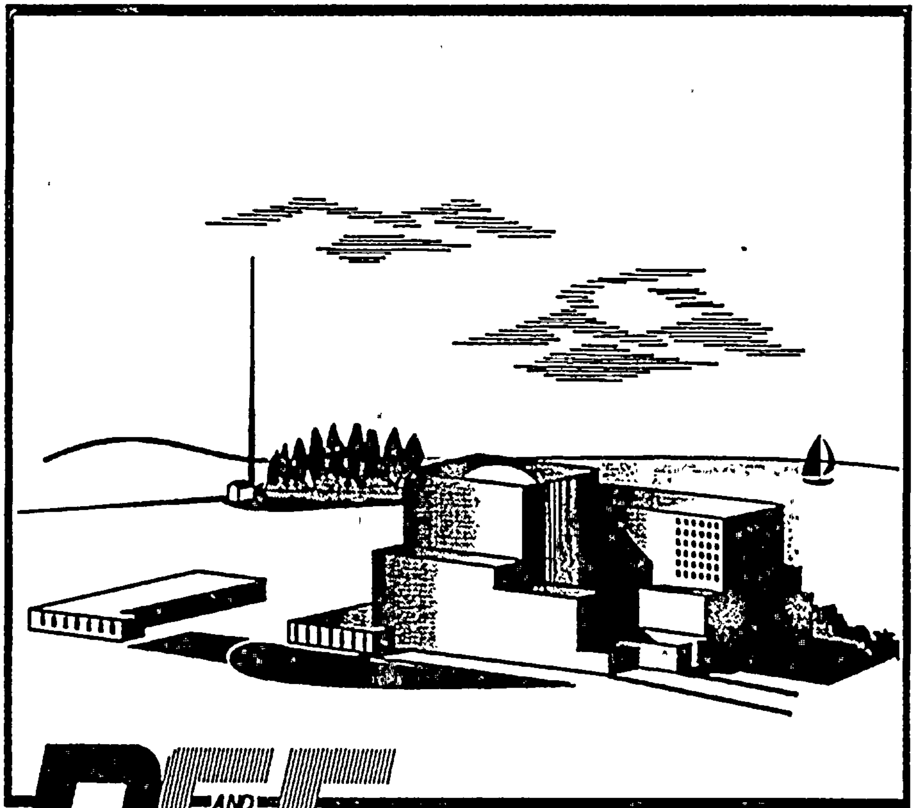

Rochester Gas and Electric Corporation

R. E. Ginna Probabilistic Risk Assessment Project

Report to the United States Nuclear Regulatory Commission in response to Generic Letter 88-20

February 28, 1994

Volume 1 of 2

R. E. Ginna Probabilistic Risk Assessment Project
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1.0 Executive Summary

1.1 Background and Objectives

The R. E. Ginna Probabilistic Risk Assessment (PRA) Project conducted a full scope Level 1 and Level 2 PRA of initiating events and internal plant flooding events for Rochester Gas and Electric Corporation's (RG&E's) R. E. Ginna Nuclear Power Plant.

In January of 1989, anticipating the release of USNRC's Generic Letter 88-20, RG&E began assembling an internal team to conduct a PRA for Ginna. This core team eventually included new hires with extensive previous utility PRA experience. Many other experienced RG&E personnel were also temporarily assigned to assist the core team as required. In the end, RG&E personnel contributed over 20,000 hours to this project; this represents over one-half of the total hours spent completing the project.

In 1990, RG&E contracted with Science Applications International Corporation's (SAIC) Clearwater, Florida office to provide Level 1 / Level 2 PRA consulting services, and with EBASCO Services (through SAIC as a subcontractor) to perform a containment structural analysis. RG&E brought in Gabor, Kenton and Associates in 1993 to provide additional Level 2 consulting services.

RG&E's objectives for the R. E. Ginna PRA Project were twofold: 1) To provide technical response to USNRC Generic Letter 88-20 consistent with RG&E's voluntary commitments; and, 2) Provide a firm foundation for future use of PRA methods and models in the operation of Ginna. To that end, RG&E management decided to conduct a full scope Level 1 / Level 2 PRA. Further, it was decided that all work on the project would be conducted to quality assurance standards consistent with 10 CFR 50 Appendix B.

In the past, PRAs have established rigid "cutoff" dates at the beginning of their projects; that is, a "snapshot" of the plant as of the established cutoff date would be modeled. No plant modifications subsequent to the cutoff date would be included in the final PRA models. Changes in PRA technology (most notably, the introduction of personal computer based solution software that allows rapid and inexpensive requantification cycles) allowed RG&E to be flexible with the concept of a model cutoff date, except for the collection and analysis of plant specific data. Therefore, the PRA model described in this report represents the actual configuration of the Ginna plant as of preparations for the 1994 annual refueling outage with a very few minor exceptions.

1.2 Plant Familiarization

Ginna is RG&E's only nuclear generating unit. RG&E announced plans to build a nuclear power plant on the south shore of Lake Ontario about 16 miles northeast of Rochester, New York in August of 1965. Actual construction began June 29, 1966, and initial criticality was achieved on October 4, 1969. Commercial operation was declared on June 1, 1970. Initial licensed output was 1300 MWt and 420 MW net electrical power. On March 1, 1972, licensed output was increased to 1520 MWt and 490 MW net electrical power. RG&E is currently licensed by the United States Nuclear Regulatory Commission to operate Ginna through September 18, 2009.

Ginna features a two-loop Westinghouse pressurized water reactor nuclear steam supply system consisting of two hot legs, two U-tube steam generators, a pressurizer, and two cold legs with a reactor coolant pump in each cold leg. The secondary system consists of a turbine generator, a condenser, and a feedwater and condensate system. Auxiliary equipment includes a radioactive waste disposal system, fuel handling systems, a main transformer, a circulating water system drawing water from Lake Ontario, and engineered safety features systems. The turbine generator and condenser systems were also supplied y Westinghouse. Other initial plant structures and the balance of plant and auxiliary systems were designed either by Gilbert Associates, Incorporated or RG&E personnel.

The reactor containment building was designed by Gilbert Associates, Incorporated. It 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 leak-tightness. 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.

1.3 Methodology

There were three distinct technical activities in the overall Ginna PRA: Level 1 analysis for internal initiating events; Level 1 analysis for internal plant flooding; and, Level 2 analysis.

1.3.1 Level 1 Analysis for Internal Initiating Events

The R. E. Ginna PRA Project utilized standard small event tree / large linked fault tree Level 1 methodology. Functional 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.

Fault trees were developed for each of the systems identified in the top logic with the exception of the Main Feedwater System and the Reactor Protection System; 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. A total of 14 separate, quality assurance-controlled System Work Packages were developed during the course of this project.

Fault tree basic events were quantified with a mixture of generic data from throughout the nuclear industry and Ginna specific data. Plant specific data analysis included initiating event frequencies and equipment for which plant specific data was requested in Generic Letter 88-20. An eight-year (January 1, 1980 through December 31, 1988) data window was established for quantifying failure rates and maintenance unavailabilities. Licensee Event Reports and Ginna Station Event Reports were also reviewed for this period.

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 results. These refined values were calculated using the Technique for Human Error Rate Prediction (THERP) for time-independent human failure events and the SAIC time-reliability correlation (TRC) for time-dependent human failure events.

SAIC's Computer Assisted Fault Tree Analysis (CAFTA) code was used to build, integrate, and solve the fault trees and event trees. Model development, integration and solution was performed on personal microcomputers using either the Intel 80386DX33 or 80486DX33 microprocessor and 16 Mb of random access memory.

1.3.2 Level 1 Analysis for Internal Plant Flooding Initiating Events

The integrated plant model used for the Level 1 internal initiating events analysis was modified for assessing the risk of core damage from internal plant flooding initiating events. All basic events in the model were linked to the equipment identification number (EIN) of an appropriate piece of equipment in the plant. Components not directly modeled in the internal initiating events fault trees were also accounted for at this stage.

A complex relational database was developed for the EINs in the model that included detailed location information. A set of flood areas / flood zones were developed from studying plant layout drawings and from an extensive series of walkdowns. Potential flood initiators were cataloged for each of the flood areas / flood zones.

The CAFTA code was used to develop and quantify over 1,200 top events through a series of screening analyses. In the final analysis, remaining sequences were evaluated for true vulnerabilities, and frequencies were refined.

1.3.3 Level 2 Analyses

Preliminary steps to the Level 2 Analysis task included compilation of a Ginna-specific model for the Modular Accident Analysis Program (MAAP), and a containment ultimate failure pressure structural analysis. The first step of the Level 2 Analysis task proper is to use minimal cut sets from the Recovery Analysis task as inputs to determine the status of systems identified in the Containment Systems Event Tree (CSET). Once the CSET is solved, the end state frequencies are binned into Plant Damage States (PDSs). The results of the PDS grouping are then input into the Containment Event Tree (CET) to calculate containment failure frequencies.. The Modular Accident Analysis Program (MAAP) was used to determine source terms.

1.4 Summary of Major Findings

The total calculated core damage frequency from internal initiating events was 8.23E-05 / year. The dominant contributors to this frequency were loss of instrument air at about 27% of the total core damage frequency; a tube rupture in steam generator B (EMS01B) at about 23.5% of the total core damage frequency; small-small break LOCAs at about 12.1% of the total core damage frequency; and, a tube rupture in steam generator A (EMS01A) at about 10.4% of the total core damage frequency. Other initiating events contributing to the total calculated core damage frequency were interfacing systems LOCAs (9.6%); medium break LOCAs (7.2%); small break LOCAs (6.2%); and, large break LOCAs (3.9%).

Figure 1-1 shows a breakdown of calculated core damage frequency by sequence; Figure 1-2 shows a breakdown of calculated core damage frequency by initiating event.

Dominant contributors to risk include:

- Operator response to steam generator tube ruptures;
- PORV and / or safety valve LOCAs;
- Failures of the recirculation function;
- Isolation of the ruptured steam generator during a SGTR event;
- Failures of safety (high pressure) injection; and,
- Restoration of off-site power.

Several notable inter-system dependencies were discovered during the course of the Ginna PRA project. While these dependencies are not dominant contributors to calculated risk, they are discussed as follows:

- Reliance of major safety functions on the B Station Battery (BTRYB) -- Several important safety functions require 125 VDC power from the B Station Battery. These functions include automatic opening of Reactor Coolant System (RCS) PORVs 430 and 431C, and operation of Turbine Driven AFW Pump DC Lube Oil Pump PLO11. Because of these dependencies, loss of BTRYB is more risk significant than loss of BTRYA.

- Single-point failure of switch to off-site power -- Normally, power generated on-site is used for loads such as Reactor Coolant Pumps PRC01A and PRC01B; Main Feedwater Pumps PFW01A and PFW01B; Circulating Water Pumps PCW01A and PCW01B; Instrument Air Compressors CIA02A, CIA02B and CIA02C and Service Air Compressor CSA02; and other large, 4160 VAC loads and 480 VAC non-vital loads. Following a turbine trip, Turbine Lube Oil Pressure Switches 63-3/AST, 63-4/AST and 63-5/AST energize Turbine Trip Auxiliary Relays 63/X3, 63/X4 and 63/X5 (powered from Main Control Board 125 VDC Distribution Panel A [DCPDPCB04A]). These relays, in conjunction with Station 13A 115 kVAC Circuit Breakers Auxiliary Relay 52Z, energize Turbine Auto Stop Timer Relay 62AST, which will energize Generator Primary Lockout Relay 86P/1G. Either 86P/1G or Generator Backup Lockout Relay 86BU/1G (powered from Main Control Board 125 VDC Distribution Panel A [DCPDPCB04A]) must energize and signal Generator Auxiliary Lockout Relay 86X/1G (powered from Main Control Board 125 VDC Distribution Panel B [DCPDPCB04B]) to energize in order for the circuit breakers feeding 4160 VAC buses 11A and 11B to automatically switch over to being fed from Auxiliary Transformers 12A (PXYD012A) and 12B (PXYD012B), respectively. Thus, failure of 125 VDC from either DCPDPCB04A or DCPDPCB04B following a turbine trip would result in failure to automatically switch to the off-site sources.

The total calculated core damage frequency for internal plant flooding sequences is 5.05E-06 per year of operation. This conservative estimate is dominated by feedwater line break initiating events on the turbine building mezzanine level (4.01E-06 / year, about 79% of the total). In these sequences, the bulk of the serious damage comes from the high energy line break's initial destructive force; the effects of high energy line breaks (destruction of block walls between the Turbine Building and the Intermediate Building, etc.) are conservatively included in the internal initiating events models. Additional failures assumed to be caused from the flooding nature of these sequences include a loss of the 4160 VAC / 480 VAC electrical buses that are located at the east end of the floor. In reality, loss of this equipment during a feedwater line break would not be a certainty; the buses and the main feedwater lines are located at opposite ends of the building, with the main condenser and much other heavy equipment located in between.

The Level 2 analysis clearly shows that the dominant contributors to the calculated release frequency are the containment bypass sequences. Steam generator tube ruptures and interfacing systems LOCAs (ISLOCAs) account for approximately 42% of the total core damage frequency.

The second most important set of core damage sequences impacting the Level 2 results are loss of containment isolation sequences. These sequences would result in early radionuclide releases. This class of sequences represents about 3% of the total core damage frequency.

The Level 2 analysis indicates that the structural integrity of the Ginna containment is very unlikely to be significantly challenged by the physical processes and loading mechanisms that occur at or before containment failure. The conditional probability of early containment failure due to in-vessel steam explosions, direct containment heating, hydrogen combustion and related phenomena is calculated to be approximately 0.05%

As a result of the high reliability of containment heat removal systems (principally the containment recirculating fan coolers) the threat of long-term containment overpressure failure is negligible. The Ginna systems analysis for core damage and containment systems indicates that, for all significant core damage sequences with AC power available or recovered, containment heat removal would also be available. Hence, long-term overpressurization of containment resulting from steam production is negligible.

Figure 1-1
Total Calculated Core Damage Frequency for Internal Initiating Events by Sequence

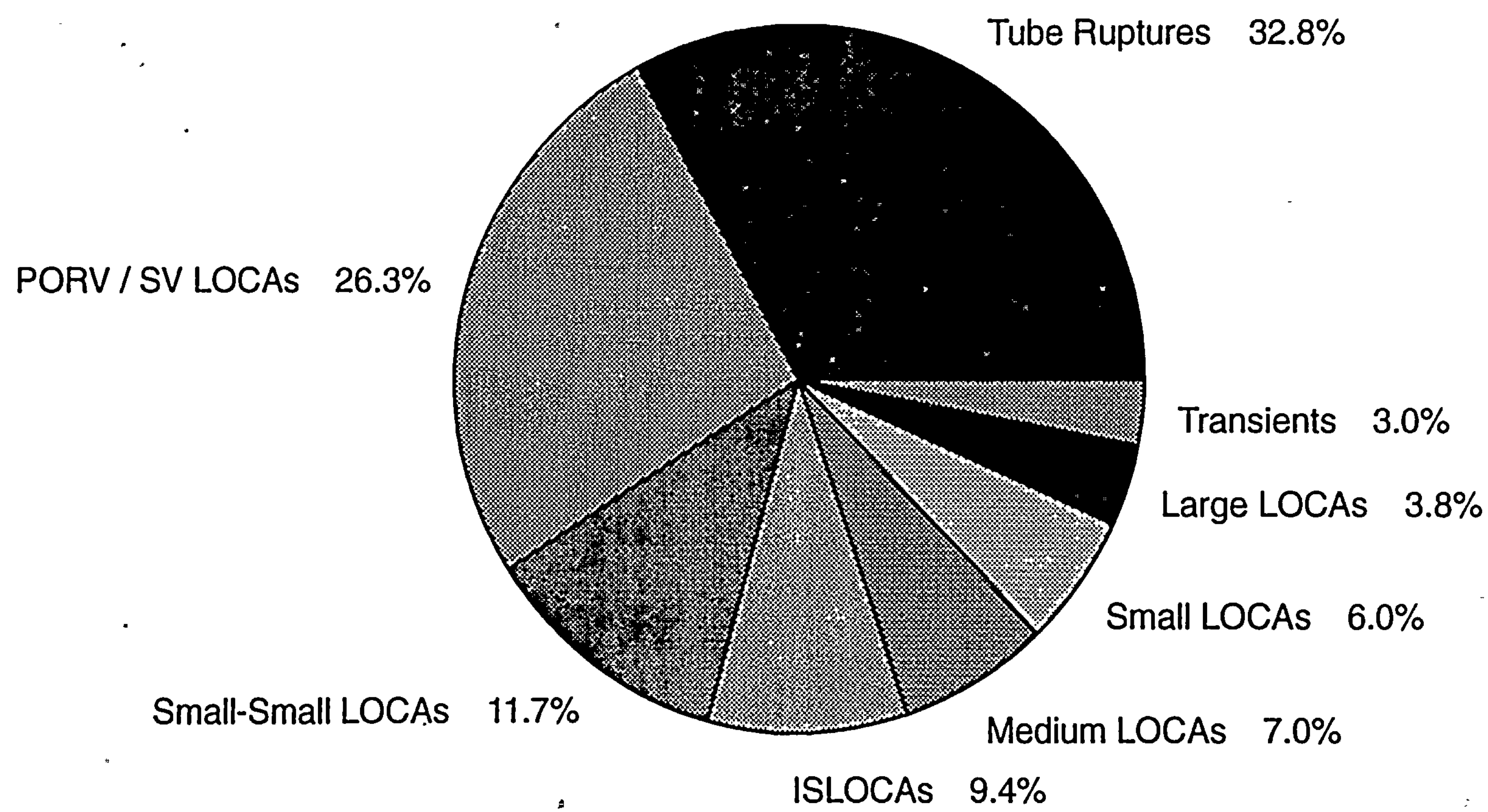
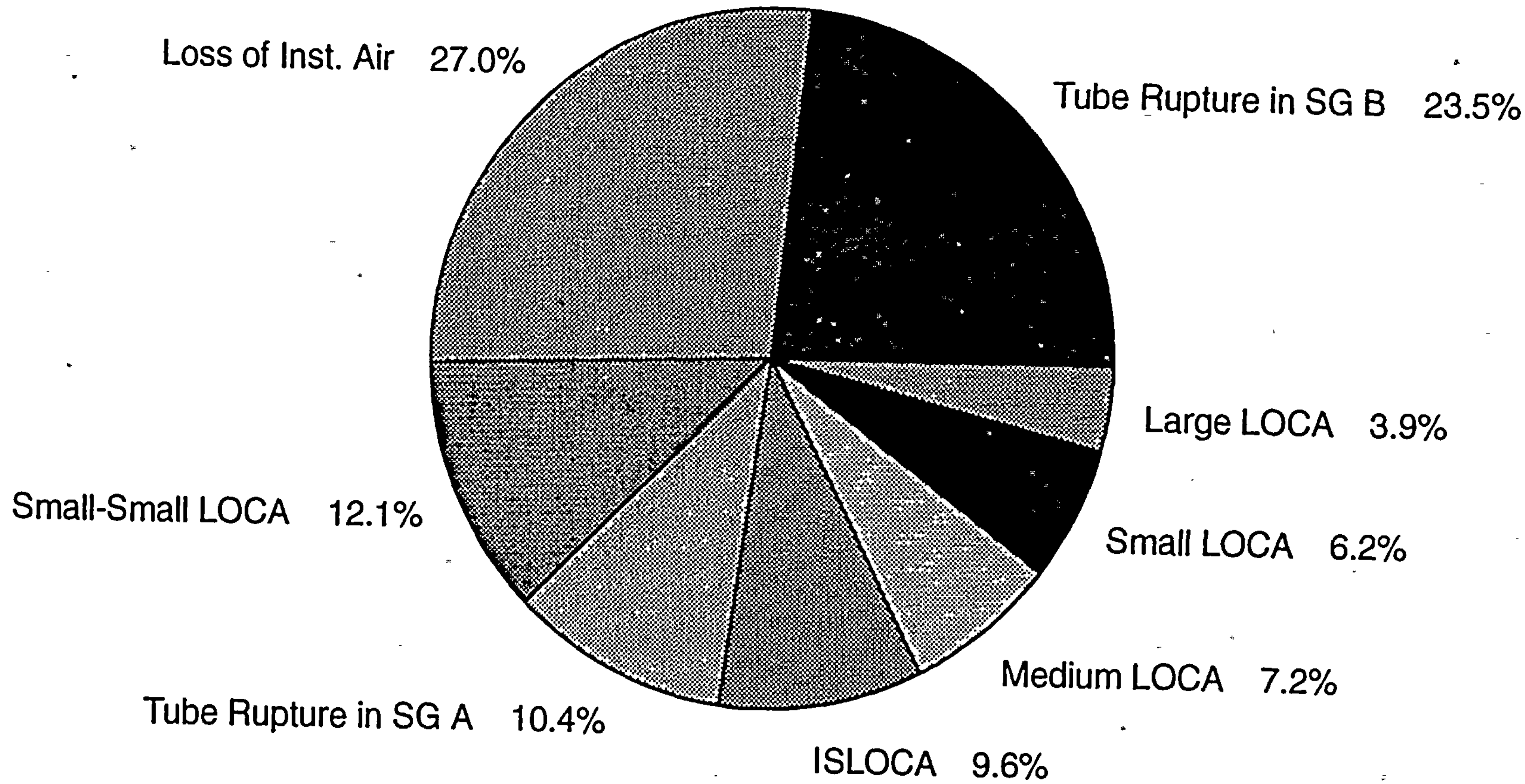


Figure 1-2
Total Calculated Core Damage Frequency for Internal Initiating Events by Initiating Event



2.0 Examination Description

2.1 Introduction

This document is being submitted to the United States Nuclear Regulatory Commission (USNRC) to meet Rochester Gas and Electric (RG&E) Corporation's commitments made in response to Generic Letter 88-20. Specifically, this document reports the results (and the methodology used to generate the results) of the R. E. Ginna Probabilistic Risk Assessment project, a full Level 1 and Level 2 probabilistic risk assessment (PRA) for internal initiating events and internal plant flooding , conducted on the R. E. Ginna Nuclear Power Plant in Ontario, New York.

2.2 Conformance with Suggested Methodologies in Generic Letter 88-20 and NUREG-1335

USNRC Generic Letter 88-20, issued November 23, 1988, asked all licensees to perform an individual plant examination for severe accident vulnerabilities. Supplement 1 to Generic Letter 88-20 initiated this examination period and provided submittal guidance in the form of NUREG-1335, *Individual Plant Examination Submittal Guidance.*

After considering the requests contained in Generic Letter 88-20, RG&E voluntarily initiated a full Level 1 and Level 2 PRA program for Ginna. When weighing the options presented in the generic letter, it was felt that the insights gained from a PRA program would be beneficial to the safe and efficient operation of Ginna.

Additional guidelines and objectives in Generic Letter 88-20 include:

> *The licensee staff should be used to the maximum extent possible in the performance of the IPE.* As discussed in Section 5, RG&E personnel contributed over 20,000 hours to this project, filling many key roles.
>
> *Unresolved Safety Issue (USI) A-46 should be resolved as part of the IPE.* Consideration of decay heat removal is basic to the performance of a PRA. As can be seen from the discussion in Section 3.4.6, results of this PRA have resolved this issue for Ginna.
>
> *Vulnerabilities identified during the IPE process should be corrected where appropriate.* Section 3.4.2 and Section 6 discuss the results of the Ginna PRA, and how those results have been addressed.
>
> *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 PRA. See section 4 for details.

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 for minor omissions of sections dealing with support state methodology. The Ginna PRA utilizes the large linked fault tree approach, and not the support state approach; sections on the support state methodology have, therefore, been omitted.

2.3 General Methodology

In the interests of effective project management, the Ginna PRA was organized into thirteen major tasks. These tasks are discussed in Sections 2.3.1 through 2.3.13.

2.3.1 Accident Sequence Analysis

This task began by identifying the initial list of internal initiating events (see Section 3.1.1); additional initiating events were later added as a result of insights from the Systems Analysis task. Functional event sequence diagrams (FESDs) were then constructed to provide analysts with insights into potential accident sequences. Event trees were constructed (see Section 3.1.2) for each of the unique accident sequence groups.

2.3.2 Systems Analysis

The Systems Analysis task is traditionally the major focus of the Level 1 portion of the PRA. Using the success criteria established in the Accident Sequence Analysis task, analysts prepared work packages containing detailed logic models for 14 groups of systems (see Section 3.2.1).

2.3.3 Data Analysis

The initial stage of the Data Analysis task involved reviewing Ginna plant records for a period from January 1980 through December 1988. Using the data collected from these reviews and a collection of generic failure data from throughout the industry (see Section 3.3.1), analysts compiled a set of Ginna-specific failure data (see Section 3.3.2) needed to quantify the logic models constructed in the Accident Sequence Analysis and Systems Analysis tasks. Also included in this analysis was consideration of plant-specific common cause data (Section 3.3.4), test and maintenance unavailability data (Section 3.3:5), and initiating event frequency data (Section 3.3.6).

2.3.4 Human Reliability Analysis

Human failure events of two types are defined in the logic models constructed in the Systems Analysis Task: Latent human errors that took place prior to the transient being analyzed; and, errors committed after the start of the transient being analyzed. These events were then given conservative screening values prior to the quantification of the logic models. Following the initial quantification, dominant human failure events were put through a more detailed analysis (see Section 3.3.3). This analysis also quantified identified nonrecovery events from the initial quantification. The detailed quantification process included analysis of the accident sequences, analysis of the appropriate Ginna procedures, interviews with Ginna licensed operators and observation of selected transients in the Ginna control room simulator.

2.3.5 Quantification

With the advent of PRA quantification software based on personal computer technology, quantification has become a very iterative process. The logic models developed in the Accident Sequence Analysis and the Systems Analysis tasks and the plant specific data developed in the Data Analysis task are integrated into many accident sequence logic models and solved in this task.

2.3.6 Recovery Analysis

The Recovery Analysis task uses the minimal cut sets from the Quantification task as its input. This task is used to examine these preliminary results in detail. Sometimes, errors are discovered in logic and / or data. These errors are corrected and fed back to the Quantification task for requantification; hence, the iterative nature of the analysis. Nonrecovery events are assigned as appropriate; conservative screening values are usually assigned first. If the sequence in question still remains above the cutoff standard, these nonrecovery events are quantified in detail by the Human Reliability Analysis task. The output of the Recovery task is a completed list of quantified minimal cut sets for each of the sequences defined in the Accident Sequence Analysis task.

2.3.7 Level 2 Analysis

Preliminary steps to the Level 2 Analysis task included compilation of a Ginna-specific model for the Modular Accident Analysis Program (MAAP), and a containment ultimate failure pressure structural analysis. The first step of the Level 2 Analysis task proper is to use minimal cut sets from the Recovery Analysis task as inputs to determine the status of systems identified in the Containment Systems Event Tree (CSET) (see Section 4.3.1). Once the CSET is solved, the end state frequencies are binned into Plant Damage States (PDSs) as described in Section 4.3. The results of the PDS grouping are then input into the Containment Event Tree (CET) to calculate containment failure frequencies as shown in Section 4.5. The Modular Accident Analysis Program (MAAP) was used to determine source terms (see Section 4.7).

2.3.8 Internal Flooding Analysis

Although internal flooding is classified as an external initiating event, Generic Letter 88-20 specifically asked that it be included in the IPE process. Taking the completed, integrated plant logic model developed in the Quantification task, this task assigned an appropriate Ginna Equipment Identification Number (EIN) to each of the basic events. Thus, a complete list of modeled plant equipment was developed. From this list, a second list of equipment requiring either AC power or DC power (or both) was developed. A database was constructed using this second list that included detailed information on the location of each of these pieces of powered equipment. In addition, support equipment not included in the PRA logic model was added to the database for each of the pieces of modeled equipment. An analysis was conducted to break the plant into appropriate flood areas and zones, and to determine potential flood initiators in each of those areas / zones.

The main flood analysis was completed in several phases. In the first screening analysis, a list of failed basic events and flood initiating events was generated for each flood area / zone. If there were no failed basic events in a zone, those zones were dropped from further consideration. The zones remaining after this phase were then examined to determine if, for example, water could pool on the floor, or if a broken line or tank could potentially spray sensitive equipment in the logic model..

For any remaining areas / zones, a detailed analysis was conducted. This detailed analysis included measuring the height of each piece of modeled equipment in the zone; evaluating potential flood-induced failure modes of each piece of modeled equipment; and, quantifying potential flood initiating events.

2.3.9 Sensitivity, Uncertainty and Modifications Evaluation

The sensitivity of the calculated core damage frequency to changes in data and modeling assumptions was evaluated in this task. Importance measures were calculated, and potential risk-reducing improvements were identified and evaluated.

2.3.10 Technology Transfer and Documentation

Contractor personnel from Science Applications International Corporation (SAIC) and Gabor, Kenton and Associates (GKA) conducted training for RG&E employees with no prior PRA experience prior to the start of the applicable tasks. A majority of the technology transfer occurred through on the job training in each of the tasks.

Quality of documentation was stressed throughout the Ginna PRA project. A minimum of one work package was published under the project quality assurance program for each of the technical tasks.

2.3.11 Project Management

In addition to overseeing the various contracts, this task was responsible for serving as the integrating function for all of the project's technical tasks. Adherence to quality assurance procedures and quality of documentation were stressed throughout the project.

2.3.12 Quality Assurance

The Ginna PRA project was conducted entirely under a quality assurance program designed to meet the requirements of 10 CFR 50 Appendix B. This program, administered under the Science Applications International Corporation (SAIC) quality assurance structure, included two sets of project-specific procedures:

> *Project Quality Assurance Procedures* (PQAPs) were written to relate the needs of the Ginna PRA project directly back to the criteria of 10 CFR 50 Appendix B, 10 CFR 50 Part 21 and the SAIC corporate quality assurance program. PQAPs included Organization; Stop Work Orders; Handling of Safety Concerns (10 CFR 50 21 Notifications); Quality Assurance Program; Indoctrination and Training; Certification of Audit Personnel; Review of Work Packages and Technical Reports; Control of RG&E Supplied Documents; Preparation of Project Quality Assurance Procedures (PQAPs); Preparation of Task Quality Assurance Procedures (TQAPs); Document Control; Temporary Changes to Work Packages; Corrective Action; Quality Assurance Records; Audit Planning; Conduct and Records; and, Software Control.

Task Quality Assurance Procedures (TQAPs) were written for each of the technical tasks. A TQAP explicitly describes how work is to be done on each task, what inputs the task is to use, how the task is to be documented, and what outputs the task is expected to generate for each of the other tasks.

All work packages were reviewed extensively by both SAIC and RG&E personnel under the project quality assurance program. In addition, periodic quality assurance audits were conducted by RG&E and SAIC auditors.

2.3.13 Software

In addition to commercially available personal computer software such as *WordPerfect*, *Microsoft Access* and *Lotus 1-2-3*, the Ginna PRA project used the CAFTA+ suite of PRA software and the Risk Management Query System (RMQS) package from Science Applications International Corporation and the Modular Accident Analysis Program (MAAP) 3.0B Version 19 from the Electric Power Research Institute. All non-commercially available packages were treated under a project-specific software quality control program.

2.4 Requested Information

2.4.1 Containment Building Information

Most of the plant layout and containment building information used in the Ginna PRA project may be found in the Ginna Updated Safety Analysis Report (UFSAR). Additional information on the Ginna containment may be found in Section 4.

2.4.2 Other PRAs Reviewed

The Ginna PRA staff reviewed many of the PRAs available in the literature (WASH-1400, NUREG-1150, NSAC/60, etc.) during this project. Due to the considerable prior experience of the Ginna PRA staff, the project's collective memory included knowledge of these studies and many other plant-specific PRAs.

RG&E personnel on the Ginna PRA staff also kept in close touch with their counterparts who were conducting PRAs for the other Westinghouse two-loop pressurized water reactors at Point Beach, Kewaunee and Prairie Island. In January of 1992, the RG&E project manager and lead data analyst assisted Wisconsin Electric Power Company (WEPCO) in an extensive, week-long review of the Point Beach PRA.

2.4.3 PRA Basis Documentation

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

Ginna Updated Final Safety Analysis Report (UFSAR);

Ginna Technical Specifications;

Ginna plant procedures;

Licensee Event Reports (LERs);

RG&E controlled drawings;

System Training Descriptions;

Information from the former Ginna Master Equipment Database (GMEDB);

Information from the new Configuration Management Information System (CMIS);

Interviews with operators and many other experienced Ginna personnel;

Plant walkdowns; and,

Control room simulator observations.

2.4.4 Plant Walkdowns

Walkdowns were conducted throughout the Ginna PRA project as a primary source of information on plant configuration, operations and maintenance.

Systems walkdowns were conducted when appropriate during the Systems Analysis task by each of the RG&E and contractor 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.

Extensive walkdowns were conducted by RG&E personnel over a 30 month period to facilitate construction of the internal flooding analysis equipment location database and to answer questions raised during other portions of the PRA. The close proximity of Ginna to the RG&E engineering offices (25 miles) meant that the RG&E systems analysts could conduct walkdowns as required. The flood walkdowns were later also used for supplemental information during the Human Reliability Analysis task.

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 Level 1 Analysis

3.1.1 Identification of Initiating Events

3.1.1.1 Introduction

The objective of this task was to define classes of events that formally begin the task of defining potential accident sequences for Ginna. The risk at Ginna was then assessed and quantified by identifying subsequent events that lead to core damage (found in the Level 1 PRA) and / or lead to containment vulnerability (found in the Level 2 PRA). Each "sequence" is really a family of sequences of a functional/systemic type. As such, it must begin with an upset condition within the plant, such as a loss of coolant accident (LOCA), or a shock from outside the plant, such as a flood. This special event is called the initiating event (IE). The Level 1 PRA only dealt with the first type of IE, internal IEs.

In the Level 1 portion of the PRA, the IE may be a component failure or a human action that causes a demand for an automatic or manual reactor trip. With only rare exceptions, such an event will be safely accommodated using safety grade or other plant equipment according to the emergency operating procedures (EOPs) or other procedures. Only on those instances in which multiple systems or components are postulated to fail will there arise the possibility of inadequate core cooling (ICC) so as to challenge the integrity of the core and, even less likely, simultaneously propagate to a challenge to containment integrity.

Adequate core cooling following a trip is a matter of shutting down the reactor, i.e., removing the active heat source, and transferring the residual decay heat from the core through the water media to an ultimate heat sink, such as by steaming to atmosphere outside the containment. Hence the failure to shutdown the reactor when demanded, called ATWS (anticipated transient without scram), and a failure somewhere in the path to the heat sink are the two general potential kinds of core damage opportunities. Further, the intended heat sink path at Ginna, as is typical of a PWR, is a linked set of water systems from the reactor pressure vessel (RPV), through the steam generators (SGs), and finally out the power conversion system (PCS). Breach in the integrity of any heat sink subsystem is a potential kind of core damage opportunity, namely a LOCA, a steam generator tube rupture (SGTR), or one of a variety of PCS failures. Since the only way to damage the core is to disturb this plant heat balance, all core damage sequences must eventually appear functionally like one of these kinds.

Ginna, however, 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 as much as a challenge as the "classical" IEs, such as LOCAs. But because of system interactions, these transients may in fact dominate the risk importance ranking of sequences and must be identified.

3.1.1.2 General Analysis Approach

The principal product of the Initiating Events Analysis is a preliminary list of the most important IE classes for Ginna. Later development in the systems analyses may add to this list those system-induced or other special IEs that for plant-specific reasons are also important or lead to varieties of the classical IEs that need separate modeling. The preliminary list anticipates some of the typically modeled special IEs.

The process of identifying initiating events hence was performed in three basic steps:

1. Development of a preliminary, as–complete–as–possible, list of IEs;

2. Grouping of these according to equivalent plant impact; and,

3. Finalizing the IE list by adding initiators that were identified in systems work.

The preliminary list of IEs was obtained by:

1. The top-down considerations such as outlined in the introduction;

2. Examining Ginna systems and actuations;

3. Examining the Ginna emergency procedures;

4. Examining Ginna LERs;

5. Examining the EPRI list of initiators; and,

6. Reviewing the PRAs of other 2-loop Westinghouse plants.

All initiating events involve loss of primary integrity, i.e., LOCAs of various types, or non-LOCA transients that automatically trip the reactor or induce procedurally directed manual trip. Figure 3.1.1-1 indicates a typical breakdown of internal IEs as usually developed in PRAs. The LOCAs are often partitioned as to whether the radiation or leakage remains contained or not, or equivalently whether the LOCA breaches only the RCS primary boundary or not. Transients involve heat balance problems — overcooling, undercooling, and overpower. A variety of transients are not initially of this type, e.g., loss of station power. Figure 3.1.1-1 indicates prototypical kinds of IEs for each of the six subcategories.

Generic Letter 88-20, NUREG-1335, and NUREG/CR-3485 list several of the standard PRA initiator classes:

1. LOCAs (small-small, small, medium, large);

2. SGTRs;

3. ISLOCAs (interfacing systems LOCAs);

4. Loss of off-site power; and,

5. "Other transients", e.g., turbine trips, loss of main feedwater, etc.

This list is consistent with the core cooling challenges described above and Figure 3.1.1-1 but not in as much detail. The list for Ginna includes and extends these IE classes and is "complete" in this sense. To expand on the other transient category, LERs from 1980 to 1990 and the EPRI work on initiators was reviewed and the preliminary list was completed.

The IEs in the preliminary list were then grouped into larger IE classes. The criterion for grouping together any two initiators was whether they would produce an equivalent impact on the plant. For example, PORV challenging IEs could be grouped together because of their potential for inducing a LOCA. (Notice that this grouping is not done, since one of the major headings on each transient event tree includes the possibility of PORV opening, and the net result is the same.) Table 3.1.1-1 lists the issues that past PRAs address in distinguishing IEs and the manner in which the IE analysis disposed of the issues (again, their acronyms are spelled out in the list of initiators at the end of the section).

Another example: Turbine trips and reactor trips are essentially equivalent when the reactor power is over 50% and may be grouped together (see Figure 3.1.1-2). This "routine" trip category would also include any transient which the operators would need only to use EOP ES-0.1, *Reactor Trip Response* in their response, which includes transients for which there is sufficient availability within the PCS. A loss of support system or subsystem can be included in this category were the lost support not to contribute immediately to the failure of a safety system. However, the support system IEs have been a major focus of recent PRAs and this tactic is not usually pursued.

The result of these two steps is an initial list of grouped IE classes, which is the product of the of the subtask which this section documents.

The third step was to await the system modeling and computer solution to identify support system failures, e.g., a dc bus, that need to be extracted from the routine trip category and modeled separately.

Section 3.1.1.3 describes the grouping process and its results. Section 3.1.1.4 summarizes and presents the initial list of initiating events for the Ginna PRA. Section 3.1.1.5 lists references for this section.

3.1.1.3 Ginna-Specific Considerations

This section discusses some Ginna design features which have been identified because of their potential impact on initiating event selection and grouping. Ginna consists of front line, or power production systems that directly provide the nuclear energy conversion to electricity and support systems that cool, energize, or operate equipment in the production systems. Each of these is reviewed for initiating event potential. The section is divided into power production systems, support systems, EOPs, and LERs.

3.1.1.3.1 Power Production Systems

Because of the dependencies between systems in the plant, it is conceivable, if not likely, for the upset of any system to lead to a transient. Typically, only the power production systems — the reactor, the feedwater and condensate system, and the PCS — are instrumented so as to produce a reactor trip. Table 3.1.1-2 (from Figure 7.2-1 of the Ginna UFSAR [Ref. 3.1.1-7] and surrounding text) indicates the designed trip signals for the reactor. Note that most of the trip criteria are symptom oriented, e.g., high power range, rather than system oriented, e.g., turbine generator trip. This allows for a functional protection irrespective of the peculiar systemic fault but does not allow easy identification of systemic IEs. Table 3.1.1-3 is a list of automatic or manual trip requirements on a system or component basis.

Trips arise with problems with reactor power, the RCS boundary, SG level maintenance and the PCS. Reactor power problems include reactivity insertion (too much reactivity at power) and loss of shutdown (ATWS). The RCS boundary, including the SGs and the high and low pressure safety injection systems interfaces, result in the variety of LOCAs/SGTRs.

3.1.1.3.1.1 Main Feedwater

On reactor trip, the feedwater regulatory valves open. These valves remain open until SG levels reach 67%, or the RCS temperature drops below 554°F or an SI signal is produced (Figure 3.1.1-3). If the overcooling is sufficient to initiate SI, the MFW pumps are tripped and reactor trip follows. Otherwise the FW pumps recirculate and FW is isolated. Either condition is equivalent to a (recoverable) loss of MFW.

Any condition that leads to a low steam generator level would lead to an actuation signal for auxiliary feedwater (Figure 3.1.1-4). Hence, AFW is indeed auxiliary feedwater rather than emergency feedwater, being the preferred post-trip source of water to the SGs.

Figures 3.1.1-5 through 3.1.1-8 are plots of pressurizer level, pressurizer pressure, RCS wide range pressure, and steam generator pressures from a reactor trip from full power run on the Ginna control room simulator; Figures 3.1.1-9 through 3.1.1-12 show the same parameters for a loss of off-site power transient. Notice that the plant's response induced by these different initiators is essentially alike. However, since the emergency diesel generators (EDGs) are required for the latter transient but not necessarily the former, these transients are distinguished.

Notice also that a crucial point demonstrated by these transients is that the case of solely a loss of feedwater initiator does not challenge the RCS PORVs without accompanying further failures. NUREG-0611, pg. II-12 and 13 [Ref. 3.1.1-8] also supports this, namely whenever the reactor trips and the steam valves open, the RCS pressure will be maintained below the PORV setpoint. Table 3.1.1-4 indicates the conditions needed to challenge the PORVs from various information sources, namely a failure of both the steam dump valves and pressurizer spray valves, a transient too fast or too strong for these valves to work adequately or transients that lead to SG dryout.

To bound the situation, however, the UFSAR Chapter 15 cases (USFAR, Figures 2-3, -6, -9, -12) include a slow reactor trip (the reactor is assumed not to trip on turbine trip until the high pressurizer trip signal is reached) along with failure of automatic steam dump. In this case, the RCS pressure is calculated to reach some 2500 psig, above the PORV setpoint of 2335 psig.

Table 3.1.1-5 [Ref. 3.1.1-9] shows how the operation of the reactor coolant pumps (RCPs) affects an extended loss of feedwater to the SGs.

3.1.1.3.1.2 Steam Generator

There is nothing unusual about the Ginna SGs to warrant identifying any new initiators. However, the event in January 1982 [Ref. 3.1.1-10] necessitates that this initiator class be considered without any other considerations. Table 3.1.1-6 [Ref. 3.1.1-11] shows a generic timeline for a single tube rupture event, similar to that at Ginna.

3.1.1.3.1..3 Main Steam

Turbine trip is essentially the same as reactor trip (Figure 3.1.1-2). The sources of turbine trip are listed in Table 3.1.1-7. A steamline break downstream of the MSIV would act simply as a loss of load, since the MSIV would close.

3.1.1.3.1.4 Reactor Coolant System

Four inadvertent SI actuations have occurred at Ginna [Ref. 3.1.1-12]. These all occurred at shutdown [Ref. 3.1.1-5], but this initiator may need distinguishing anyway. Table 3.1.1-8 shows the actuation logic for SI.

Various pipe sizes in the RCS and interfacing systems would lead to a variety in equivalent diameters for LOCAs. A particular LOCA type is a LOCA induced by the failure of an RCP seal.

3.1.1.3.2 Support Systems

3.1.1.3.2.1 Off-Site Power

Station power is normally generated on-site. However, two independent lines enter substations 12A and 12B to provide off-site ac if needed. The emergency equipment are aligned to the buses from these off-site sources and hence no fast transfer is necessary at Ginna. Loss of off-site power will be distinguished as a separate initiator, since it is topical and produces distinct plant demands. Also, separate transformer initiators will be distinguished to account for the independent off-site sources. Notice that these initiators are not failures of the separate emergency buses but the off-site sources themselves.

3.1.1.3.2.2 Other Support Systems.

Several support systems directly lead to reactor trip or a required manual trip (see Table 3.1.1-3). System initiators will be reviewed and finalized during the Systems Analysis.

3.1.1.3.3 Westinghouse Low Pressure Emergency Operating Procedures

The Ginna EOPs [Ref. 3.1.1-1] include subprocedures that address the generic IE classes listed in section 1 (typically the E series). They also include loss of heat sink (which includes loss of main and auxiliary feedwater, FR-H.1) and high SG level (FR-H.3), due for example, to excessive feedwater. Since excessive feedwater will trip the reactor and thus cause a loss of feedwater (flow), then this initiator may not need to be distinguished as a separate variety of feedwater transient.

3.1.1.3.4 Ginna Licensee Event Reports (LERs) Since 1980

Ginna LERs [Ref. 3.1.1-5] were examined as a sanity check for the top-down analysis. Table 3.1.1-9 summarizes these LERs.

The dominant cause of trips is the B steam generator. Not only did a tube in this SG burst, causing the 1982 event [LER 82-3], but subsequently in 1988 a tube leak in SG B was large enough to force a manual shut down [LER 88-4]. In all, indications of plugging in SG B occur much more frequently than in SG A.

There have been two station ac power losses, one in 1981 [LER 81-7] and one in 1988 [LER 88-6]. However, the new second independent source will reduce the frequency of a loss of off-site power considerably.

There have been 3 trips caused when operators were attempting to manually control feedwater flow to the SGs for whatever reason [LERs 85-6, 85-7, and 85-8. The pending digital feedwater control system may eliminate these initiators. There have been 4 inadvertent SI actuations [LERs 84-6, 85-4 (2), and 89-3] , all with the reactor at zero power, although one [LER 84-6] occurred when the RCS pressure was some 2000 psig. About 25% of the reactor trips in the LERs were induced by errors by operators or other personnel.

Seven trip/shutdowns involved post-trip problems, including the SGTR event. Following two trips, shrinkage in the pressurizer was enough to drive the level below the tech spec level of 12% [LERs 83-7 and 83-21].

The PORV opened on the 1982 SGTR [LER 82-3] and also following a manual turbine trip while the reactor was at zero power in 1983 [LER 83-23]. These events do not seem inconsistent with the assumption made according to the UFSAR and simulator information that PORVs generally will not be challenged from trips at power.

3.1.1.3.5 EPRI Initiating Event Types

Table 3.1.1-10 lists the EPRI transient types for PWRs [Ref. 3.1.1-6]. Type 13, startup of inactive coolant pump, is assumed not to be possible, since Technical Specification 3.1.1.1.a requires all RCPs to operate at above 8.5% power [Ref. 3.1.1-13]. Also, type 41, fire within plant, is excluded since it is not an internal event in the PRA sense. As before, the preliminary IE category is listed for each EPRI type (their acronyms are spelled out in the preliminary list of initiators in Table 3.1.1-13).

3.1.1.3.6 PRAs For Other Westinghouse Two-Loop Plants

The Initiating Event Notebook from the Point Beach PRA [Ref. 3.1.1-14] was reviewed for other initiators since Point Beach is a sister plant. Along with experience of past PRAs several other transient types were identified (Table 3.1.1-11) and various LOCAs and steamline or feedline breaks were identified (Table 3.3.3-12). The net result is a list of 54 initiating event types, one of which [Item 13] is not applicable to Ginna because of technical specifications and one of which [Item 41] is out of scope of internal initiators.

3.1.1.4 Identification And Grouping Of Initiators

3.1.1.4.1 Transient Initiating Events

3.1.1.4.1.1 Reactor Trip

The reactor trip category of transient initiating events includes all initiators which cause a reactor trip and /or recoverable losses of main feedwater, condensate, turbine bypass, and the condenser for decay heat removal. Inadvertent actuation of Safety Injection is also included under the reactor trip initiator.

Following receipt of a valid reactor trip signal, the reactor trip breakers will open, and the control rods will fall into the core within about one second. A turbine trip is initiated simultaneously. The main feedwater regulating valves 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 feedwater regulating valves are controlled automatically to maintain pre-determined levels. The auxiliary feedwater pumps will automatically start on low steam generator level, and the condenser steam dump system will automatically operate to maintain the average reactor coolant system (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 20%. If pressurizer level continues to decrease, the pressurizer heaters will be automatically deenergized (to prevent burnout), and the letdown isolation valve will be automatically closed. The electrical distribution system will automatically transfer house loads to off-site 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.

3.1.1.4.1.2 Loss Of Off-Site Power - Pre Reactor Trip

A loss of off-site power is defined as a complete loss of all alternating current electrical power from all off-site sources caused by a failure of: 1) The RG&E transmission network up to, but not including, the breaker connecting RG&E Station 204 to Ginna station auxiliary transformer PXYD12A; and 2) The Transmission network up to, but not including, RG&E Station 13A (the Ginna switchyard).

3.1.1.4.1.3 Loss Of Off-Site Power - Post Reactor Trip

This event is analogous to the loss of off-site power described in Section 4.1.2, but it may happen following the occurrence of any of the other initiating events described in this work package. A turbine trip / reactor trip may challenge the transient stability of the transmission grid due to the sudden loss of generation at Ginna. While the Ginna 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 gnerating capacity could fail both of the off-site power sources. Partial losses of off-site power following a reactor trip will not be considered.

3.1.1.4.1.4 Loss Of Main Feedwater

This event includes any initiating event which results in unrecoverable loss of main eedwater pumps PFW01A and PFW01B.

3.1.1.4.1.5 Main Feedwater Line Breaks

A main feedwater line break on the feedwater lines to either steam generator, will result in high energy relaease that could potentially damage and / or destroy equipment and instrumentation located in the general vicinity of the break. These feedwater line breaks could occur on the lines feeding either steam generator inside Containment, upstream of the isolating check valves; on the lines feeding either steam generator that run through the Intermediate Building; or, in the Turbine Building.

3.1.1.4.1.6 Excessive Feedwater

A feedwater overfill would cause overcooling and shrinkage in the reactor coolant system. Water overflowing into the main steam lines is a further potential problem of this initiating event.

3.1.1.4.1.7 Steam Line Breaks

Any main steam line break could result in rapid overcooling of the Reactor Coolant System and actuation of SI. A steam line break also could damage an / or destroy equipment and instrumentation in the area of the break. Steam line breaks could occurr on either main steam line inside Containment; inside the Turbine Building; or, on either main steam line inside the Intermediate Building. Breaks that would not be of concern from a high-energy line break standpoint include failure (open) of one or more of the steam dump valves; inadvertent operation of the main steam safety valves (open) on steam generator A; or, failure of the main steam safety valves (open) on steam generator B or a break in the portion of the steam generator B main steam line that runs outside of Containment, from the outer Containment wall to the outer Intermediate Building wall.

3.1.1.4.1.8 Loss Of Instrument Air Pressure

Loss of air pressure to air operated valves and instrumentation throughout the plant would result in a reactor trip to do upset conditions in the feedwater / condensate systems. This initiating event would also complicate trip recovery due to air operated valves going to their "fail safe" positions.

3.1.1.4.1.9 Anticipated Transients Without Scram (ATWS)

This initiating event includes any failures to scram the reactor when a valid trip signal is present.

3.1.1.4.1.10 Loss Of Safety-Related Service Water Header A or B

These two initiating events are defined as a total loss of flow from either one of the two 20" safety-related headers in the Service Water System (see Section 3.2.1.13).

3.1.1.4.1.11 Loss Of Component Cooling Water

This initiating event is defined as a complete loss of flow from the Component Cooling Water System.

3.1.1.4.1.12 Loss Of A 480 VAC Bus

A review of Ginna procedures and past analyses [Ref. 3.1.1-16] has concluded that failure of any one of the 480 VAC buses will not cause a reactor trip.

3.1.1.4.1.13 Loss Of A 125 VDC Bus

Loss of power on the 125 VDC system would result in the following failures [Ref. 3.1.1-16]:

> Failure of BTRYA or DCPDPCB03A: Isolates all letdown, closes of all steam dump AOVs to main condenser A, defeats train A ESFAS automatic and manual steam line isolation and feedwater line isolation and ESFAS train A reset and block, isolates the long-term nitrogen supply to PORV 430, isolates one train of the reactor head vent solenoid valves, initiates train A of containment isolation, fails closed ARV 3410 and trips main feedwater pump PFW01A; and,

Failure of BTRYB or DCPDPCB03B: Isolates all letdown, closes of all steam dump AOVs to main condenser B, fails closed PORVs 430 and 431C, isolates all Control Room outside air dampers, defeats train B ESFAS steam line automatic and manual isolation and feedwater line isolation and ESFAS train B reset and block, isolates the long-term nitrogen supply to PORV 431C, isolates one train of the reactor head vent solenoid valves, initiates train B of containment isolation, fails closed ARV 3411, trips main feedwater pump PFW01B, trips both circulating water pumps on high condenser pit level,

3.1.1.4.1.14 Loss Of Control Building Ventilation

Ginna control building ventilation consists of a single train that cools and circulates air to the control room. The battery rooms are cooled by a single train of HVAC, while the relay room is cooled by non-safety related coolers. However, the failure of the ventilation systems for these rooms should not result in a reactor trip, since the areas are subject to operator inspections on a regular basis. If room heatup becomes a concern in any of these areas, temporary measures would be taken [Ref. 3.1.1-15].

3.1.1.4.1.15 Loss Of A 120 VAC Instrument Bus

The 120 VAC system consists of Bus 1A (IBPDPCBAR), Bus 1B (IBPDPCBBW), Bus 1C (IBPDPCBCB), and Bus 1D (IBPDPCBDY). Buses 1A and 1C are supplied from both inverters and constant voltage transformers; Buses 1B and 1D are supplied only by constant voltage transformers. Review of Ginna procedure P-10, *Instrument Bus Failure Reference Manual* [Ref. 3.1.1-18] indicates that failure of one of these instrument buses will not result in a reactor trip.

3.1.1.4.2 Loss Of Coolant Accident (LOCA) Initiating Events

3.1.1.4.2.1 Very Large Break LOCA

A very large break LOCA is defined as a severe breach of the reactor coolant system resulting in a leakage that is beyond the design capacity of the emergency core coolant systems. For the purposes of the Ginna PRA, and for consistency with past risk assessments, a very large break LOCA will be defined as a reactor pressure vessel rupture.

3.1.1.4.2.2 Large Break LOCAs

A large break LOCA is defined as a break in the reactor coolant system greater than of equal to 5.5 inches effective diameter. A break of this size results in a leakage that is within the capacity of the emergency core cooling system, where successful operation of low pressure injection with the residual heat removal pumps are required to prevent core damage [Ref. 3.1.1-21].

3.1.1.4.2.3 Medium Break LOCAs

A medium break LOCA is defined as a break in the reactor coolant system greater than of equal to 1.5 inches effective diameter and less than 5.5 inches effective diameter. A break of this size results in a leakage that is within the capacity of one safety injection pump [Ref. 3.1.1-21].

3.1.1.4.2.3 Small Break LOCAs

A small break LOCA is defined as a break in the reactor coolant system between 1 and 1.5 inches effective diameter. Flow from this size break alone cannot remove enough decay heat to prevent core damage; flow will be large enough, however, to require reactor coolant system makeup in excess of the capacity of one positive displacement charging pump. This class of LOCAs also includes failures of the reactor coolant pump seals.

3.1.1.4.2.4 Small-Small Break LOCAs

A small-small break LOCA is defined as a break in the reactor coolant system of less than 1 inch effective diameter. The RCS will not depressurize to the Safety Injection setpoint due to the flow out of the break alone. RCS inventory loss is small enough to allow rapid depressurization to the RHR setpoint using the steam generators if one accumulator is available.

3.1.1.4.2.5 Steam Generator Tube Rupture

A steam generator tube rupture is defined as a complete severance of a single tube. The resulting primary to secondary leakage will require successful safety injection to prevent core damage. A steam generator tube rupture could occurr in either steam generator.

3.1.1.4.2.6 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. ISLOCAs are discussed in Section 3.1.3 [Ref. 3.1.1-20].

3.1.1.5 Summary List Of Initiating Events

The grouping of preliminary initiating events shown in Tables 3.1.1-10, 3.1.1-11, 3.1.1-12, and 3.1.1-13, and discussed above in Section 3.1.1.4, resulted in 32 initiating events that should be investigated in the Ginna PRA. These 32 initiating events are shown in Table 3.1.1-14.

3.1.1.6 References

3.1.1-1 R. E. Ginna Nuclear Power Plant *Emergency Operating Procedures*, E and F series, 1989.

3.1.1-2 *Individual Plant Examination for Severe Accident Vulnerabilities*-10CFR§50.54(f), Generic Letter No. 88-20, USNRC, Washington DC, November 23, 1988.

3.1.1- 3 *Individual Plant Examination: Submittal Guidance*, NUREG-1335, USNRC, Washington DC, August 1989.

3.1.1- 4 A. El-Bassioni, et al., *PRA Review Manual*, NUREG/CR-3485, USNRC, Washington DC, September 1985.

3.1.1- 5 R. E. Ginna Nuclear Power Plant, Unit No. 1, Docket Number 05000224, *Licensee Event Reports*, Sequence Coding and Search System, Oak Ridge National Laboratory, 1980-1990.

3.1.1- 6 A. S. McClymont and B. W. Poehlman, *ATWS: A Reappraisal, Part 3: Frequency of Anticipated Transients*, EPRI NP-2230, January 1982.

3.1.1-7 R. E. Ginna Nuclear Power Plant *Updated Final Safety Analysis Report* (UFSAR), Revision 8, July, 1992.

3.1.1-8 NUREG-0611, *Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants*, USNRC, Washington DC, January 1980.

3.1.1-9 Westinghouse, *Emergency Response Guidelines Background*, FR-H.1, LP-Rev. 1. p. 54.

3.1.1-10 D. D. Woods, *Operator Decision Behavior During the Steam Generator Tube Rupture at the Ginna Nuclear Power Station*, 82-1C57-CONRM-R2, Westinghouse R&D Center, Unrestricted Research Report, Pittsburgh, PA, April 14, 1982.

3.1.1-11 Westinghouse, *Emergency Response Guidelines Background*, E-3, LP-Rev. 1, p. 11.

3.1.1-12 Grove Engineering, Inc., *R. E. Ginna Nuclear Power Plant RCS Transient Validation Report*, CP-80212-C-RD, August 10, 1989.

3.1.1-13 R. E. Ginna Nuclear Power Plant, *Technical Specifications*, Amendment No. 48, April 9, 1992.

3.1.1-14 *Point Beach PRA Initiating Event Notebook*, WP-4, Rev. 1, August 24, 1989.

3.1.1-15 Devonrue, Ltd., Control Building Ventilation Analysis for Ginna Station, September, 1990.

3.1.1-16 RG&E internal correspondence, M. D. Flaherty to T. A. Daniels, *Electric Power System Level Initiating Events*, NSL-PRALT-92.095, September 21, 1992.

3.1.1-17 RG&E Ginna Procedure P-11, *Electrical Distribution Panel Reference Manual*, Revision 0, March 26, 1992.

3.1.1-18 RG&E Ginna Procedure P-10, *Instrument Failure Reference Manual*, Revision 1, January 10, 1992.

3.1.1-19 RG&E internal correspondence, J. Pacher to T. Schuler, *Engineering Review Of MCB DC Panel Job Aids For Operators In Response To LER-90-017*, November 20, 1991.

3.1.1-20 Science Applications International Corporation SAIC-749-01-100, *Interfacing Systems LOCAs Work Package*, Revision 0.

3.1.1-21 Science Applications International Corporation SAIC-749-01-14, *Accident Sequences Definition Work Package*, Revision 2.

Table 3.1.1-1
Issues That Help Distinguish Initiating Events

Issue	*Disposition*
• Event trips the reactor	TRIP
• Manual trip required	TRIP
	SWnLOSS
	CCWnLOSS
	IALOSS
• Challenges PORV	Event tree header only
• Leaves PCS unavailable	MFWLOSS
	MFWLOSSREC
	MFWLB
	EXCESSFW
• Leaves PCS recoverable	MFWLOSSREC
	EXCESSFW
• Involves feed water vs. steam from the SGs	PRESLB
	POSTSLB
	MFWLB
• Break is located upstream of MSIV	PRESLB
	POSTSLB
• Break is within containment	xBLOCA
	SGTR
	ISLOCA
• Break that requires secondary cooling	SSBLOCA
	SBLOCA
• SGTR equivalent to burst in single tube	SGTR
• Break in excess of ECCS	RCSRUPTURE

Table 3.1.1-2
Reactor Trip

Primary trips
- High power range level trip
- High reactor coolant pressure
- High pressurizer level
- Manual trip
- SI

Overpower ΔT trip
Overtemperature ΔT trip

Nuclear overpower trip (With interlocks)
- Source range level trip
- Intermediate range level trip
- Low power range level trip
- Pump breaker trip
- Low feedwater flow
- Turbine generator trip (if reactor power > 50%)
- Low reactor coolant flow
- Low-low steam generator water level
- Fixed low pressure trip
- Turbine load
- Average nuclear flux

Table 3.1.1-3
Automatic or Manual Trips from Ginna Systems

	Automatic Trip Source	*Ginna PRA Name*
1.	Loss of MG sets	TI00RXTRIP
2.	Loss of instrument bus	TI0INSnBUS
3.	Loss of DC bus	TI00DCLOSS
	Manual Trip Source	*Ginna PRA Name*
4.	Loss of instrument air	TI00IALOSS
5.	Loss of component cooling water	TI0CCnLOSS
6.	Loss of service water	TI0SWnLOSS

Table 3.1.1-4
Possible Transients that Lift Pressurizer PORVs or Safeties at Ginna

UFSAR Chapter 15 Candidates For PORV Challenges

Decrease in steam flow
Load drop
Loss of vacuum
Turbine trip
Locked RCP rotor
Control rod withdrawal at power

PORV Challenges According to NUREG-0611 [Ref. 8]

Loss of station power
Uncontrolled rod withdrawal at low power
Turbine governor or control valve closure
MSIV closure
Loss of load

UFSAR Chapter 15 Candidates For Pressurizer Safety Valve Challenges

ATWS
Locked RCP rotor

Ginna Past PORV Openings

1/25/82, LER 38 (82-005): PORV was lifted manually in depressurization efforts during SGTR and stuck open and had to be blocked

6/19/83, LER 84 (84-024): PORV lifted following TT because both pzr spray vlvs failed to open and control RCS pressure

10/23/86, LER 131 (86-008): PORV lift on runback and rod drop plus electric fault preventing steam dump and pressurizer spray

11/28/86, LER 134 (86-011): PORV lift on loss of load (MSIVs) steam dump not sized to handle pressure increase; pzr sprays could not act fast enough

Table 3.1.1-5
Impact of RCP Trip on Loss of Heat Sink

Parameter	*Case 1*	*Case 2*	*Case 3*
PORVs open	30.75 (min)	37.83	35.80
SG dry out	33.10	42.50	40.93

Case 1 is all RCPs running
Case 2 is all RCPs tripped at reactor trip
Case 3 is all RCPs tripped 5 min after reactor trip

Reactor tripped at 28 sec; main feedwater lost at 10 sec.

Table 3.1.1-6
Timeline for Single Tube, Double-Ended SGTR

Event	*Estimated Occurrence Time (sec)*
Tube failure	0
Reactor trip signal	232
Steam dump operation	233
Turbine isolation	234
SI signal	250
MFW isolation	257
AFW actuation	310

Table 3.1.1-7
Turbine Trip Sources

Shaft overspeed trip

Low bearing oil pressure trip

Solenoid trip by:
- Reactor trip
  - Manual pushbutton
  - Trip of all main feedwater pumps
  - Generator trip on fault
  - Trip of all circulating water pumps

Thrust bearing pressure (due to wearout) trip

Low vacuum trip (due to loss of circulating water or excessive air leakage through turbine gland packing

Table 3.1.1-8
Actuation Logic for SI

- Low pressurizer pressure (2/3 channels)
- Low steam line pressure (2/3 channels)
- High containment pressure (2/3 channels)
- Manual

Table 3.1.1-9
Trip Synopsis from LERs

Trips	At > 3% Power	Shutdown
Turbine trip	2	1 (manual trip)
LOSP	2	
SGTR	2 (1 manual SD)	
Inadvertent SI	1 at 2000 psig SD	3 (1 human induced)
Failure in manual FW control	3	
Human induced	5	
Other causes	7	
Manual shutdowns	5	
Post-trip/shutdown problems	7	
SGTR	1	
Pressurizer level drops below 12%	1	1
PORV opens	1	1
Manual turbine trip fails	2	
Unknown P-T conditions	1	

NOTE: The total of trips above do not necessarily include all Ginna trips in the 1980s, since trips did not initially need to be reported in the LER system.

Table 3.1.1-10
EPRI PWR Transient Types

	Category	*Ginna PRA Name*
1.	Loss of RCS flow (1 loop)	TI0RXTRIPP
2.	Uncontrolled rod withdrawal	TI0RXTRIPP
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	TI0RXTRIPP
10.	Containment pressure problems	TI00RXTRIP
11.	CVCS malfunction - boron dilution	TI0RXTRIPP
12.	Pressure/temperature/power imbalance - rod position error	TI00RXTRIP
13.	Startup of inactive coolant pump	Not possible at Ginna
14.	Total loss of RCS flow	TI0RXTRIPP
15.	Loss or reduction in feedwater flow (1 loop)	TI0RXTRIPP
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)	TIFWEXCS
20.	Increase in feedwater flow (all loops)	TIFWEXCS
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)	TIRXTRIP
25.	Loss of condenser vacuum	TIRXTRIP
26.	Steam generator leakage	TIRXTRIP
27.	Condenser leakage	TIRXTRIP
28.	Miscellaneous leakage in secondary system	TIRXTRIP
29.	Sudden opening of steam relief valves	TISLBSVn
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
35.	Loss of all off-site power	TInnLOSP
36.	Pressurizer spray failure	TIRXTRIP
37.	Loss of power to necessary plant systems	TIRXTRIP
38.	Spurious trips - cause unknown	TIRXTRIP
39.	Automatic trip - no transient condition	TIRXTRIP
40.	Manual trip - no transient condition	TIRXTRIP
41.	Fire within plant	Not an internal initiating event

Table 3.1.1-11
Initiating Events Specific to Ginna or PRA Experience

	Category	*Ginna PRA Name*
42.	Loss of MG sets	TIRXTRIP
43.	Loss of instrument bus	TIINnBUS
44.	Loss of dc bus	TI000DCn
45.	Loss of instrument air	TIIALOSS

Table 3.1.1-12
SLBs, FWLBs, and LOCAs Specific to Ginna

	Category	Ginna PRA Name
46.	Small-small break LOCA	LISSLOCA
47.	Small break LOCA	LISBLOCA
48.	Large break LOCA	LILBLOCA
49.	LOCA in excess of ECCS	LIRVRUPT
50.	SGTR (single tube burst in either SG)	LI0SGTRn
51.	SGTR (single tube burst in SG B)	LI0SGTRB
52.	Interfacing system LOCA	LIISLOCA
53.	Steamline break downstream of MSIV	TISLBnnn
54.	Main feedwater break	TIFLBnnn

Table 3.1.1-13
Initiating Events Disposition

	Category Name	*Designator*	*Need to Distinguish*
General IEs			
1	Reactor trip with PCS available	TIRXTRIP	yes
2	Reactor trip challenging PORV	TI0RXTRIPP	no
3	Loss of offsite power	TInnLOSP	yes
4	Loss of offsite from one source	TIHALFLOSP	no
5	Unrecoverable loss of MFW pumps	TIFWLOSS	yes
6	Recoverable loss of MFW pumps	TIMFWLOSSR	no
7	Main feedline break	TIFLBnnn	yes
8	Excessive feedwater	TIFWEXCS	yes
9	Steam line break before MSIV	TISLBnnn	yes
10	Steam line break after MSIV	TISLBnnn	yes
11	Inadvertent SI	TI0INADVSI	no
12	Large LOCA	LILBLOCA	yes
13	Small LOCA	LISBLOCA	yes
14	Small-small LOCA	LISSLOCA	yes
15	SGTR (either SG)	LI0SGTRn	yes
16	SGTR in SG B	LI0SGTRB	yes
17	Interfacing systems LOCA	LIISLOCA	yes
18	LOCA in excess of ECCS	LIRVRUPT	yes
Support System IEs That Require Manual Reactor Trip			
18	Loss of service water train n	TI000SWn	yes
19	Loss of component cooling water	TI00CCW	yes
20	Loss of instrument air	TIIALOSS	yes
Other Support System IEs			
21	Loss of ac bus n	TI0ACnLOSS	no
22	Loss of dc bus n	TI000DCn	yes
23	Loss of room ventilation	TI00CBHVAC	no
24	Loss of inverter ventilation	TI00CBHVAC	no
25	Loss of instrument bus	TI0INSTBUS	no
UFSAR Chapter 15 IE			
26	Loss of MFW w/o RT/SD	TI0MFWATWS	no

Table 3.1.1-14
Final Ginna PRA Initiating Events

	Description	Designator
1	Reactor Trip	TIRXTRIP
2	Loss Of Off-Site Power - grid	TIGRLOSP
3	Loss Of Off-Site Power - Switchyard	TISWLOSP
4	Loss Of Off-Site Power Following Reactor Trip	ACLOPRTALL
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	TIOFLBTB
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	Excessive Feedwater	TIFWEXCS
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	TIOSLBSD
18	Inadvertent Safety Valve Operation On SG A	TISLBSVA
19	Inadvertent Safety Valve Operation (Or Exterior SLB) On SG B	TISLBSVB
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	LIOSGTRA
27	Steam Generator Tube Rupture In SG B	LIOSGTRB
28	Loss Of Service Water Safety-Related Header A	TI000SWA
29	Loss Of Service Water Safety-Related Header B	TI000SWB
30	Loss Of Component Cooling Water	TI000CCW
31	Loss Of Main DC Distribution Panel A (DCPDPCB03A)	TI000DCA
32	Loss Of Main DC Distribution Panel B (DCPDPCB03B)	TI000DCB

Figure 3.1.1-1
General Classes of PWR Initiating Events.

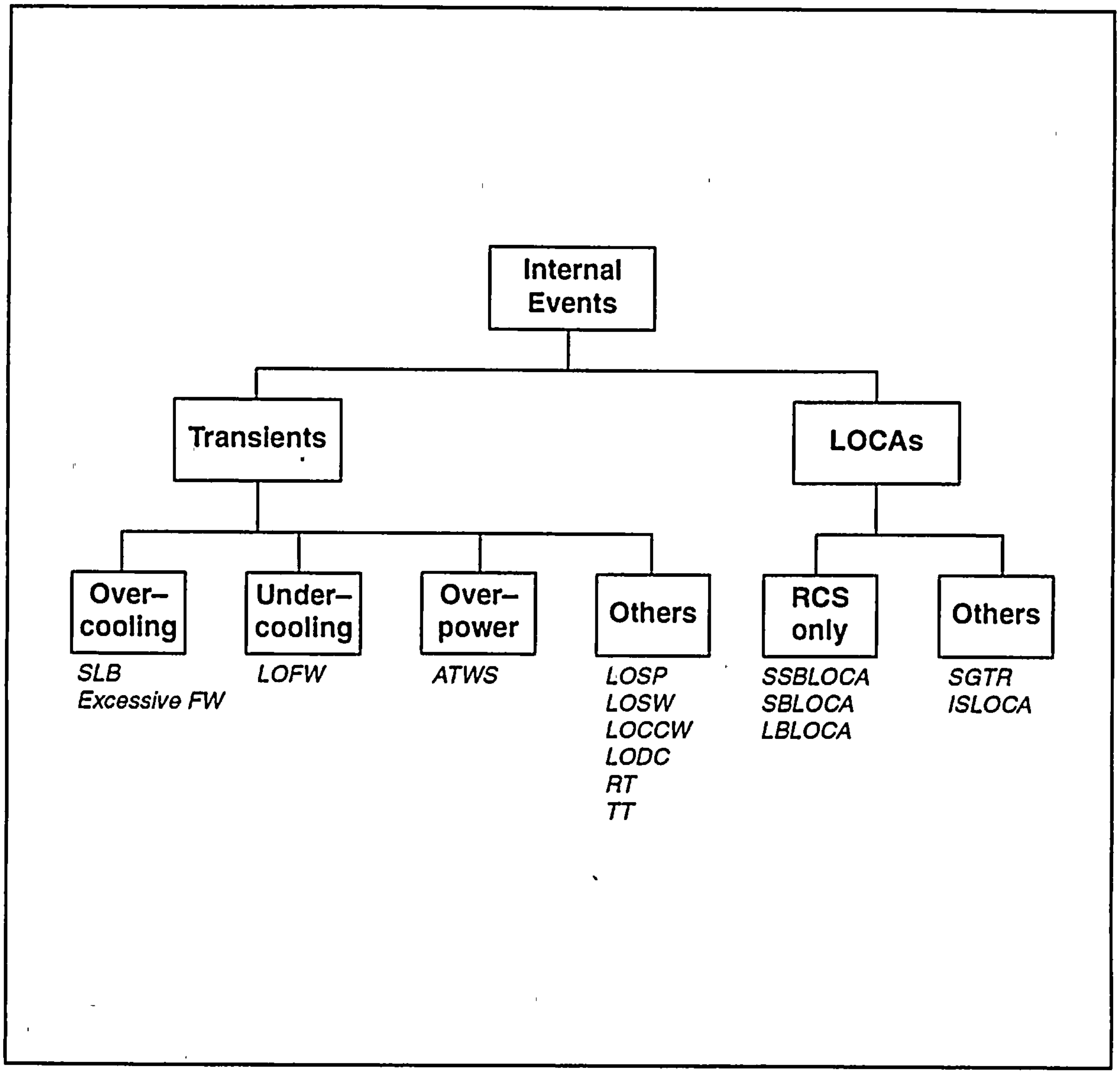


Figure 3.1.1-2
Turbine Trip and Reactor Trip Induce Each Other

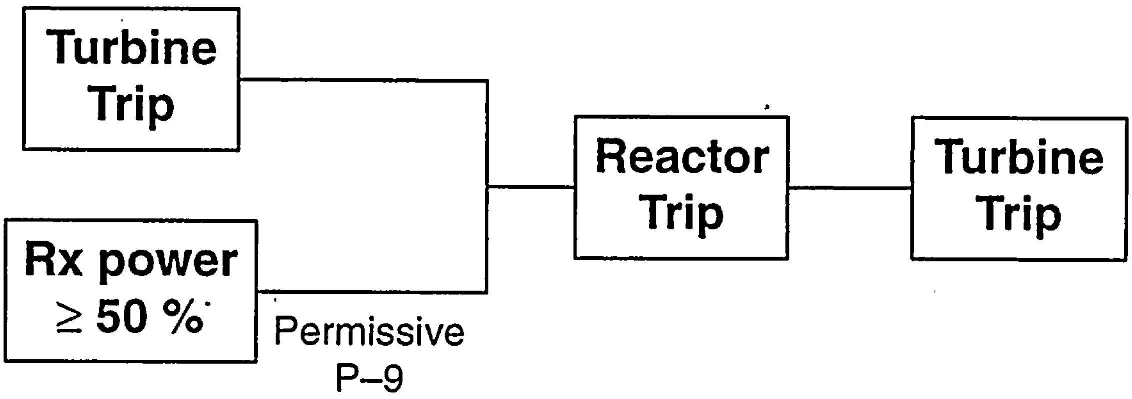


Figure 3.1.1-3
Reactor Trip Induces MWF Isolation and Possibly MFW Trip, the Latter Which Induces RT

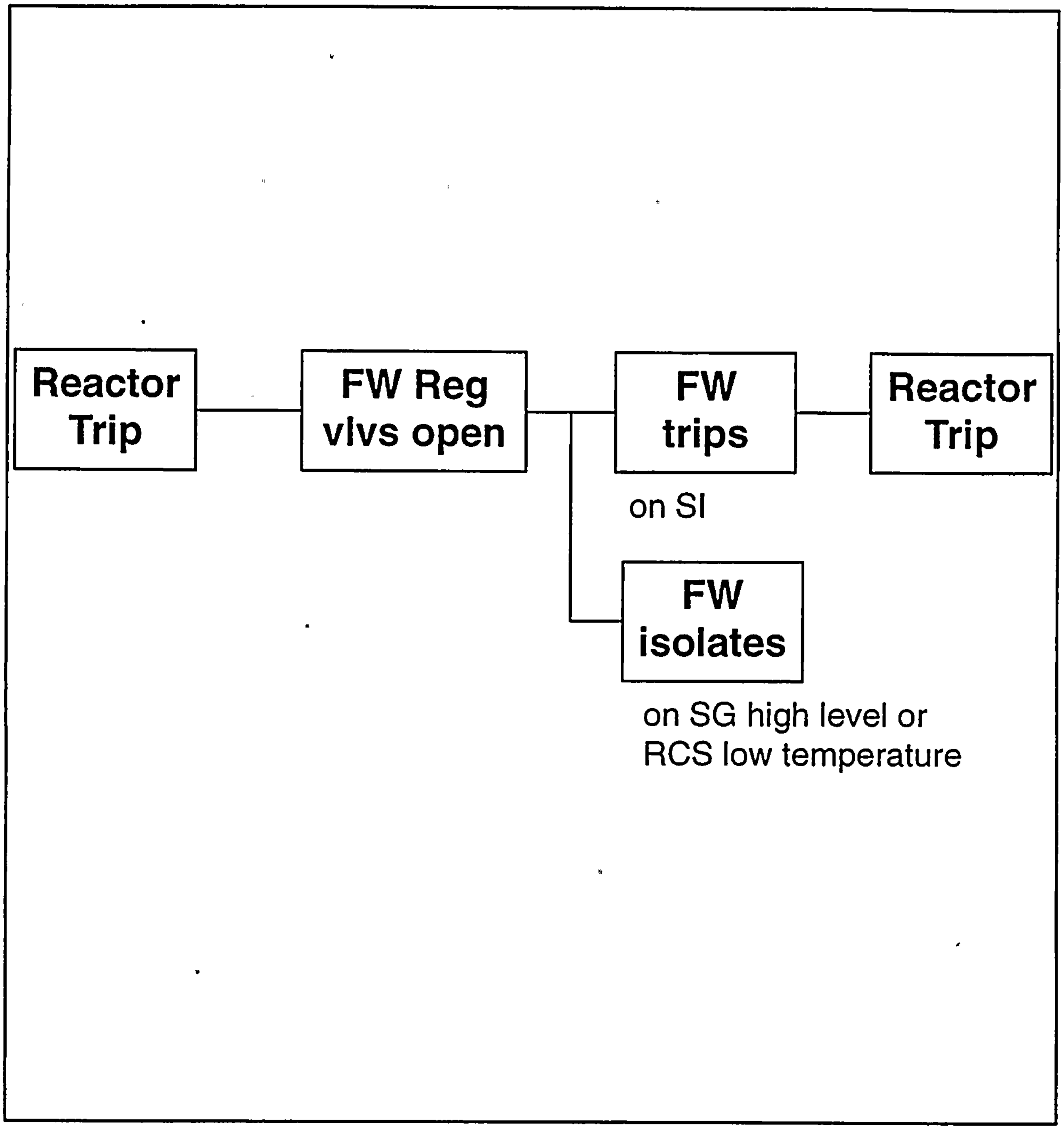


Figure 3.1.1-4
Actuation of AFW Pumps

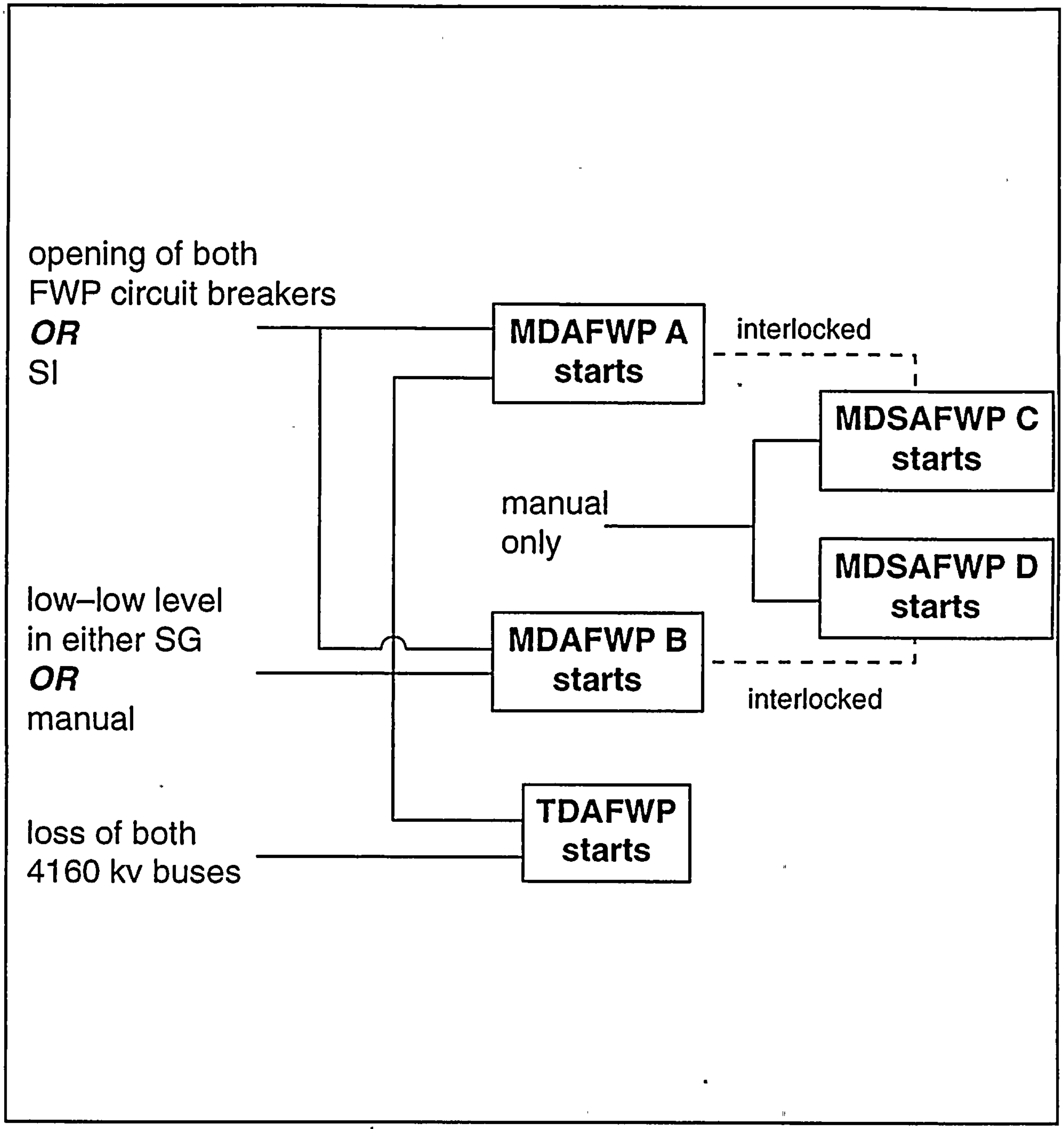


Figure 3.1.1-5
Pressurizer Level Response During Simulation of a Reactor Trip

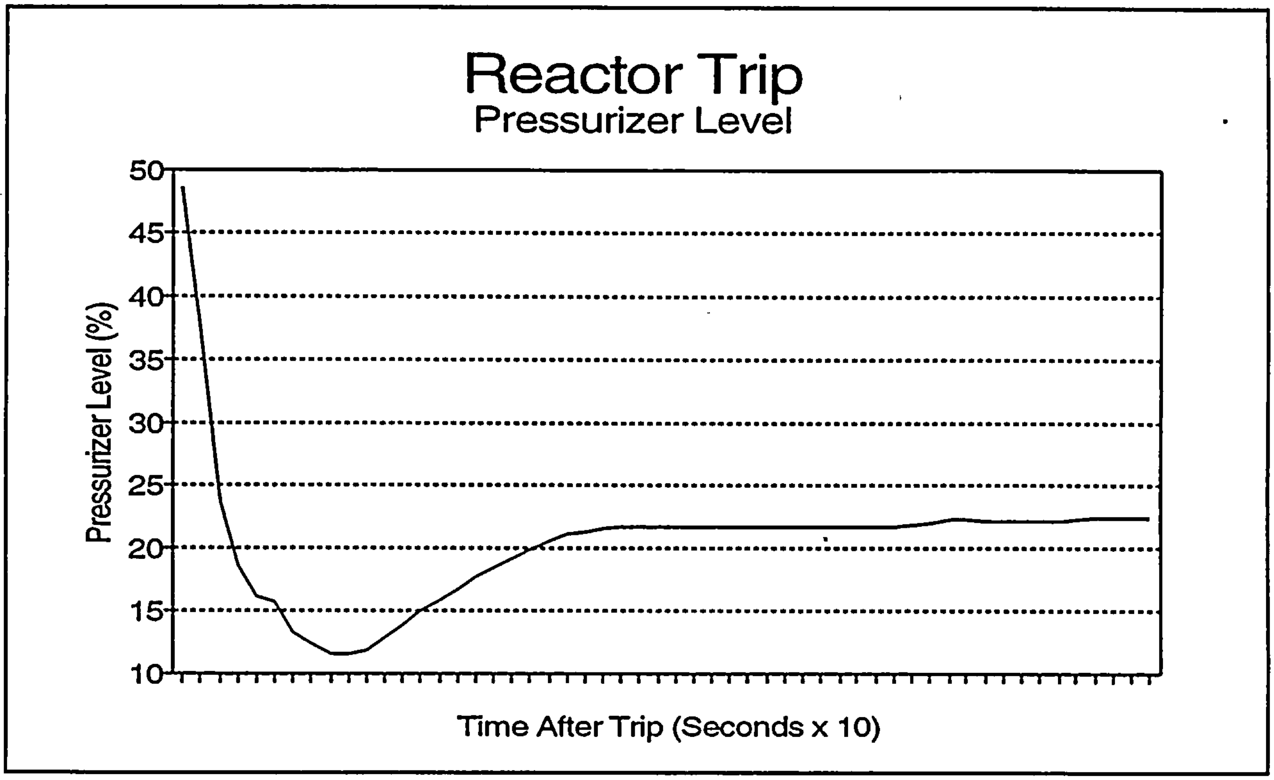


Figure 3.1.1-6
Pressurizer Pressure Response During Simulation of a Reactor Trip

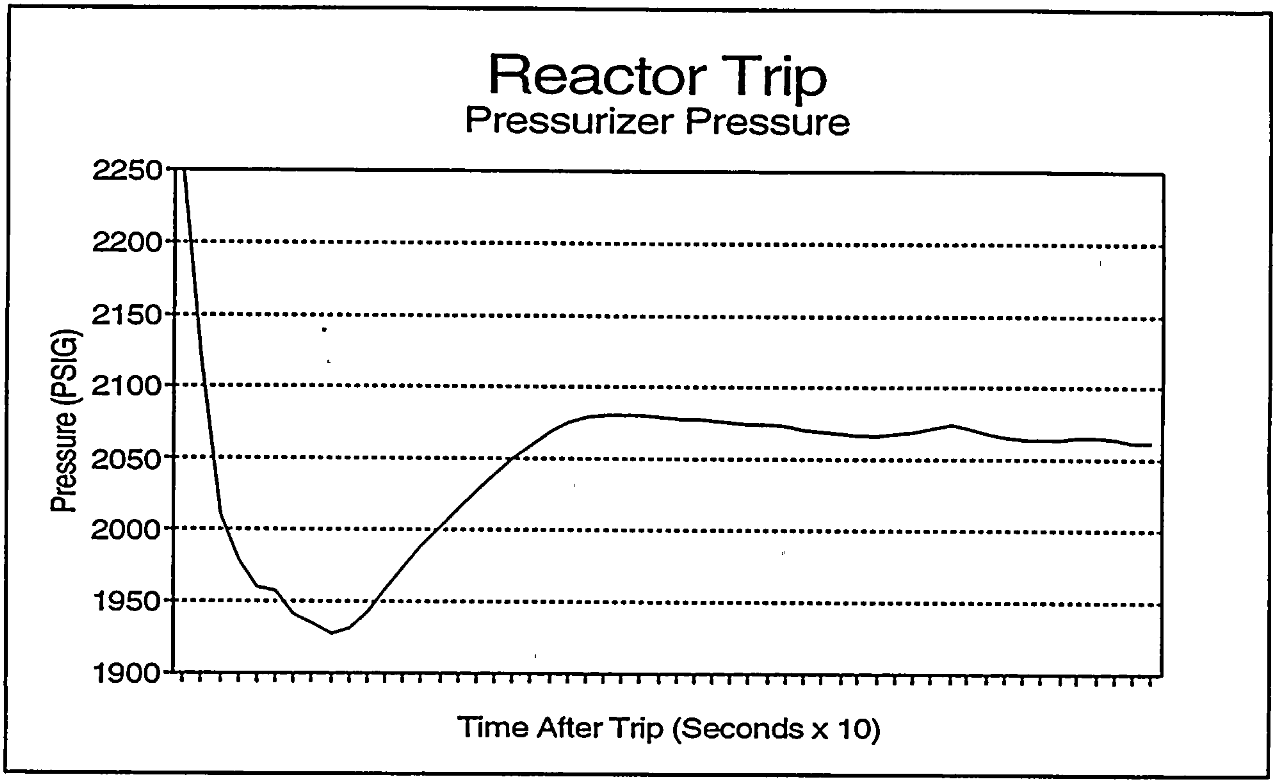


Figure 3.1.1-7
RCS Pressure Response During Simulation of a Reactor Trip

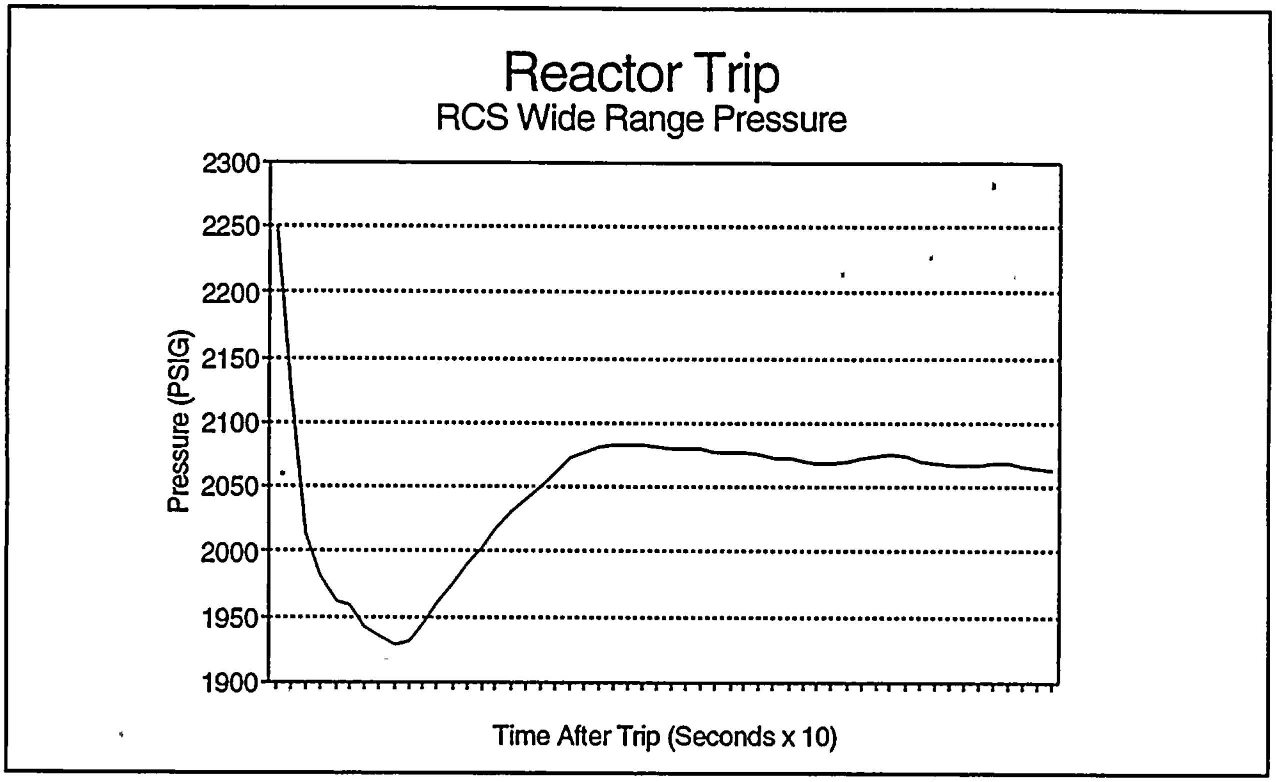


Figure3.1.1- 8
Steam Generators Pressure Responses During Simulation of a Reactor Trip

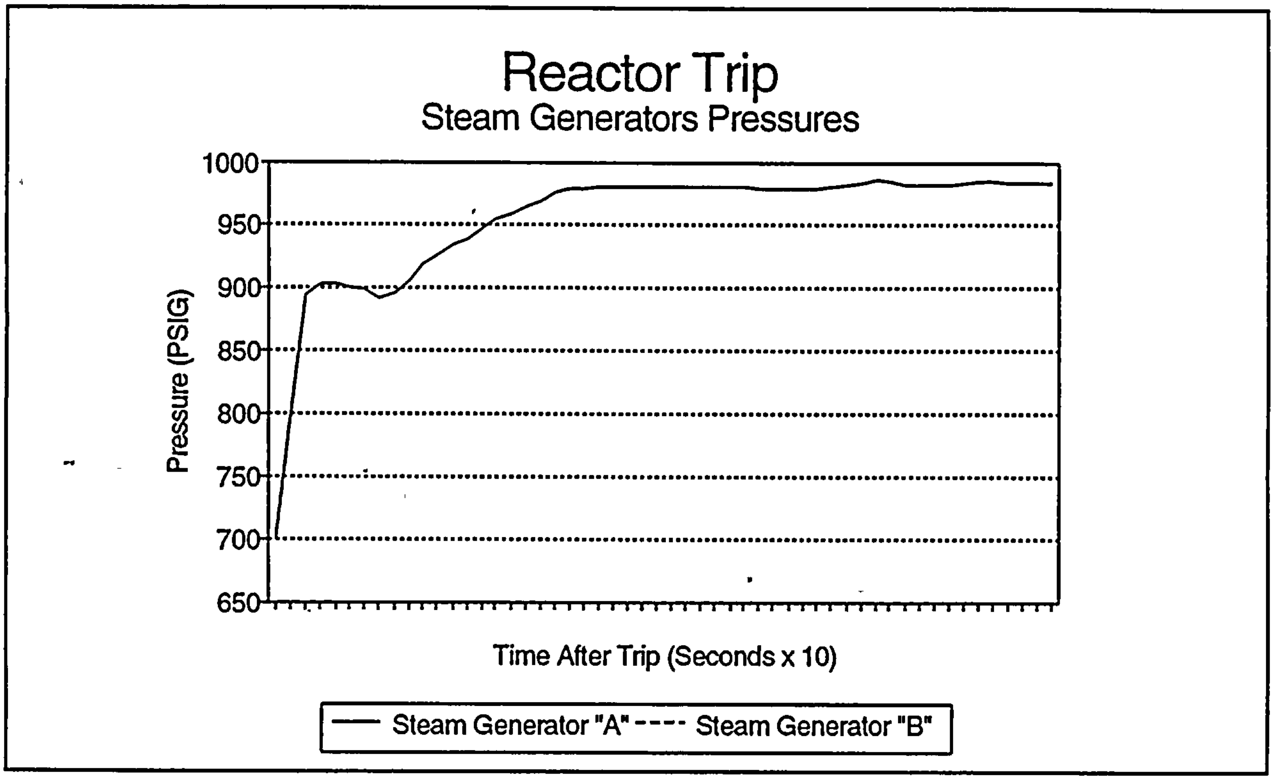


Figure 3.1.1-9
Pressurizer Level Response During Simulation of a Loss of Off-Site Power

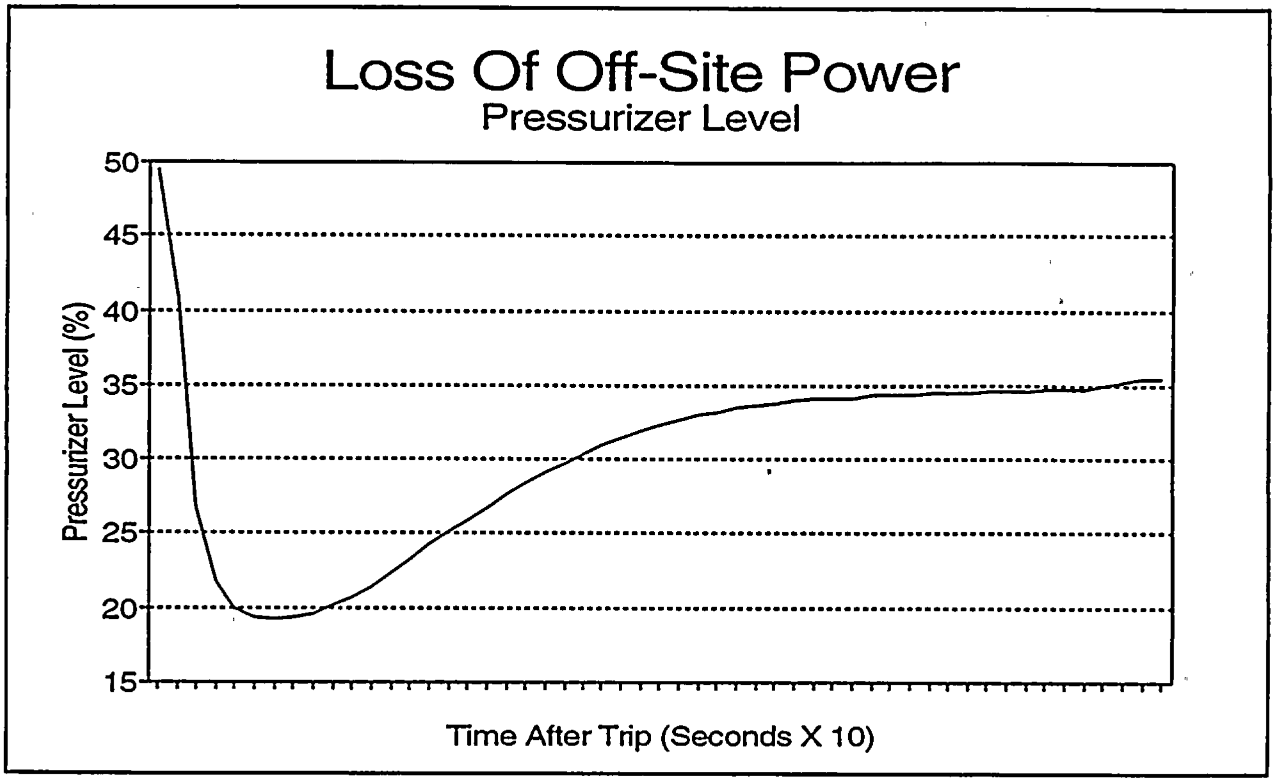


Figure 3.1.1-10
Pressurizer Pressure Response During Simulation of a Loss of Off-Site Power

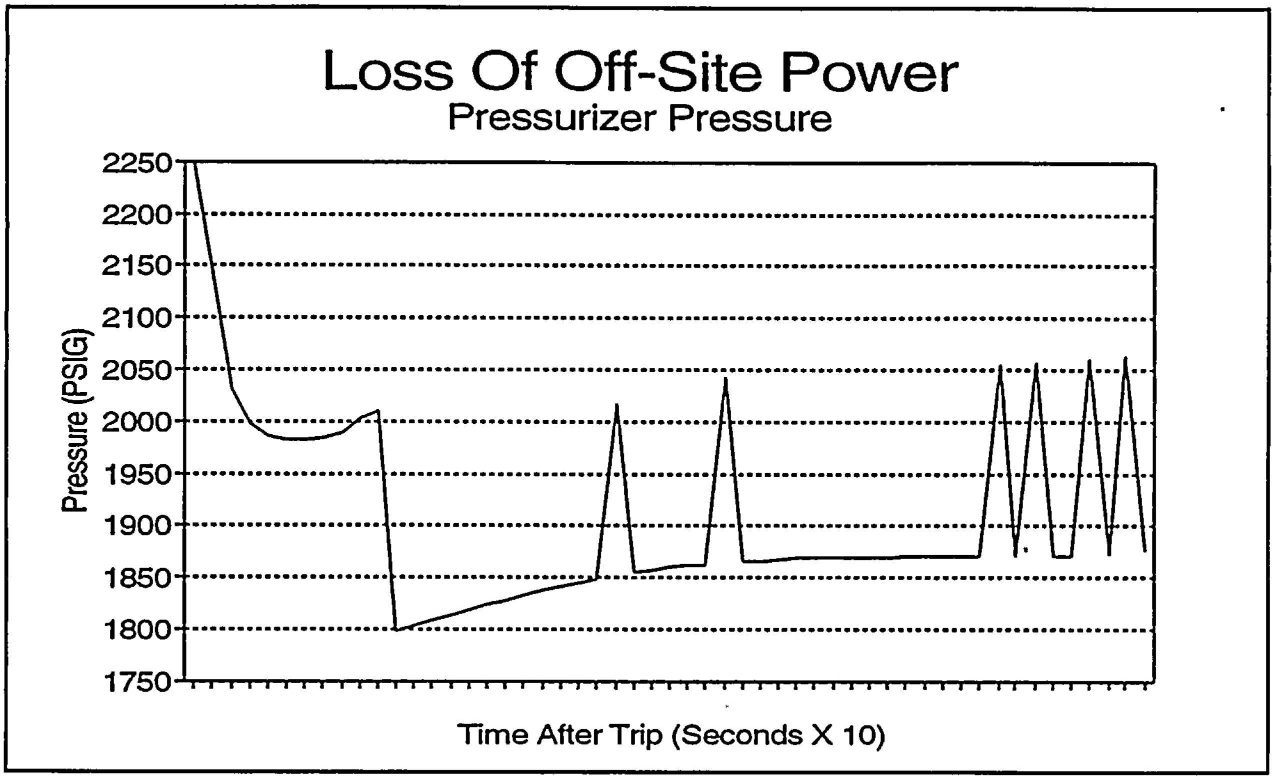


Figure 3.1.1-11
RCS Pressure Response During Simulation of a Loss of Off-Site Power

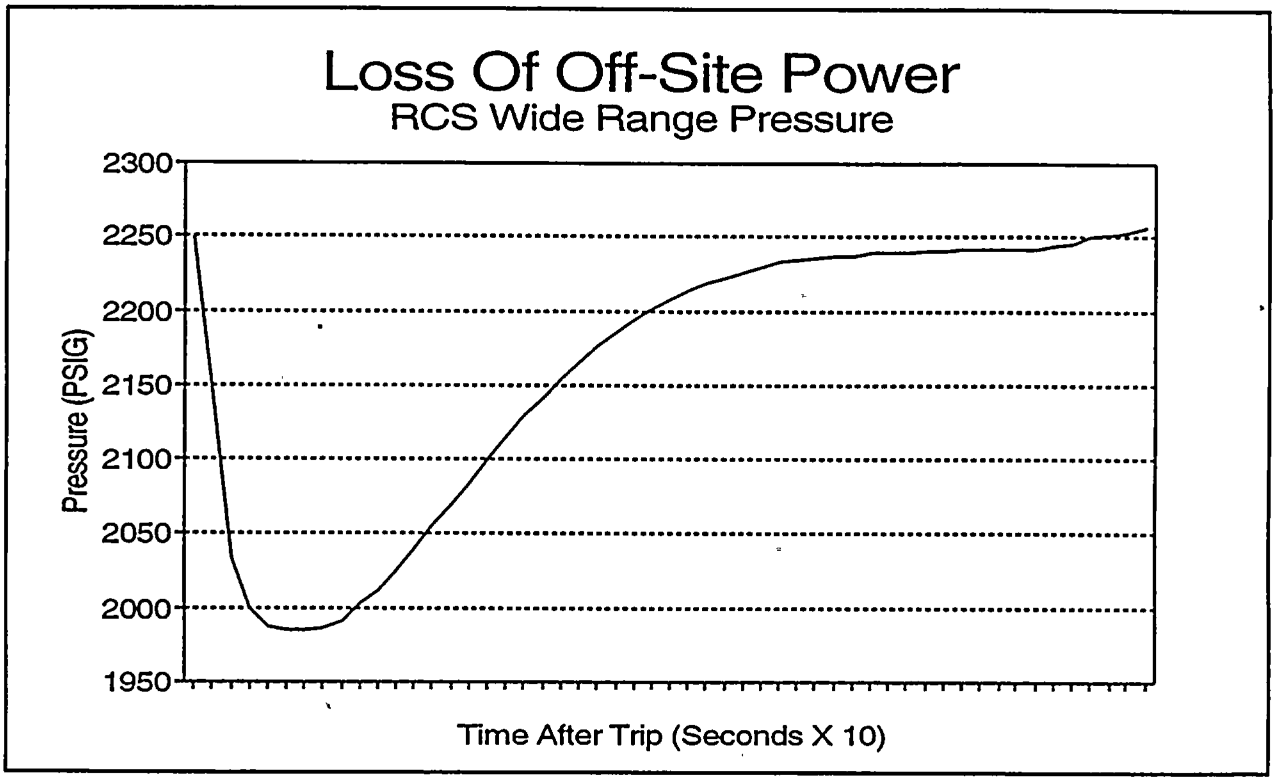
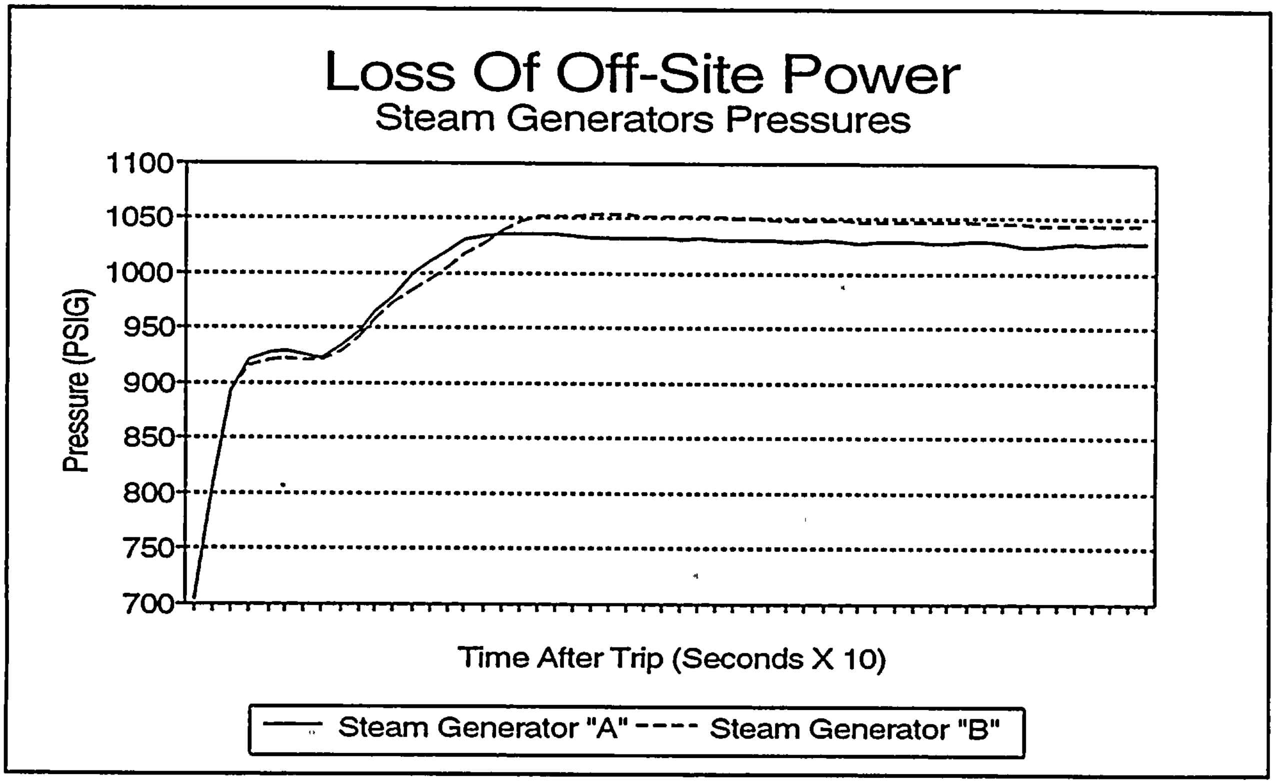


Figure 3.1.1-12
Steam Generator Pressure Response During Simulation of a Loss of Off-Site Power.



3.1.2 Functional Event Trees

3.1.2.1 Introduction

For the purposes of this risk assessment, a core-damage accident is defined by an initiating event and the consequent and subsequent success and failures of plant systems called upon to protect the reactor core from damage. As a practical matter, it is not possible to identify and evaluate the frequency of every possible core-damage sequence; the use of accepted PRA practices, such as logic model development supplemented by a thorough review of plant operating history, gives confidence that all important risk contributors have been identified.

Six subtasks must be accomplished in order to completely specify the core-damage accident sequences:

1. Develop initial list of initiating events,
2. Establish success criteria,
3. Develop functional event sequence diagrams (FESDs),
4. Develop accident sequences,
5. Include system initiating events, and
6. Define and bin end states.

The complete list of initiating events, including both general (step 1) and system-level (step 5) initiators, is given in Section 3.1.1[Ref. 3.1.2-2]. The FESDs (step 3), which relate post-trip system operation and operator actions as specified in the Ginna Emergency Operating Procedures (EOPs), are documented in the *Functional Event Sequence Diagram Work Package* [Ref. 3.1.2-3]. Specification of plant damage states (PDSs) required to support the Level 2 (containment performance) analysis is beyond the scope of this task; however, the development of core-damage accident sequences has been accomplished while keeping in mind the importance of the Level 1 / Level 2 PRA interface. Thus, this section discusses the remaining subtasks (steps 2, 4, and 6), thereby providing the link among the initiating event definitions, FESD development, system fault tree modeling, human reliability analysis (HRA) efforts, and the Level 2 analysis.

Section 3.1.2.2 discusses the process used to determine success criteria. The accident sequences, expressed in the form of event tree models, are presented in Section 3.1.2.3. The event tree top logic models, which relate the occurrence of the event tree branches to system-level fault trees, are described in Section 3.1.2.4. Section 3.1.2.5 describes the modeling interfaces between the accident sequences and other PRA tasks (systems analysis, human reliability analysis, and the Level 2 analysis). The event tree plots are shown in Figures 3.1.2-3 through 3.1.2-9.

3.1.2.2 Success Criteria Determination

The term *success criteria* refers to the minimal combination of plant systems and equipment that must function in order to prevent core damage. Several types of success criteria, ranging in order from global to specific, can be considered: core safety functions, sequence-level success criteria, and system-level success criteria. Note that system-level success criteria are the interface between the accident sequence analysis task and the systems analysis task (i.e., they specify system-level fault tree top events), and thus only suggest the major front-line equipment requirements. For example, a typical success criteria for safety injection (SI) could be "one-of-three SI pumps"; this statement does not specify how the SI pump flow is routed to the RCS nor does it consider the need for support systems (e.g., electric power, etc.). Such considerations are addressed during system-level fault tree construction.

3.1.2.2.1 Core Safety Functions

In order to prevent a nuclear power plant severe accident, only one safety function must be accomplished: The preservation of heat removal from the reactor core. This ultimate safety function can be better understood by developing several intermediate safety functions that relate reactor core heat removal to the operation of plant systems:

1. Control of reactivity;

2. Preservation of reactor coolant system (RCS) inventory; and,

3. Heat removal from the RCS.

Reactivity control directly relates to the amount of heat being generated within the core, which dictates the rate at which energy must be removed from the core and 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 safety functions are performed.

Similarly, the amount of RCS inventory determines in large measure whether core heat removal can be provided. Core damage is assumed to occur for any significant durations of core uncovery. In considering RCS inventory concerns, loss-of-coolant-accident (LOCA) break size is the single parameter that dictates the necessary success criteria. Break size determines break flow rate and subsequent RCS pressure which, in turn, determines required system response.

Heat removal from the RCS can be achieved in one of two ways. The typical way is by using the steam generators 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 the atmosphere via steam vented from the secondary side. A second method to remove heat from the RCS may occur unintentionally; namely, by means of primary system cooling following a LOCA; 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 is Lake Ontario via Service Water (SW), Component Cooling Water (CCW), and the Residual Heat Removal (RHR) system heat exchangers once the injection systems have been switched to the containment sump recirculation mode. Note that this second method of heat removal can also be used following failure of the steam generators (i.e., the first method) by opening both Power Operated Relief Valves (PORVs), intentionally creating a controlled LOCA.

It should be noted that heat removal and, to a lesser extent, RCS inventory control, can be phased activities. This phasing has traditionally been referred to as *short-term* versus *long-term*. For example, containment sump recirculation following a LOCA provides both long-term RCS inventory control and heat removal. Depending on the LOCA break size, recirculation may be initiated as soon as one-half hour (for large LOCAs) or up to several hours (for small LOCAs). Since there is a range in the potential duration of each phase according to initiator type and function considered, the distinction between short-term and long-term is only used colloquially and is not made rigorous.

3.1.2.2.2 Sequence-Level and System-Level Success Criteria

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

1. The impact of initiating events and subsequent system failures upon the core safety functions defined in Section 3.1.2.2.1;

2. The impact of initiating events upon plant system performance;

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

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

As a beginning step in the identification of success criteria, the initiating events were grouped according to the first three items given 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. Then, sequence-level and system-level success criteria for each group of initiators were identified using thermal-hydraulic analyses.

3.1.2.2.2.1 Initiating Event Grouping

In general, accident sequences have been traditionally grouped according to initiating event type; this categorization scheme has been followed in the Ginna PRA. Table 3.1.2-1 shows the categorization of initiating events with respect to the first three influences listed above.

The impact of initiating events on the core safety functions is the major consideration in the categorization process. It should be recalled that an initiating event is a combination of equipment failures and/or operator actions that leads to a need for reactor trip. All initiators that are followed by a subsequent failure of the reactor trip system have been placed under the Anticipated Transient Without Scram (ATWS) category. Note that in this PRA, ATWS is not caused by any single initiator; rather, it is the combination of initiator occurrence and reactor trip system failure that leads to ATWS sequences.

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 reactor coolant pump (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 heat removal function 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 function. Further, the impact of initiating events on plant system performance has only an indirect influence on the accident sequence grouping process, as noted in Table 3.1.2-1.

3.1.2.2.2.2 Review of Thermal-Hydraulic Analyses

The Ginna UFSAR [Ref. 3.1.2-4] provided the starting point for determination of success criteria. Use of the UFSAR is of limited use for a PRA project, however, 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 PRA (e.g., accident scenarios timelines, which could be used to determine available operator cue times, etc.). Thus, a series of thermal-hydraulic analyses [Refs. 3.1.2-5 - 3.1.2-41] were carried out using the MAAP code [Ref. 3.1.2-42] to determine success criteria. Table 3.1.2-2 lists the analyses performed and their results. A working definition of 1800°F for the hottest core node (TCRHOT) was used to indicate the onset of core damage, but in most cases core heat removal is either clearly lost or clearly maintained. Note that this table only shows the equipment which was available, not necessarily what was used. For example, neither pressurizer PORV opens during larger LOCAs but was assumed to be available.

3.1.2.2.2.3 Reactivity Control Success Criteria

For all initiating events except large LOCAs, the reactivity control safety function is achieved if the reactor protection system (RPS) inserts at least one bank of its rod cluster control assemblies (RCCAs). This success criteria is based on a recent Westinghouse Owners Group (WOG) report that addresses the compliance of Westinghouse PWRs with the ATWS rule [Ref. 3.1.2-43, page 3-5] and states that ". . . the insertion of only one RCCA bank adds sufficient reactivity to preclude peak RCS pressure concerns during the limiting ATWS events." Following large LOCAs, the reactor is shutdown by the presence of boric acid in the RWST and by the loss of moderator due to the LOCA. As such, reactivity control is not required to be identified separately.

3.1.2.2.2.4 RCS Inventory Success Criteria

As discussed in the *Initiating Events Work Package* [Ref. 3.1.2-2], RCS pressure will remain below the PORV setpoint (2335 psig) following a reactor trip if pressurizer spray is operable. Certain initiators inherently lower RCS pressure (e.g., LOCAs, steamline breaks, etc.), and the PORVs will not be challenged following such initiators. Note that several MAAP runs indicate PORV lift during SGTR and SSLOCA initiators; such results are not realistic since MAAP does not consider RPS system delays and ESFAS actuation delays. In practice, the PORVs do not lift following MSIV closure in response to SI actuation.

The Ginna UFSAR [Ref. 3.1.2-4], which discusses the ability of the Ginna ECCS design to meet the requirements of 10 CFR §50.46, states that the makeup flow rate from one charging pump is adequate to sustain pressurizer level at 2250 psia for a break size of 3/8-inch or less equivalent diameter. MAAP run 9S0ABCDE shows that two CVCS pumps will provide RCS inventory control for a 3/8 inch LOCA, but does not demonstrate that only one CVCS is inadequate. The Ginna PRA does not make the distinction of a LOCA small enough to discount inventory control actions.

The result of the MAAP runs is that the LOCA break sizes for Ginna partition into four general categories.

1.	Small-small LOCA (SSLOCA)	<1	cannot depressurize to SI setpoint on break size alone; RCS inventory loss is small enough to allow rapid RCS depressurization to the RHR setpoint using the steam generators if one accumulator is available.
2.	Small LOCA (SLOCA)	1 to 1½	cannot depressurize to SI setpoint on break size alone; further, RCS inventory loss is large enough that it is not possible to depressurize to the RHR setpoint prior to core uncovery
3.	Medium LOCA (MLOCA)	1½ to 5½	slowly depressurizes below the RHR setpoint on break size alone but SI is needed initially to avoid core melt
4.	Large LOCA (LLOCA)	≥ 5½	depressurizes to the RHR setpoint essentially immediately

SSLOCA. MAAP run 9S11BCDE-2 and SLOCA32 demonstrates that 1/3 SI pumps is sufficient for inventory makeup but not for core cooling. Hence, AFW is required for SSLOCAs. Note that for small enough SSLOCAs (approximately a 3/8 inch break), 2 charging pumps are sufficient to provide the inventory control role in place of SI (9S0ABCDE); however, this was not considered since the charging pumps are shed following an SI signal.

Note also that somewhere in the 1/4 inch size range, the break should be small enough to remain within the capacity of one charging pump and could therefore be classified as a transient rather than a LOCA. However, this distinction has not been made for the Ginna PRA project.

MAAP runs SLOCA21, SLOCA22, SLOCA23, SLOCA24, and SLOCA25 confirm the viability of rapid RCS cooldown using the steam generators and accumulators to the RHR setpoint; this action is, thus, a possible recovery of a complete SI system failure during SSLOCAs.

SLOCA. MAAP run 9S11BCDE-2 confirms that 1/3 SI pumps is sufficient for RCS inventory makeup and core cooling, thus, AFW is not required for break sizes greater than one inch equivalent diameter. However, the uncertainties inherent in a thermal-hydraulic code such as MAAP make it difficult to claim that rapid RCS cooldown is a viable recovery option for breaks greater than one inch equivalent diameter (MAAP runs SLOCA26, SLOCA26B, and SLOCA27 indicate sensitivity to break discharge coefficients).

MLOCA. Runs 9S21BC2E, 9S31BCDE, 9S41BC2E, and 9S51BC2E demonstrate that 1/3 SI pumps is sufficient for injection in MLOCAs. Meanwhile, runs 9S3AB12E and 9S4AB12E indicate that the break is not large enough for RHR alone to prevent core damage. Therefore, only 1/3 SI pumps is required until the RWST is depleted. Runs 9S21BCD2 and 9S21BC2E also indicate that the gain from accumulators for a 2 inch LOCA is minimal enough to ignore the accumulators in the MLOCA success criteria.

Finally, run 9S2A2C2E demonstrates that AFW alone is sufficient to reduce RCS pressure to the RHR setpoint, but not prior to the onset of core damage. Since runs 9S21BC2E, 9S31BCDE, and 9S41BC2E demonstrate that 1/3 SI pumps is sufficient for core cooling without AFW, the availability of AFW is of no consequence.

LLOCA. The Ginna UFSAR [Ref. 3.1.2-4], particularly Figure 6.3-4, indicates that a large LOCA begins around the 10 inch equivalent break and maybe as small as a 6 inch equivalent break. MAAP runs 9S5AB12E, 9S6AB12E, and 9S8AB12E show that adequate core cooling is achieved using 1/2 RHR pumps as emergency core coolant injection for LOCAs as small as a 5 inch equivalent break. Note that MAAP run 9S51BC2E indicates that a 5 inch LOCA can also be mitigated using 1/3 SI pumps (i.e., no injection from the RHR pumps). Rather than create a special category of LOCAs which can be mitigated using either 1/3 SI pumps or 1/2 RHR pumps, it was arbitrarily (but conservatively) assumed that LLOCAs encompassed any break greater than 5.5 inches.

SGTR. A steam generator tube has an inner diameter of 0.775 inch [Ref. 3.1.2-4, Table 5.4-2] and since the standard SGTR that is modeled is the break of one tube, this scenario falls within the SSLOCA category of LOCAs. Note that during an SGTR, the affected generator will be filling with water, yet the LOCA characteristics of the SGTR will be reducing the RCS pressure below the PORV setpoint. Hence, even on loss of all feed flow to the S/Gs, the bleed and feed criteria of low S/G level per FR-H.1 [Ref. 3.1.2-44, step 10] will not occur and is not an option for recovery. Therefore, this has not been included in the success criteria.

RCS inventory control following a SGTR event is complicated by the fact that this type of LOCA bypasses the containment; however, the LOCA can be arrested if break flow is terminated by equalizing RCS and ruptured steam generator pressure. Isolation of the ruptured steam generator (e.g., closure of its MSIV, etc.) does not imply termination of break flow; the RCS will continue to depressurize through the break, and the ruptured steam generator pressure will rise to its ARV setpoint. (Note that the ARV setpoint is adjusted to 1050 psig in step 3a of E-3 [Ref. 3.1.2-45], and the operator is not directed to isolate the ARV until steam generator pressure drops below 1050 psig.) Thus, in addition to isolation of the ruptured steam generator, RCS pressure must be lowered below the ARV setpoint of 1050 psig as a necessary condition for break flow termination.

Given the success of SI in the short term, the Ginna EOPs direct the plant operators to partially cooldown and depressure the RCS to below the steam generator ARV setpoint, thereby ensuring that the ARV and safety valves are closed. Note that SI flow must also be terminated once the cooldown depressurization is completed to prevent completely filling the ruptured steam generator, repressurizing it, and challenging its safety valves. An alternative approach, given the failure of SI, is to rapidly cool the RCS to the RHR setpoint using the intact steam generator. MAAP runs RUH2A, RUH2B, and RUH2C support this alternative option. 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.

At the time when RCS and ruptured steam generator pressures are equalized, the break flow rate (which equals the SI flow rate) is about 1.2 to 1.3 ft^3/s (540 to 580 gpm) [Ref. 3.1.2-46, p. 4-4]. The RWST is required to contain a minimum of 300,000 gallons at all times [Ref. 3.1.2-47]; this suggests that either (1) the RWST must be refilled or (2) the RCS must be cooled and depressurized to atmospheric pressure within 8.6 to 9.3 hours if break flow is not terminated (assuming that the equilibrium break flow rate is a reasonable average over the range of RCS pressures).

Another major concern during an SGTR event is preventing the ruptured steam generator from overfilling. As noted above, overfilling the ruptured steam generator may lead to repressurization; of particular concern is failure of the ruptured steam generator ARV to reclose following liquid relief. Concerns have been expressed that the main steam header may collapse following an overfill condition (due to water hammer, static load, etc.); however, it is noted that the steam header was filled during the Ginna SGTR event on January 25, 1982.

Westinghouse has extensively studied steam generator overfill following SGTR events [Ref. 3.1.2-46], calculating the time margin to overfill for a variety of scenarios. The Westinghouse study determines a basecase margin to overfill of 14 minutes, using a conservative set of assumptions (e.g., RCS pressure initially at 2000 psig, higher protection system setpoints, higher decay heat, etc.); the sequence of events is shown in Table 3.1.2-3. The thermal-hydraulic simulation used assumes that both the ARV and the safety valves have the same setpoint. Thus, the resulting plot of steam generator pressure does not indicate ARV/SV closure upon the completion of the RCS depressurization nor after SI termination; however, it is assumed that the time of SI termination is, in fact, the time when the ruptured steam generator's pressure falls below the safety valve setpoint.

Westinghouse considers two key elements in determining the margin to overfill following plant equipment failures: (1) operator action times, and (2) plant response time. For example, failure of the ARV to close on the ruptured steam generator would lead to a delay in the start of RCS cooldown while the operators closed the associated block valve. Similarly, the duration of RCS cooldown is affected by the availability of AFW. In general, the plant response time is proportional to operator action times, but the relationship is not a one-to-one ratio. Additional delays in operator action time following RCS cooldown have less effect since the primary-to-secondary leak rate is lower during this time period. The impact of plant equipment failures on the overfill margin, as calculated by Westinghouse, are summarized in Table 3.1.2-4.

The last scenario, failure to isolate MFW, requires additional explanation to ensure correct interpretation. In the basecase, it was assumed that the MFW control system would initially throttle MFW flow to compensate for leakage into the ruptured steam generator prior to reactor trip, and further throttle MFW flow in response to reduced steam flow following turbine trip. The assessment of failure to isolate MFW flow was based on the assumption that full MFW flow was maintained until automatic MFW isolation occurred following the SI signal.

Westinghouse considered that (1) failure to isolate the steam supply to the turbine-driven AFW pump and (2) failure of the safety valve on the ruptured steam generator to reclose were unlikely events due to system design features. Accordingly, there is no estimate of the impact of these failures on the overfill margin. However, the failure to prevent overfill of the steam generator is assumed to require safety injection to makeup lost inventory.

Seal LOCA. A special source of potential LOCA at Ginna involves the reactor coolant pump (RCP) seals. The combined loss of seal injection to the RCP shaft (CVCS) with the loss of component cooling water (CCW) to the RCP thermal barrier cooling coil in either or both of the RCPs can lead to a degradation in seal integrity and hence a LOCA. Each of these functions, seal injection and thermal barrier cooling, helps maintain the seal's integrity and the functions are redundant [Ref. 3.1.2-4, p. 5.4-42]. Note that failure of injection includes the potential failure to discharge (letdown) as well.

The Ginna seal is a three-stage seal [Ref. 3.1.2-4, 5.4-1 and Figure 5.4-3] (i.e., there are three seals within the sealing assembly of each RCP). The first stage is a variable orifice seal, variable in the sense that by design, volumetric flow rate will increase as RCS pressure decreases. The limiting failure case for a seal with respect to seal leak rate is the catastrophic failure of all three seals in the seal assembly. However, another potential limiting case involves the failure of the second and third seals with the variable orifice seal intact. Since the flow rate would increase over time, the integrated flow might exceed that of the catastrophic failure case.

Westinghouse has extensively studied seal LOCAs [Ref. 3.1.2-48], including the development of an event tree model to catalog the failure types of seal ruptures and thermal hydraulic exercise of a code specifically developed to predict seal flow rates. The net result was that a seal LOCA at Ginna can result in at most, 480 gpm/pump [Ref. 3.1.2-48, p. 10-27] or a total flow rate of 960 gpm. This represents the catastrophic failure of all three stages in both RCP seals. Using standard conversions (see Table 3.1.2-5), this flow is equivalent to a fixed orifice diameter break of 1.04 inches. Table 3.1.2-6 provides additional supporting information.

As noted above, a second limiting case may be the failure of the second and third stages of the seal but the survival of the first stage. The first stage is a variable orifice seal such that leakage from the failed stages will increase in volumetric flow rate as pressure in the RCS decreases, until the RCS is saturated. At normal operating pressure this flow rate is much less than the maximum flow calculated above, but as RCS depressurizes, the integrated flow might compare to the catastrophic failure case.

Three MAAP runs (denoted by SB01[O], SB02[△], SB03[□]) were performed (MAAP assumes fixed orifice seals) to periodically increase the flow rate based on RCS pressure (0.25, 0.5, and 1.0 inches, respectively). These runs also assumed that 1 AFW and 1 SI train was available. Figure 3.1.2-1 shows that RCS pressure easily drops to the SI setpoint of 1723 psig [Ref. 3.1.2-4, Table 7.3-1].

MAAP runs SLOCA22, SLOCA24, SLOCA25, and SLOCA27 also confirm that rapid RCS depressurization using the steam generators to the RHR setpoint is a viable recovery for RCP seal LOCAs. It is noted that a catastrophic failure of all three seal stages in both RCPs is equivalent to a 1.04 inch equivalent diameter break and, thus, suggests that a RCP seal LOCA is an SLOCA. However, this result is based on a conservative set of assumptions (primarily, that all three seal stages fail at the same time); further, the basic scheme used to calculate this equivalent break size is uncertain (e.g., the discharge coefficient used by MAAP is not strictly applicable to RCP seal LOCAs).

Hence, the MAAP runs support the initial assessment that a seal LOCA falls in the SSLOCA category, no matter the seal failure mechanism or number of RCPs affected.

PORV LOCA. According to MAAP runs 9FB12A, 9FB12D, and 9FB12H, a single PORV is enough to depressurize the RCS to the SI setpoint without the aid of AFW. Hence, this LOCA is classified as a MLOCA. In addition, a PORV diameter is 3 inches [Ref. 3.1.2-4, Table 5.4-2] which also falls in the MLOCA category.

3.1.2.2.2.5 RCS Heat Removal Success Criteria

Steam generator cooling is the preferred RCS heat removal scheme for transients (i.e., non-LOCA initiating events) as well as small LOCAs, Seal LOCAs and SGTR sequences. Since each steam generator can remove 50% of the rated thermal power, one steam generator can easily remove the entire decay heat load of the reactor. In order to use the steam generators to remove decay heat, there must be an adequate source of feedwater and a steam vent path. The UFSAR [Ref. 3.1.2-4, p. 10.5-2] states that, "the turbine-driven auxiliary feedwater pump can supply 200% of the required feedwater for removal of decay heat from the plant"; since this pump provides 400 gpm, the implied success criteria for steam generator feedwater is 200 gpm. Feedwater source characteristics are shown in Table 3.1.2-7. The steam vent path can be provided by the steam dump system, the atmospheric relief valves (ARVs), or by the steam generator safety valves when either AFW, MFW, or SAFW is providing the feedwater. If the condensate booster pumps are being used to feed the steam generators, then the ARVs must be used to depressurize the steam generators below the condensate booster pump shutoff head. It should also be noted that a large steamline break will fail the TDAFW as a source of heat removal (i.e., fails driving source).

Primary bleed and feed cooling (BAF) is an alternate method of decay heat removal for transients and small LOCAs in the event that steam generator cooling is lost. The Ginna Emergency Operating Procedures (step 12a of FR-H.1 [Ref. 3.1.2-44]), require operators to "Check SI pumps - AT LEAST ONE RUNNING", indicating that the success criteria for the "feed" portion of bleed and feed as 1/3 SI pumps. Steps 13c and 19 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. MAAP also supports this success criteria. However; MAAP runs 9FB12A, 9FB12D, and 9FB12H indicate that 1/2 PORVs may also be sufficient. Since these options are not provided in the EOPs, the 1/3 SI pumps and 2/2 PORVs is identified as the success criteria for the Ginna PRA. The remaining options can be considered for recovery as necessary.

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 primary bleed and feed 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.

It should be noted that it is conservatively assumed that containment heat removal is required to support the recirculation function; failure of containment heat removal leads to containment failure due to overpressurization and, thus, loss of the containment sump inventory and the recirculation function. 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 to aid in the determination of plant damage states.

3.1.2.2.2.6 Success Criteria Summary

A summary of the sequence-level and system-level success criteria is presented in Table 3.1.2-8.

3.1.2.2.3 Initiators and Inter-System Dependencies Affecting the Safety Functions

The success of the systems that provide the three safety functions discussed in Section 3.1.2.2.1 can be affected by the initiator or subsequent failures of other systems. Most of these kinds of dependencies were identified in the system and model development efforts, where the system interactions were 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 synopsized in Table 3.1.2-9, which indicates how the various initiators used in the PRA model impact some of the systems associated with the safety functions. A description of each initiator is provided in the *Initiating Events Work Package* [Ref. 3.1.2-2].

An initiator dependency may 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 interaction, i.e, is a direct source of the inoperability of the system. The reactivity and inventory control dependencies are challenges (with the exception of seal cooling failures) and the heat removal dependencies are faults of the affected system. For example, SI is challenged either by LOCAs which actually lower RCS inventory or by transients, such as steamline breaks, which lower pressurizer level because of shrinkage due to overcooling. In addition, at Ginna, system interaction between the instrument air system and the pressure control system (pressurizer and PORVs) means that a loss of pressurizer spray, which challenges the PORVs, can be caused by a loss of instrument air which also fails the PORVs closed and hence challenges the pressurizer SRVs. A loss of service water will lead to a manual trip in which charging is tripped and CCW is lost which fails (if only temporarily) all seal cooling, challenging seal integrity. Finally, a steamline or main feedline break in the Intermediate Building produces a steam environment that is assumed to fail all of the auxiliary feedwater pumps. A steamline or feedline break in the Turbine Building is assumed to fail the MFW pumps, instrument air system, and the auxiliary feedwater pumps (due to the block wall which exists between the Turbine and Intermediate Buildings).

Figure 3.1.2-2 is 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 Intermediate Building and Standby Auxiliary Feedwater Pump Building heating, ventilation and air conditioning of the standby auxiliary and auxiliary feedwater pump rooms), and direct water injection (e.g, safety injection into the RCS). Two connections are noted but a decision was made in the PRA based on information from plant personnel that these were not significant supports. Realize also that timing enters some of the connections between bubbles, e.g., the CCW/SW heat exchange may begin immediately but is not required typically until late in a sequence and the HVAC interaction is a long-duration evolution, potentially many hours.

Each of the initiator and inter-system dependencies, as well as others identified in the course of the PRA, 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.

3.1.2.3 Event Tree Development

Core-damage accident sequences have been delineated by translating the success criteria established in Section 3.1.2.2 into Boolean logic. The overall approach used is the "small event tree - large fault tree" method, in which a relatively small set of event trees are developed to address all possible accident sequences. Initiator-specific and sequence-specific effects are captured by embedding initiating events and logic flags into the fault tree models as appropriate, thereby uniquely configuring each fault tree for each accident sequence. This approach was selected because RG&E intends to maintain the Ginna PRA as a "living PRA"; there is only one fault tree per system (not several which contain subtle differences according to the various initiating events and sequences), thus allowing ready and consistent update to plant "as-built" conditions.

Event trees have been developed for transients, SSLOCAs, SLOCAs, MLOCAs, LLOCAs, SGTRs, and ATWS events. Very large LOCAs (reactor vessel rupture, initiator LI0RPVRUPT) by definition cause break flow rates that exceed the capacity of the ECCS; thus, they lead directly to core damage and no event model is required. Interfacing system LOCAs (ISLOCAs) are discussed separately [Ref. 3.1.2-49].

Event tree end states represent one of three possibilities: (1) safe, stable shutdown; (2) core damage; or (3) a transfer to another event tree. The event trees generally address sequences which occur during the first 24 hours following the occurrence of an initiator.

The following sections describe each event tree.

3.1.2.3.1 Transient Event Tree

The transient event tree is a straightforward translation of the success criteria developed in Section 3.1.2.2. Failure of the reactivity control safety function (Event K) is immediately transferred to the ATWS event tree. Two types of transient-induced LOCAs (failure to maintain the RCS integrity safety function) are considered: (1) RCP seal LOCAs (Event Q1), which are transferred to the SSLOCA event tree, and (2) PORV LOCAs (Event Q2), which are transferred to the MLOCA event tree. The RCS heat removal safety function is addressed in four events (B1, L1, UH1, and P1). Events B1 (AFW) and L1 (MFW and SAFW) address failure to remove decay heat using the steam generators. Note that two events have been used since AFW is the preferred source of steam generator feedwater following reactor trip; the use of MFW and SAFW is a recovery action. Events UH1 (failure of SI flow) and P1 (failure of the PORVs) address primary bleed-and-feed. Two events have been used to separate the core-damage sequences arising from failure to achieve bleed-and-feed for the Level 2 analysis. Initial success of bleed-and-feed is transferred to the MLOCA event tree for consideration of the low pressure recirculation function and containment heat removal function. (Note: It is conservatively assumed that containment failure due to overpressure results in a loss of low pressure recirculation capability following bleed-and-feed.)

The transient event tree generates 32 core-damage sequences, as described in the following sections.

3.1.2.3.1.1 Sequence T/B1/L1/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCS integrity is preserved (no RCP seal LOCA - success of Event Q1, and no PORV LOCA - success of Event Q2). All steam generator cooling is lost (Events B1 and L1), and bleed-and-feed cooling is commenced (success of Events UH1 and P1). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Events UH1 or P1). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.2 Sequence T/B1/L1/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCS integrity is preserved (no RCP seal LOCA - success of Event Q1, and no PORV LOCA - success of Event Q2). All steam generator cooling is lost (Events B1 and L1), and bleed-and-feed cooling is commenced (success of Events UH1 and P1). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Events UH1 or P1). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.3 Sequence T/B1/L1/XL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCS integrity is preserved (no RCP seal LOCA - success of Event Q1, and no PORV LOCA - success of Event Q2). All steam generator cooling is lost (Events B1 and L1), and bleed-and-feed cooling is commenced (success of Events UH1 and P1). Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.4 Sequence T/B1/L1/P1

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCS integrity is preserved (no RCP seal LOCA - success of Event Q1, and no PORV LOCA - success of Event Q2). All steam generator cooling is lost (Events B1 and L1), and the SI pumps are started in preparation for bleed-and-feed cooling is commenced (success of Event UH1). However, the PORVs fail to open (Event P1) and, thus, core cooling is lost due to failure to establish a bleed path.

This sequence is totally defined in the transient event tree.

3.1.2.3.1.5 Sequence T/B1/L1/UH1

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCS integrity is preserved (no RCP seal LOCA - success of Event Q1, and no PORV LOCA - success of Event Q2). All steam generator cooling is lost (Events B1 and L1), and bleed-and-feed cooling is required to reestablish core cooling. However, the SI pumps fail to operate (Event UH1) and, thus, core cooling is lost due to failure to establish a feed source.

This sequence is totally defined in the transient event tree.

3.1.2.3.1.6 Sequence T/Q2/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is preserved (success of Event Q1); however, a PORV or SV sticks open following its lift due to loss of pressurizer spray or fast closure of the MSIVs (Event Q2). High pressure injection is established (success of Event UH2), thus providing short-term RCS inventory control and heat removal. Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.7 Sequence T/Q2/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is preserved (success of Event Q1); however, a PORV or SV sticks open following its lift due to loss of pressurizer spray or fast closure of the MSIVs (Event Q2). High pressure injection is established (success of Event UH2), thus providing short-term RCS inventory control and heat removal. Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.8 Sequence T/Q2/XL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is preserved (success of Event Q1); however, a PORV or SV sticks open following its lift due to loss of pressurizer spray or fast closure of the MSIVs (Event Q2). High pressure injection is established (success of Event UH2), thus providing short-term RCS inventory control and heat removal. Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.9 Sequence T/Q2/UH2

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is preserved (success of Event Q1); however, a PORV or SV sticks open following its lift due to loss of pressurizer spray or fast closure of the MSIVs (Event Q2). High pressure injection is not established (Event UH2) and, thus, core cooling is lost due to failure to establish an injection source.

This sequence originates in the transient event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.10 Sequence T/Q1/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.11 Sequence T/Q1/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.12 Sequence T/Q1/XH

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is not achieved (Event XH); thus, core cooling is lost.

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.13 Sequence T/Q1/B1/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan

coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.14 Sequence T/Q1/B1/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.15 Sequence T/Q1/B1/XH

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is not achieved (Event XH); thus, core cooling is lost.

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.16 Sequence T/Q1/B1/L1/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA and the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.17 Sequence T/Q1/B1/L1/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA and the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.18 Sequence T/Q1/B1/L1/XL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.19 Sequence T/Q1/B1/L1/P2

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Since the steam generators are not operating (Events B1 and L1), it is not possible to rapidly depressurize to LPI conditions. Bleed-and-feed cooling is the only method to restore core cooling; note that the SI pumps are already operating in response to the RCP seal LOCA. However, the PORVs fail to open (Event P2) and, thus, core cooling is lost due to failure to establish a bleed path. (Note: the bleed path must be larger than that produced by a seal LOCA.)

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.1.20 Sequence T/Q1/UH2/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition

of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.2.1.3.1.21 Sequence T/Q1/UH2/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.22 Sequence T/Q1/UH2/XL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); however, upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.23 Sequence T/Q1/UH2/UL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection does not operate (Event UL); thus, core cooling is lost.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.24 Sequence T/Q1/UH2/UA

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is not maintained due to accumulator failure (Event UA). Thus, core cooling is lost during the RCS depressurization period.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.25 Sequence T/Q1/UH2/P3SS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head also fails (Event P3SS) even though AFW is available (success of Event B1). Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.26 Sequence T/Q1/UH2/B1/FC/XCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.27 Sequence T/Q1/UH2/B1/FC/UCS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the RCP seal LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.28 Sequence T/Q1/UH2/B1/XL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); however, upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.29 Sequence T/Q1/UH2/B1/UL

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection does not operate (Event UL); thus, core cooling is lost.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.30 Sequence T/Q1/UH2/B1/UA

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is not maintained due to accumulator failure (Event UA). Thus, core cooling is lost during the RCS depressurization period.

This sequence originates in the transient event tree, transfers to the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.1.31 Sequence T/Q1/UH2/B1/P3SS

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head also fails (Event P3SS) even though MFW or SAFW is available (success of Event L1; note that AFW has failed - Event B1). Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.1.32 Sequence T/Q1/UH2/B1/L1

Following the occurrence of a transient initiator (Event T), the reactor is successfully shutdown (success of Event K). RCP seal integrity is lost (Event Q1), starting a small-small LOCA. High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head is not possible since AFW (Event B1), MFW, and SAFW (Event L1) are not available. Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence originates in the transient event tree, and terminates in the small-small LOCA event tree.

3.1.2.3.2 Small-Small LOCA Event Tree

The SSLOCA event tree is a straightforward translation of the success criteria developed in Section 3.1.2.2. Failure of the reactivity control safety function (Event K) is immediately transferred to the ATWS event tree. Given the success of high pressure injection (success of Event UH2), the event tree addresses failure of steam generator heat removal (Events B1 and L1, as used in the transient event tree) which is needed to ensure that RCS pressure falls below the SI shutoff head, failure of primary bleed-and-feed given a complete loss of steam generator heat removal (Event P2), the transition into high pressure recirculation (Event XH), and the status of containment heat removal (Events FC, UCS, and XCS). (Similar to Section 3.1.2.3.1 above, it is assumed that containment failure due to overpressure results in a loss of high pressure recirculation capability.) The successful establishment of bleed-and-feed is transferred to the MLOCA event tree. If there is no SI flow, the SSLOCA event considers a rapid depressurization of the RCS (Event P3SS) to the RHR setpoint to allow use of the low pressure injection system; note that sequences in which the RCS is successfully depressurized are transferred to the LLOCA event tree (to address failures in the accumulators, LPI, LPR, and containment heat removal).

The SSLOCA event tree generates 23 core-damage sequences, as described in the following sections.

3.1.2.3.2.1 Sequence SS/FC/XCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.2 Sequence SS/FC/UCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.3 Sequence SS/XH

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and AFW (success of Event B1). Upon RWST depletion, high pressure recirculation is not achieved (Event XH); thus, core cooling is lost.

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.4 Sequence SS/B1/FC/XCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.5 Sequence SS/B1/FC/UCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.6 Sequence SS/B1/XH

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates to replenish RCS inventory (success of Event UH2); RCS pressure is maintained below the shutoff head of the SI pumps through use of the steam generators and MFW or SAFW (success of Event L1; note that AFW is unavailable - Event B1). Upon RWST depletion, high pressure recirculation is not achieved (Event XH); thus, core cooling is lost.

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.7 Sequence SS/B1/L1/FC/XCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA and the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.2.8 Sequence SS/B1/L1/FC/UCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA and the PORVs (the bleed path for bleed-and-feed cooling). It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.2.9 Sequence SS/B1/L1/XL

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Bleed-and-feed cooling is initiated by opening the PORVs (success of Event P2). Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.2.10 Sequence SS/B1/L1/P2

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection operates in an attempt to replenish RCS inventory (success of Event UH2); however, RCS pressure remains above the shutoff head of the SI pumps due to failure of all steam generators feedwater (AFW failure - Event B1, MFW and SAFW failure - Event L1). Since the steam generators are not operating (Events B1 and L1), it is not possible to rapidly depressurize to LPI conditions. Bleed-and-feed cooling is the only method to restore core cooling; note that the SI pumps are already operating in response to the small-small LOCA. However, the PORVs fail to open (Event P2) and, thus, core cooling is lost due to failure to establish a bleed path.

This sequence originates in the small-small LOCA event tree, and terminates in the medium LOCA event tree.

3.1.2.3.2.11 Sequence SS/UH2/FC/XCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.12 Sequence SS/UH2/FC/UCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.13 Sequence SS/UH2/XL

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); however, upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.14 Sequence SS/UH2/UL

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection does not operate (Event UL); thus, core cooling is lost.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.15 Sequence SS/UH2/UA

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); since AFW is available (success of Event B1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is not maintained due to accumulator failure (Event UA). Thus, core cooling is lost during the RCS depressurization period.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.16 Sequence SS/UH2/P3SS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head also fails (Event P3SS) even though AFW is available (success of Event B1). Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.17 Sequence SS/UH2/B1/FC/XCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.18 Sequence SS/UH2/B1/FC/UCS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the small-small LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UL). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.19 Sequence SS/UH2/B1/XL

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection operates (success of Event UL); however, upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.20 Sequence SS/UH2/B1/UL

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is maintained via the accumulators (success of Event UA). Low pressure injection does not operate (Event UL); thus, core cooling is lost.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.21 Sequence SS/UH2/B1/UA

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); even though AFW is failed (Event B1), MFW or SAFW is available (success of Event L1), and a rapid RCS depressurization using the steam generators (success of Event P3SS) is successful in lowering pressure to the RHR pump shutoff head. During the depressurization, RCS inventory is not maintained due to accumulator failure (Event UA). Thus, core cooling is lost during the RCS depressurization period.

This sequence originates in the small-small LOCA event tree, and terminates in the large LOCA event tree.

3.1.2.3.2.22 Sequence SS/UH2/B1/P3SS

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head also fails (Event P3SS) even though MFW or SAFW is available (success of Event L1; note that AFW has failed - Event B1). Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.2.23 Sequence SS/UH2/B1/L1

Following the occurrence of a small-small LOCA (Event SS), the reactor is successfully shutdown (success of Event K). High pressure injection fails (Event UH2); a rapid RCS depressurization using the steam generators to the RHR pump shutoff head is not possible since AFW (Event B1), MFW, and SAFW (Event L1) are not available. Thus, core cooling is lost while the RCS remains pressurized above the RHR pump shutoff head.

This sequence is totally defined in the small-small LOCA event tree.

3.1.2.3.3 Small LOCA Event Tree

The SLOCA event tree is a straightforward translation of the success criteria developed in Section 3.1.2.2. Failure of the reactivity control safety function (Event K) is immediately transferred to the ATWS event tree. SI system failure (Event UH2) leads directly to core damage since, as discussed in Section 3.1.2.2, it is not possible to rapidly depressurize the RCS to the RHR setpoint prior to significant core voiding. Note that for SLOCAs, the break itself will depressurize the RCS below the SI pump shutoff head; hence, the steam generators are not required and do not appear in the SLOCA event tree. The remaining events address the transition into high pressure recirculation (Event XH) and the status of containment heat removal (Events FC, UCS, and XCS). (Similar to Section 3.1.2.3.1 above, it is assumed that containment failure due to overpressure results in a loss of high pressure recirculation capability.)

The SLOCA event tree generates four core-damage sequences, as described in the following sections.

3.1.2.3.3.1 Sequence S/FC/XCS

Following the occurrence of a small LOCA (Event S), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small LOCA event tree.

3.1.2.3.3.2 Sequence S/FC/UCS

Following the occurrence of a small LOCA (Event S), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, high pressure recirculation is achieved (success of Event XH). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain high pressure recirculation).

This sequence is totally defined in the small LOCA event tree.

3.1.2.3.3.3 Sequence S/XH

Following the occurrence of a small LOCA (Event S), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, high pressure recirculation is not achieved (Event XH); thus, core cooling is lost.

This sequence is totally defined in the small LOCA event tree.

3.1.2.3.3.4 Sequence S/UH2

Following the occurrence of a small LOCA (Event S), the reactor is successfully shutdown (success of Event K). However, the SI pumps fail to operate (Event UH2) and, thus, core cooling is lost due to loss of RCS inventory.

This sequence is totally defined in the small LOCA event tree.

3.1.2.3.4 Medium LOCA Event Tree

The MLOCA event tree is a straightforward translation of the success criteria developed in Section 3.1.2.2. Failure of the reactivity control safety function (Event K) is immediately transferred to the ATWS event tree. SI system failure (Event UH2) leads directly to core damage. The remaining events address the transition into low pressure recirculation (Event XL) and the status of containment heat removal (Events FC, UCS, and XCS). (Similar to Section

3.1.2.3.1 above, it is assumed that containment failure due to overpressure results in a loss of low pressure recirculation capability.)

The MLOCA event tree generates four core-damage sequences, as described in the following sections.

3.1.2.3.4.1 Sequence M/FC/XCS

Following the occurrence of a medium LOCA (Event M), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence is totally defined in the medium LOCA event tree.

3.1.2.3.4.2 Sequence M/FC/UCS

Following the occurrence of a medium LOCA (Event M), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Event UH2). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence is totally defined in the medium LOCA event tree.

3.1.2.3.4.3 Sequence M/XL

Following the occurrence of a medium LOCA (Event M), the reactor is successfully shutdown (success of Event K). The SI pumps operate (success of Event UH2) to provide high pressure injection. Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence is totally defined in the medium LOCA event tree.

3.1.2.3.4.4 Sequence M/UH2

Following the occurrence of a medium LOCA (Event M), the reactor is successfully shutdown (success of Event K). However, the SI pumps fail to operate (Event UH2) and, thus, core cooling is lost due to loss of RCS inventory.

This sequence is totally defined in the medium LOCA event tree.

3.1.2.3.5 Large LOCA Event Tree

The LLOCA event tree is a straightforward translation of the success criteria developed in Section 3.1.2.2. No reactivity control event is required per the success criteria. Modeled events include: (1) failure of the accumulators (Event UA), (2) failure of low pressure injection (Event UL), (3) failure of low pressure recirculation (Event XL), and (4) the status of containment heat removal (Events FC, UCS, and XCS). (Similar to Section 3.1.2.3.1 above, it is assumed that containment failure due to overpressure results in a loss of low pressure recirculation capability.)

The LLOCA event tree generates five core-damage sequences, as described in the following sections.

3.1.2.3.5.1 Sequence A/FC/XCS

Following the occurrence of a large LOCA (Event A), the core is immediately reflooded by the accumulators (success of Event UA). Low pressure injection operates to maintain short-term RCS inventory control and cooling (success of Event UL). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Events UH1 or P1). Containment spray injection operates (success of Event UCS); however, containment spray recirculation fails (Event XCS). Thus, core cooling is lost when the containment fails since the sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence is totally defined in the large LOCA event tree.

3.1.2.3.5.2 Sequence A/FC/UCS

Following the occurrence of a large LOCA (Event A), the core is immediately reflooded by the accumulators (success of Event UA). Low pressure injection operates to maintain short-term RCS inventory control and cooling (success of Event UL). Upon RWST depletion, low pressure recirculation is achieved (success of Event XL). The containment fan coolers fail to operate (Event FC), necessitating the use of the containment spray system to prevent containment overpressurization due to continued addition of RCS inventory from the LOCA. It is assumed that the containment fan coolers fail while the RWST is in use (i.e., during Events UH1 or P1). Containment spray injection fails (Event UCS); thus, core cooling is lost shortly after recirculation begins since the containment sump inventory is depleted through the ruptured containment (required to sustain low pressure recirculation).

This sequence is totally defined in the large LOCA event tree.

3.1.2.3.5.3 Sequence A/XL

Following the occurrence of a large LOCA (Event A), the core is immediately reflooded by the accumulators (success of Event UA). Low pressure injection operates to maintain short-term RCS inventory control and cooling (success of Event UL). Upon RWST depletion, low pressure recirculation is not achieved (Event XL); thus, core cooling is lost.

This sequence is totally defined in the large LOCA event tree.

3.1.2.3.5.4 Sequence A/UL

Following the occurrence of a large LOCA (Event A), the core is immediately reflooded by the accumulators (success of Event UA). However, the RHR pumps fail to operate (Event UL) and, thus, core cooling is lost due to loss of RCS inventory.

This sequence is totally defined in the large LOCA event tree.

3.1.2.3.5.5 Sequence A/UA

Following the occurrence of a large LOCA (Event A), core reflood does not occur due to failure of the accumulators (Event UA). As previously discussed, it is assumed that the RHR pumps alone (low pressure injection) cannot supply water fast enough to prevent core damage without the accumulators.

3.1.2.3.6 Steam Generator Tube Rupture Event Tree

In addition to accounting for the success criteria developed in Section 3.1.2.2, the SGTR event tree has been developed in consideration of (1) the needs of the human reliability analysis and the Level 2 analysis, and (2) the impact of various equipment failures upon the plant response. The SGTR event tree proceeds in a chronological manner (i.e., from left to right across the event headings); this ordering is not the most efficient with respect to minimization of the total number of sequences, but was selected to assist in understanding and use of the event tree.

The first two events (Event I1 and I2) address failure to isolate the ruptured steam generator steam header (excluding the ARV) and the AFW supply; failure of either implies overfill of the ruptured steam generator. Overfill is an important plant condition for two reasons:

1. Liquid flow through the ruptured steam generator ARV will occur, increasing the probability that it will fail to reclose when RCS and ruptured steam generator pressures are reduced, and

2. The likelihood that the rupture location remains submerged during core-damage accident progression is increased if the ruptured steam generator is in an overfill condition.

The third isolation-related event (Event I3) pertains to reclosure of the ruptured steam generator ARV; it is located after events which address the conditions necessary for the ARV to reclose (i.e., after RCS cooldown and depressurization, which implies the need for cooling from the intact steam generator). Event I3 has been split into two events (I3S and I3L) to address the different reclosure probabilities following steam or liquid flow through the ARV. The occurrence of Events I1 or I3 implies a continual loss of RCS inventory unless the RCS is completely depressurized; Event I2 is not a directly threat to RCS inventory control, but rather establishes the boundary conditions for Event I3 (either steam or liquid relief).

If the SI system is operating (success of Event UH2), the plant operators will perform a short RCS cooldown and depressurization (Event D) to quickly reclose the ruptured steam generator ARV. Once the ruptured ARV is reclosed (implying that pressure is less than 1070 psig), RCS inventory control is regained. However, failure to establish RCS inventory control (caused by either a failed-open ARV - Event I3, or an unisolated steam header - Event I1) necessitates the need to rapidly depressurize the RCS in order to terminate break flow and RCS inventory loss. Two events are important: (1) Event P3TR, which represents use of the intact steam generator ARV to cool the plant to the RHR setpoint, and (2) Event SC, which represents the establishment of RHR cooling. It is assumed that once RHR cooling is established, the break flow can be controlled either through (1) continued depressurization to atmospheric pressure, or (2) use of normal RCS makeup (e.g., CVCS).

If the SI system is not working (Event UH2), it is also possible to rapidly depressurize the RCS to the RHR setpoint prior to significant core voiding.

The SGTR event tree generates 27 core-damages, as described in the following sections.

3.1.2.3.6.1 Sequence R/I3S/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2), and AFW is supplied to the intact S/G (success of Event B1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D); these actions prevent the ruptured S/G from overfilling. However, the ARV on the ruptured S/G fails to reseat following steam relief (Event I3S), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is commenced (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.2 Sequence R/D

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2), and AFW is supplied to the intact S/G (success of Event B1). However, RCS cooldown or depressurization is not successful (Event D), leading to eventual core uncovery when the RWST is depleted.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.3 Sequence R/B1/I3S/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2). AFW to the intact S/G fails (Event B1), and MFW or SAFW is used to ensure steam generator cooling (success of Event L1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D); these actions prevent the ruptured S/G from overfilling. However, the ARV on the ruptured S/G fails to reseat following steam relief (Event I3S), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is commenced (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.4 Sequence R/B1/D

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2). AFW to the intact S/G fails (Event B1), and MFW or SAFW is used to ensure steam generator cooling (success of Event L1). However, RCS cooldown or depressurization is not successful (Event D), leading to eventual core uncovery when the RWST is depleted.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.5 Sequence R/B1/L1

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2). However, intact steam generator cooling is lost due to failure of AFW (Event B1), MFW, and SAFW (Event L1); thus, RCS cooldown and depressurization is not possible, and the core uncovers when the RWST is depleted. Note that operators cannot utilize feed and bleed since the water level in the ruptured steam generator prevents entering procedure FR-H.1.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.6 Sequence R/UH2/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI fails to operate (Event UH2), but AFW is available to ensure cooling of the intact steam generator (success of Event B1). A cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.7 Sequence R/UH2/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI fails to operate (Event UH2), but AFW is available to ensure cooling of the intact steam generator (success of Event B1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.8 Sequence R/UH2/B1/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI fails to operate (Event UH2) and AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). A cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.9 Sequence R/UH2/B1/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI fails to operate (Event UH2) and AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.10 Sequence R/UH2/B1/L1

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); AFW is also isolated (success of Event I2), preventing overfill from this source. SI operates to replenish RCS inventory (success of Event UH2). However, intact steam generator cooling is lost due to failure of AFW (Event B1), MFW, and SAFW (Event L1); thus, RCS cooldown and depressurization is not possible, leading to relatively short-term core uncovery when the RWST is depleted. Note that operators cannot use feed and bleed since the water level in the ruptured steam generator prevents entering procedure FR-H.1.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.11 Sequence R/I2/I3L/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2), and AFW is supplied to the intact S/G (success of Event B1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D). However, the ARV on the ruptured S/G fails to reseat following liquid relief caused by the overfill (Event I3L), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is commenced (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.12 Sequence R/I2/I3L/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2), and AFW is supplied to the intact S/G (success of Event B1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D). However, the ARV on the ruptured S/G fails to reseat following liquid relief caused by the overfill (Event I3L), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is not achieved prior to core uncovery (Event P3TR) since liquid flow through the stuck open ARV does not provide the necessary cooldown.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.13 Sequence R/I2/D

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2), and AFW is supplied to the intact S/G (success of Event B1). However, RCS cooldown or depressurization is not successful (Event D), leading to eventual core uncovery when the RWST is depleted.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.14 Sequence R/I2/B1/I3L/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2). AFW to the intact S/G fails (Event B1), and MFW or SAFW is used to ensure steam generator cooling (success of Event L1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D). However, the ARV on the ruptured S/G fails to reseat following liquid relief due to the overfill (Event I3L), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is commenced (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.15 Sequence R/I2/B1/I3L/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2). AFW to the intact S/G fails (Event B1), and MFW or SAFW is used to ensure steam generator cooling (success of Event L1). RCS cooldown and depressurization are achieved to reduce RCS pressure below the S/G ARV setpoint, and SI flow is terminated (success of Event D). However, the ARV on the ruptured S/G fails to reseat following liquid relief due to the overfill (Event I3L), leading to a constant loss of RCS inventory through the broken tube and stuck-open ARV. A cooldown to RHR conditions is not achieved prior to core uncovery (Event P3TR) since liquid flow through the stuck open ARV does not provide the necessary cooldown.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.16 Sequence R/I2/B1/D

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2). AFW to the intact S/G fails (Event B1), and MFW or SAFW is used to ensure steam generator cooling (success of Event L1). However, RCS cooldown or depressurization is not successful (Event D), leading to eventual core uncovery when the RWST is depleted.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.17 Sequence R/I2/B1/L1

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2). However, intact steam generator cooling is lost due to failure of AFW (Event B1), MFW, and SAFW (Event L1); thus, RCS cooldown and depressurization is not possible, and the core uncovers when the RWST is depleted.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.18 Sequence R/I2/UH2/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI fails to operate (Event UH2), but AFW is available to ensure cooling of the intact steam generator (success of Event B1). A cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.19 Sequence R/I2/UH2/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI fails to operate (Event UH2), but AFW is available to ensure cooling of the intact steam generator (success of Event B1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.20 Sequence R/I2/UH2/B1/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI fails to operate (Event UH2) and AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). A cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.21 Sequence R/I2/UH2/B1/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI fails to operate (Event UH2) and AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.22 Sequence R/I2/UH2/B1/L1

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is isolated (success of Event I1); however, AFW is not isolated in time to prevent overfill (Event I2). SI operates to replenish RCS inventory (success of Event UH2); further, intact steam generator cooling is lost due to failure of AFW (Event B1), MFW, and SAFW (Event L1). Thus, RCS cooldown and depressurization is not possible, leading to relatively short-term core uncovery.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.23 Sequence R/I1/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is not isolated (Event I1), causing a continual loss of RCS inventory until the RCS is completely depressurized. Note that SI operation may delay this sequence, but eventually SI will fail due to RWST depletion. AFW flow is available to the intact steam generator (success of Event B1), and a cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR). However, RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.24 Sequence R/I1/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is not isolated (Event I1), causing a continual loss of RCS inventory until the RCS is completely depressurized. Note that SI operation may delay this sequence, but eventually SI will fail due to RWST depletion. AFW is available to ensure cooling of the intact steam generator (success of Event B1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.25 Sequence R/I1/B1/SC

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is not isolated (Event I1), causing a continual loss of RCS inventory until the RCS is completely depressurized. Note that SI operation may delay this sequence, but eventually SI will fail due to RWST depletion. AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). A cooldown to RHR conditions is commenced and completed before substantial voiding occurs in the RCS (success of Event P3TR), but RHR cannot be established (Event SC).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.26 Sequence R/I1/B1/P3TR

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is not isolated (Event I1), causing a continual loss of RCS inventory until the RCS is completely depressurized. Note that SI operation may delay this sequence, but eventually SI will fail due to RWST depletion. AFW fails to operate (Event B1), but MFW or SAFW operates to ensure cooling of the intact steam generator (success of Event L1). However, a cooldown to RHR conditions is not completed before substantial voiding occurs in the RCS (Event P3TR).

This sequence is totally defined in the SGTR event tree.

3.1.2.3.6.27 Sequence R/I1/B1/L1

Following the occurrence of a SGTR (Event R), the reactor is successfully shutdown (success of Event K). The ruptured S/G steam header is not isolated (Event I1), causing a continual loss of RCS inventory until the RCS is completely depressurized. Note that SI operation may delay this sequence, but eventually SI will fail due to RWST depletion. Intact steam generator cooling is lost due to failure of AFW (Event B1), MFW, and SAFW (Event L1); thus, RCS cooldown and depressurization is not possible, leading to relatively short-term core uncovery.

This sequence is totally defined in the SGTR event tree.

3.1.2.3.7 Anticipated Transients Without Scram Event Tree

The ATWS event tree is based on the work of the Westinghouse Owners Group [Ref. 3.1.2-43], including the underlying success criteria and placement of events in the event tree. The generic ATWS event tree developed by the WOG has been adapted to the Ginna plant by linking Ginna-specific fault tree models for major systems (e.g., MFW, AFW, etc.). The reactivity control safety function has been parsed into two events: (1) Event KM, which addresses mechanical failures of the control rod drive system, and (2) Event KE, which addresses failures of the RPS and scram breakers. This distinction has been made to account for possible recovery options using the control rods. If the scram failure is due to mechanical causes (Event KM), then the control rods are assumed to be stuck in their pre-trip positions; no further recoveries (e.g., manual rod insertion, etc.) are possible. If the scram failure is due to failures in the RPS or the scram breakers (Event KE), then manual rod insertion is possible and is considered in the ATWS event tree. (Note that failure to trip the control rod drive MG sets is considered under Event KE.) The RCS integrity safety function involves seven events (PL, MF, RI, AM, FF, PF, and PR). During an ATWS event, RCS pressure may exceed 3200 psig (the maximum allowable limit for RCS integrity) depending on: (1) the initial power level (Event PL), (2) the availability of MFW (Event MF), (3) whether or not manual rod insertion occurs (Event RI), (4) whether or not AMSAC actuates, (5) the availability of AFW given that MFW is not available, (6) the time in the fuel cycle, and (7) operation of the pressurizer SVs and PORVs. In the event tree structure, the first six events establish boundary conditions for the actual primary pressure relief event (Event PR). Event PR is split into four events (Events PR1, PR2, PR3, and PR4) to account for the various combinations of manual rod insertion success/failure and AFW flow; the influence of fuel cycle life is considered in the top logic for these four events.

The ATWS event tree generates 24 core-damage sequences, as described in the following sections.

3.1.2.3.7.1 Sequence IE/KE/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is less than 40% (success of Event PL); thus, RCS integrity is assured since there is no possibility of a pressure pulse greater than 3200 psig. Short-term core cooling is provided by 50% of the total installed AFW capacity (success of Event PF). However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.2 Sequence IE/KE/PF

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is less than 40% (success of Event PL); thus, RCS integrity is assured since there is no possibility of a pressure pulse greater than 3200 psig. Short-term core cooling is not provided due to complete failure of AFW (Event PF), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.3 Sequence IE/KE/PL/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL); RCS integrity is assured due to continued MFW operation (success of Event MF). However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.4 Sequence IE/KE/PL/MF/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI), AMSAC actuates (success of Event AM), and full AFW is available (success of Event FF); RCS pressure is maintained less than 3200 psig (success of Event PR1) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.5 Sequence IE/KE/PL/MF/PR1

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI), AMSAC actuates (success of Event AM), and full AFW is available (success of Event FF); however, RCS pressure exceeds 3200 psig (Event PR1) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.6 Sequence IE/KE/PL/MF/FF/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI), AMSAC actuates (success of Event AM), and 50% AFW is available (failure of Event FF, and success of Event PF); RCS pressure is maintained less than 3200 psig (success of Event PR2) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.7 Sequence IE/KE/PL/MF/FF/PR2

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI), AMSAC actuates (success of Event AM), and 50% AFW is available (failure of Event FF, and success of Event PF); however, RCS pressure exceeds 3200 psig (Event PR2) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.8 Sequence IE/KE/PL/MF/FF/PF

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI) and AMSAC actuates (success of Event AM); however, no AFW is available (failure of Events FF and PF), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.9 Sequence IE/KE/PL/MF/AM

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are inserted (success of Event RI); however, AMSAC fails to actuate (Event AM), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.10 Sequence IE/KE/PL/MF/RI/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI), AMSAC actuates (success of Event AM), and full AFW is available (success of Event FF); RCS pressure is maintained less than 3200 psig (success of Event PR3) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.11 Sequence IE/KE/PL/MF/RI/PR3

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI), AMSAC actuates (success of Event AM), and full AFW is available (success of Event FF); however, RCS pressure exceeds 3200 psig (Event PR3) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.12 Sequence IE/KE/PL/MF/RI/FF/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI), AMSAC actuates (success of Event AM), and 50% AFW is available (failure of Event FF, and success of Event PF); RCS pressure is maintained less than 3200 psig (success of Event PR4) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.13 Sequence IE/KE/PL/MF/RI/FF/PR4

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI), AMSAC actuates (success of Event AM), and 50% AFW is available (failure of Event FF, and success of Event PF); however, RCS pressure exceeds 3200 psig (Event PR4) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.14 Sequence IE/KE/PL/MF/RI/FF/PF

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI) and AMSAC actuates (success of Event AM); however, no AFW is available (failure of Events FF and PF), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.15 Sequence IE/KE/PL/MF/RI/AM

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not the control rods are manually inserted, (2) whether or not AMSAC actuates to trip the turbine, (3) the amount of feedwater available, (4) the time in core life, and (5) operation of the pressurizer SVs and PORVs. In this sequence, control rods are not inserted (Event RI) and AMSAC fails to actuate (Event AM), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.16 Sequence IE/KM/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is less than 40% (success of Event PL); thus, RCS integrity is assured since there is no possibility that a pressure pulse greater than 3200 psig. Short-term core cooling is provided by 50% of the total installed AFW capacity (success of Event PF). However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.17 Sequence IE/KM/PF

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL): RCS integrity is assured due to continued MFW operation (success of Event MF). However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.18 Sequence IE/KM/PL/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to an electrical malfunction in the RPS (Event KE). Reactor power prior to the initiator is greater than 40% (Event PL); RCS integrity is assured due to continued MFW operation (success of Event MF). However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.19 Sequence IE/KM/PL/MF/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. Note that manual control rod insertion is not possible due to the mechanical failure of the control rods. In this sequence, AMSAC actuates (success of Event AM) and full AFW is available (success of Event FF); RCS pressure is maintained less than 3200 psig (success of Event PR3) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.20 Sequence IE/KM/PL/MF/PR3

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. Note that manual control rod insertion is not possible due to the mechanical failure of the control rods. In this sequence, AMSAC actuates (success of Event AM) and full AFW is available (success of Event FF); however, RCS pressure exceeds 3200 psig (Event PR3) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.21 Sequence IE/KM/PL/MF/FF/LT

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. Note that manual control rod insertion is not possible due to the mechanical failure of the control rods. In this sequence, AMSAC actuates (success of Event AM) and 50% AFW is available (failure of Event FF, and success of Event PF); RCS pressure is maintained less than 3200 psig (success of Event PR4) due to either a combination of favorable core life and SV/PORV operation. However, the reactor must be rendered subcritical to ensure long-term core cooling; emergency boration fails (Event LT), leading to core damage.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.22 Sequence IE/KM/PL/MF/FF/PR4

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. Note that manual control rod insertion is not possible due to the mechanical failure of the control rods. In this sequence, AMSAC actuates (success of Event AM) and 50% AFW is available (failure of Event FF, and success of Event PF); however, RCS pressure exceeds 3200 psig (Event PR4) due to either an unfavorable core life and/or failure of the pressurizer SVs and/or PORVs.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.23 Sequence IE/KM/PL/MF/FF/PF

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. Note that manual control rod insertion is not possible due to the mechanical failure of the control rods. In this sequence, AMSAC actuates (success of Event AM); however, no AFW is available (failure of Events FF and PF), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.3.7.24 Sequence IE/KM/PL/MF/AM

Following the occurrence of an initiating event (Event IE), the reactor fails to trip due to a mechanical malfunction of the control rods (Event KM). Reactor power prior to the initiator is greater than 40% (Event PL) and MFW fails (Event MF); thus, an RCS pressure pulse greater than 3200 psig is possible, depending on (1) whether or not AMSAC actuates to trip the turbine, (2) the amount of feedwater available, (3) the time in core life, and (4) operation of the pressurizer SVs and PORVs. In this sequence, AMSAC fails to actuate (Event AM), leading to loss of RCS integrity due to overpressurization.

This sequence is totally defined in the ATWS event tree.

3.1.2.4 Supporting Top Logic

The Ginna PRA uses a common set of top logic fault trees to represent the failure (downbranch) of the events in the core-damage event trees. Table 3.1.2-10 indicates the usage of the various top logic fault trees in the various event trees. The following sections describe the top logic fault trees.

3.1.2.4.1 Event AM

Event AM accounts for the initiation of AFW by the ATWS Mitigation System Actuation Circuitry (AMSAC). This circuitry actuates all AFW pumps and sends a turbine trip signal. The probability that AMSAC fails is based on generic Westinghouse data.

3.1.2.4.2 Event B1

Event B1 accounts for achieving steam generator cooling with AFW. Note that AFW is the normal steam generator supply following reactor trip at Ginna; the MFW system is placed in standby. A long-term source of water was assumed to be required since a single CST only provides enough water to remove decay heat for two hours after a reactor from full power [Ref. 3.1.2-4, Section 10.5.2.2]. The preferred contingency is to go to a closed loop flow configuration

from the main condenser hotwell back through the CSTs. This cooling mode is essentially permanent assuming the availability of the hotwell, etc. Further contingencies are detailed in EOP ER-AFW.1 [Ref. 3.1.2-50] and are modeled in the AFW system fault tree model.

3.1.2.4.3 Event D

Event D accounts for cooldown and depressurization of the RCS following SGTRs in accordance with steps 13 and 20 of EOP E-3 [Ref. 3.1.2-45]. This event is only applicable when SI is in operation (success of Event UH2). Failure of Event D implies that RCS and ruptured S/G pressure remains above the adjusted ARV setpoint (1070 psig) and, thus, that primary-to-secondary break flow is not terminated. The only cooldown mechanism modeled is use of the intact steam generator ARV.

3.1.2.4.4 Event FC

Event FC accounts for the availability of the containment fan coolers following reactor trip. The occurrence of Event FC implies that all four containment fan coolers have failed. This event is important whenever the containment is being pressurized (e.g., during LOCAs and bleed-and-feed operations) as it implies the need to start the containment spray system (Events UCS and XCS). Containment failure due to overpressurization is important to both the Level 1 (core damage assessment) and the Level 2 (containment performance assessment) analyses. For the Level 1 analysis, containment failure implies loss of containment sump recirculation capability (both HPR and LPR). For the Level 2 analysis, containment failure implies a direct radionuclide release pathway to the environment.

3.1.2.4.5 Event FF

Event FF accounts for the availability of all three AFW pumps sending flow to both steam generators following an ATWS event. Event FF is used in the ATWS event tree in combination with another AFW-related event (Event PF), manual control rod insertion (Event RI), and primary relief events (Events PR1, PR2, PR3, and PR4) to determine if RCS pressure exceeds 3200 psig.

3.1.2.4.6 Event I1

Event I1 accounts for isolation of the steam side of the ruptured S/G following SGTR. The occurrence of Event I1 implies that the ruptured S/G steam header is not isolated, leading to a constant loss of RCS inventory until the RCS is completely depressurized. There are several pathways which must be isolated, including the SVs, the MSIV, the turbine-driven AFW pump steam supply, the blowdown lines, the blowdown sample lines, and various vent and drain valves (the ruptured S/G ARV is treated separately by Events I3S and I3L). These pathways are of

varying size and, hence, the time required to void the RCS (and time required to deplete the RWST) is a function of which pathway is not isolated.

3.1.2.4.7 Event I2

Event I2 accounts for isolation of AFW into the ruptured S/G following SGTR. The occurrence of Event I2 implies that AFW is not isolated in time to prevent overfill of the ruptured S/G, leading to liquid flow through the ARV.

3.1.2.4.8 Event I3L

Event I3L accounts for failure of the ruptured S/G ARV to reclose following liquid flow through the valve caused by ruptured S/G overfill following SGTR.

3.1.2.4.9 Event I3S

Event I3S accounts for failure of the ruptured S/G ARV to reclose following steam flow through the valve; this condition implies that no overfill of the ruptured S/G occurs following SGTR.

3.1.2.4.10 Event KE

Event KE accounts for the availability of the electrical portions of the reactor scram function (including the RPS, the reactor scram breakers, and failure of the plant operators to trip the control rod drive MG sets within one minute). Failure of Event KE implies that the RPS signal has failed and that the operator has failed to initiate a manual scram. The probability of Event KE is based on generic Westinghouse data.

3.1.2.4.11 Event KM

Event KM accounts for the availability of the mechanical portions of the reactor scram function (including the control rod drives). Failure of Event KM implies that the control rods cannot be inserted into the reactor core by any means. The probability of Event KM is based on generic Westinghouse data.

3.1.2.4.12 Event L1

Event L1 accounts for some of the possible activities of restoring steam generator cooling following the loss of AFW. The occurrence of Event L1 represents the failure of all of these restoration events. Restoration of steam generator cooling includes four possibilities: (1) restoration of AFW, (2) restoration of MFW, (2) use of SAFW, and (4) implementation of secondary system blowdown to use condensate flow. Event L1 models the MFW and SAFW options only. Restoration of AFW is considered on a cut-set-basis during the recovery analysis. The bleed-and-feed cooling criterion would typically arise before sufficient depressurization to use condensate cooling could be affected, particularly after subtracting the time taken up by the preferred secondary restoration activities. Hence, the blowdown/condensate option is conservatively not model.

3.1.2.4.13 Event LT

Event LT accounts for the ultimate shutdown of the reactor following an ATWS event using emergency boration.

3.1.2.4.14 Event MF

Event MF accounts for the availability of MFW following an ATWS event; the occurrence of Event MF implies that MFW has failed. The loss of MFW following an ATWS poses a challenge to the RCS integrity critical safety function since peak RCS pressure may exceed 3200 psig. The Event MF top logic is a simplified fault tree model, accounting for major MFW support systems and the impact of initiating events which directly fail MFW.

3.1.2.4.15 Event P1

Event P1 accounts for the availability of the PORVs during bleed-and-feed operations initiated following transient initiators. The occurrence of Event P1 implies that either PORV has failed to manually open. Note that bleed-and-feed in the transient event tree is modeled using both Events UH1 and P1; failure to open the PORVs in accordance with step 13 of EOP FR-H.1 [Ref. 3.1.2-44] is included within the definition of event RCHFD01BAF, which appears in the Event UH1 top logic.

3.1.2.4.16 Event P2

Event P2 accounts for the availability of the PORVs during bleed-and-feed operations initiated following SSLOCAs. The occurrence of Event P2 implies that either PORV has failed to manually open. Note that bleed-and-feed in the SSLOCA event tree is modeled using both Events UH2 and P2; failure to open the PORVs in accordance with step 13 of EOP FR-H.1 [Ref. 3.1.2-44] is included within the definition of event RCHFD01BAF, which appears in the Event P2 top logic. The treatment of bleed-and-feed for SSLOCAs differs from that of transients with respect to the human error modeling since the SI pumps are automatically started during SSLOCAs by ESFAS.

3.1.2.4.17 Event P3SS

Event P3SS accounts for rapid RCS cooldown and depressurization to the RHR setpoint using the steam generators following SSLOCAs. The occurrence of Event P3SS implies that the RCS is not cooled to the RHR setpoint in accordance with step 19 of EOP E-2 [Ref. 3.1.2-51] (which transfers to ES-1.2 [Ref. 3.1.2-52]) prior to core uncovery. Event P3SS is a recovery action for failure of the SI pumps (Event UH2) in the SSLOCA event tree. The only cooldown mechanism modeled is use of the steam generator ARVs since the turbine bypass system is unavailable due to closure of the MSIVs by the SI signal.

3.1.2.4.18 Event P3TR

Event P3TR accounts for rapid RCS cooldown and depressurization to the RHR setpoint using the intact steam generator following SGTRs. The occurrence of Event P3SS implies that the RCS is not cooled to the RHR setpoint in accordance with EOP ES-3.1 [Ref. 3.1.2-53] prior to core uncovery. Event P3SS is a recovery action for failure of the SI pumps (Event UH2) in the SGTR event tree. The only cooldown mechanism modeled is use of the intact steam generator ARV.

3.1.2.4.19 Event PF

Event PF accounts for the availability of 50% AFW flow (i.e., either the turbine-driven pump or both motor-driven pumps) following an ATWS event. Event PF is used in the ATWS event tree in combination with another AFW-related event (Event FF), manual control rod insertion (Event RI), and primary relief events (Events PR1, PR2, PR3, and PR4) to determine if RCS pressure exceeds 3200 psig.

3.1.2.4.20 Event PL

Event PL accounts for the reactor power level immediately prior to an ATWS event; the occurrence of Event PL means that power is greater than 40%. High initial power is one of the conditions that may lead to challenge of the RCS integrity critical safety function following an ATWS. The Event PL probability has been quantified from plant-specific data.

3.1.2.4.21 Event PR1

Event PR1 accounts for maintenance of RCS integrity following an ATWS, given that manual rod insertion has succeeded and 100% AFW flow is available. The failure of Event PR1 implies that RCS peak pressure has exceeded 3200 psig. The probability of Event PR1 is based on the operability of the PORVs and pressurizer SVs at various times in the fuel cycle.

3.1.2.4.22 Event PR2

Event PR2 accounts for maintenance of RCS integrity following an ATWS, given that manual rod insertion has succeeded and 50% AFW flow is available. The failure of Event PR2 implies that RCS peak pressure has exceeded 3200 psig. The probability of Event PR2 is based on the operability of the PORVs and pressurizer SVs at various times in the fuel cycle.

3.1.2.4.23 Event PR3

Event PR3 accounts for maintenance of RCS integrity following an ATWS, given that manual rod insertion has failed and 100% AFW flow is available. The failure of Event PR3 implies that RCS peak pressure has exceeded 3200 psig. The probability of Event PR3 is based on the operability of the PORVs and pressurizer SVs at various times in the fuel cycle.

3.1.2.4.24 Event PR4

Event PR4 accounts for maintenance of RCS integrity following an ATWS, given that manual rod insertion has failed and 50% AFW flow is available. The failure of Event PR4 implies that RCS peak pressure has exceeded 3200 psig. The probability of Event PR4 is based on the operability of the PORVs and pressurizer SVs at various times in the fuel cycle.

3.1.2.4.25 Event Q1

Event Q1 accounts for the possibility for transient-induce LOCAs due to failure of one or both RCP seal assemblies. Seal LOCA is assumed to occur upon the loss of both RCP seal support system (seal injection from CVCS and thermal barrier cooling via CCW) when the RCP is operating. Additional logic (gate TNOTQ1) models failure of the RCPs to operating following a reactor trip (e.g., due to loss of electrical power supply, etc.). Sequences which contain the success of Event Q1 are reviewed, and cut sets which appear that are common with either the Event Q1 cut sets or the TNOTQ1 cut sets are removed (using the Delete-Term option in CAFTA). Sequences which contain the failure of Event Q1 are transferred to the SSLOCA event tree.

3.1.2.4.26 Event Q2

Event Q2 accounts for the possibility of transient-induced LOCAs due to stuck-open PORVs or pressurizer SVs. Following an uncomplicated reactor trip, the pressurizer spray valves open to limit RCS pressure below the PORV setpoint; failure of pressurizer spray is assumed to cause a PORV challenge [Ref. 3.1.2-2]. If both PORVs fail to open, it is assumed that the pressurizer SVs will be challenged. Certain initiators inherently cause low RCS pressure immediately after reactor trip, and additional logic (gate TNOTQ2) has been developed accordingly. Sequences which contain the success of Event Q2 are reviewed, and cut sets which appear that are common with either the Event Q2 cut sets or the TNOTQ2 cut sets are removed (using the Delete-Term option in CAFTA). Sequences which contain the failure of Event Q2 are transferred to the MLOCA event tree.

3.1.2.4.27 Event RI

Event RI accounts for the achievement of manual control rod insertion by the operators within the first minute of an ATWS sequence (step 1 of FR-S.1 [Ref. 3.1.2-54]). Note that success of this event does not preclude the need for long-term reactor shutdown. Event RI is used in the ATWS event tree in combination with AFW-related events (Event FF and PF) and primary relief events (Events PR1, PR2, PR3, and PR4) to determine if RCS pressure exceeds 3200 psig.

3.1.2.4.28 Event SC

Event SC accounts for the availability of the RHR system following SGTR events. The occurrence of Event SC implies that normal RHR cooling, in accordance with EOP ES-3.1 [Ref. 3.1.2-53], step 10 has not been established.

3.1.2.4.29 Event UA

Event UA accounts for the availability of the accumulators during LLOCA sequences. Failure of Event UA implies that both accumulators have failed and inject their contents into the RCS.

3.1.2.4.30 Event UCS

Event UCS accounts for the availability of the containment spray system in the injection mode. Initial results of the Level 2 analysis suggest that the containment spray system is not required following LOCAs or bleed-and-feed operations if at least one containment fan cooler is operating (success of Event FC). The occurrence of Event UCS implies that both containment spray trains have failed. Containment failure due to overpressurization is important to both the Level 1 (core damage assessment) and the Level 2 (containment performance assessment) analyses. For the Level 1 analysis, containment failure implies loss of containment sump recirculation capability (both HPR and LPR). For the Level 2 analysis, containment failure implies a direct radionuclide release pathway to the environment.

3.1.2.4.31 Event UH1

Event UH1 accounts for manual actuation and operation of the SI system during primary bleed-and-feed operations. Failure of Event UH1 implies loss of flow from all SI pump trains. The logic for Event UH1 includes a human failure event (RCHFD01BAF) which represents failure to implement bleed-and-feed in accordance with EOP FR-H.1 [Ref. 3.1.2-44], step 11. Note that bleed-and-feed is modeled using both Events UH1 and P1; failure to open the PORVs in accordance with EOP FR-H.1 [Ref. 3.1.2-44], step 13 is included within the definition of event RCHFD01BAF.

3.1.2.4.32 Event UH2

Event UH2 accounts for automatic actuation and operation of the SI system during SSLOCA, SLOCA, MLOCA, and SGTR sequences. Failure of Event UH2 implies loss of flow from all SI pump trains. Actuation failures are modeled within the ESFAS fault tree, which is linked to the SI fault tree during the quantification process.

3.1.2.4.33 Event UL

Event UL accounts for the injection phase during a large LOCA. Since 1/2 RHR pumps is sufficient, the occurrence of Event UL implies the failure of both RHR trains. The RHR system fault tree model considers the possibility of flow diversion through a broken RHR pipe which is directly connected to the RCS.

3.1.2.4.34 Event XCS

Event XCS accounts for the availability of the containment spray system in the recirculation mode. Initial results of the Level 2 analysis suggest that the containment spray system is not required following LOCAs or bleed-and-feed operations if at least one containment fan cooler is operating (success of Event FC). The occurrence of Event XCS implies that both containment spray trains have failed. Containment failure due to overpressurization is important to both the Level 1 (core damage assessment) and the Level 2 (containment performance assessment) analyses. For the Level 1 analysis, containment failure implies loss of containment sump recirculation capability (both HPR and LPR). For the Level 2 analysis, containment failure implies a direct radionuclide release pathway to the environment.

3.1.2.4.35 Event XH

Event XH accounts for the implementation of high pressure recirculation (HPR) from the containment sump. The MAAP runs performed to establish success criteria (see Section 3.1.2.2) indicates that the RCS pressure will remain above the RHR setpoint at the time when the RWST is depleted for SSLOCAs and SLOCAs. HPR is accomplished by supplying the SI pumps with containment sump water which is provided by the RHR system; note that decay heat is removed using the RHR heat exchangers.

3.1.2.4.36 Event XL

Event XL accounts for the establishment of low pressure, cold leg recirculation from the containment sump. The occurrence of Event XL represents the failure of both RHR trains in sump recirculation mode to provide flow cooled by the RHR heat exchangers to the RCS.

3.1.2.5 Modeling Interfaces

Definition of accident sequences necessarily involves consideration of how the various PRA technical tasks interact to generate the final project results. Among the most important tasks are the systems analysis task (fault tree development), the human reliability analysis, and the Level 2 analysis (particularly, the development of plant damage states). The following sections summarize these interfaces.

3.1.2.5.1 Systems Analysis

The top logic links the various system-level fault trees to the occurrence of the event tree headings; Table 3.1.2-11 provides a complete of the various system-level top events involved.

3.1.2.5.2 Human Reliability Analysis

An important consideration in defining human failure events (HFEs) in the integrated model (including the top logic and the system-level fault trees) is the treatment of dependencies; this issue is particularly difficult to treat across the various system-level fault trees since these fault trees have been developed by several analysts. Thus, a search of the top logic and all system-level fault trees was conducted to (1) identify all HFEs, (2) relate the HFEs to the event tree headings, and (3) ensure that their dependencies are considered. Table 3.1.2-12 lists all HFEs which appear in the integrated model, and shows how they relate to the accident sequence events. It should be noted that the final system-level fault trees may contain other HFEs which are not used in the Level 1 analysis (e.g., they pertain to the Level 2 analysis, or are otherwise not used). The summary of the MAAP runs presented Section 3.1.2.2 provides detailed timing information for possible use in the quantification of the HFEs (e.g., cue times, available response times, etc.).

3.1.2.5.3 Level 2 Analysis

As noted in Section 3.1.2.1, the definition of plant damage states (PDSs) is performed by the Level 2 analysis [Ref. 3.1.2-55]; however, the core-damage events trees have been structured, in part, to support the assignment of PDSs. For example, the failure of primary bleed-and-feed may be caused by either failure of the SI system or failure of the PORVs to open. The specific failure involved is of great importance to the Level 2 analysis since it establishes the initial and boundary conditions for the post-core-melt accident progression analysis (e.g., the presence or absence of injection flow, the RCS pressure, etc.). The following sections discuss how the core-damage event tree structure is useful in assigning PDS vectors to the Level 1 results.

3.1.2.5.3.1 Containment Bypass

Containment bypass is indicated for all ISLOCA and certain SGTR sequences.

3.1.2.5.3.2 Containment Isolation Status

This attribute is not generally addressed in the Level 1 PRA; the closure of certain containment penetrations is modeled where such closures impact system performance (e.g., IA to the containment, etc.). Note that failures of support systems (e.g., DC power) which lead to core damage may also preclude closure of certain containment penetrations.

3.1.2.5.3.3 Transient or LOCA Type

The initiating event type is readily discernable from the event tree which generates the core-damage sequence.

3.1.2.5.3.4 Reactor Shutdown

The reactor is not shutdown (i.e., is generating significant fission power) in all ATWS core-damage sequences.

3.1.2.5.3.5 Station Blackout

This attribute is not generally addressed in the Level 1 PRA. There is no separate event tree for station blackout; rather, station blackout sequences arise from the transient sequences due to failures in the AC power system. In general, station blackout sequences will be initiated by one of the two initiators related to loss of offsite power (TI00GRLOSP and TI00SWLOSP); however, the Level 1 PRA is also capable of producing station blackout sequences with other initiators (in such cases, the loss of offsite power occurs after reactor trip).

3.1.2.5.3.6 Power Recovery

Restoration of offsite power is considered in the recovery analysis of the Level 1 PRA.

3.1.2.5.3.7 RCS Pressure

RCS pressure at the time of core damage may be inferred from the event tree structure on a sequence-specific basis.

3.1.2.5.3.8 Status of In-Vessel Injection

The occurrence of Events UH1 or UH2 indicate failure of all SI during the injection phase: Event XH addresses failures of high pressure recirculation. Failure of low pressure injection is indicated by the occurrence of Event UL; Event UX addresses low pressure recirculation. Failure of the accumulators is indicated by the occurrence of Event UA.

In certain cases, it is possible to infer if the RHR pumps are operating in a "deadhead" situation (i.e., RCS pressure is above the RHR pump shutoff head). Note that the Level 1 event trees do not always ascertain the operation of each injection source. For example, the SLOCA event tree does not contain Event UL since low pressure injection cannot be used to mitigate an SLOCA; note that the RHR pumps would be automatically started on all LOCAs. It is not generally correct to assume RHR system operation since the failures which cause the sequence to progress to core damage may also imply failure of the RHR system.

Initial experience with the Level 1 sequences suggests that the most probable injection source failures are not recoverable.

3.1.2.5.3.9 Containment Fan Coolers

The containment fan coolers are known to be failed whenever Event FC occurs.

3.1.2.5.3.10 Containment Spray

The containment spray system is known to be failed whenever Events UCS (injection) or XCS (recirculation) occur.

3.1.2.5.3.11 Steam Generator Isolated

The steam side of the ruptured steam generator is known to be unisolated whenever Events I1, I3S, or I3L occur. Failure to isolate AFW to the ruptured steam generator occurs whenever Event I2 occurs.

3.1.2.5.3.12 Steam Generator Break Covered

This attribute is not explicitly modeled in the Level 1 PRA. Overfill of the ruptured steam generator is indicated by the occurrence of Events I1 or I2; however, the time and duration of overfill with respect to the onset of core damage is not specified.

3.1.2.6 References

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3.1.2-23 Rochester Gas & Electric Corporation, *Ginna PRA MAAP Run 9FB12D*, September 17, 1993.

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Table 3.1.2-1 CATEGORIZATION OF INITIATORS WITH RESPECT TO SUCCESS CRITERIA					
Initiator Type	*Impact on Core Safety Functions*			*Impact on Plant System Performance*	*Level 2 Analysis Considerations*
	Reactivity Control	*RCS Inventory Control*	*RCS Heat Removal*		
transients	None; transients followed by reactor trip system failure are grouped under the ATWS category.	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.	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, CIS).
LOCAs	None; LOCAs followed by reactor trip system failure are grouped under the ATWS category.	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. The initiator leading to a transient-induced LOCA may degrade plant system performance.	Major impact, depending on the location of the LOCA. LOCAs in SI or RHR injection piping will partially failure 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 RPS.	Major impact if the peak pressure exceeds the RCS design pressure limit.	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 3.1.2-2
SUMMARY OF MAAP RUNS TO SUPPORT SUCCESS CRITERIA

Case	IE	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accumulators	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	2	2	1	2	• isolate ruptured S/G at time=0 • AFW to intact S/G only • C/D on intact S/G 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	2	1	1	2	• isolate ruptured S/G at time=0 • AFW to intact S/G only • C/D on intact S/G 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	2	0	1	2	• isolate ruptured S/G at time=0 • AFW to intact S/G only • C/D on intact S/G at time=45 m • accumulators blocked at 300 psia	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	2	0	1	2	• RUH2C with ruptured S/G safety valve 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	2	0	1	2	• RUH2C with ruptured S/G safety valve failed open at 20 m	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	2	0	1	2	• 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	2	0	1	2	• 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	2	0	1	2	• RUH2G with intact S/G ARV opened wide at 30 m	no	

Table 3.1.2-2
SUMMARY OF MAAP RUNS TO SUPPORT SUCCESS CRITERIA

Case	*IE*	*LOCA Size and Location*	*CVCS Pumps*	*SI Pumps*	*RHR Pumps*	*Accumulators*	*AFW Pumps*	*PORVs*	*Other Initial and Boundary Conditions*	*Core Above 1800F*	*Results*
RUH2I	SGTR	• 4.9E-3 ft^2 (one tube) • hot leg of S/G • 0.50 ft above tube sheet	0	0	2	0	1	2	• RUH2G with intact S/G ARV opened wide at 45 m	no	• this MAAP run suggests that rapid RCS cooldown can be delayed up to 30 m following the failure to isolate the ruptured S/G header • a 45 m delay was acceptable, but MAAP support team suggested using the 30 m case (RUH2H) to account for any uncertainties
SLOCA21	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=45 m • accumulators blocked at 300 psia	no	• reach RHR shutoff head at time=3.5 h • PORV lift; MAAP modeling issue
SLOCA22	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • (SLOCA21 with RCP LOCA, delayed depressurization, and rapid cooldown)	no	• little change from SLOCA21 • PORV lift; MAAP modeling issue
SLOCA23	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • (SLOCA21 with delayed depressurization and rapid cooldown)	no	• little change from SLOCA21
SLOCA24	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • VFSEP=0.3 • (SLOCA22 with VFSEP=0.3)	no	• comparible to SLOCA22 • PORV lift; MAAP modeling issue
SLOCA25	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • VFSEP=0.7 • (SLOCA22 with VFSEP=0.7)	no	• TCRHOT slightly increases, but turned around by RHR flow • PORV lift; MAAP modeling issue

Table 3.1.2-2
SUMMARY OF MAAP RUNS TO SUPPORT SUCCESS CRITERIA

Case	IE	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accumulators	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
SLOCA26	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • VFSEP=0.7 • FCDBRK=1.0 • (SLOCA25 with FCDBRK=1.0)	yes	• core uncovers and heats up to 2000F even with accumulators dumping • PORV lift; MAAP modeling issue
SLOCA26B	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• C/D on both S/G at time=60 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • VFSEP=0.7 • FCDBRK=1.0 • (SLOCA26 using both S/G ARVs)	yes	• core heats up to 2000F • PORV lift; MAAP modeling issue
SLOCA27	LOCA	• 5.9E-3 ft^2 (1.04 inch) • cold leg (RCP node)	0	0	2	1	1	2	• isolate one S/G at time=0 • C/D on other S/G at time=45 m • accumulators blocked at 300 psia • tried to force C/D at 100 F/h • VFSEP=0.7 • FCDBRK=1.0 • (SLOCA26 with earlier cooldown)	no	• core uncovers, but only heats up to 1000F
9FB12A	LMFW	N/A	0	1	2	2	0	1	• no MFW or SAFW	yes	• core temperature reaches 2500 F, but does not go to core melt • BAF cue at time=1385.7 s
9FB12D	LMFW	N/A	0	1	2	2	0	1	• 9FB12A, except that 1 CVCS pump is initially operating (turned off during bleed-and-feed)	yes	• core temperature reaches 1800F, but does not melt • BAF cue at time=846.8 s
9FB12G	LMFW	N/A	0	1	2	2	0	2	• 9FB12A with 2 PORVs	no	• brief core uncovery • BAF cue at time=1385.7 s • RWST depleted at time=13.5 h
9FB12H	LMFW	N/A	0	2	2	2	0	1	• 9FB12A with 1 PORV and 2 SI pumps	no	• BAF cue at time=1385.7 s • recirc at time=24104.8 s
FB13E	LMFW	N/A	0	3	2	2	0	2	• no MFW or SAFW • delay the start of BAF until 0.5 h after cue is received	no	• S/G level reached 3ft at time=0.4 h • BAF initiated at time=1 h

Table 3.1.2-2
SUMMARY OF MAAP RUNS TO SUPPORT SUCCESS CRITERIA

Case	IE	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accumulators	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
9S0ABCDE	LOCA	• 7.7E-4 ft^2 (3/8 inch) • hot leg	2	0	0	0	0	2	• no MFW or SAFW	no	• 2 CVCS pumps can provide core cooling for very small LOCAs; note that CVCS pumps are tripped by SI signal • PORV lift; MAAP modeling issue
SLOCA32	LOCA	• 3.1E-2 ft^2 (0.75 inch) • cold leg	0	1	0	0	0	2	• rerun of 9S11BCDE-2 with 0.75 inch dia LOCA to confirm need for S/G cooling for SSLOCAs	yes	• confirms that S/G cooling is needed for LOCAs < 1 inch dia
9S11BCDE	LOCA	• 5.4E-3 ft^2 (1 inch) • hot leg	0	1	0	0	0	2	• no MFW or SAFW	no	• indeterminate; CVCS flow may be providing core cooling (CVCS pumps tripped by SI signal)
9S11BCDE-2	LOCA	• 5.4E-3 ft^2 (1 inch) • hot leg	0	1	0	0	0	2	• rerun of 9S11BCDE without CVCS pumps	no	• confirms that S/G cooling is not needed for LOCAs > 1 inch dia • RWST depleted at time=13.5 h
9S21BCD2	LOCA	• 2.2E-2 ft^2 (2 inch) • hot leg	0	1	0	2	0	2	• no MFW or SAFW	no	• RWST depleted at time=10.9 h
9S21BC2E	LOCA	• 2.2E-2 ft^2 (2 inch) • hot leg	2	1	0	0	0	2	• no MFW or SAFW	no	• confirms MLOCA success criteria • RWST depleted at time=11 h
9S2A2C2E	LOCA	• 2.2E-2 ft^2 (2 inch) • hot leg	0	0	0	0	1	2		yes	• fuel heatup starts at time=0.52 h • fuel reaches 1800F at time=0.72 h • RCS pressure above RHR pump shutoff head during fuel heatup
9S31BCDE	LOCA	• 4.9E-2 ft^2 (3 inch) • hot leg	0	1	0	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=11 h • RCS pressure below RHR pump shutoff head at time of recirc switchover
9S3AB12E	LOCA	• 4.9E-2 ft^2 (3 inch) • hot leg	0	0	1	2	0	2	• no MFW or SAFW	yes	• confirms that SI is required for 3 inch dia LOCAs; RCS will not depressurize to RHR pump shutoff head prior to core damage
9S41BC2E	LOCA	• 8.7E-2 ft^2 (4 inch) • hot leg	0	1	0	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=10.2 h
9S4AB12E	LOCA	• 8.7E-2 ft^2 (4 inch) • hot leg	0	0	1	0	0	2	• no MFW or SAFW	yes	• confirms that SI is required for 4 inch dia LOCAs; RCS will not depressurize to RHR pump shutoff head prior to core damage

Table 3.1.2-2
SUMMARY OF MAAP RUNS TO SUPPORT SUCCESS CRITERIA

Case	IE	LOCA Size and Location	CVCS Pumps	SI Pumps	RHR Pumps	Accumulators	AFW Pumps	PORVs	Other Initial and Boundary Conditions	Core Above 1800F	Results
9S5AB12F	LOCA	• 1.4E-1 ft^2 (5 inch) • hot leg	0	0	1	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=2.3 h
9S5IBC2E	LOCA	• 1.4E-1 ft^2 (5 inch) • hot leg	0	1	0	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=8.5 h
9S6AB12E	LOCA	• 2.0E-1 ft^2 (6 inch) • hot leg	0	0	1	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=2.1 h
9S8AB12E	LOCA	• 3.5E-1 ft^2 (8 inch) • hot leg	0	0	1	0	0	2	• no MFW or SAFW	no	• RWST depleted at time=2.1 h

Table 3.1.1-3 CONSERVATIVE BASECASE SGTR TIME SEQUENCE AS DETERMINED BY WESTINGHOUSE		
Event	*Time (s)*	*Notes*
Isolation of ruptured S/G	600	S/G isolation is assumed to occur at either 10 m, or when S/G reaches 33%
Start RCS cooldown	904	The delay from S/G isolation to the start of cooldown is assumed to be 5 m
Complete RCS cooldown	1354	
Start RCS depressurization	1476	The delay from completion of S/G cooldown to the start of depressurization is assumed to be 2 m
Complete RCS depressurization	1538	
Terminate SI	1618	The delay from completion of depressurization to SI termination is 160 s (assumed 1 m delay, plus 100 s to reach SI termination criterion)

Table 3.1.1-4 EFFECT OF PLANT EQUIPMENT FAILURES ON OVERFILL MARGIN AS DETERMINED BY WESTINGHOUSE			
Equipment Failure	*Assumed Delay (m)*	*Decrease in Overfill Margin (m)*	*Extrapolated Delay Required to Cause Overfill (m)*
failure to isolate AFW to ruptured S/G	2	4	7
ruptured S/G AVR fails open at 10 m	5, 20, 30	0	failure to isolate the ruptured S/G ARV does not impact the overfill margin
failure to close ruptured S/G MSIV (analysis assumed a loss of offsite power; thus, the steam dump was closed)	4	4	7
failure to isolate MFW	3.9	3.9	7

Table 3.1.1-5
SEAL LOCA SUPPORT CALCULATIONS

Standard formula:

$Q = v\ \dot{m}$ where Q is the volumetric flow rate (gpm)

v is the specific volume (ρ^{-1}, $ft^3/lb\text{-}m$)

$\dot{m}$ is the mass flow rate (lb-m/s)*

MAAP formula [42]

$\dot{m} = A_b G C_d$ where A_b is the area of the break (in^2)

G is the mass flux ($lb\text{-}m/ft^2\text{-}s$)

C_d is break discharge coefficient (0.75 per [42])*

$$A_b = \frac{\pi}{4}\left(\frac{d}{12}\right)^2 \ (ft^2)$$

$= 5.4542\ 10^{-3}\ d^2$ where d is the diameter of the break (in)

Per ASME steam tables:

v ($ft^3/lb\text{-}m$) at 550°F	p=2200	p=2250	p=2300
	0.02135	0.021335	0.02132

The value of 0.021335 for 2250 psi is used.

This results in:

$Q = 0.021335\ (ft^3/lb\text{-}m) \cdot 7.48\ (g/ft^3) \cdot 60\ (s/m) \cdot 5.4542\ 10^{-3}\ (ft^2) \cdot 0.75 \cdot G\ (lb\text{-}m/ft^2\text{-}s) \cdot d^2$ (gpm)†

or $Q = 0.039169 \cdot 22{,}767 \cdot d^2$ (gpm) where G is calculated in Table 6

or $Q = 891.8\ d^2$ (gpm).

Hence, $d = 1.04$ in when $Q = 960$ gpm.

* Note that the units must be converted for consistency.
† Units are converted for consistency.

Table 3.1.1-6
MASS FLUX CALCULATION
(Supports Table 3.1.1-5)

MAAP formula [42]:

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

where G is the mass flux (lb-m/ft^2-s)
p_u is the upstream pressure (psi)
r is max (η_{crit}, p_d/p_u)
v is specific volume (ft^3/lb-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, η = 0.83.

Thus, η_{crit} = min (0.83, 1050/2250) = 0.47 and r = max (0.47, 14.7/2250) = 0.47

This results in:

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

or G^2 = 518,339,254.7 (lb-m^2/ft^4-s^2)

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

* Note that the units must be converted for consistency.
† Units are converted for consistency.
ζ This value is consistent with other Westinghouse calculations.

Table 3.1.1-7 FEEDWATER SOURCE CHARACTERISTICS			
System	*Pump Configuration*	*Pump Characteristics*	*UFSAR [Ref. 3.1.1-4] Reference*
Auxiliary Feedwater (AFW)	2 motor-driven 1 turbine-driven	200 gpm at 1085 psig 400 gpm at 1085 psig	p. 10.5-5
Main Feedwater (MFW)	2 motor-driven	7400 gpm at 1015 psig	p. 10.4-6
Standby Auxiliary Feedwater (SAFW)	2 motor-driven	200 gpm at 1085 psig	p. 10.5-6
Condensate	3 motor-driven	9400 gpm	p. 10.4-3

Table 3.1.2-8 SEQUENCE-LEVEL AND SYSTEM-LEVEL SUCCESS CRITERIA			
Initiator Group	*Reactivity Control*	*RCS Inventory Control*	*RCS Heat Removal*
transients	RPS	RCP seal integrity: RCP seal injection or thermal barrier cooling for all RCPs and PORV/SV closure: pressurizer spray or PORV reclosure/isolation and SV reclosure (following failure of PORVs to lift)	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: 2/2 PORVs and 1/3 SI pumps (HPI) and 1/2 RHR pumps (LPI) and 1/2 RHR heat exchangers (LPR)
SSLOCAs (< 1")	RPS	HPI: S/G cooling to allow RCS depressurization to SI pump shutoff head and 1/3 SI pumps or LPI and LPR: rapid cooldown to LPI conditions using the steam generators and 1/2 accumulators and 1/2 RHR pumps	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: 2/2 PORVs and 1/3 SI pumps (HPI) and 1/2 RHR pumps (LPI) and 1/2 RHR heat exchangers (LPR) or LPI and LPR: 1/2 RHR pumps and 1/2 RHR heat exchangers (LPR)
SLOCAs (1"-1.5")	RPS	HPI and HPR: 1/3 SI pumps (HPI) and 1/2 RHR pumps (HPR)	HPI and HPR: 1/3 SI pumps (HPI) and 1/2 RHR pumps (HPR) and 1/2 RHR heat exchangers (HPR)
MLOCAs (1.5"-5.5")	RPS	HPI: 1/3 SI pumps and LPR: 1/2 RHR pumps	HPI: 1/3 SI pumps and LPR: 1/2 RHR pumps and 1/2 RHR heat exchangers
LLOCAs (> 5.5")	not required	LPI and LPR: 1/2 RHR pumps and short-term core flood: 1/2 accumulators	LPI and LPR: 1/2 RHR pumps and 1/2 RHR heat exchangers

Table 3.1.2-8 SEQUENCE-LEVEL AND SYSTEM-LEVEL SUCCESS CRITERIA			
Initiator Group	*Reactivity Control*	*RCS Inventory Control*	*RCS Heat Removal*
SGTRs	RPS	**high pressure break flow termination:** 1/3 SI pumps (HPI) <u>and</u> S/G isolation <u>and</u> equalization of RCS and S/G pressures below the S/G safety valve setpoint <u>or</u> **LPI and LPR:** rapid cooldown to LPI conditions using the steam generators <u>and</u> 1/2 RHR pumps	**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>or</u> **LPI and LPR:** 1/2 RHR pumps <u>and</u> 1/2 RHR heat exchangers (LPR)

Table 3.1.2-8
SEQUENCE-LEVEL AND SYSTEM-LEVEL SUCCESS CRITERIA

Initiator Group	*Reactivity Control*	*RCS Inventory Control*	*RCS Heat Removal*
ATWS	achieve subcriticality within 10 min: emergency boration using 1/3 CVCS pumps or trip rod MG sets	maintenance of RCS pressure less than 3200 psig: power < 40% or power > 40% and MFW or AMSAC and 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 manual rod insertion and 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 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 100% AFW and > 209 days into fuel cycle or 155 to 209 days into fuel cycle and 1/2 PORVS or 111 to 155 days into fuel cycle and 2/2 PORVs	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

Table 3.1.1-9
MATRIX OF PROXIMATE INITIATING EVENT EFFECTS

	Reactivity Control	*Inventory Control*				*Heat Removal*	
	RT	*SI*	*PV*	*SV*	*SE*	*MF*	*AF*
TI00RXTRIP	x						
TI00GRLOSP	x		x	x		x	
TI00SWLOSP	x		x	x		x	
TI0MFWLOSS	x					x	
TI0FWEXCES	x	x				x	
TI00LOSSSW	m				x		
TI0CCWLOSS	m						
TI00IALOSS	m		x	x			
TI0DCBATTA							
TI0DCBATTB			x	x			
TI0MFWLBAI	x	x					
TI0MFWLBBI	x	x					
TI0MFWLBAO	x	x					x
TI0MFWLBBO	x	x					x
TI0PRSLBOA	x	x					x
TI0PRSLBOB	x	x					x
TI00PRSLBO	x	x	x	x		x	x
TI00MFWLBO	x	x	x	x		x	x
TI0PRSLBSD	x	x					
TIPRSLBSVA	x	x					
TIPRSLBSVB	x	x					
LI0SSBLOCA	x	x					
LI00SBLOCA	x	x					
LI00MBLOCA	x	x					
LI00LBLOCA	x	x					
LI000SGTRA	x	x					
LI000SGTRB	x	x					
ISLOCAs	x	x					

Legend

m	a manual trip of the reactor assumed	SV	a challenge to the RCS SRVs results
RT	an automatic reactor trip results	SE	a loss of all seal cooling (thermal barrier and injection) results
SI	a condition for automatic safety injection actuation results	MF	a loss of main feedwater results (i.e., not merely isolation)
PV	a challenge to the PORVs results	AF	a failure of all auxiliary feedwater results

Table 3.1.1-10
USAGE OF TOP LOGIC IN THE EVENT TREES

Event	*Event Tree*						
	Transient	*SSLOCA*	*SLOCA*	*MLOCA*	*LLOCA*	*SGTR*	*ATWS*
AM							X
B1	X	X				X	
D						X	
FC		X	X	X	X		
FF							X
I1						X	
I2						X	
I3L						X	
I3S						X	
KE							X
KM							X
L1	X	X				X	
LT							X
MF							X
P1	X						
P2		X					
P3SS		X					
P3TR						X	
PF							X
PL							X
PR1							X
PR2							X
PR3							X
PR4							X
Q1	X						
Q2	X						

Table 3.1.1-10 USAGE OF TOP LOGIC IN THE EVENT TREES							
	Event Tree						
Event	*Transient*	*SSLOCA*	*SLOCA*	*MLOCA*	*LLOCA*	*SGTR*	*ATWS*
RI							X
SC							
UA					X		
UCS		X	X	X	X		
UH1	X						
UH2		X	X	X		X	
UL					X		
XCS		X	X	X	X		
XH		X	X				
XL				X	X		

Table 3.1.1-11
SYSTEM-LEVEL TOP EVENTS

Gate	*Description*	*System*	*Top Logic*
AC040	No Power on Bus 11A	AC	L1, MF, TNOTQ1
AC140	No Power on Bus 11B	AC	L1, MF, TNOTQ1
AF100	No Flow To Either S/G From Any AFW Train	AFW	B1
AF400	Turbine-Driven AFW Pump Train Fails To Provide Flow to S/Gs	AFW	PF
AF493	Air-Operated Valve 4297 Fails To Close To Isolate S/G A (TDAFW Pump)	AFW	I2
AF497	Air-Operated Valve 4298 Fails To Close To Isolate S/G B (TDAFW Pump)	AFW	I2
AF500	Motor-Driven AFW Pump Train A Fails To Provide Flow To S/Gs	AFW	PF
AF586	Failure To Close MOV 4007 To Isolate S/G A When Required	AFW	I2
AF600	Motor-Driven AFW Pump Train B Fails To Provide Flow To S/Gs	AFW	PF
AF686	Failure To Close MOV 4008 To Isolate S/G B When Required	AFW	I2
AF800	Less Than Full AFW Flow To Either S/G	AFW	FF
AF900	Failure Of Standby Auxiliary Feedwater To Both Steam Generators	AFW	L1
CC010	CCW Not Available To RCP A Pump Seal	CCW	Q1
CC020	CCW Not Available To RCP B Pump Seal	CCW	Q1
CR400	Failure to Provide Flow From Containment Sprays During Recirculation	CS	XCS
CS300	Failure to Provide Flow From Containment Spray During Injection	CS	UCS
CT312	Failure of Main Steam Safety Valves to Reclose	CIS	I1
CT313	Failure of TDAFW Steam Admission Line from S/G A	CIS	I1
CT315	Failure of MSIV 3517 to Close	CIS	I1
CT326	Failure of Miscellaneous Manual Valves for Penetration 401 to Close	CIS	I1
CT330	Failure of Containment Penetration 206b (S/G A Blowdown Sample Line)	CIS	I1
CT335	Failure of Containment Penetration 321 (S/G A Blowdown Line)	CIS	I1
CT342	Failure of Main Steam Safety Valves to Reclose	CIS	I1
CT343	Failure of TDAFW Steam Admission Line From S/G B	CIS	I1
CT345	Failure of MSIV 3516 to Close	CIS	I1
CT356	Failure of Miscellaneous Manual Valves for Penetration 402 to Close	CIS	I1

Table 3.1.1-11 SYSTEM-LEVEL TOP EVENTS			
Gate	*Description*	*System*	*Top Logic*
CT360	Failure of Containment Penetration 207b (S/G B Blowdown Sample Line)	CIS	I1
CT365	Failure of Containment Penetration 322 (S/G B Blowdown Line)	CIS	I1
CV500	No Boron Injection From CVCS	CVCS	LT
CV998	Loss Of Seal Injection Or Return To RCP A	CVCS	Q1
CV999	Loss Of Seal Injection Or Return To RCP B	CVCS	Q1
DC303	No DC Power To Bus 11A (Normal) and Bus 12B (Emergency) (Circuit E25)	AC	TNOTQ1
DC505	No DC Power To Bus 11B (Normal) and Bus 12A (Emergency) (Circuit E104)	AC	TNOTQ1
HV800	Failure of Containment HVAC System (Four of Four Fail)	HVAC	FC
IA000	No Air to 2" Instrument Air Header by Both Dryers	IA	L1, MF
MS511	ARV Failure For S/G A	TGP	D, P3SS, P3TR1, P3TR2
MS551	ARV Failure For S/G B	TGP	D, P3SS, P3TR1, P3TR2
RC100	Failure Of Pressurizer Spray (Manual Actuation)	PPC	D
RC150	Failure Of Pressurizer Spray (Automatic Actuation)	PPC	Q2
RC200	Both Pressurizer PORVS Fail To Automatically Open On Demand	PPC	PR1, PR2, PR3, PR4
RC250	Either Pressurizer PORV Fails to Automatically Open On Demand	PPC	PR2, PR3, PR4
RC300	Either Pressurizer PORV Fails To Open When Manually Demanded	PPC	D, P1, P2
RC600	PORV Block Valve 515 Fails To Close On Demand	PPC	Q2
RC700	PORV Block Valve 516 Fails To Close On Demand	PPC	Q2
RH200	Failure To Provide Any Flow From RHR In Injection Phase	RHR	UL
RR100	Failure Of RHR Sump Recirculation	RHR	XL
SI100	Failure To Deliver Flow From 1 Of 3 SI Pumps To The RCS During Injection	SI	UH1, UH2
SI500	Inadequate Flow From Both Accumulators (TSI03A and TSI03B)	SI	UA
SR500	Failure To Deliver Flow From 1 Of 3 SI Pumps To The RCS During Recirculation	SI	XH
SW200	Loss of SW Flow to IA Compressors CIA02A, CIA02C and Relay Room AC Units	SW	L1, MF

Table 3.1.1-12 APPEARANCE OF HUMAN FAILURES EVENTS				
Event	*Location*	*Screening Probability*	*Description*	*Notes*
AFHFD04297	AFW	1.00e-01	Operators fail to close air operated valve 4297 to isolate S/G A	Event I2
AFHFD04298	AFW	1.00e-01	Operators fail to close air operated valve 4298 to isolate S/G B	Event I2
AFHFD1ATRP	AFW	1.00e+00	Operators fail to reopen MOV 4007 after Pump 1A trips	Event B1
AFHFD1BTRP	AFW	1.00e+00	Operators fail to reopen MOV 4008 after Pump 1B trips	Event B1
AFHFDAFWAB	AFW	1.00e+00	Operators fail to open cross-tie valves between AFW motor-driven trains	Event B1
AFHFDC4007	AFW	1.00e-01	Operators fail to close 4007 to isolate S/G A	Event I2
AFHFDC4008	AFW	1.00e-01	Operators fail to close 4008 to isolate S/G B	Event I2
AFHFDPCD04	AFW	1.00e+00	Operators fail to provide water to the CSTs from the Hotwell	Event B1
AFHFDSAFWX	AFW	1.00e-04	Operators fail to start SAFW Pump 1C and 1D	Event B1
AFHFDSWX03	AFW	1.00e+00	Operators fail to perform suction transfer from CST to SW	Event B1
AFHFDXSAFW	AFW	1.00e+00	Operators fail to open cross-tie valves between SAFW trains and/or isolate	Event L1
CCHFDSTART	CCW	1.00e-01	Operator fails to start a CCW pump following an event with both a LOOP and SI	no event-specific connotation
CSHFDRECIR	CS, top logic	1.00e-01	Operators fail to switch to containment spray recirculation mode	Event XCS
CTHFDISOLA	CIS, top logic	1.00e-04	Operators fail to isolate S/G A after failure of tubes	Event I1
CTHFDISOLB	CIS, top logic	1.00e-04	Operators fail to isolate S/G B after failure of tubes	Event I1
CVHFDBORAT	top logic	1.00e-01	Operators fail to implement emergency boration	Event LT
HVHFDRELRM	HVAC	1.00e+00	Operator fails to start HVAC in Relay Room following a LOOP	no event-specific connotation

Table 3.1.1-12
APPEARANCE OF HUMAN FAILURES EVENTS

Event	*Location*	*Screening Probability*	*Description*	*Notes*
HVHFD_CTMT	HVAC	1.00e+00	Operator fails to re-start containment cooling	Event FC
IAHFDCNTBK	IA, SW	1.00e-01	Operators fail to restore IA to the containment (AOV 5392, SW to IA compressors)	no event-specific connotation
MFHFDMF100	top logic	1.00e-01	Operator fails to reestablish main feedwater flow	Event L1
RCHFD00RCP	top logic	1.00e-01	Operators fail to trip RCPs after loss of CCW support	Event Q1
RCHFD01BAF	top logic	1.00e-01	Operators fail to implement bleed and feed	Events UH1 and P2
RCHFDCD0SS	top logic	1.00e-01	Operator fails to cooldown to RHR after SI fails -- SSLOCA	Event P3SS
RCHFDCDDPR	top logic	1.00e-01	Operators fails to cooldown and depressurize RCS during SGTR given SI operation	Event D
RCHFDCDTR1	top logic	1.00e-01	Failure to cooldown to RHR after ruptured S/G isolation fails	Event P3TR1
RCHFDCDTR2	top logic	1.00e-01	Operator fails to cooldown to RHR after SI fails -- SGTR	Event P3TR2
RCHFDPLOCA	top logic	1.00e-01	Operators fail to close PORV block valve (515/516) to terminate LOCA	Event Q2
RCHFDSCRAM	top logic	1.00e-01	Operators fail to trip rod drive MG sets during ATWS	Event KE
RHHFD0SGTR	top logic	1.00e+00	Failure to establish and maintain RHR cooling following SGTR	Event SC; includes an estimate of RHR system reliability in addition to human error
RPHFD00MRI	top logic	2.10e-01	Operators fail to manually insert rods	Event RI
RRHFDRCR0A	top logic	1.00e-01	Failure to Switch to Recirculation After LLOCA	Event XL; replacement for event RRHFDRECRC in LLOCA sequences
RRHFDRCR0M	top logic	1.00e-01	Failure to Switch to Recirculation After MLOCA	Event XL; replacement for event RRHFDRECRC in MLOCA, PORV LOCA (T/Q2), and bleed-and-feed sequences (transients, SSLOCAs)
RRHFDRCR0S	top logic	1.00e-01	Failure to Switch to Recirculation After SLOCA	Event XH; replacement for event RRHFDRECRC in SLOCA sequence
RRHFDRCRSS	top logic	1.00e-01	Failure to Switch to Recirculation After SSLOCA	Event XH; replace for event RRHFDRECRC in SSLOCA and RCP seal LOCA (T/Q1) sequences
SWHFDSW01A	SW	1.00e-01	Operators fail to start PSW01A after no auto start or failure of other pump	no event-specific connotation

Table 3.1.1-12 APPEARANCE OF HUMAN FAILURES EVENTS				
Event	*Location*	*Screening Probability*	*Description*	*Notes*
SWHFDSW01B	SW	1.00e-01	Operators fail to start PSW01B after no auto start or failure of other pump	no event-specific connotation
SWHFDSW01C	SW	1.00e-01	Operators fail to start PSW01C after no auto start of failure of other pump	no event-specific connotation
SWHFDSW01D	SW	1.00e-01	Operators fail to start PSW01D after no auto start or failure of other pump	no event-specific connotation

Figure3.1.2-1
A Seal LOCA is a SSLOCA

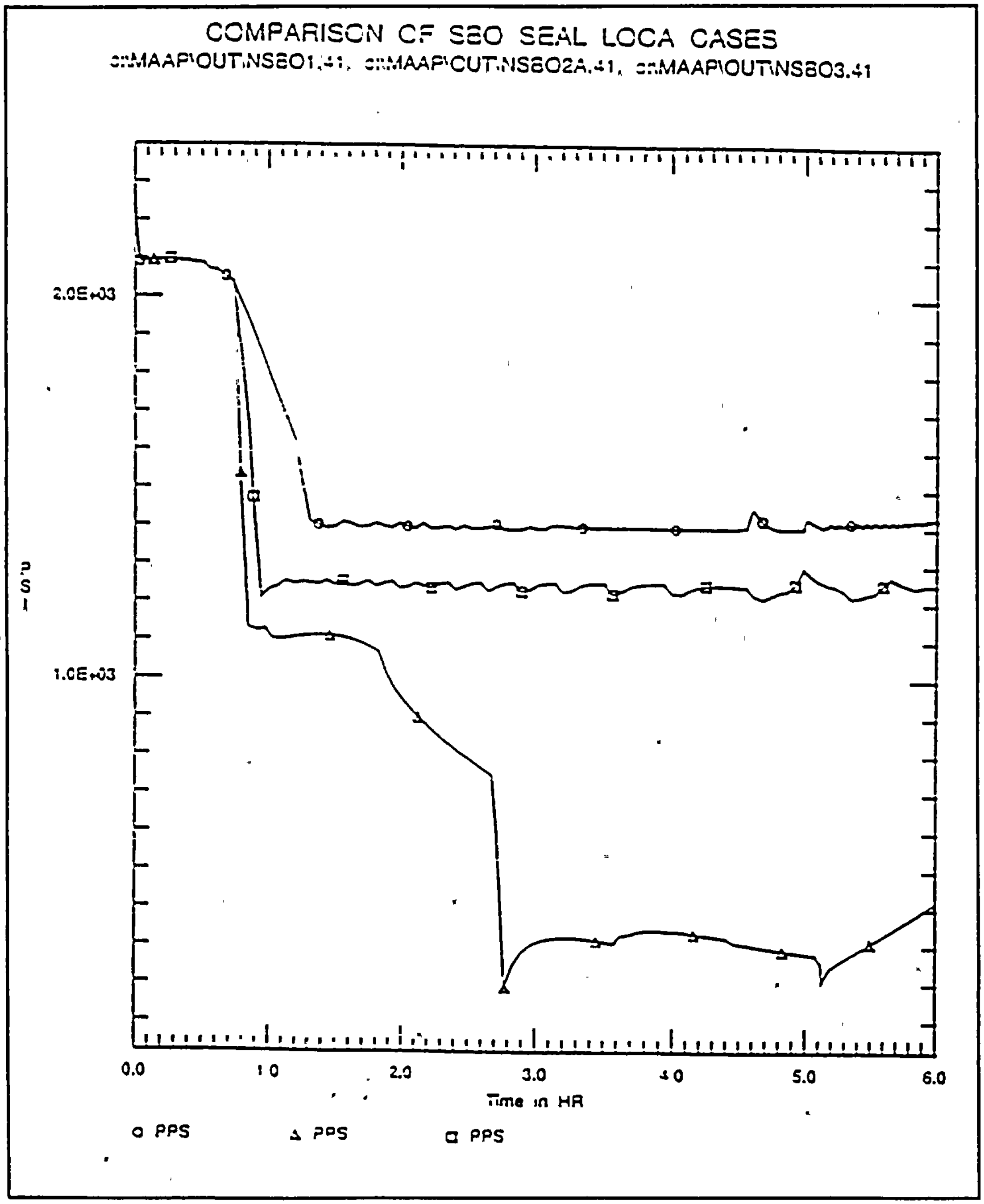
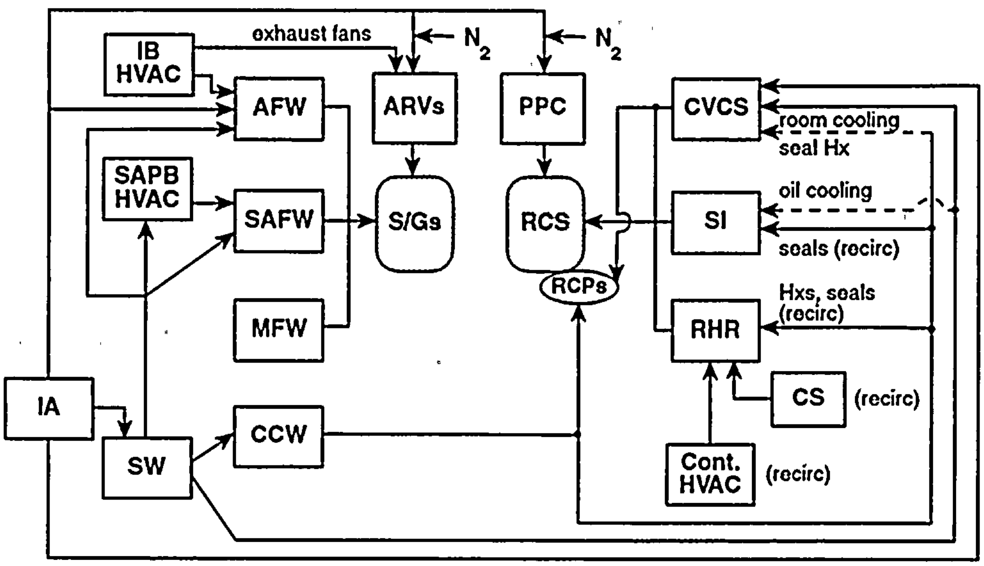
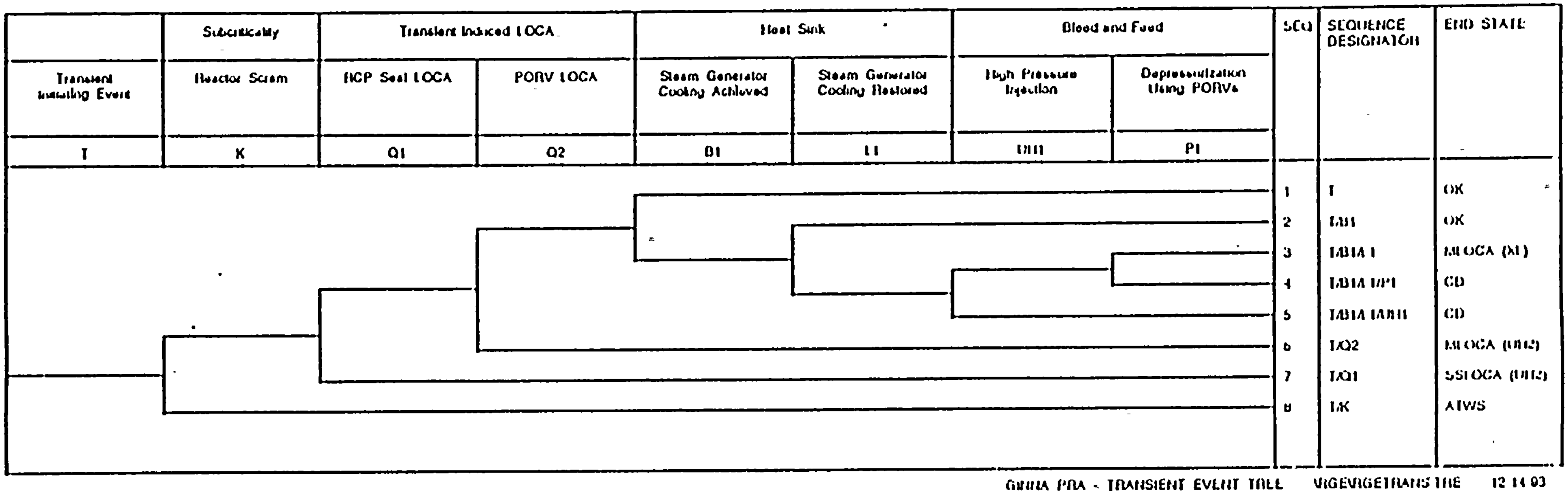


Figure 3.1.2-2
Bubble Chart of System Dependencies



A ──▶ B	indicates that system A supports, i.e., supplies water or air to system B
A-----▶ B	indicates that system A supports system B but not in a way significant to PRA

Figure 3.1.2-3
Transient Event Tree



Rochester Gas & Electric Corporation

R. E. Ginna PRA Project

Figure 3.1.2-4
Small-Small LOCA Event Tree

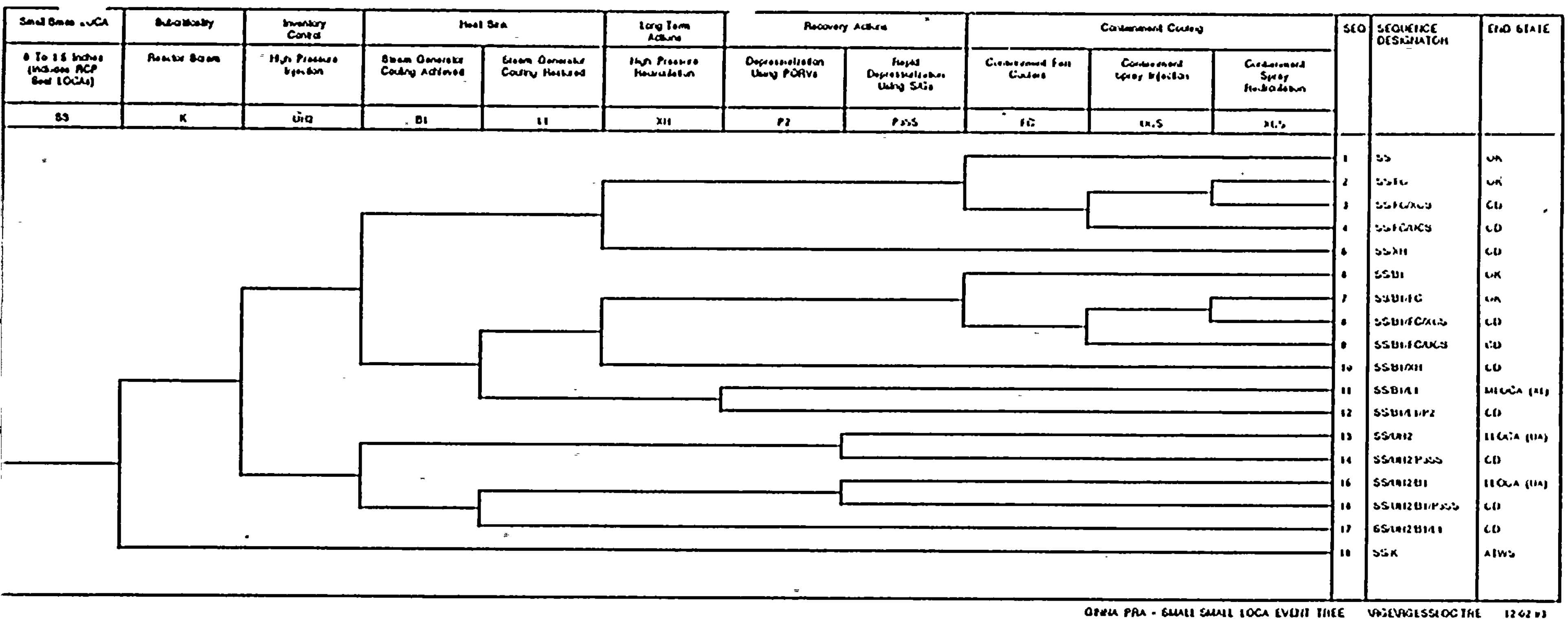
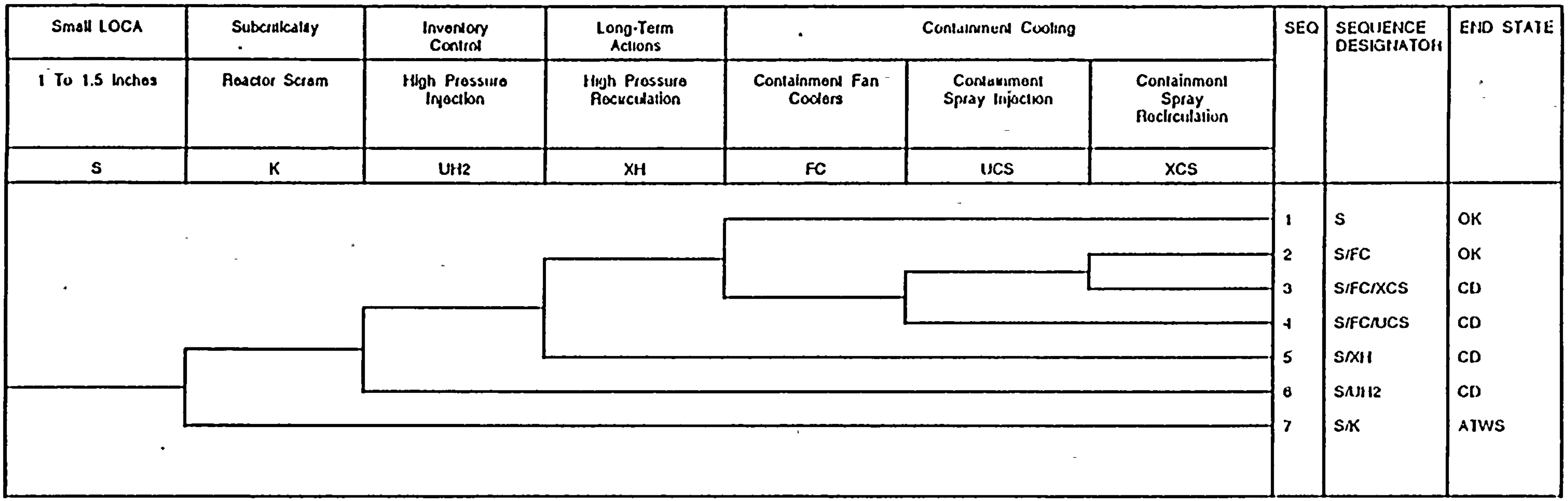
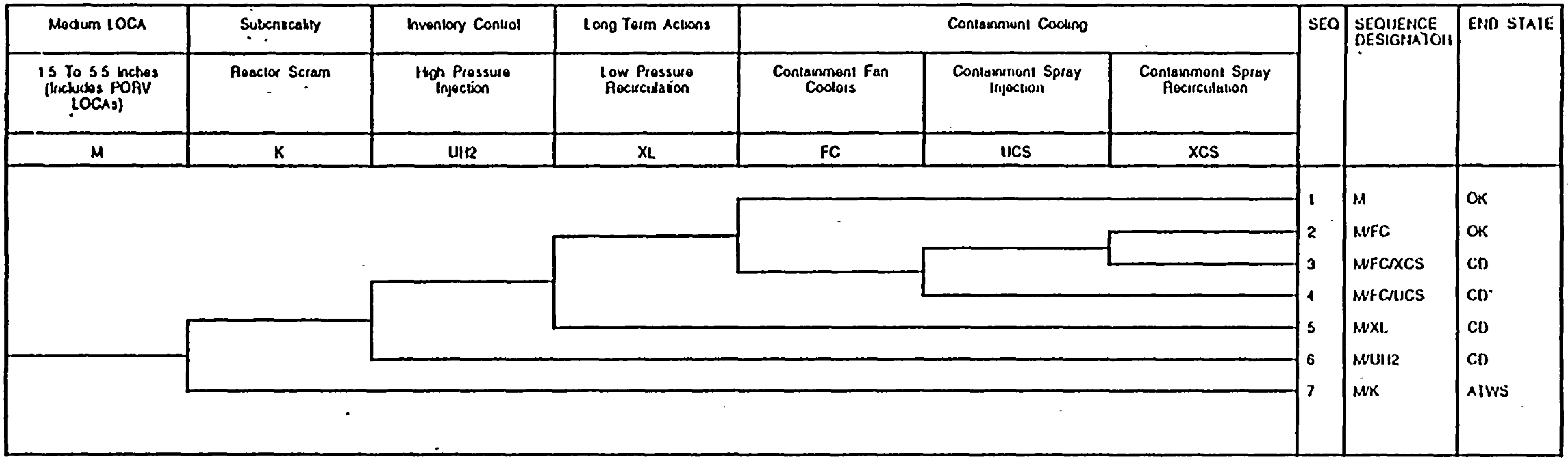


Figure 3.1.2-5
Small LOCA Event Tree



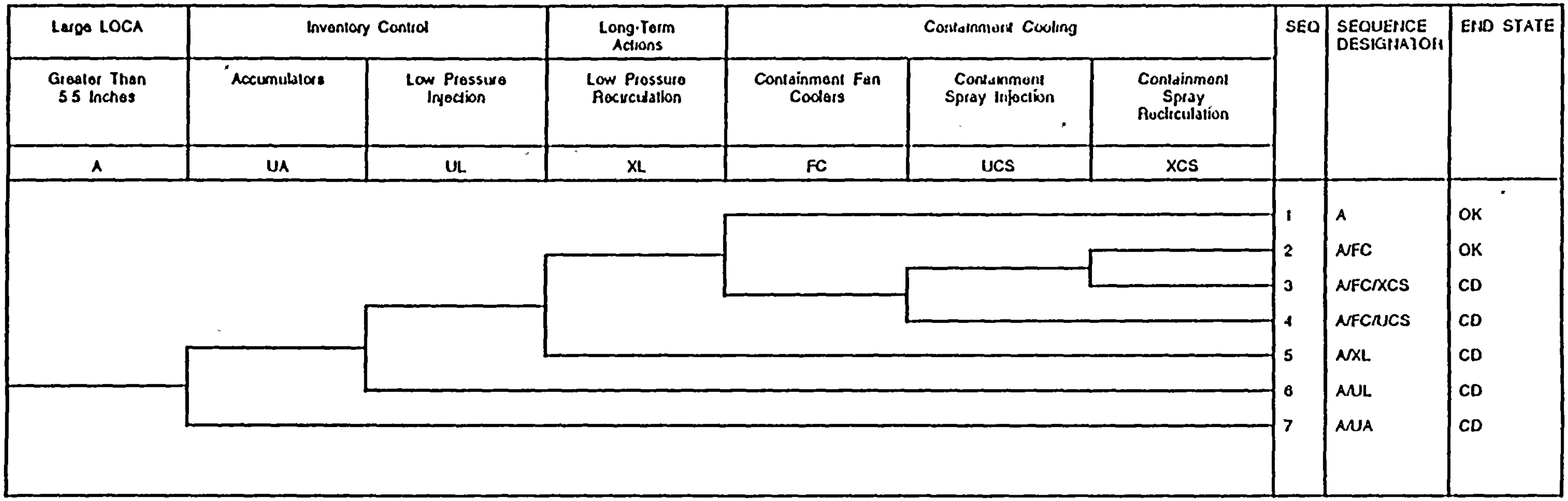
GINNA PRA - SMALL LOCA EVENT TREE \RGE\RGESLOCA.TRE 12-02-93

Figure 3.1.2-6
Medium LOCA Event Tree



GINNA PRA - MEDIUM LOCA EVENT TREE .\RGE\RGEMLOCA.TRE 12 02 93

Figure 3.1.2-7
Large LOCA Event Tree



GINNA PRA - LARGE LOCA EVENT TREE .ARGE\RGELLOCA.TRE 12-02-93

Figure 3.1.2-8
Steam Generator Tube Rupture Event Tree

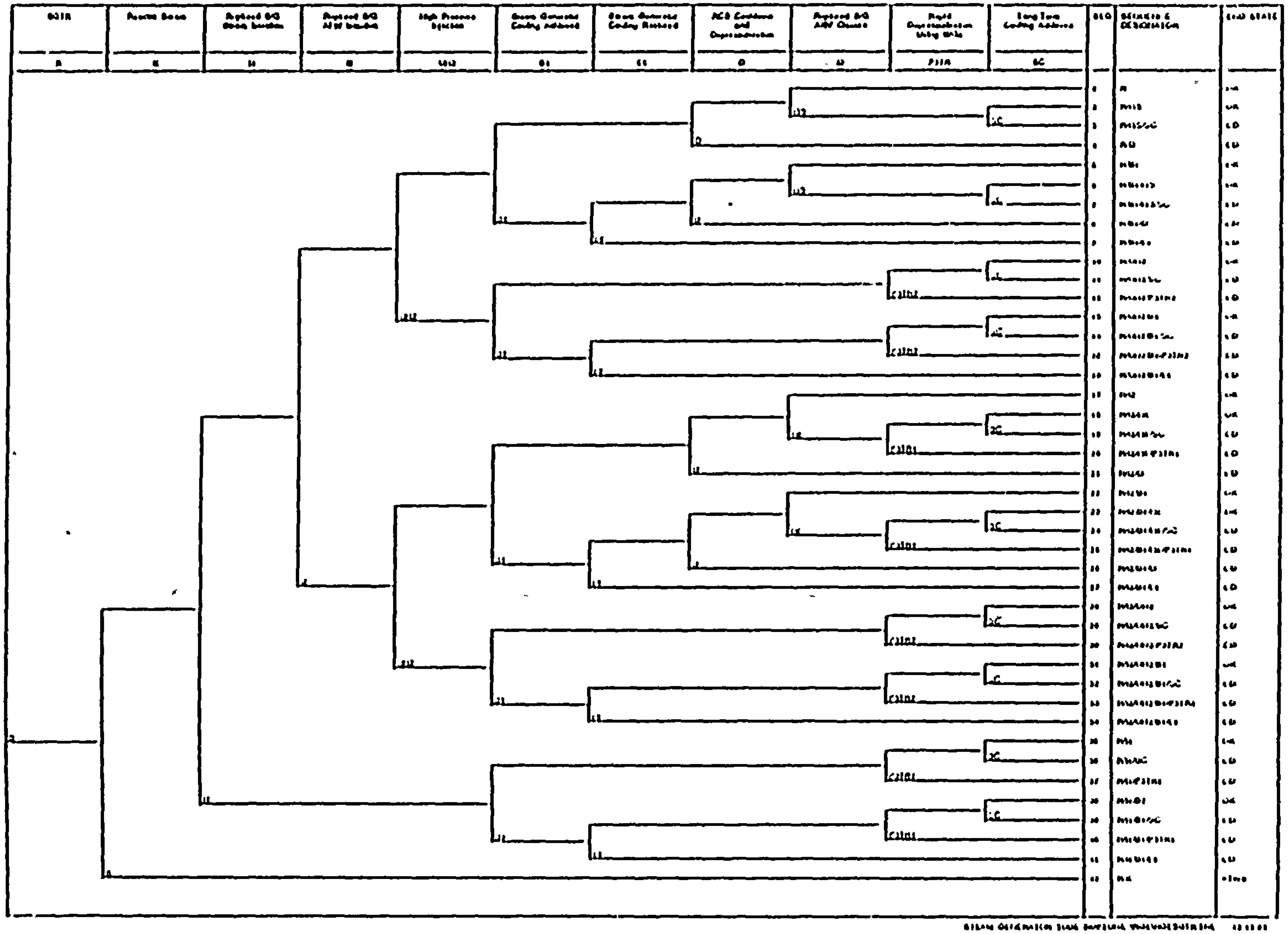
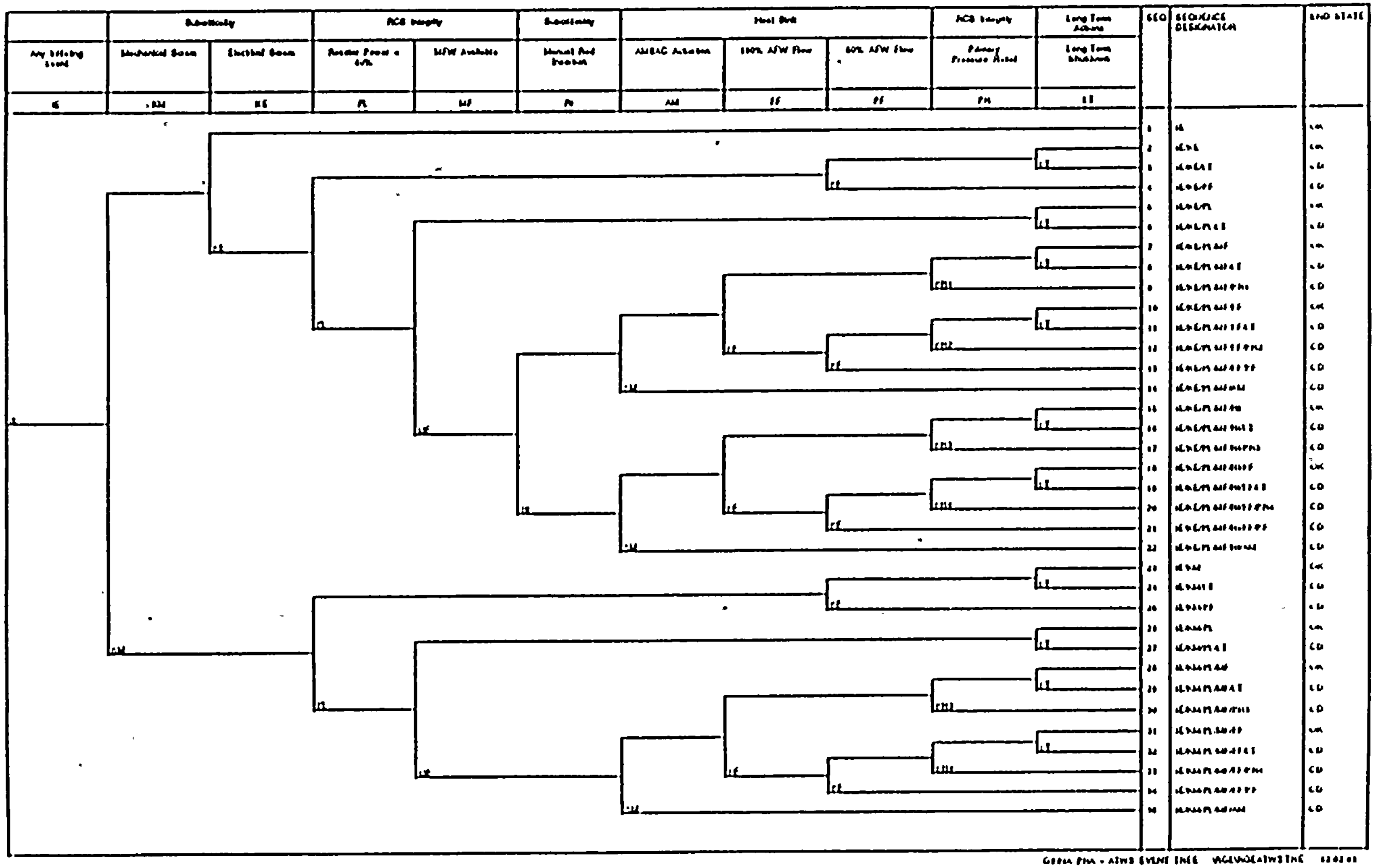


Figure 3.1.2-9
Anticipated Transients Without SCRAM (ATWS) Event Tree



3.1.3 Special Event Tree - Interfacing Systems Loss of Coolant Accidents

3.1.3.1 Introduction

This section discusses the assessment of the core damage potential from interfacing systems LOCAs (ISLOCAs) for the R.E. Ginna Nuclear Power Plant. The assessment of ISLOCAs has changed over the years as PRA techniques have improved and analysts have increased their understanding of the scenarios involved. The following provides a brief overview of the techniques which have been used previously and provides the basis for method to be used in the Ginna PRA Project.

The first nuclear power plant PRA, WASH-1400 [Ref. 3.1.3-1], identified as its fifth PWR sequence type, a LOCA that resulted in a loss of Reactor Coolant System (RCS) inventory outside the Containment Building, referred to as sequence V. This event eventually became known as an 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. Steam Generator Tube Ruptures (SGTRs) can be included within this type of LOCA, but historically have been distinguished as a separate LOCA initiator for various reasons (initiators LI000SGTRA and LI000SGTRB for the Ginna PRA). 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. 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 6×10^{-6}/yr, which was acknowledged to be approximately an order of magnitude high if appropriately consideration was taken for testing the status of the valve.

Several years later, the Oconee PRA [Ref. 3.1.3-2] more explicitly detailed a frequency analysis of the initiator types related to ISLOCAs. This analysis recognized the possibility of several different types of valve failure scenarios: rupture-rupture, leak-leak, and rupture-leak. 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 [Refs. 3.1.3-3 and 3.1.3-4]. 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 [Refs. 3.1.3-5 - 3.1.3-9]. The approach to be used for the Ginna PRA is a compilation of these methods, designed to identify all potential ISLOCA scenarios but only perform detailed evaluations of the most likely sequences.

3.1.3.2 Methodology

The RCS at Ginna "communicates" with other water systems, many of which are designed to a lower pressure than the approximately 2250 psi 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 leaving containment is normally provided with at least two isolation boundaries or valves which are designed to close and isolate containment following an accident (i.e., for non-emergency lines). These isolation valves also typically serve to provide a barrier between the RCS and low pressure interfacing systems where applicable. As discussed above, any breach of a RCS interface that results in water exiting the RCS and containment is called an interfacing systems LOCA.

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 *a priori* 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 failed. 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 consisted of the following tasks:

1. Identifying the systems that interface with the RCS and exit the containment through a mechanical penetration. This effectively determined the penetrations that contain high/low pressure interfaces.

2. 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.

3. Screening each scenario and if it is greater than the 1.00E-06/yr truncation limit used in the NUREG/CR-4550 studies, recover the scenario, where appropriate, and quantify it in detail.

3.1.3.3 Identification of Water Systems Interfaces With the RCS

Figure 3.1.3-1 (developed from [Ref. 3.1.3-10]) shows the major connections to the RCS that also leave 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 3.1.3-1 is discussed below

3.1.3.3.1 Penetrations 111 and 140

These two penetrations contain the Residual Heat Removal (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.

3.1.3.3.2 Penetrations 101 and 113

These two penetrations contain the high pressure Safety Injection (SI) lines to both RCS cold and hot legs. The SI system for Ginna is not normally operating and has a design pressure of only 1750 psig [Ref. 3.1.3-11, Table 6.3-3] 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.

3.1.3.3.3 Penetrations 100 and 102

These two penetrations contain the Chemical and Volume Control System (CVCS) lines associated with normal and alternate charging [Ref. 3.1.3-12]. 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 result in an ISLOCA, multiple valves would have to fail to close that are 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 [Ref. 3.1.3-13]. Section 9.3.4.4.5.1 of Ref. 3.1.3-11 provides additional information with respect to a break of the CVCS piping related to these penetrations.

[illegible]

3.1.3.3.4 Penetration 112

This penetration contains the CVCS piping associated with letdown [Ref. 3.1.3-14]. 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.

3.1.3.3.5 Penetrations 205, 206a, and 207a

These three penetrations contain the RCS Hot Leg sample lines, and the pressurizer liquid and steam sample lines [Ref. 3.1.3-15]. 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. 3.1.3-11, 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 (CIS), the loss of air, or power. There is also a throttled valve outside containment to reduce the sampling system pressure for each line. In addition, 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. 3.1.3-11, Section 9.3.2.1.2.2]. Therefore, based on the system design, these penetrations were not included in the ISLOCA assessment.

3.1.3.3.6 Reactor Coolant Drain Tank Pentrations

There is only one line which directly connects the RCS to the Reactor Coolant Drain Tank (RCDT) [Ref. 3.1.3-16]. 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 [Ref. 3.1.3-17] 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 also several other lines from the tank that exit containment. However, each of these lines has two containment isolation valves which will close on a CIS. 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.

3.1.3.3.7 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 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.

3.1.3.3.8 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 [Ref. 3.1.3-12]. The failure of the seal assembly is considered in the plant model [Ref. 3.1.3-18] and is not evaluated further in this analysis. However, component cooling water (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 the analysis.

3.1.3.3.9 Comparison to UFSAR Listing Of Containment Isolation Valves

The Ginna UFSAR contains a list of all mechanical penetrations for containment [Ref. 3.1.3-11, Table 6.2-15]. A review of this table was performed to identify all penetrations that included lines which interfaced with the RCS to ensure that all potential ISLOCA locations were identified.

3.1.3.4 Identification of ISLOCA Scenarios and Their Consequences

An assessment of each of the penetrations identified in Table 3.1.3-1 as requiring evaluation 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-06/yr. However, it is noted that Refs. 3.1.3-5 and 3.1.3-6 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 and [Ref. 3.1.3-19] were relied on extensively to determine the potential break locations outside of containment while [Ref. 3.1.3-18] was used to evaluate the consequences. The assignment of failure probabilities and frequencies for the identified scenarios is provided in Section 3.1.3.5.

3.1.3.4.1 Penetration 101

Figure 3.1.3-2 shows a simplified diagram of the equipment and layout related to containment penetration 101 [Ref. 3.1.3-20]. 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 TSI03B) 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 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 3.1.3-2. As shown on this table, the SI system piping downstream of the pumps is designed and tested for high pressure service and based on [Ref. 3.1.3-6] would most likely withstand the introduction of primary system fluid except for potentially the flanges associated with the pumps. However, it is conservatively assumed for the purposes of this analysis that the piping does fail. 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 870B to close, and that the majority of water from Pump C goes out the break since it is of lower pressure). 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 [Ref. 3.1.3-21]). Therefore, a pipe break in this specific location is unlikely.

(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 a 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 [Ref. 3.1.3-22]. Consequently, since an independent check valve failure would have to be included, the failure of both pumps given a pipe break in either location was not considered further. It should be noted that this same reasoning is used for not considering the potential for three SI pumps failing in scenario (a) described above.

Since scenario (b) requires the failure of an additional check valve than (a) and only one SI pump is affected (versus two), this scenario was also not considered any further. Section 3.1.3.5.1 provides the screening assessment of scenario (a).

3.1.3.4.2 Penetration 110b

Figure 3.1.3-3 shows a simplified diagram of the equipment and layout related to containment penetration 110b. This penetration contains the SI pump test line to the Reactor Water Storage Tank (RWST) and is directly related to penetrations 101 and 113 (Figures 3.1.3-2 and 3.1.3-5, respectively). The isolation valves located between the test line and the RCS and whose failure initiates the ISLOCA are discussed in Sections 3.1.3.4.1 and 3.1.3.4.4.

Table 3.1.3-3 provides information related to the test line design parameters. Tables 3.1.3-2 and 3.1.3-5 provide additional information.

As can be seen from Table 3.1.3-3, the SI test line piping is designed for high pressure service and based on [Ref. 3.1.3-6] would most likely withstand the introduction of primary system fluid, except for the branch line to the RWST containing manual valve 882 (the line downstream of 884 was not considered further since there are already three normally closed manual valves to this point). Since a break in the branch line requires the additional failure of manual valve 882, this branch line was ignored and only the following potential ISLOCA scenario was considered:

(a) A break in the SI test line between manual valve 879 and containment. This break location can be assumed to fail at least two SI pumps since it is essentially equivalent to the break described in Section 3.1.3.4.2, scenario (a). The loss of the third SI pump would require the failure of an additional check valve (872A or 872B); however, since these check valves encounter different system operating conditions than the check valves located in the Cold and Hot Leg injection lines, a common cause failure of the check valve was not considered credible. Consequently, an independent check valve failure would have to be included in addition to the failure of valves isolating the RCS in order to fail all three SI pumps. Since check valves 872A and 872B are verified to close during quarterly testing of the pumps [Ref. 3.1.3-24], the independent failure rate was assumed to be very low and only the scenario of two pumps failing was considered.

It should be noted that the section of piping considered for the pipe break 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. Section 3.1.3.5.2 provides the screening assessment of scenario (a).

3.1.3.4.3 Penetrations 111 and 112

Figure 3.1.3-4 shows a simplified diagram of the equipment and layout related to containment penetration 111 [Ref. 3.1.3-23] and 112 [Ref. 3.1.3-14]. 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.

The RHR and CVCS lines are seamless or weldless stainless steel piping as described in Table 3.1.3-4.

As can be seen from Table 3.1.3-4, the introduction of primary system fluid into the RHR system and CVCS would most likely result in an ISLOCA due to the design rating of the low pressure piping. This is also supported by Appendix F of [Ref. 3.1.3-9] which indicates that the RHR system will rupture given the loss of RCS integrity with a probability of 0.98. It is noted that there is a relief valve located inside containment for this penetration (203) 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. 3.1.3-11. Section 5.4.5.3.1.2]. However, this capacity would not be sufficient to relieve a significant loss of RCS integrity through the RHR injection lines. Therefore, the impact of this relief valve was not considered further. There are essentially 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. 3.1.3-11, 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. 3.1.3-11, Section 5.4.5.3.5] and would not provide much relief for a large break. Consequently, it is 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 CIS 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. 3.1.3-24]). 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 just downstream of AOV 371 which can be used if necessary. 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). Therefore, this ISLOCA sequence is not evaluated further since it will be automatically isolated.

It should be noted that there is significant piping inside containment (325 feet [Ref. 3.1.3-25 and 3.1.3-26]) which also has the potential of breaking. In addition, Appendix F of [Ref. 3.1.3-9] shows that the dominating rupture point associated with the RHR piping is at the heat exchangers which are protected by check valves 697A and 697B. Therefore, it is conservative to assume that the piping will rupture between containment and these two check valves (135 feet of piping [Ref. 3.1.3-27]). Section 5.4.5.3.2 of Ref. 3.1.3-11 provides additional details with respect to overpressurization events during non-full power conditions. Section 3.1.3.5.2 provides the screening assessment of scenario (a).

3.1.3.4.4 Penetration 113

Figure 3.1.3-5 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 TSI03A) 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 motor-operated valve (MOV 878A). The second path from Cold Leg B requires the failure of two check valves (867A and 878G).

The SI lines are seamless or welded stainless steel piping as described in Table 3.1.3-5.

Since Table 3.1.3-5 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. Section 3.1.3.5.3 provides the screening assessment of this scenario. It is noted that this section of piping is of short length (100 feet [Ref. 3.1.3-28]) since check valves 889A and 870A are containment isolation valves and located close to containment by design.

3.1.3.4.5 Penetrations 124a and 124c

Figure 3.1.3-6 shows a simplified drawing of the equipment and layout related to containment penetrations 124a and 124c [Ref. 3.1.3-29]. These penetrations contain the CCW supply and return lines, respectively, for the excess letdown heat exchanger. Based on conversations with Ginna Operations [Ref. 3.1.3-30], this system is normally isolated at both the component cooling water 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 also fail the entire CCW system. Based on the significance of this ISLOCA scenario, it was evaluated in more detail.

The RHR lines are seamless or welded carbon steel piping as described in Table 3.1.3-6.

As can be seen from Table 3.1.3-6, any introduction of RCS fluid into the component cooling water line 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 a 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. 3.1.3-31],

(f) CCW check valve 743 or AOV 745 would have to rupture to provide a leak path outside of containment (AOV 745 is located only 1 foot from the penetration [Ref. 3.1.3-32]), and

(g) the normal flow rate through the CCW heat exchanger is only 5,000 lb/hr or 10 gpm [Ref. 3.1.3-11, Table 9.3-7] while relief valve 744 is designed to relieve 20 gpm [Ref. 3.1.3-17].

It is noted that air-operated valve 123 is the limiting factor for 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.

3.1.3.4.6 Penetrations 125 and 128

Figure 3.1.3-7 shows a simplified drawing of the equipment and layout related to containment penetrations 125 and 128 [Ref. 3.1.3-32]. These penetrations contain the CCW return and supply lines, respectively, for the RCP B thermal cooler and are normally in operation. A failure of the coils carrying RCS fluid within the thermal cooler could potentially result in an ISLOCA within the CCW system. As noted above, an ISLOCA would also fail the entire CCW system.

Table 3.1.3-6 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 3.1.3-7, 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 motor-operated valve 749B (located less than 6 inches from the penetration [Ref. 3.1.3-33]) which automatically closes on a CIS. The probability of two valves failing to close in addition to a thermal barrier cooling coil rupture is considered very low. 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 air-operated valve 754B and motor-operated valve 749 (automatically isolates on a CIS) 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. 3.1.3-34]. 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. Therefore, 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.

3.1.3.4.7 Penetration 126 and 127

Figure 3.1.3-8 shows a simplified drawing of the equipment and layout related to containment penetrations 126 and 127 [Ref. 3.1.3-32]. As can be seen, these penetrations are completely analogous to penetrations 125 and 128 in that they contain the CCW supply and return lines, respectively, for the RCP A thermal 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 3.1.3.4.6.

3.1.3.4.8 Penetration 140

Figure 3.1.3-9 shows a simplified diagram of the equipment and layout related to containment penetration 140 [Ref. 3.1.3-25]. 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 3.1.3-9, the only one potential ISLOCA path is through MOVs 700 and 701.

The RHR lines are seamless or weldless stainless steel piping as described in Table 3.1.3-7.

As can be seen from Table 3.1.3-7, 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. This is also supported by Appendix F of [Ref. 3.1.3-9] which indicates that the RHR system will rupture given the loss of RCS integrity with a probability of 0.98. 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 3.1.3.4.3 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.

(b) A break in the suction line between the RWST and check valve 854. 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 draining 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. Any leakage associated with 854 would be detected due to increased radioactivity or level in the RWST. Also, a large hatch at the top of the RWST is normally maintained open during power operation in order to provide operators with visual indication of the water level. This large opening could provide some protection against a tank rupture by allowing excess water to escape. Consequently, since it can be conservatively assumed that the backseating of check valve 854 is verified once a year, and there is some doubt whether the RWST would actually rupture, this ISLOCA path was ignored.

As discussed above, there is only ISLOCA location to be considered for this penetration. Section 3.1.3.5.4 provides the screening assessment of scenario (a).

3.1.3.5 Screening Evaluation of Ginna ISLOCA Scenarios

All of the ISLOCA scenarios identified in Section 3.1.3.4 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 PRAs have utilized several different analytical models to determine ISLOCA frequencies and differ in the type of failure modes considered and initial assumptions. Several of the more well-known analytical models are summarized in Appendix E of [Ref. 3.1.3-7] and after review, it was determined that the techniques presented in [Ref. 3.1.3-5] will be utilized for the Ginna PRA since they provide the most applicable information.

Table 3.1.3-8 summarizes the analytical models to be used for determining the ISLOCA initiator frequencies while Table 3.1.3-9 presents the failure data required by these analytical models. The ISLOCA frequencies which are calculated are then multiplied by 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 PRA. The data window for the Ginna PRA was from January 1, 1980 through December 31, 1988 or 78,912 hours [Ref. 3.1.3-35]. The number or reactor critical hours in this same time period was 64,054 hours [Ref. 3.1.3-36] or 81% of the time. Therefore, each frequency was multiplied by 7,110 hours (0.81 x 8760 hrs/yr).

The application of the data for the five scenarios described in Section 3.1.3.4 is provided below. The final results are summarized in Section 3.1.3.6.

3.1.3.5.1 Evaluation of Penetration 101

Section 3.1.3.4.1 identifies two potential ISLOCA initiating event scenarios for this penetration. The first scenario involves the failure of check valves 867B and 878J on the SI injection line to Cold Leg A. The testing procedures for Ginna were reviewed and it was found that 867B is only leak tested once every refueling outage or cold shutdown. However, any leakage through this valve during power operation would be discovered very quickly due to changes in accumulator TSI03B level, pressure, or boron concentration. Check valve 878J is verified for leakage on a monthly basis by using the accumulator and opening the test line to the RWST to measure any flow through the valve [Ref. 3.1.3-37]. Therefore, using equation 1 with T defined as 730 hours (8760/12), and the data presented in Table 3.1.3-9, we find:

$$\langle\lambda\rangle = \tfrac{1}{2}\,(6.8\text{E-07/hr})^2(730\text{ hrs}) + (6.8\text{E-07/hr})(2.80\text{E-04})$$

$$= 1.69\text{E-10} + 1.90\text{E-10} = 3.59\text{E-10/hr}$$

or, converting this to a reactor year frequency,

$$\langle\lambda\rangle = (7110\text{ hrs/yr})(3.59\text{E-10/hr}) = 2.55\text{E-06/yr}$$

The second scenario 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 [Ref. 3.1.3-38]. The position indication of the MOV is also verified each refueling outage and has its breaker locked open to prevent inadvertent change of its position; however, this was conservatively ignored. Therefore, using equation 4 with T defined as 28,800 hours (40 months × 720 hours), and the data presented in Table 3.1.3-9, we find:

$$\langle\lambda\rangle = (6.8E\text{-}07/hr)^2(2.78E\text{-}08/hr)(28{,}800\ hrs)^2 + (6.8E\text{-}07/hr)^2(1.07E\text{-}04)(28{,}800\ hrs) + (6.8E\text{-}07/hr)^2(2.68E\text{-}04)(28{,}800\ hrs) + 2(6.8E\text{-}07/hr)(2.78E\text{-}08/hr)(2.8E\text{-}04)(28{,}800\ hrs)$$

$$= 1.07E\text{-}11 + 1.42E\text{-}12 + 3.57E\text{-}12 + 3.05E\text{-}13 = 1.60E\text{-}11/hr\ .$$

or, converting this to a reactor year frequency,

$$\langle\lambda\rangle = (7110\ hrs/yr)(1.60E\text{-}11/hr) = 1.13E\text{-}07/yr$$

The sum of these two scenarios is thus:

$$\langle\lambda\rangle_{101} = 2.55E\text{-}06/yr + 1.13E\text{-}07/yr = 2.66E\text{-}06/yr$$

This is a higher value than the 1.0E-06/yr truncation limit defined in Section 3.1.3.2 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 3.1.3.4.3). Therefore, an unisolable 3-4 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 sump recirculation.

However, there are two very conservative assumptions in this scenario. First is the fact that the check valve isolating accumulator TSI03B (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 [Ref. 3.1.3-5] for this check valve to close on demand. The second conservative assumption is related to the failure of the SI piping located between check valves 889B and 870B, and containment. Based on Refs. 3.1.3-5 - 3.1.3-7, this section of piping should not be expected to fail when exposed to RCS fluid. In fact, Appendix F of Ref. 3.1.3-5 identifies a failure probability of 4.46E-04 for smaller rated piping when exposed to RCS pressures and temperatures. Therefore, a failure probability of 0.1 can conservatively be applied to this penetration as follows:

$$\langle\lambda\rangle_{101} = (2.66E\text{-}06/yr)(0.1) = 2.66E\text{-}07$$

This value is considered appropriate and conservative since the potential for human error inducing the ISLOCA for this penetration is very small.

[illegible]

3.1.3.5.2 Evaluation of Penetration 111

Section 3.1.3.4.3 identifies three potential ISLOCA initiating event scenarios for this penetration. The first scenario involves the failure of motor-operated valves 721 and 720 on the normal RHR injection line to Cold Leg B. The testing procedures for Ginna were reviewed and it was found that these two MOVs are leak tested following each cold shutdown and refueling outage [Ref. 3.1.3-39]. In addition, MOV 721 has an interlock preventing the valve from opening when RCS pressure is greater than 410 psig [Ref. 3.1.3-11, 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. Both MOVs also have their breakers locked open and positions verified each shift [Ref. 3.1.3-40]. 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.

Reference 3.1.3-41 shows that Ginna averaged one cold shutdown a year in addition to the refueling outage during the data window used for the Ginna PRA. Therefore, using equation 2 with T defined as 4380 hours (8760 hrs/2) and the data provided in Table 3.1.3-9, we find:

$$\begin{aligned}\langle\lambda\rangle = &\{(6.0E\text{-}07/hr)^2 + (2.78E\text{-}08/hr)^2 + (6.0E\text{-}07/hr)(2.78E\text{-}08/hr)\}\ 4380\ hrs\\ &+ \tfrac{1}{2}\{(6.0E\text{-}07/hr)(9.78E\text{-}08/hr) + (2.78E\text{-}08/hr)(9.78E\text{-}08/hr)\}\ 4380\ hrs\\ &+ 2(6.0E\text{-}07/hr)(1.07E\text{-}04) + 2(2.78E\text{-}08/hr)(1.07E\text{-}04)\end{aligned}$$

$$= 1.65E\text{-}09 + 1.34E\text{-}10 + 1.28E\text{-}10 + 5.95E\text{-}12 = 1.92E\text{-}09/hr$$

or, converting this to a reactor year frequency,

$$\langle\lambda\rangle = (7110\ hrs/yr)(1.92E\text{-}09/hr) = 1.37E\text{-}05/yr$$

The second and third scenarios involve the two low pressure safety injection 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 to RCS pressure and do not have their power removed. The check valves and MOVs are also leak tested following each cold shutdown and refueling outage [Ref. 3.1.3-46]. Therefore, using equation 3 with T defined as 4380 hours (8760 hrs/2), and the data provided in Table 3.1.3-9, we find:

$$\begin{aligned}2\langle\lambda\rangle = 2\ \{&(2.78E\text{-}08/hr + 6.00E\text{-}07/hr)(6.8E\text{-}07/hr)(4380\ hrs)\\ &+ \tfrac{1}{2}(6.8E\text{-}07/hr)(9.78E\text{-}08/hr)(4380\ hrs) + (6.8E\text{-}07/hr)(1.07E\text{-}04)\}\end{aligned}$$

$$= 2\ \{1.87E\text{-}09 + 1.46E\text{-}10 + 7.28E\text{-}11\} = 4.18E\text{-}09/hr$$

or, converting this to a reactor year frequency,

$$\langle\lambda\rangle = (7110\ hrs/yr)(4.18E\text{-}09/hr) = 2.97E\text{-}05/yr$$

The sum of these two scenarios is thus:

$$\langle\lambda\rangle_{111} = 1.37\text{E-05/yr} + 2.97\text{E-05/yr} = 4.34\text{E-05/yr}$$

This is significantly higher than the 1.0E-06/yr truncation limit defined in Section 3.1.3.2 and is due mainly to the number of potential ISLOCA initiator paths. These scenarios are also very important 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 somewhat conservative to assume that the ISLOCA will occur in the section of piping between check valves 697A and 697B, and containment. Appendix F of [Ref. 3.1.3-9] provides a pipe break probability of 4.0E-01 for 8 inch schedule 20 piping. Since Section 3.1.3.4.3 states that there is 3 times as much RHR piping located inside containment versus that in the identified ISLOCA section, this probability was reduced by a factor of three, or 1.33E-01. Therefore, the ISLOCA frequency for this penetration is as follows:

$$\langle\lambda\rangle_{111} = (4.34\text{E-05/yr})(0.133) = 5.79\text{E-06/yr}$$

There does not appear to be any other potential recovery paths for this ISLOCA scenario since it cannot be isolated.

3.1.3.5.3 Evaluation of Penetration 113

As stated in Section 3.1.3.4.4, this penetration is completely analogous to penetration 101. Therefore, the same ISLOCA frequency of 2.66E-07/yr is applied (see Section 3.1.3.5.1).

3.1.3.5.4 Evaluation of Penetration 140

Section 3.1.3.4.8 identifies one potential ISLOCA initiating event scenario that is equivalent to the first scenario described in Section 3.1.3.5.2. That is, there are two normally closed MOVs with the same interlocks and administrative controls. Therefore, the same ISLOCA frequency of 1.37E-05/yr can be used. Since there are no check valves protecting the RHR system from the RCS, the pipe rupture probability of 0.98 as calculated in Appendix F of [Ref. 3.1.3-9] can be assumed appropriate. However, this probability was dominated by a failure of the RHR heat exchangers (6.0E-01). As shown on Figure 3.1.3-9, there are two MOVs which are each located approximately 25 feet from the penetration [Ref. 3.1.3-42]. These MOVs can be expected to isolate the ISLOCA once operators have identified its location (there are pressure indicators located between the pumps and the heat exchangers). Table A.3-5 of [Ref. 3.1.3-7] suggests a human error probability of 0.1 to close these valves immediately after the event. Therefore, the final initiating event frequency for this penetration is as follows:

$$\langle\lambda\rangle_{140} = (1.37\text{E-05/yr})(0.1) = 1.37\text{E-06/yr}$$

This ISLOCA scenario can be further recovered once it is isolated if the RHR pumps have not been flooded. However, this was not assessed in any detail because of the timing issues involved (i.e., at what time is the pipe break isolated).

3.1.3.6 Final Results

Table 3.1.3-10 summarizes the results of the ISLOCA assessment for the Ginna PRA. As can be seen, the dominating contributor to the ISLOCA frequency is with respect to penetrations 111 and 140.

3.1.3.7 References

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3.1.3-28 RG&E Drawing C-381-355, Sheet 2, *Safety Injection, SI Pump to Penetration #113 (EWR 2512)*, Revision 1, September 13, 1983.

3.1.3-29 RG&E Drawing 33013-1246-1, *Auxiliary Coolant Component Cooling Water (AC) P&ID*, Revision 6, June 6, 1991.

3.1.3-30 RG&E Interoffice Correspondence, M. Flaherty to PRA File 1.3.2, *Documentation of Conversation with John Cook Concerning Excess Letdown Operation*, October 27, 1992.

3.1.3-31 RG&E Procedure AP-CCW.1, *Leakage into the Component Cooling Loop*, Revision 7, February 22, 1990.

3.1.3-32 RG&E Drawing C-381-356, *Aux. Coolant System, Miscellaneous Branch Connections (EWR 2512)*, Revision 2, September 28, 1983.

3.1.3-33 RG&E Drawing C-381-356, Sheet 7, *From Pen's 127 and 128 to A.C. Isometric C-381-356 Sheet 5 (EWR-2512)*, Revision 1, January 12, 1983.

3.1.3-34 Letter from Steve Greer, Altran Corporation, to Thomas Newberry, RG&E, Subject: *Evaluation of NRC IEN 89-54, "Potential Overpressurization of the CCW System*", dated March 9, 1992.

3.1.3-35 SAIC Project Document No. 749-03-22.1, *Plant-Specific Data Work Package for R.E. Ginna Nuclear Power Plant*, Revision 0, June 26, 1992.

3.1.3-36 RG&E Design Analysis NSL-4976-DA003, *Probabilistic Risk Assessment, Determination of Reactor Critical Hours*, Revision 0, September 17, 1990.

3.1.3-37 RG&E Procedure PT-2.2M, *Safety Injection System Monthly Test*, Revision 8, May

1, 1992.

3.1.3-38 RG&E Procedure PT-2.10.4, *Safety Injection Check Valve and MOV Leakage Test*, Revision 14, February 15, 1992.

3.1.3-39 RG&E Procedure PT-2.4.1, *Cold/Refueling Motor Operated Valve Surveillance (RHR System - 700 Valves)*, Revision 10, October 15, 1991.

3.1.3-40 RG&E Procedure 0-6.13, *Daily Surveillance Log*, Revision 72, July 29, 1992.

3.1.3-41 Grove Engineering, Inc, *R.E. Ginna Nuclear Power Plant RCS Transient Validation Report*, August 10, 1989.

3.1.3-42 RG&E Drawing C-381-354, Sheet 5, *From Pen. #140 to Residual Heat Pump Suctions (EWR-2512)*, Revision 5, May 13, 1992.

3.1.3-43 RG&E Procedure RSSP-15.6, *ISI Hydro Test of Class 2 Piping, Safety Injection Discharge*, Revision 9, September 12, 1991.

3.1.3-44 RG&E Procedure RSSP-15.1, *ISI Hydro Test of Class 2 Piping, Safety Injection and Containment Spray Pipe Suction*, Revision 10, April 24, 1991.

3.1.3-45 RG&E Procedure RSSP-15.11, *ISI Hydro Test of Class 2 Piping, RHR System - High Pressure*, Revision 8, April 8, 1992.

3.1.3-46 RG&E Procedure RSSP-13.9, *ISI Hydro Test of Class 1, 2, and 3 Piping - Component Cooling Water*, Revision 7, October 2, 1991.

3.1.3-47 RG&E Procedure RSSP-15.9.1, *ISI Hydro Test of RHR Suction Stop Valves, MOV 700 and MOV 701*, Revision 0, April 22, 1989.

3.1.3-48 RG&E Procedure RSSP 15.10, *ISI Hydro Test of Class 2 Piping, RHR System - Low Pressure Piping*, Revision 7, January 29, 1992.

3.1.3-49 RG&E Procedure RSSP-15.25, *ISI Static Head Hydro Test of Class 2 Piping - Reactor Water Storage Tank*, Revision 1, September 18, 1991.

Table 3.1.3-1
Comparison to Ginna UFSAR Table 6.2-15

Penetration	*System*	*Disposition*
100	CV	operates at RCS pressure and temperature
101	SI	modeled
102	CV	operates at RCS pressure and temperature
106	CV	operates at RCS pressure and temperature
108	CV	operates at RCS pressure and temperature
110a	CV	operates at RCS pressure and temperature
110b	SI	modeled
111	RH	modeled
112	CV	modeled
113	SI	modeled
120a	SI	only connected to top of the accumulators
124a	CC	modeled
124c	CC	modeled
125	CC	modeled
126	CC	modeled
127	CC	modeled
128	CC	modeled
140	RH	modeled
141	RH	connected to sump, not RCS
142	RH	connected to sump, not RCS
205	--	operates at RCS pressure and temperature
206a	--	operates at RCS pressure and temperature
207a	--	operates at RCS pressure and temperature

Table 3.1.3-2
Penetration 101 Piping Evaluation

Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 650°)*[19]	*Hydro Test Pressure (@ 100°)*	*Flanges*
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

Table 3.1.3-3
Penetration 110b Piping Evaluation

Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 650°)*	*Hydro Test Pressure (@ 100°)*	*Flanges*
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

Table 3.1.3-4
Penetration 111 Piping Evaluation

Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 600°)*	*Hydro Test Pressure (@ 100°)*	*Flanges*
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

Table 3.1.3-5 **Penetration 113 Piping Evaluation**					
Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 650°)*	*Hydro Test Pressure (@ 100°)*	*Flanges*
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
PSI01A, PSI01B, PSI01C suction	304/40S	4	370	263	At pumps

Table 3.1.3-6 **Penetrations 124a and 124c Piping Evaluation**					
Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 500°)*	*Hydro Test Pressure (@ 100°)*	*Flanges*
CCW Piping (Associated with HX)	A106/40	2	150	165	At pumps

Table 3.1.3-7 **Penetration 140 Piping Evaluation**					
Section of Piping	*Type/ Schedule*	*Size (in)*	*Design Pressure (@ 600°)*	*Hydro Test Pressure (@ 100°)*	*Flanges*
RCS to 701	316/160	10	2580	2459	None
701 to 854 and RHR Pumps A and B	304/40S	10	600	188	At pumps
854 to RWST	304/40S	10	150	35	None

Table 3.1.3-8 ISLOCA Frequency Analytical Models						
#	*Configuration*	*Equation*	*Failure Modes Included*	*Assumptions*	*ISLOCA Related Failure Modes Not Included*	*Source*
1	Two check valves in series (with accumulator located inbetween)	$\langle\lambda^T\rangle = \frac{1}{2}\lambda^2 T + \lambda\,\lambda_d$ T = time interval between leak tests	• Leak or rupture > 150 gpm (λ) • Probability of failure to reseat on demand (λ_d)	• Failure to hold on demand = failure to reseat on demand • No credit taken for leaking accumulator check valve (i.e., use of accumulator relief valve to relieve pressure) • Accumulator parameter changes will identify leak failures of first check valve	• Leak < 150 gpm • Stuck open	[5, Section 4.3]
2	Two normally closed MOVs in series with no permanent pressure indicator located inbetween	$\langle\lambda^T\rangle = \left(\lambda_L^2 + \lambda_R^2 + \lambda_R\lambda_L\right)T + \frac{1}{2}\left(\lambda_L\lambda_T + \lambda_R\lambda_T\right)T + 2\lambda_L\lambda_d + 2\lambda_R\lambda_d$ T = time interval between leak tests	• Transfers open (λ_T) • Internal leak (λ_L) • Rupture (λ_R) • Probability of failing open while indicating closed (λ_d)	• Valve discs are stroked and leak tested at startup and each cold shutdown • MOVs are not equipped with stem mounted limit switches • Both MOVs have identical failure freq for each failure mode • Both valves are inside containment	• Mispositioned MOV	[Ref. 3.1.3-5, Section B.1.2]

Table 3.1.3-8
ISLOCA Frequency Analytical Models

#	*Configuration*	*Equation*	*Failure Modes Included*	*Assumptions*	*ISLOCA Related Failure Modes Not Included*	*Source*
3	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	$\langle \lambda^T (CV,MV) \rangle = \left(\lambda_{MV(R)} + \lambda_{MV(L)} \right) \lambda_{CV} T + \frac{1}{2} \lambda_{CV} \lambda_{MV(T)} T + \lambda_{CV} \lambda_{J}$ T = time interval between leak tests	CV: • Leak or rupture > 150 gpm (λ) MOV: • Rupture (λ_R) • Leak (λ_L) • Probability of failing open while indicating closed (λ_J) • Transfers open (λT)		CV: • Stuck open • Failure to hold on demand	[Ref. 3.1.3-5, Section B.1.2]

Table 3.1.3-8 ISLOCA Frequency Analytical Models						
#	*Configuration*	*Equation*	*Failure Modes Included*	*Assumptions*	*ISLOCA Related Failure Modes Not Included*	*Source*
4	Two check valves and a normally closed MOV in series. Check valves are on the high pressure side.	$\langle\lambda^T(CV,CV,MV)\rangle = \lambda_{CV}^2\,\lambda_{MV}T^2 + \lambda_{CV}^2\lambda_{MV(d)}T + \lambda_{CV}^2\lambda_{MV(e)}T + 2\lambda_{CV}\lambda_{MV}\lambda_{CV(d)}T$ T = time interval between tests	CV: • Leak or rupture > 150 gpm (λ_{CV}) • Probability of failure to reseat on demand (λ_d) MOV: • Rupture (λ_{MV}) • Probability of failing open while indicating closed (λ_d) • Inadvertently opened by operator (λ_d)	• Failure to hold on demand = failure to reseat on demand	CV: • Stuck open MOV: • Leak • Mispositioned at start of operating cycle • Spuriously opens	[Ref. 3.1.3-5, Section B.2.1]

Table 3.1.3-9
Data for ISLOCA Events

Component	*Failure Mode*	*Value*	*Source*
Check Valve	leak or rupture > 150 gpm	6.80E-07/hr	[7, Table A.2-1]
	failure to reseat on demand	2.80E-04/d	[7, Table A.2-1]
Motor-Operated Valve	transfers open	9.78E-08/hr	[7, Table A.2-1]
	internal leak	6.00E-07/hr	[7, Table A.2-1]
	rupture	2.78E-08/hr	[7, Table A.2-1]
	fails open while indicating closed	1.07E-04/d	[5, Section A.2.3]
	inadvertently opened by operator	2.68E-04/d	[7, Table A.2-1]
			5 = Ref. 3.1.3-5
			7 = Ref. 3.1.3-7

Table 3.1.3-10
ISLOCA Frequency Summary

ISLOCA	*Penetration*	*Frequency*	*LOCA Size*	*SI/RHR Status*
1	101	2.66×10^{-7}/yr	4 in diam.	all SI is lost
2	111	5.79×10^{-6}/yr	10 in diam.	all RHR is lost
3	113	2.66×10^{-7}/yr	4 in diam.	all SI is lost
4	140	1.37×10^{-6}/yr	10 in diam.	all RHR is lost
	TOTAL	7.69×10^{-6}/yr		

Figure 3.1.3-1
Water systems connected to the RCS and their related penetrations (denoted as P###)

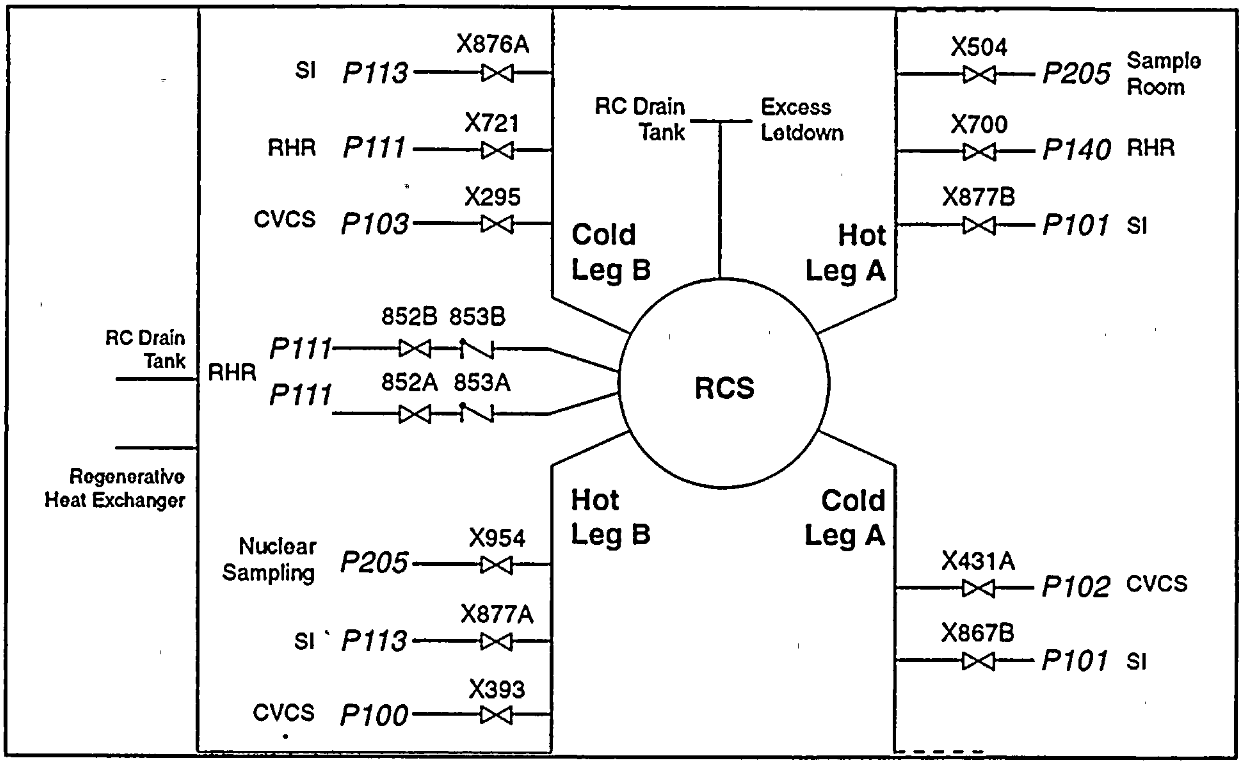


Figure 3.1.3-2
Penetration 101 (Safety Injection)

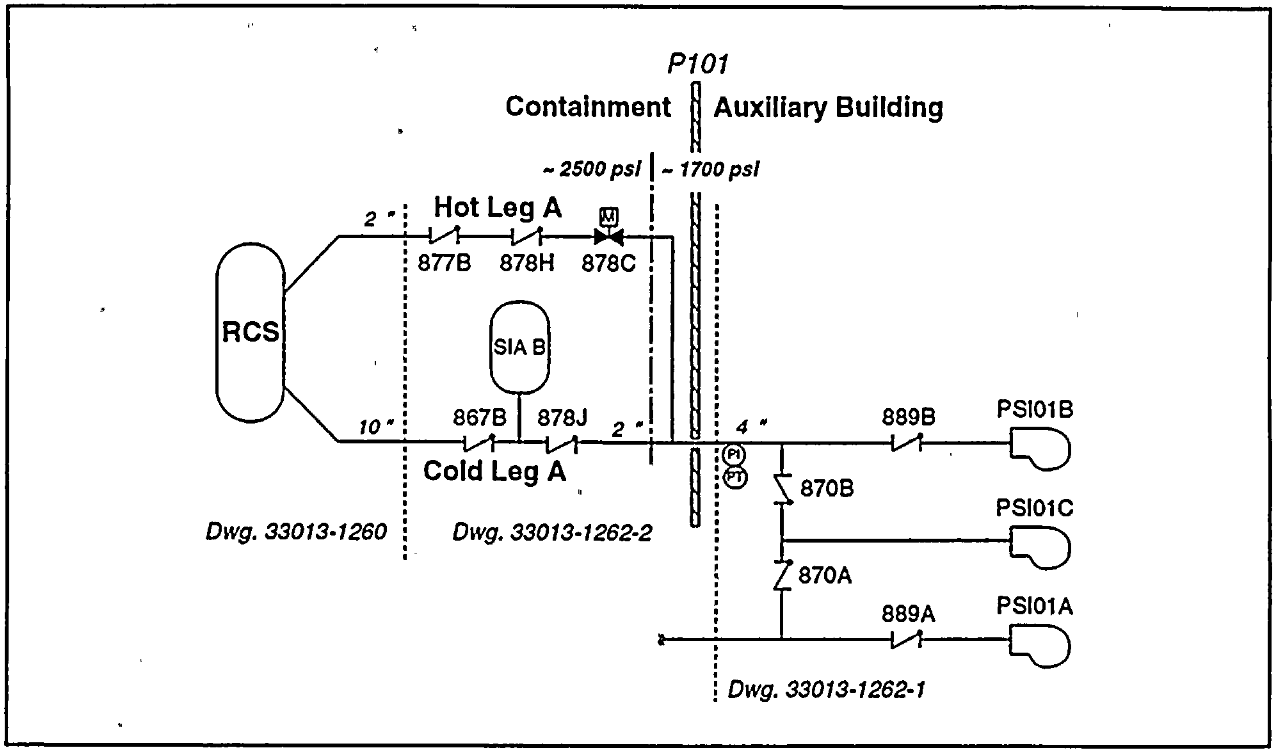


Figure 3.1.3-3
Penetration 110b (SI Test Line)

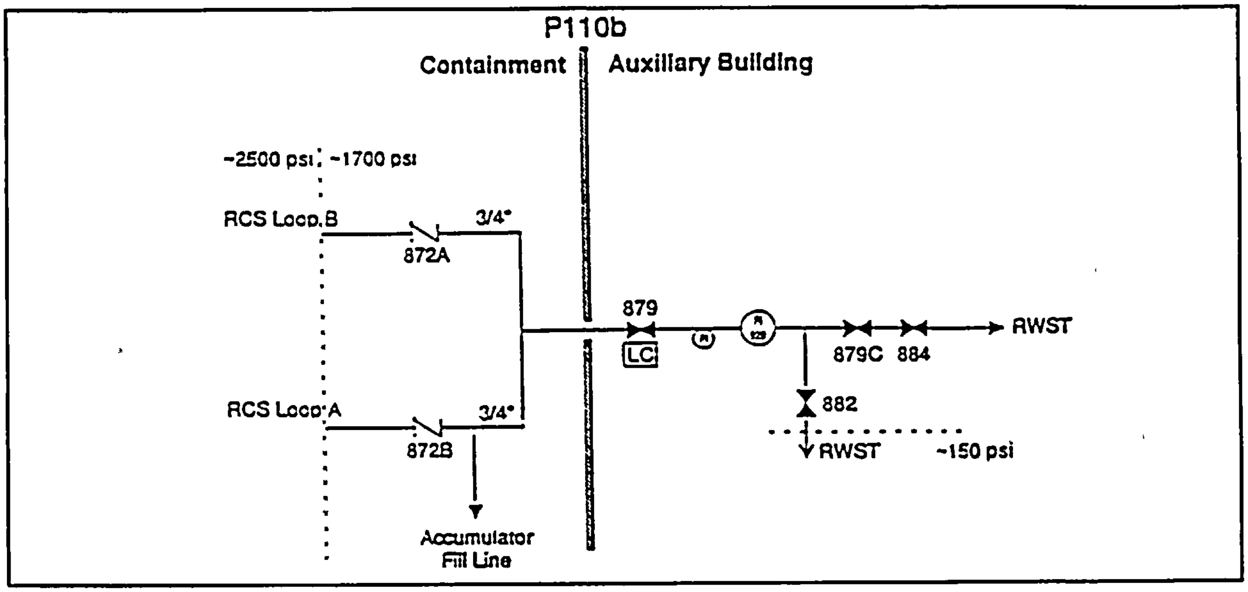


Figure 3.1.3-4
Penetration 111 (Residual Heat Removal)

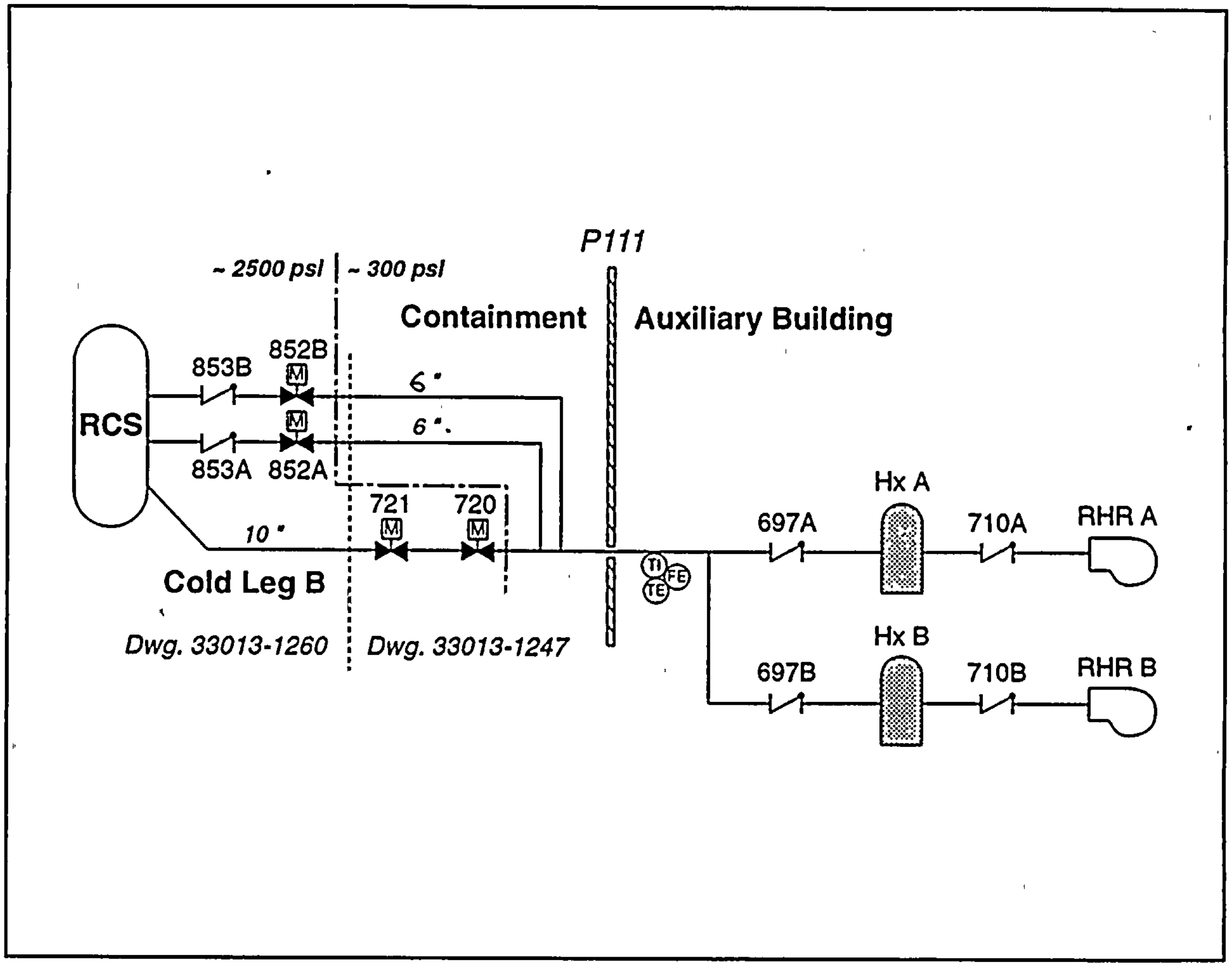


Figure 3.1.3-5
Penetration 113 (Safety Injection).

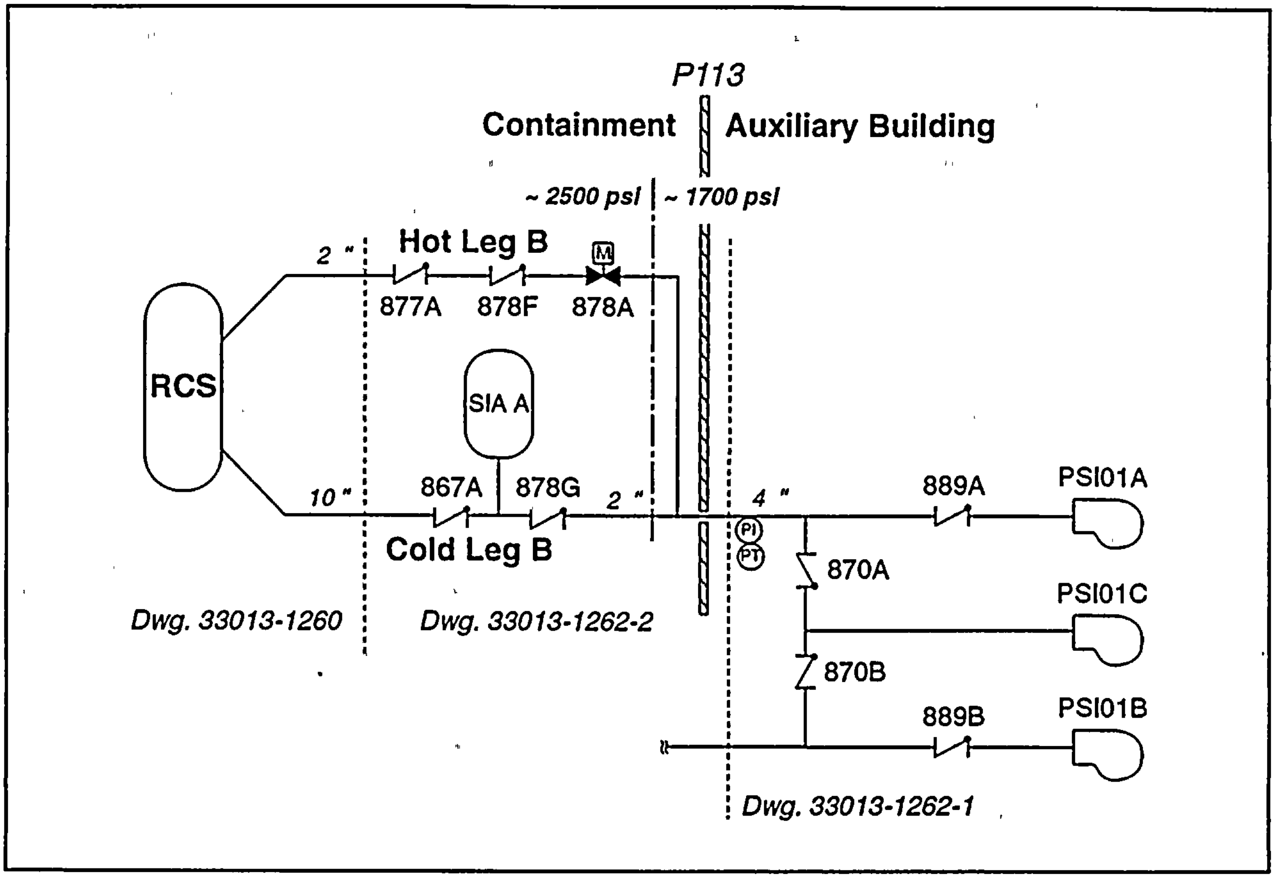
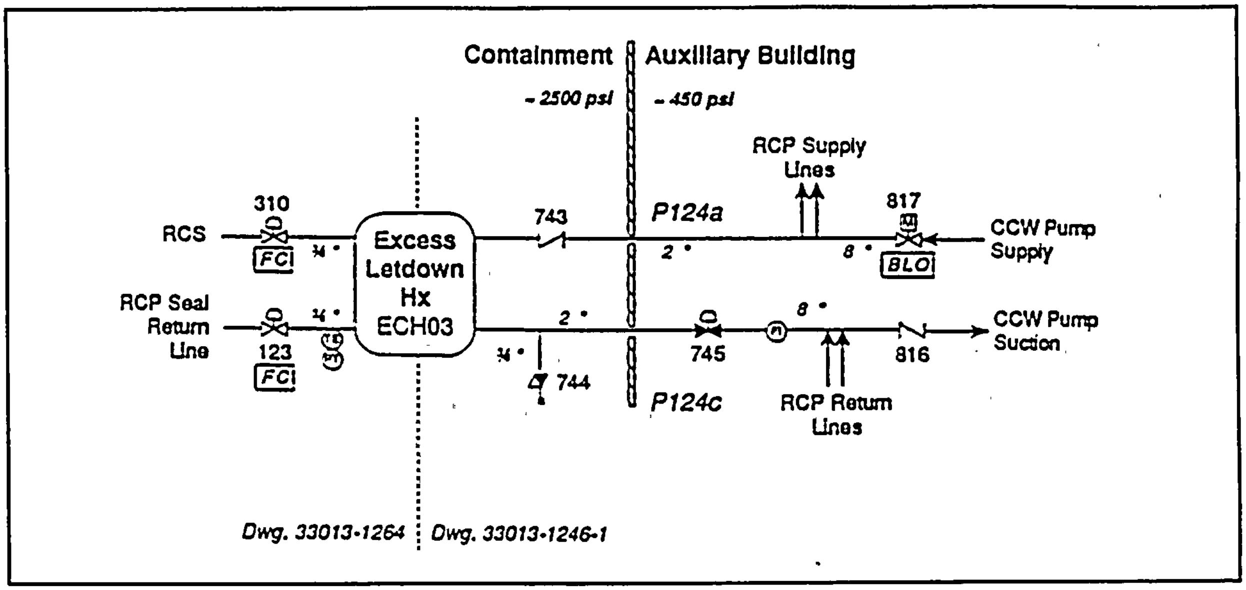


Figure 3.1.3-6
Penetrations 124a and 124c (CCW for Excess Letdown HX)



[illegible]

Figure 3.1.3-7
Penetrations 125 and 128 (CCW for RCP 1B)

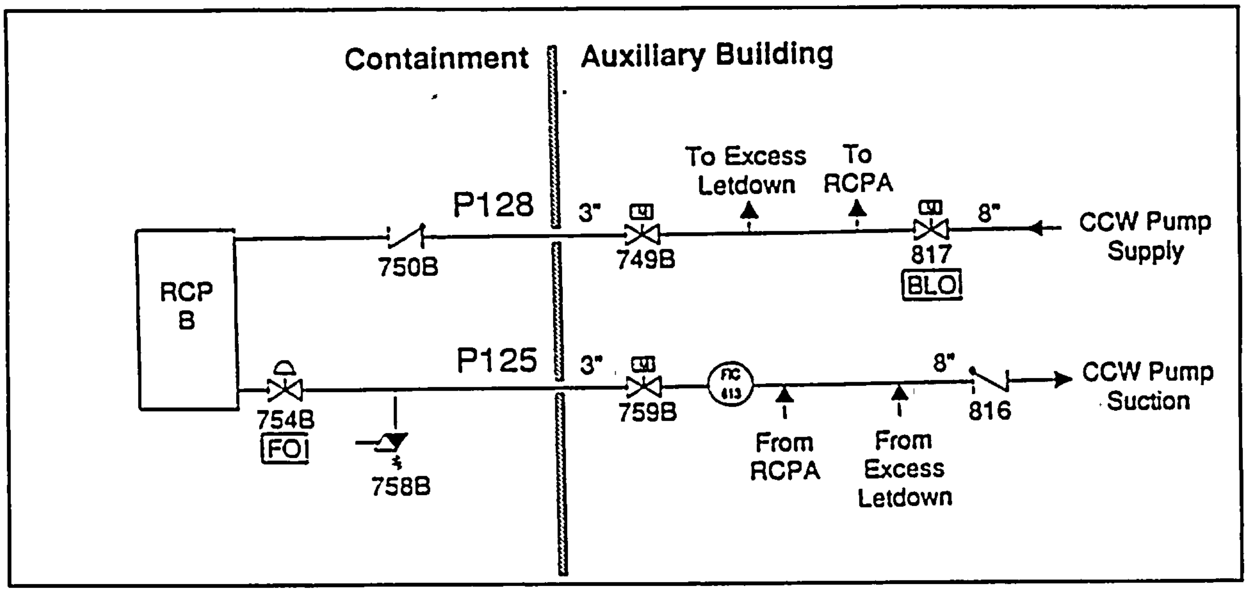


Figure 3.1.3-8
Penetrations 126 and 127 (CCW for RCP 1A)

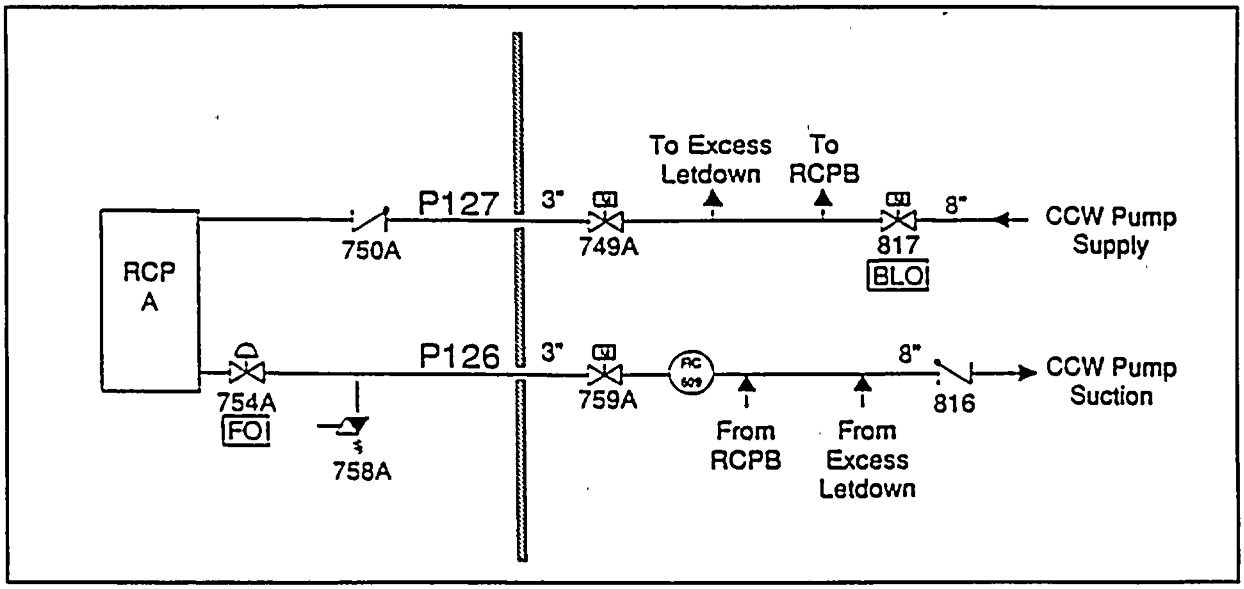
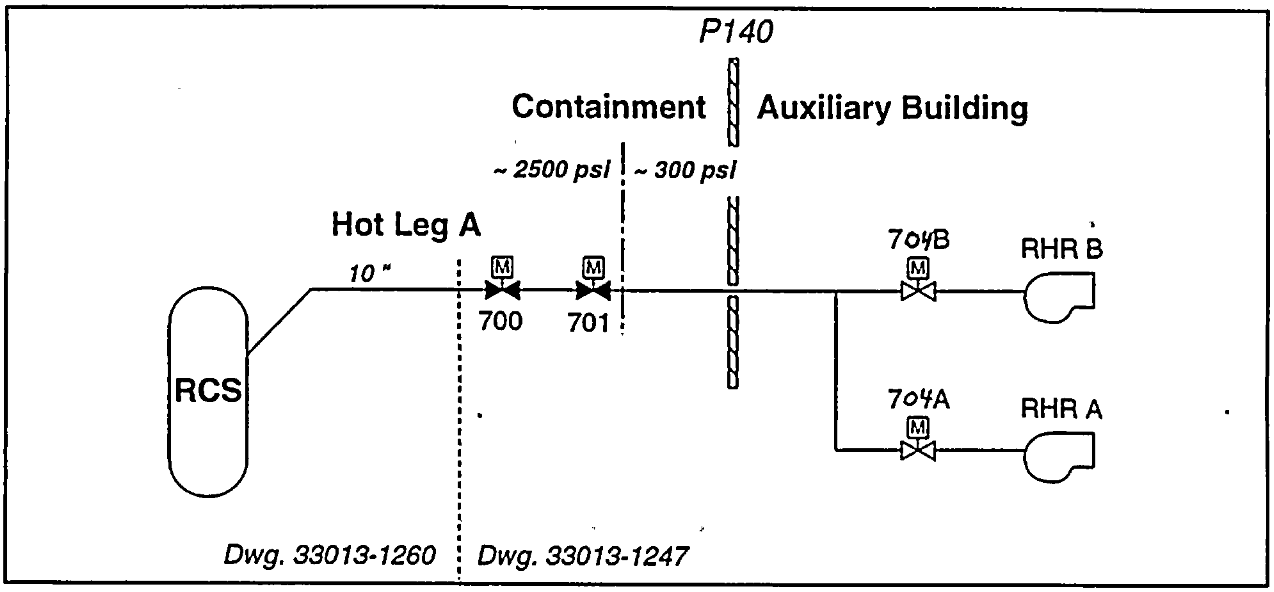


Figure 3.1.3-9
Penetration 140 (Residual Heat Removal)



3.1.4 Support Systems Event Trees

The Ginna PRA utilizes the small event tree / large, linked fault tree methodology. All support systems are explicitly modeled via fault tree interfaces. No support system event trees were required for the Ginna PRA.

3.1.5 Sequence Grouping and Level 2 Interface

Sequence grouping and other functions of the Level 1 / Level 2 interface were carried out under the Level 2 task; therefore, discussion of these functions is included in Section 4.3.

3.2 Systems Analysis

3.2.1 Systems Descriptions

3.2.1.1 Auxiliary Feedwater Systems

3.2.1.1.1 Purpose and Design Basis of the Auxiliary Feedwater Systems

The Auxiliary Feedwater (AFW) System, as defined for this analysis, consists of both the Auxiliary Feedwater System and the Standby Auxiliary Feedwater (SAFW) System. Top events supported by the Auxiliary Feedwater System fault tree models include no flow to either steam generator from any AFW train; turbine driven AFW pump train fails to provide flow to the steam generators; motor driven AFW pump train A fails to provide flow to the steam generators; motor driven AFW pump train B fails to provide flow to the steam generators; no AFW flow to either steam generator; and, failure of standby auxiliary feedwater flow to both steam generators.

The main function of the Auxiliary Feedwater System is to maintain steam generator water inventory when the Main Feedwater (MFW) System is not available. The AFW system is used during plant startup, cooldown, shutdown operations, and emergency situations. Below approximately 4% of reactor power, the MFW pumps cannot be used; consequently, the AFW pumps provide water to maintain the desired level in the steam generators. In addition, AFW provides emergency feedwater flow to the steam generators whenever the MFW System is not supplying sufficient flow.

The purpose of the standby portion of the system is to provide backup feedwater in the event that the AFW System is inoperable due to a high-energy line break in the Intermediate Building or other similar common mode failure event. The Standby Auxiliary Feedwater System can be brought into service by proceduralized operator actions in the control room.

The Auxiliary Feedwater System is considered an engineered safety feature (ESF) since it protects the core and prevents the release of reactor coolant through pressurizer safety valves by maintaining a secondary heat sink for residual heat removal. Any one of three AFW pumps, or one of two SAFW pumps, supplying feedwater to one of two steam generators will sufficiently cool the Reactor Coolant System to the temperature at which the Residual Heat Removal (RHR) System can be utilized for heat removal.

The AFW System is designed to mitigate the consequences of the following design basis accidents:

1. Loss of main feedwater transient.

    a. Loss of main feedwater with off-site power available.
    b. Loss of main feedwater without off-site power available.
    c. Rupture of feedwater line.

2. Rupture of a main steam line.

3. Loss of all AC power (off-site and on-site).

4. Loss-of-coolant accident (LOCA).

Following a reactor trip, decay heat is dissipated by evaporating water in the steam generators and venting the generated steam either to the condensers through the steam dump, or to the atmosphere through the steam generator safety valves or the atmospheric relief valves. Consequently, steam generator water inventory must be maintained at a level sufficient to ensure adequate heat transfer and continuation of the decay heat removal process. This water level can be maintained by the AFW System which is capable of functioning for extended periods, allowing time to proceed with an orderly cooldown of the plant to the point where the RHR System can assume the burden of decay heat removal. The AFW System flow and the emergency water supply capacity are sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown.

The AFW System is capable of supplying water at a pressure equal to or greater than the lowest main steam safety valve setpoint plus accumulation (1085 psig) within one minute. The system continues to operate until steam generator pressure falls to the point where the RHR System can be operated. During periods of MFW System outage (e.g., loss of off-site electrical power for periods greater than 24 hours), the AFW System will operate continuously to meet long-term single failure design criterion.

The standby portion of the AFW System was installed to provide an independent system capability following a high-energy line break or fire in the Intermediate Building which could render the three AFW pumps inoperable. The SAFW System consists of two motor-driven pumps located in a plant area separate from the AFW System. It is manually actuated and aligned so that each SAFW pump supplies one steam generator.

3.2.1.1.2 Auxiliary Feedwater Systems Description

The main portion of the AFW System consists of two motor driven pumps (PAF01A and PAF01B) and one turbine-driven pump (PAF03). Normally, each motor driven pump supplies one steam generator, but the alignment can be altered to allow either motor driven AFW pump to supply either or both steam generators. The turbine driven AFW pump is normally aligned to supply feedwater to both steam generators. Each motor driven pump supplies the steam generators through normally open, motor operated discharge valves (4007 and 4008) while the turbine driven pump provides water through normally open, air operated valves (4297 and 4298). The SAFW System consists of two motor-driven pumps (PSF01A and PSF01B) 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 steam generator.

The two main motor driven AFW pumps (PAF01A and PAF01B) are 480 VAC, 3 phase, 300 hp, 3600 rpm motors, capable of pumping 200 gpm at 1085 psig. Each pump contains an oil pump which will start when the AFW pump starts. The AFW pumps have splash-lubricated gears; the motors are of an open, drip-proof design powered from the ESF buses with emergency diesel backups. The turbine driven auxiliary feedwater pump (PAF03) receives steam from either or both steam generators and is capable of pumping 400 gpm at 1085 psig. It has both AC and DC lube oil pumps (PLO10 and PLO11, respectively) with the AC lube oil pump normally running. The turbine driven 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.

The normal system lineup is for motor-driven AFW pump PAF01A to supply Steam Generator A (EMS01A), and for pump PAF01B to supply Steam Generator B (EMS01B). However, the motor driven AFW pumps can be remotely cross-connected to feed either one or both steam generators. Air operated discharge valves 4480 and 4481 are provided to allow bypassing of the motor driven AFW pumps' discharge motor operated valves 4007 and 4008, respectively, during periods when low flow is required.

Turbine driven AFW pump PAF03 discharges into a common header; this common header supplies flow to either one or both steam generators. A manual cross-connection (manual valves 4359 and 4360 and motor operated valves 4000A or 4000B) between motor driven AFW pumps PAF01A and PAF01B and turbine driven AFW pump PAF03 is provided for an alternate flowpath. This allows for continuous makeup to the steam generators during extended hot shutdown conditions.

All three AFW pumps have recirculation lines back to condensate storage tanks TCD02A and TCD02B. The air operated recirculation valves for the motor-driven AFW pumps (air operated valves 4304 and 4310) open automatically on high discharge pressure of 1350 psig. The turbine driven AFW pump's recirculation valve (AOV 4291) is normally open, but automatically opens on low flow of 100 gpm.

Water is supplied to the AFW pumps by means of gravity feed from the two 30,000 gallon capacity condensate storage tanks located in the basement of the Service Building. For reactor power operation, Technical Specifications require a minimum of 22,500 gallons in at least one tank, with a single condensate storage tank supplying enough water to remove decay heat for two hours after a reactor trip from full power. The Service Water System provides a backup water supply to the AFW system. Feedwater can also be provided per plant procedures through the yard fire hydrant system, the condenser hotwells, and outside condensate storage tank TCD03.

The SAFW System consists of two motor driven pumps, each capable of supplying 200 gpm at 1085 psig. The pumps are powered from ESF buses for reliable power supply. The pumps do not have an automatic actuation capability; rather, they may be initiated and operated manually from the main control board in the control room. In the event that the 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 existing control room indicators, alarms, and annunciators. The operators are instructed by procedures to manually disconnect the affected AFW pump from the bus and place the respective SAFW pump into operation on the associated bus. Flow to the steam generators is controlled by throttling the associated standby pump discharge valve (motor operated valves 9704A and 9704B).

The normal water supply for SAFW is from the Service Water System through respective loops which can be cross-connected if necessary. However, the Fire Service Water System can be used if there is a total loss of Service Water by use of a fire hydrant connection located inside the SAFW Building. The Condensate Test Tank (TCD01) with a 10,000 gallon capacity is provided to store condensate quality water as a source of supply for periodic testing of the SAFW System.

Simplified flow diagrams for the Auxiliary Feedwater Systems are shown in Figures 3.2.1-1, 3.2.1-2 and 3.2.1-3.

3.2.1.1.3 Auxiliary Feedwater Systems Electrical Depencencies

As part of the review for NUREG-0737, Item II.E.1.1, an evaluation was performed to determine if there was an essential dependence of the turbine-driven auxiliary feedwater pump on AC power. The only AC dependence discovered was the need for service water cooling of the lube oil for the turbine driven AFW pump. The turbine driven AFW pump has both an AC lube-oil pump (PLO10) and a DC lube oil pump (PLO11). These pumps direct the oil through a heat exchanger (EAF01), which depends on the AC-powered Service Water System for cooling. In the event of a total loss of AC power, lube oil cooling capability for the turbine driven AFW pump would be lost due to the unavailability of AC power to the service water pumps.

Rochester Gas & Electric conducted a test on August 10, 1979, to demonstrate that the turbine driven AFW pump could operate for two hours without lube oil cooling water flow. The test was run for 1 hour and 45 minutes with the final 1 hour and 15 minutes of the test with the pump at rated speed, but only 50% of required plant flow. The test showed that the pump and turbine bearing temperatures remained well within allowable limits. RG&E also implemented a procedure to ensure that the turbine driven AFW pump is periodically checked if all AC power is lost. Based on the results of the recirculation flow test and the procedure, the Nuclear Regulatory Commission concluded that the turbine driven Auxiliary Feedwater pump does not have an essential AC power dependency.

3.2.1.1.4 Auxiliary Feedwater Systems Cooling Water Dependencies

The motor driven AFW pumps require service water cooling to the pump bearings and lube oil coolers. The turbine driven AFW pump requires service water cooling for the lube oil cooler only. The SAFW motor driven pumps do not require any cooling water.

3.2.1.1.5 Auxiliary Feedwater Systems Instrument Air Dependencies

The Auxiliary Feedwater System, as modeled in the Ginna PRA, requires air pressure to close valves 4297 and 4298, the turbine driven AFW pump flow control valves to steam generators EMS01A and EMS01B, respectively.

3.2.1.1.6 Auxiliary Feedwater Systems Actuation and Control Dependencies

The AFW System will automatically actuate under various conditions to maintain steam generator inventory. The turbine driven AFW (TDAFW) pump steam admission valves (motor operated valves 3504A and 3505A) will open to start turbine driven AFW pump PAF03 and open the pump discharge valve (motor operated valve 3996) on the following signals:

- 2/3 low-low level (17%) in both steam generators;
- Loss of voltage on both 4160V buses (11A and 11B);
- ATWAS Mitigation System Actuation Circuitry (AMSAC) actuation; or,
- Manual actuation.

Motor driven AFW pumps PAF01A and PAF01B and their associated discharge motor operated valves (4007 and 4008) are actuated on the following signals:

- 2/3 low-low level (17%) in either steam generator;
- AMSAC actuation;
- Manual actuation;
- Both MFW pump breakers open; or,
- Initiation of Engineered Safety Features Actuation System (ESFAS) train A or B.

The actuation scheme for the AFW motor-driven pumps is shown in Figures 3.2.1-4 and 3.2.1-5.

There is no automatic actuation of the SAFW System. However, a SAFW pump cannot be started if any of the following conditions are true:

- Low level in SAFW Condensate Test Tank TCD01 (when in test configuration);
- Valve 9707A or 9707B starts to close (when in test configuration);
- Valve 9629A or 9629B starts to close (when in normal configuration);
- Auxiliary feedwater pump PAF01A or PAF01B breaker (BUS14/21C and BUS16/14C respectively) closes (train dependent);
- Initiation of ESFAS train A or B (train dependent);
- Undervoltage on Bus 14 or 16 (train dependent);

3.2.1.1.7 Auxiliary Feedwater Systems Heating, Ventilation and Cooling Dependencies

An analysis performed for RG&E shows that the TDAFW pump area rises to 145°F after four hours without any ventilation during a station blackout (SBO) event. This temperature rise was acceptable for SBO purposes; however, it is unknown whether the equipment can survive in this environment for extended periods of time. Consequently, it was conservatively assumed that cooling was required for the three AFW pumps (PAF01A, PAF01B and PAF03). The SAFW Pump Building requires ventilation if the doors to the building are not opened; freezing is a concern during the winter months.

3.2.1.1.8 Auxiliary Feedwater Systems Controls and Instrumentation

The motor driven (PAF01A and PAF01B) and turbine driven (PAF03) AFW pumps each have an automatically controlled minimum flow recirculation system sized and periodically tested to ensure that sufficient minimum flow will be provided under all accident and normal operating conditions to prevent pump damage from overheating. In addition, motor driven AFW pump discharge motor operated valves 4007 and 4008 will close upon their respective pump trip. These valves can then be manually reopened if necessary.

There is a primary and secondary flow instrumentation channel for each AFW pump. The primary channel indicates flow (FT-2001 and FT-2002) and, for the motor driven pumps, controls the individual discharge valves (motor operated valves 4007 and 4008). The secondary flow instrumentation indicates flow only (FT-2013 and FT-2014). The primary and secondary channels are powered from opposite 120 VAC instrument buses with flow indication provided on the main control board by a dual-movement vertical scale indicator. In addition, redundant level indications and low level alarms in the control room are provided for the condensate storage tanks (LT-2022A and LT-2022B). This allows the operators to anticipate the need to make up water or transfer to an alternate supply and prevent low pump suction pressure..

The following is a description of the AFW bypass switches used for air operated valves 4480 and 4481:

NORM — The motor driven AFW pumps will start and the bypass valves will close on the following signals:

- ESFAS signal (train dependent)
- 2/3 low-low level in either steam generator (closes both valves; starts both motor driven AFW pumps)
- Both MFW pump breakers (BUS11A/07 and BUS11B/25) open

DEF Defeats start signal to the motor driven AFW pumps when both MFW pump breakers are open, and allows use of the bypass valves. However, when the main turbine is latched, the defeat is automatically bypassed no matter what position the switch is in. If the switch were left in the DEF position concurrent with a turbine trip, both MFW pump breakers open, and a SI signal present, there is a 30 second delay from the time of turbine trip to the start signal for AFW pump PAF01A, and 32 seconds for AFW pump PAF01B.

The SAFW pump (PSF01A and PSF01B) start / stop logic is manually controlled from the control room or from a local station near the pumps in the Standby AFW Building. A switch for transfer of control from local to the control room (43/SAFWP1C and 43/SAFWP1D) is provided at the local control station. Control room indication provides the status of this transfer switch. If the local mode switch is in test, the SAFW pumps will trip on 2 feet low level in SAFW Condensate Test Tank TCD01, or if the manual suction valve (9707A or 9707B) to test tank TCD01 is not open. A SAFW pump (PSF01A or PSF01B) cannot be started if the corresponding motor driven auxiliary feedwater pump (PAF01A or PAF01B) is connected to the bus or if its associated suction valve (9629A or 9629B) is closed. The discharge valves (9701A and 9701B), when in the automatic mode, will open when their associated auxiliary feedwater pump is started and will then throttle back to less than 230 gpm. The discharge valve will close when the SAFW pump is stopped. The pump recirculation valves (9710A and 9710B) are controlled by flow controllers (FT-4084 and FT-4085 respectively) set to open when the associated pump breaker is closed and flow is less than 80 gpm. Recirculation is back to SAFW Condensate Test Tank TCD01.

Alarms, controls, and indications for AFW are on the Main Control Board center right section. Major AFW system control room indications are listed below:

- AFW motor driven pump flow to each steam generator (two channels each);
- AFW motor driven pump discharge pressure;
- AFW turbine driven pump discharge flow (two channels);
- AFW turbine driven pump flow to each steam generator (two channels each);
- SAFW motor driven pump flow (one channel each);
- SAFW motor driven pump discharge pressure;
- Narrow-range steam generator level (three channels each);
- Wide-range steam generator level (one channel each);
- Main and standby auxiliary feedwater pump status indication;
- Main and standby auxiliary feedwater valve position indication; and,
- Condensate storage tank levels (two channels per tank).

3.2.1.1.9 Location of Major Auxiliary Feedwater Systems Components

Motor driven auxiliary feedwater pumps PAF01A, PAF01B, turbine driven auxiliary feedwater pump PAF03, their support equipment and major valves are located in the basement (elevation 253) of the Intermediate Building North (clean) side. Condensate storage tanks TCD02A and TCD02B are in the basement (elevation 253) of the Service Building, in the Water Treatment Room. Standby auxiliary feedwater pumps PSF01A, PSF01B, their support equipment and condensate test tank TCD01 are located in the Standby Auxiliary Feedwater Building (elevation 271).

3.2.1.110 Normal Auxiliary Feedwater Systems Operation

Prior to reactor power reaching 2% to 4% during plant startup when the MFW pumps cannot be used, AFW provides water to maintain the desired level in the steam generators. This is normally done using the following method: One motor-driven AFW pump (PAF01A or PAF01B) is started; the pump discharge valves (4007 and 4008) are closed; and, the bypass valves (4480 and 4481) are throttled to maintain the desired steam generator levels. An additional AFW pump is then added if necessary. However, at or above an RCS temperature of 350°F, motor operated valves 4007 and 4008 must be opened as required by Technical Specifications.

After the reactor is above 2% to 4% power, the AFW System is lined up to respond to any potential loss of MFW flow to the steam generators. The motor driven AFW pumps are lined up to supply their respective steam generators while the turbine driven AFW pump discharges to a common header and then divides to provide flow to both steam generators. All valves in the main system flowpaths, except for the TDAFW steam admission valves (3505A and 3505B), are open when the reactor is at power.

The AFW System also supplies feedwater to maintain steam generator level during cooldown operations. At approximately 2% to 4% reactor power, the MFW pumps will be turned off and normally both motor driven AFW pumps will be used to supply feedwater to the steam generators. The AFW motor driven pump crosstie valves (4000A and 4000B), discharge valves (4007 and 4008), and the bypass valves (4480 and 4481) are aligned as needed to maintain the desired steam generator levels.

The AFW System is also used to supply feedwater to the steam generators during shutdown operations. This is normally accomplished by using one motor driven AFW pump (PAF01A or PAF01B) and opening the AFW motor driven pump crosstie valves (4000A or 4000B) to provide flow to both steam generators.

The SAFW System does not perform any functions during normal plant operation; however, the SAFW pumps are aligned to provide flow to their respective steam generators with all valves in the flowpath open except for the service water supply valves (9629A and 9629B).

3.2.1.1.11 Auxiliary Feedwater Systems Performance During Accident Conditions

The AFW System provides emergency feedwater flow to the steam generators whenever the MFW System is not supplying sufficient flow. The motor driven auxiliary feedwater pumps will start if the level in one steam generator decreases to a low-low level of 17% due to shrinking of steam generator water inventory during a rapid power reduction, or a loss of MFW. In addition, both bypass valves (4480 and 4481) will close and both discharge valves (4007 and 4008) will throttle back to maintain a flow of less than 230 gpm (200 gpm minimum) to each steam generator. The two motor driven AFW pumps (PAF01A and PAF01B) will also start and feed the steam generators with the discharge valves (4007 and 4008) throttled between 200 to 230 gpm and the bypass valves closed upon an ESFAS signal (either train) or if both MFW pump breakers open.

The turbine driven auxiliary feedwater pump (PAF03) will automatically start if the level in both steam generators decreases to a low-low level of 17%. The pump will also start immediately on loss of power (undervoltage) to both 4160 VAC service buses (Bus 11A and Bus 11B). Since the condensate storage tanks (TCD02A and TCD02B) can only provide a limited amount of water for AFW, additional condensate sources are required in the long term if the MFW and Condensate Systems are not recovered. The most desired source of water is from the condenser hotwell since the treated water it contains will not chemically contaminate the steam generators.

The SAFW system is started manually and only activated by the operators if all other forms of feedwater are lost to the steam generators. If SAFW is required, the system is aligned such that each pump supplies one steam generator.

3.2.1.1.12 Auxiliary Feedwater Systems Test And Maintenance

The AFW and SAFW Systems are normally in standby during reactor power operation, ready to supply emergency feedwater flow to the steam generators. Since AFW and SAFW are not normally operating, they are periodically tested to ensure that the system will function as designed. In addition, preventative maintenance is performed on the system components to provide additional assurance of their reliability.

Traditionally, many of the instrument calibrations performed on the AFW and SAFW Systems resulted in declaring a train inoperable. Consequently, the unavailability of system trains was relatively high since there were a large number of calibration-related events. However, it was more recently determined that the calibration of the AFW flow transmitters did not result in the trains being unavailable. In addition, other calibrations are not considered to render the component inoperable since an auxiliary operator is stationed in the area during the test capable of performing the necessary actions to recover the system. Therefore, no unavailability due to instrument calibration was modeled.

Auxiliary operators perform walkdowns approximately every four hours in accordance with plant procedures. Included with these walkdowns are verification of the AFW pump valve lineups, a check of the pump casing temperatures, and confirmation that the TDAFW pump governor (9519E) and trip throttle valve (3652) are properly latched. For SAFW, auxiliary operators check the status of the pump's local / remote switch (43/SAFWP1C and 43/SAFWP1D) and SAFW room cooling units (AFA01A and AFA01B).

3.2.1.1.13 Auxiliary Feedwater Systems Operating Experience

The following is a listing of Licensee Event Reports (LERs) which were generated against the AFW and SAFW Systems between January 1, 1980 and May 22, 1990 [Ref. 18.1.13]. These LERs were reviewed to ensure that the failure modes which have been historically observed for the AFW and SAFW Systems are adequately addressed in the fault tree model.

83-001 On January 4, 1983, during the performance of S-30.5, *Standby Auxiliary Feedwater Pump Valve and Breaker Position Verification*, service water suction valve 9626A to SAFW pump PSF01A was found in the closed position. The last verification of the valve in the open position was made on December 22, 1982 by a Shift Technical Advisor. A detailed investigation into the event could find no reason for the mispositioned valve; however, it was attributed to either human error or tampering. This event is addressed in the fault tree by failure to restore equipment to service after maintenance or testing.

83-014 On March 29, 1983, technicians found that the output from steam generator level transmitters LT-461, LT-462, LT-463, LT-471, and LT-473, was low by 2 to 2.5% of span, which is approximately two inches of water. This event was attributed to instrument drift and the transmitters were recalibrated. This specific event is not addressed by the fault tree model since the level transmitters failing low is success for initiating AFW. That is, if the level transmitters were reading two inches of water too low, then AFW would be initiated earlier.

87-006 On November 30, 1987 while investigating a problem with the SAFW room cooling unit AFA01B control room indicating light, the associated breaker (MCCL/02M) was found in the off position. The last verification of the breaker in the on position was made on November 18, 1987. No root cause for the mispositioned breaker could be found; however, locks were subsequently placed on the SAFW room cooling units' breakers. This event is addressed in the fault tree by failure to restore equipment to service after maintenance or testing.

3.2.1.1.14 Plant Specific Data Analysis for the Auxiliay Feedwater Systems

Maintenance and Testing Activities. There were numerous out-of-service events related to the AFW and SAFW Systems [Ref. 18.1.14]. This can be attributed to Technical Specifications which allow single trains of either system to be removed from service for extended periods of time. Consequently, an AFW or SAFW train was frequently removed from service for testing or instrument calibration purposes. However, testing and preventative maintenance related unavailabilities are typically not included in the model; only the failure to restore equipment following testing and maintenance is included as a result of the LERs discussed in Section 3.2.1.1.13. In addition, a large portion of the calculated out-of-service time for AFW was attributed to seismic and fire modifications. These events were not included since they are not expected to reflect future performance of the AFW or SAFW Systems.

Common Cause Failures. On October 26, 1988, check valves 4003 and 4004 for the TDAFW pump discharge lines were found to be leaking by [Ref. 18.1.15]. This resulted in air entering the discharge lines, causing the TDAFW pump flow transmitters to read erratically. Since the flow transmitters do not provide any automatic function with respect to the TDAFW pump, this failure was not modeled.
There were no common cause failures related to the SAFW System.

Component Reliabilities. There were several events associated with component reliability for the AFW and SAFW Systems. These are briefly described below.

In December 1983, workers applying insulation accidently stepped on the TDAFW pump trip throttle valve (3652) and closed it. This event is addressed in the fault tree by failure of the pump to start. In addition, on January 2, 1985, a faulty pressure switch for the TDAFW pump caused arcing and high voltage spikes in the DC electrical distribution system resulting in numerous control room alarms. The event reoccurred in June 1985. The pressure switch was replaced and the failures stopped. This event is not addressed by the fault tree model since this is an electrical distribution concern, not an AFW System concern.

On June 14, 1985, SAFW pump PSF01B failed to trip from both the Main Control Board and locally. The pump breaker BUS16/17C was then manually tripped to secure the pump. This event is also not addressed in the fault tree model since the failure is related to the electrical distribution system. That is, if an AFW and SAFW pump were to be operated simultaneously, it is only a concern for degraded voltage on the bus, not a failure of the pumps.

3.2.1.2 Component Cooling Water System

3.2.1.2.1 Purpose and Design Basis of the Component Cooling Water System

The Component Cooling Water (CCW) System is a support system that supports the Residual Heat Removal (RHR), Safety Injection (SI) and Containment Spray (CS) Systems in their performance of front line safety functions. Additionally, the CCW System is required to cool the reactor coolant pump (RCP) thermal barriers in order to prevent an RCP seal loss of coolant accident (LOCA).

The CCW System is a closed loop cooling water system designed to remove heat from various pumps and coolers and the RHR heat exchangers and to transfer it to the Service Water (SW) System for rejection to the ultimate heat sink. The CCW System consists of two pumps, two heat exchangers, a surge tank, and distribution piping serving the various heat exchangers.

The CCW System provides necessary cooling to the following standby safety equipment that are necessary to mitigate and/or prevent accidents and are modeled in the Ginna PRA:

- SI Pumps PSI01A, PSI01B, and PSI01C;
- CS Pumps PSI02A and PSI02B;
- RHR Heat Exchangers EAC02A and EAC02B; and,
- RHR Pumps PAC01A and PAC01B.

Additionally, during normal plant operation the CCW System operates to provide cooling to reactor coolant pump (RCP) motor bearing heat exchangers ECH08A and ECH08B and thermal barriers on RCPs PRC01A and PRC01B; excess letdown heat exchanger ECH03, non-regenerative heat exchanger ECH05, RCP seal water heat exchanger ECH04; boric acid recycle evaporator heat exchangers ECH01, ECH06, and ECH07; sample heat exchangers EAC01 (Failed Fuel Radiation Monitor Heat Exchanger), EAC04A and EAC04B (Steam Generator Blowdown Sample Heat Exchangers) EAC05A (Pressurizer Liquid Spray EAC05C (Pressurizer Steam Space Sample Heat Exchanger); waste evaporator condenser EWD09, waste gas compressors heat exchangers EWD01A and EWD01B; and the reactor support cooling pads.

The CCW System is designed to remove heat from plant components during plant operation, plant cooldown, and during post accident conditions. The CCW System serves as an intermediate system between the radioactive fluid systems and the Service Water System. This arrangement reduces the probability of radioactive fluid leakage to the environment via the Service Water System. Therefore, the design basis includes the detection of radioactivity entering the system from any of the cooled components and the ability to isolate any component.

During normal full-power operation at least one CCW pump and one heat exchanger are in service to accommodate the normal heat removal loads. Normally, both pumps and both heat exchangers are used to remove the residual and sensible heat during plant shutdown. If one of the pumps or one of the heat exchangers is inoperable, safe operation of the plant is not affected; however, the time to achieve shutdown is extended.

3.2.1.2.2 Component Cooling Water System Description

The CCW System consists of centrifugal pumps PAC02A and PAC02B (and associated isolation and check valves) arranged in parallel to discharge to a single header. This header then splits to supply flow to the shell of two parallel CCW to service water (CCW-to-SW) heat exchangers (EAC01A and EAC01B) and associated isolation valves. Leaving the CCW-to-SW heat exchangers, the water returns to a single header which supplies water to the above mentioned equipment, which are arranged in parallel. After cooling the equipment, the CCW enters to a single header which supplies flow to the suction of the CCW pumps. A surge tank (TAC01), which is normally vented to atmosphere, is connected to this suction header. A simplified CCW System layout drawing is shown in Figure 3.2.1-6. A more detailed description of CCW to the reactor coolant pump seals is shown on Figure 3.2.1-7.

The following describes the key CCW System components:

- CCW Pumps PAC02A and PAC02B
    - Rated flow: 2980 gpm @ 165 ft. total head
    - Capacity: 100%
    - Type: Horizontal centrifugal
- CCW Heat Exchangers EACO1A and EACO1B
    - Heat transfer: 25.15 x 10^6 BTU/hr.
    - Type: Shell and straight tube
    - Design pressure: 150 psig

System temperature control is accomplished by manually throttling service water isolation valves 4619 and 4620. Temperature of CCW supplied to various components should not normally exceed 100°F. A maximum temperature of 120°F is allowable when the RHR System is in service for plant cooldown.

Potassium chromate concentration in the CCW system is maintained between 175 and 240 ppm to minimize corrosion. Potassium chromate is added to surge tank TAC01 when needed and introduced to the CCW System by operating with the surge tank recirculation valve (725) open for 30 minutes.

Surge tank level is monitored and alarmed (high and low) in the control room. Makeup water is manually provided from either the demineralized water system or the reactor makeup water system. The CCW makeup systems are capable of coping with normal system leakage in post accident operation. Additionally, leak off from pump seals is collected in the CCW pump seal drain tank (TACO2) and can be manually pumped, using CCW pump seal drain tank pump PACO1, to surge tank TAC01.

The CCW System penetrates the containment at eight locations with four process lines providing cooling water to (1) the RCP A bearings and thermal barrier coolers, (2) the RCP B bearings and thermal barrier coolers, (3) the excess letdown heat exchanger, and (4) the reactor support coolers. However, only the isolation valves to and from the reactor support coolers receive an automatic containment isolation signal. The two lines for the RCPs have motor operated isolation valves to and from containment which can be used to isolate these lines if necessary. Automatic isolation of these lines is not provided due to the potential for damaging the RCPs following a spurious containment isolation signal. The excess letdown heat exchanger line is normally isolated by air operated valve 745. This valve was scheduled to be upgraded to receive an automatic containment isolation signal during the 1992 refueling outage; however, for the purposes of the PRA model, no containment isolation signal is assumed.

3.2.1.2.3 Component Cooling Water System Electrical Dependencies

The Component Cooling Water System requires electrical power to the following modeled loads:

- Reactor coolant pump PRC01A seal injection flow isolation valve 749A (480 VAC Motor Control Center C and 125 VDC Auxiliary Building Distribution Panel DCPDPAB01A):
- Reactor coolant pump PRC01B seal injection flow isolation valve 749B (480 VAC Motor Control Center D and 125 VDC Auxiliary Building Distribution Panel DCPDPAB01B):
- Component cooling water pump PAC02A (480 VAC Bus 14 and 125 VDC Auxiliary Building Distribution Panel DCPDPAB01A);
- Component cooling water pump PAC02B (Bus 16 and 125 VDC Auxiliary Building Distribution Panel DCPDPAB01B); and,
- Pressure Switch PS-617 (120 VAC Instrument Bus D [IBPDPCBDY]).

3.2.1.2.4 Component Cooling Water System Cooling Water Dependencies

Component Cooling Water System heat exchangers EAC01A and EAC01B are cooled by flow from the Service Water System.

3.2.1.2.5 Component Cooling Water System Instrument Air Dependencies

The Ginna PRA Component Cooling Water System model does not require any support from the Instrument Air Systems.

3.2.1.2.6 Component Cooling Water System Actuation and Control Dependencies

Component Cooling Water system pumps PAC02A and PAC02B receive signals from Bus 14 and Bus 16 undervoltage auxiliary relays (see Section 3.2.1.6) and the Engineered Safety Features Actuation System (see Section 3.2.1.7). The running CCW pump(s) will automatically trip on an undervoltage signal and a concurrent SI signal from ESFAS.

3.2.1.2.7 Component Cooling Water System Heating, Ventilation and Air Conditioning Dependencies

None of the Component Cooling Water System components modeled in the Ginna PRA require any HVAC to operate.

3.2.1.2.8 Component Cooling Water System Controls and Instrumentation

The CCW System is instrumented such that the operators in the control room would expect to receive several alarms and indications following any problem or upset. The CCW System has the following control room instrumentation:

- A temperature detector (TE-621 feeding TI-621 on the MCB) in the main outlet line for the CCW-to-SW heat exchangers;
- A pressure controller (PIC-617) on the single discharge header between the pumps and the CCW-to-SW heat exchangers;
- A temperature indicating alarm (TIA-616) in the combined CCW pumps inlet header; and.

- Redundant water level instrumentation (level transmitter LT-618, level switch LAH-618A, and level switch LAL-618B) at CCW surge tank TAC01.

The only automatic isolation signals to the in-containment portions of the CCW System are to the motor operated valves (813 and 814) to the reactor support coolers.

The CCW pumps are normally manually started and stopped from a local operating station on the 271 ft. level of the Auxiliary Building. Pump status indication is provided in the control room. No valve manipulations are necessary. One pump is normally operating, and the second is normally in automatic standby. A low discharge pressure, sensed by PIC-617, will start the standby CCW pump via auxiliary relay PIC-617-X in rack M2.

The CCW and SW valves to all heat exchangers except for the RHR heat exchangers and the standby CCW-to-SW heat exchanger are normally open. The RHR heat exchangers are isolated with remotely operable motor operated valves 738A and 738B.

3.2.1.2.9 Location of Major Component Cooling Water System Components

Most CCW equipment is located in the Auxiliary Building. CCW pumps PAC02A and PAC02B, CCW heat exchangers EAC01A and EAC01B, and CCW surge tank TAC01 are located on the operating level (elevation 271 ft.) of the Auxiliary Building. RHR pumps PAC01A and PAC01B are located in the Auxiliary Building sub-basement at an elevation of 219 ft.. RHR heat exchangers EAC02A and EAC02B are located in the basement of the auxiliary building at an elevation of 235 ft.. The CCW System also serves equipment in the Intermediate Building, and four CCW supply and return headers penetrate Containment.

3.2.1.2.10 Normal Component Cooling Water System Operation

One CCW pump and one CCW heat exchanger are normally in operation. The SW and CCW outlet valves from the standby CCW heat exchanger are closed in accordance with plant procedures. An example of this configuration is shown in Figure 3.2.1-8. The inlet valves to the RHR heat exchangers are normally shut during reactor operation, and the inlet and outlet valves to all other CCW-cooled equipment are normally open.

When the CCW System is placed into service during startup operations, the valve alignment is checked, and both pumps are started and vented. One CCW pump is then placed in the auto standby start mode. The CCW pump starting procedure is used to alternate the running and standby CCW pumps during the monthly performance test. As each CCW heat exchanger is placed into service, it is vented.

3.2.1.2.11 Component Cooling Water System Performance During Accident Conditions

No immediate change in status is required from the CCW System during accident conditions. One CCW pump and its associated CCW heat exchanger are adequate for all accidents. If an accident progresses to the point at which RHR is to be manually initiated, two motor operated valves need to be opened to allow flow to the RHR heat exchangers.

On transients in which power is lost, CCW pump feeder breakers (BUS14/23A and BUS16/16B) remain closed and the operating pump starts as soon as the Emergency Diesel Generator breaker closes to energize the bus. Loss of Instrument Air does not affect the CCW System since the only modeled air operated valves in the system, the CCW supply valves to the RCP thermal barriers (754A and 754B) fail open on loss of air pressure.

On transients in which power is lost and an SI signal is received, the CCW pumps are tripped. The CCW pumps have to be manually started for the recirculation phase of the accident.

CCW has four sets of containment penetrations since it serves the PRC01A and PRC01B seals and bearing coolers, reactor support coolers and excess letdown coolers. The CCW lines inside containment are not missile protected; thus, following medium and large LOCAs, these CCW lines could be damaged and require manual isolation.

Plant emergency operating procedures provide the steps necessary to respond to a loss of CCW while the plant is at power. If CCW to an RCP is interrupted for greater than two minutes or if a RCP motor bearing temperature exceeds 200°F, then the reactor must be tripped, initiating a loss of CCW event. Upon loss of CCW, the EOP directs the operator to check the status of the pumps, then the surge tank, and then to continue looking for valve alignment problems or significant leakage.

3.2.1.2.12 Component Cooling Water System Test and Maintenance

Technical Specifications state that both CCW pumps and heat exchangers shall be operable whenever the reactor is in a mode above cold shutdown. However, the allowed outage time for a CCW pump or a CCW heat exchanger is 24 hours, so maintenance can be performed during reactor operations. Since CCW is a normally operating system, the only technical specification-required surveillance for the equipment are those required by Section XI of the ASME Boiler and Vessel Code.

A periodic test is performed once per month. At this time In-Service Inspection / In-Service Testing (ISI / IST) data is taken for each CCW pump and the pumps are alternated. Procedures require verifying that CCW pump discharge pressure is within an acceptable range, cycling RHR inlet valves 738A and 738B, and verifying that CCW pump discharge check valves 723A and 723B are fully opening when the associated pump is running.

3.2.1.2.13 Component Cooling Water System Operating Experience

One Licensee Event Report (LER) involving the CCW System has been noted:

82-023 October 16, 1982 -- In this event, a nipple in the pump discharge vent piping was broken, taking the B CCW pump out of service. The apparent cause of the problem was a person stepping on the nipple. This event was apparently an isolated incident that did not cause system failure, thus has no implications on the CCW model. Normal plant traffic will not cause damage to the CCW System.

On July 14, 1984, high lake temperatures caused the CCW System to provide extra flow to non-regenerative heat exchanger ECH05 which resulted in low flow alarms associated with the RCPs. A second CCW pump was started and SW flow was increased. Since the non-regenerative heat exchanger is isolated on an SI signal and this high temperature problem has only occurred once in the plant's life, this combination of conditions is probabilistically unlikely and not included in the Ginna PRA model.

3.2.1.2.14 Plant Specific Data Analysis for the Component Cooling Water System

No interesting incidents were noted for the Component Cooling Water System in any of the Ginna PRA plant specific data analyses.

3.2.1.3 Containment Isolation System

3.2.1.3.1 Purpose and Design Basis of the Containment Isolation System

The Containment Isolation System is designed to isolate non-essential process lines that penetrate the containment in order to maintain the total leakage of radioactivity within design limits in the event of an accident. In addition, the system ensures that essential process lines and penetrations remain capable of maintaining containment integrity both during and following the performance of their safety related activities. The Containment Isolation System utilizes both automatic and normally closed isolation valves, and the physical design of piping systems (e.g., closed systems) and penetrations to perform its function.

The Containment Isolation System, as part of the Primary Containment System, is used in conjunction with the Engineered Safety Features Actuation System (ESFAS) to limit radioactive material release during a design basis accident within the guidelines of 10 CFR §100. This criteria is met by ensuring that no more than 0.2 percent by weight of air inside the containment vessel is released in any 24 hour period at the design pressure of 60 psig. The Containment Isolation System is designed to provide at least two barriers against the leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident (LOCA). These barriers, in the form of gland seals, closed systems, isolation valves, and flanges, are defined for each process line and penetration depending on its function. The current criteria outlining the isolation requirements for process lines are contained in 10 CFR §50 Appendix A, General Design Criteria (GDC) 54, 55, 56, and 57. Since Ginna was designed and built prior to the issuance of these criterion, the Containment Isolation System was reviewed in detail during the NRC's Systematic Evaluation Program (SEP) and, more recently, by RG&E and compared against the current regulations. Consequently, there may be exemptions with respect to the current GDCs or other standards which are reflected as necessary in the Ginna PRA model.

3.2.1.3.2 Containment Isolation System Description

The Containment Isolation System is designed to provide two barriers between the containment atmosphere and the environment following a design basis accident. Automatic isolation of process lines is used as necessary so that no manual operation is required for immediate isolation of containment. Automatic isolation is initiated by a containment isolation signal (CIS) which is generated by a safety injection signal or by manual actuation from the control room. The safety injection signals which initiate containment isolation are as follows:

(1)	Pressurizer low pressure	≥ 1723 psig
(2)	Steam line low pressure	≥ 514 psig
(3)	Containment high pressure	= 4 psig

All valves which receive an automatic CIS close within 60 seconds to limit the release of radioactive materia. In addition to the containment isolation signal, certain components also receive a containment ventilation isolation signal which ensures that nonessential ventilation systems are quickly isolated. Containment ventilation isolation is produced by a safety injection (SI) signal, manual containment isolation, manual containment spray, or by high containment radioactivity. Table 3.2.1-1 identifies those components which receive a containment isolation and/or containment ventilation isolation signal.

There are five classes of active mechanical penetrations at Ginna. All inactive or spare penetrations have at least one end capped and welded, and as such, are considered an extension of the containment liner. Consequently, these type of penetrations are not considered in context of the Ginna PRA Containment Isolation System model. The five types of active mechanical penetrations at Ginna are briefly described below:

Class 1 - Penetrations in this class contain normally operating outgoing lines connected to the Reactor Coolant System. GDC 55 requires at least one automatic and one manual isolation valve in series for these type of penetrations.

Class 2 - Penetrations in this class contain normally operating outgoing lines which are not connected to the Reactor Coolant System and which are not protected against missiles throughout their length inside containment. GDC 56 requires at least one automatic or one remotely operated stop valve for these type of penetrations.

Class 3 - There are two subclasses identified for Class 3 penetrations. Class 3a penetrations contain incoming lines which are connected to open systems outside containment. GDC 56 requires a check valve and either a remote-operated valve or closed manual valve, or two remote-operated valves for these type of penetrations. Class 3b penetrations contain incoming lines which are connected to closed systems outside containment. GDC 55 requires at least one check valve or two remote-operated valves for these type of penetrations.

Class 4 - Penetrations in this class contain normally operating incoming and outgoing lines which are connected to a closed system inside the containment and are protected against missiles throughout their length. The definition of a closed system is one in which no system fluid communicates directly with either primary coolant or containment atmosphere. GDC 57 requires either a locked closed, remote manual, or automatic isolation valve for these type of penetrations.

Class 5 - Penetrations in this class contain lines which may be opened to the containment atmosphere, but which are normally closed during reactor operation. GDC 56 which applies to these type of penetrations. requires either two isolation valves in series, an isolation valve and open blind flange, or two blind flanges.

In addition to these five classes are the equipment and personnel hatches which utilize redundant gland seals. Table 3.2.1-1 provides a listing of all active mechanical penetrations and their corresponding valves and class type which were initially considered in preparation of the Ginna PRA Containment Isolation System model.

3.2.1.3.3 Containment Isolation System Electrical Dependencies

Table 3.2.1-1 shows electrical system interfaces for the Containment Isolation System. All air operated containment isolation valves fail closed on loss of power while all motor operated valves which are required to close can be supplied power from the diesel generators.

3.2.1.3.4 Containment Isolation System Cooling Water Dependencies

There are no cooling water systems required for operation of the Containment Isolation System.

3.2.1.3.5 Containment Isolation System Instrument Air Dependencies

Table 3.2.1-1 lists the instrument air header by building for each air operated valve in the Containment Isolation System. All air operated containment isolation valves fail closed on loss of air. Consequently, failure of the Instrument Air System does not fail the Containment Isolation System function.

3.2.1.3.6 Containment Isolation System Actuation and Control Dependencies

All containment isolation valves which receive a containment isolation signal (CIS) or containment ventilation isolation signal are identified on Table 3.2.1-1. These valves all go to the closed or isolated position following receipt of these signals. Since a CIS is generated for all types of safety injection (SI) signals, Table 3.2.1-1 also identifies the associated ESFAS train for these components.

3.2.1.3.7 Containment Isolation System Heating, Ventilation and Cooling Dependencies

There are no HVAC interfaces required for proper Containment Isolation System operation.

3.2.1.3.8 Containment Isolation System Control and Instrumentation

Automatic initiation of the Containment Isolation System occurs as a result of an Engineered Safety Features Actuation Signal (ESFAS) which is produced by high containment pressure, low pressurizer pressure, or low steam line pressure. An actuation signal causes all automatic isolation valves to close within 60 seconds to quickly isolate nonessential penetrations. The integrity of all essential penetrations is maintained by their design and either check valves or remote valves following completion of their mission.

There are two trains of containment isolation signals available. All automatic containment isolation valves receive a signal from at least one of these two trains depending on the power source for the valve. In other words, a motor operated containment isolation valve which receives power from 480 VAC Motor Control Center D will obtain a CIS from Train B. However, several components receive signals from both trains for additional redundancy. An automatic CIS is produced from master ESFAS relays SIA-1 (for Train A) or SIB-1 (for Train B). These master relays actuate Containment Isolation Auxiliary Relays C15X and C25X, respectively. The auxiliary relays in turn actuate (i.e., deenergize) individual relays associated with each valve. The individual relays are located in Containment Isolation Relay Racks CI-A1 (powered from 125 VDC Main Control Board Distribution Panel DCPDPCB04A/VP) and CI-A2 (powered from 125 VDC Main Control Board Distribution Panel DCPDPCB04B/UP) which receive power from Main DC Distribution Panels 1A (DCPDPCB03A) and 1B (DCPDPCB03B), respectively. These relays then perform one of the following actions. For air operated valves, deenergizing the relay causes contacts in the control circuit to pick up which deenergizes the associated solenoid valve and results in the valve closing. Consequently, any loss of power to the relay causes the valve to close. For motor operated valves, deenergizing the relay causes the contacts in the control circuit to close, which enables 125 VDC control power to energize the closing logic for the valve. Any loss of power to the relay will cause the valve to close unless 125 VDC control power for the valve is also lost.

The Containment Isolation System can also be initiated manually from the control room by depressing one of two buttons on the main control board left panel. Status indication of automatic containment isolation valves is provided on the main control board upper left panel. A dim white status light indicates that the valve is open while a bright white status light indicates that the valve is closed. An open / closed indication is also provided on the containment isolation reset panel located to the left of the main control board panels by use of red (open) and green (closed) lamps.

Following actuation of the Containment Isolation System, the components which are automatically isolated can only be recovered individually, not en masse. This design approach was implemented as a result of the Three Mile Island accident and prevents an inadvertent loss of containment integrity while performing recovery actions. Consequently, resetting the containment isolation signal will not result in the automatic reopening of any containment isolation valve. Individual valves can be reopened following reset of the system for recovery purposes by the operators.

The containment ventilation isolation signal is produced by a safety injection (SI) signal, manual actuation of containment isolation, manual actuation of containment spray, or high containment radioactivity. This signal causes components directly connected to containment atmosphere to rapidly close (e.g., mini-purge valves) to rapidly close or stop operating (e.g., mini-purge fans) in order to prevent any radioactive material from escaping containment. These components typically isolate within 3 seconds.

In addition to a CIS and containment ventilation isolation signal, certain components receive other types of isolation signals. The main steam isolation valves (MSIVs) and main feedwater isolation check valves are normally open containment isolation valves; however, these valves do not receive a CIS. The MSIVs will close upon receipt of a high-high steam flow coincident with a safety injection signal, high steam flow and low T_{avg} coincident with a safety injection signal, or a high-high containment pressure of 18 psig. The main feedwater isolation check valves close after main feedwater is isolated.

3.2.1.3.9 Location of Major Containment Isolation System Components

Containment isolation relays are located in racks CIA1 and CIB1, which are located in the Relay Room of the Control Building at an elevation of 271 ft. Containment isolation valves are located in the Intermediate Building, the Auxiliary Building, and Containment.

3.2.1.3.10 Normal Containment Isolation System Operation

The Containment Isolation System is a standby safety system and has no normal operating function. However, certain process lines which are infrequently used or only active during shutdown periods utilize seals, blind flanges or locked closed valves while at power. As such, these type of penetrations are always in their fail-safe or isolated position for the purposes of this work package. All other penetrations are typically open if it is associated with a normally operating system, or use check valves if it is a standby essential system which interfaces with the Reactor Coolant System.

3.2.1.3.11 Containment Isolation System Performance During Accident Conditions

During accident conditions, the Containment Isolation System is automatically actuated by ESFAS. If a loss of off-site power or bus undervoltage condition occurs coincident with the accident initiator, all motor operated containment isolation valves are loaded onto the diesels after the associated buses are energized. In addition, all air operated valves fail to the closed position following loss of instrument air or 125 VDC control power. The MSIVs and main feedwater isolation check valves close following receipt of the previously-discussed signals.

Following receipt of an ESFAS signal, operators are instructed to verify that containment isolation and containment ventilation isolation has occurred and that all valve status lights are "bright". If automatic isolation has not occurred, operators are procedurally directed to manually initiate containment isolation. Upon receiving a manual or automatic signal, all automatic containment isolation valves are designed to close within 60 seconds. Operators are trained to manually close the containment isolation valve, or a secondary valve, if control room indication shows the valve to still be open. These valves can then only change position if operators reset the Containment Isolation System by use of a key switch and intentionally operate the valve. However, containment isolation would normally be maintained throughout the accident and valves would only be manipulated for recovery purposes such as re-establishing instrument air to containment.

3.2.1.3.12 Containment Isolation System Test And Maintenance

The Containment Isolation System is normally in standby during reactor operation. Complete system tests cannot be performed when the reactor is operating because the tests would require isolation of normally operating systems. Consequently, annual tests are performed each refueling outage to ensure that containment isolation valves close upon receipt of a CIS. Containment isolation valve leak rate testing is also performed annually during refueling outages. The only scheduled testing at power of containment isolation valves is periodic stroke testing; however, the only components which were modeled in the Ginna PRA that are stroke tested are motor operated valve 313 and air operated valves 1003A, 1003B, 1723, 1728, 5735, 5736, 5737, 5738, 7445, 7478, 7970, and 7971. These valves are tested on a quarterly basis.

Since the Containment Isolation System is normally in standby, the primary technique of ensuring that the system is in its proper configuration is through review of valve position indications in the control room and system walkdowns. The review of valve position indications is accomplished when the operators are instructed by procedures to check certain plant parameters every eight hours.
There is no regularly scheduled maintenance for the Containment Isolation System during periods of power operation.

3.2.1.3.13 Containment Isolation System Operating Experience

The following is a listing of Licensee Event Reports (LERs) which were generated against the Containment Isolation System between January 1, 1980 and May 22, 1990. These LERs were reviewed to ensure that all failure modes which have been historically observed are adequately addressed in the Ginna PRA model.

81-015 On September 23, 1981 while at 100% power, Health Physics personnel performed procedure PC-23.2, *Containment Atmospheric Sampling and Analysis During Containment Isolation*, as a training exercise. This procedure required that a non-automatic containment isolation valve in the containment air sample system be opened to perform a gas sample. Consequently, containment integrity was breached for approximately 5 minutes in violation of Technical Specification 3.6. The root cause of the event was attributed to a procedural error since the procedure did not include an initial plant condition required for the performance of the sample. This error was subsequently corrected and as such, this event is not considered in the Containment Isolation model. In addition, as a result of LER 90-017, all plant procedures were reviewed to ensure that they included the necessary restrictions on initial plant conditions.

81-021 On December 22, 1981 while at 100% power, a periodic test identified that containment gas radiation monitor return line check valve 1599 was not sealing tight. Inspection of the valve found that dirt had deposited on the seat. Air was then blown through the non-maintainable valve to clear it out and the valve was retested satisfactorily. This event is not included in the model since check valve 1599 was replaced by an air operated valve in 1982. See LERs 82-011, 82-015, and 82-019.

82-001 On January 7, 1982 while at 100% power, operations discovered that a post maintenance leak test was not performed on AOV 966B, containment isolation valve for the pressurizer liquid sample. A generic procedure was used for the maintenance activity which required leak rate testing if possible. However, since the test procedure required that the plant be at cold shutdown, maintenance personnel determined that it was not possible to perform the test. Following the discovery of this discrepancy, the procedure was temporarily changed to allow performance of the test at power. The failure to perform post maintenance testing was not modeled since this does not indicate that the valve is inoperable, only that the maintenance activity may not have resolved the initial problem. If this were the case, additional failure events would be found in the plant-specific data analysis task indicating a high component failure rate.

82-011 On April 23, 1982 during the annual refueling outage, local leak rate testing identified that containment gas radiation monitor return line check valve 1599 was not sealing tight. Inspection of the valve found that dirt had deposited on the seat. The valve was then replaced with a bolted bonnet type check valve that would enable maintenance to be performed in the future. This event is not included in the model since check valve 1599 was replaced by an air operated valve in 1982. See LERs 81-021, 82-015, and 82-019.

82-015 On June 22, 1982 while at 100% power, a periodic test identified that containment gas radiation monitor return line check valve 1599 was not sealing tight. Inspection of the valve found that dirt had deposited on the seat. Air was then blown through the valve to clear it out and the valve was retested satisfactorily. This event is not included in the model since check valve 1599 was replaced by an air operated valve in 1982. See LERs 81-021, 82-011, and 82-019.

82-019 On September 1, 1982 while at 100% power, a periodic test identified that containment gas radiation monitor return line check valve 1599 was leaking excessively. Inspection of the valve found that graphite from the vanes of the radiation monitor vacuum pump was depositing on the valve internals. In addition, wear on the valve was occurring when it was in the open position. After several unsuccessful attempts to clean the valve, action was taken to replace 1599 with a new air operated valve. Consequently, this event is not included in the model. See LERs 81-021, 82-011, and 82-015.

82-028 On December 19, 1982 while at 55% power, AOV 846, containment isolation valve for nitrogen supply to the accumulators, was found to be opening and closing sluggishly. The valve was disassembled and galling was found on the stem plug in the cage assembly. The galling was most likely attributed to foreign material that was introduced during previous piping modifications which had accumulated in the tight clearance between the stem plug and cage assembly. The galled surfaces were redressed and the valve seat was replaced. This event is addressed in the model by failure of 846 to close. See LER 83-022.

83-003 On January 8, 1983 while at 100% power, containment sump "A" isolation AOV 1728, failed to close. The valve diaphragm was replaced and post maintenance testing was performed satisfactorily. This event is addressed in the model by failure of 1728 to close.

83-012 On March 23, 1983 while at 100% power, it was discovered that the leakage rate associated with the containment personnel hatch was above administrative limits. Further investigation found that maintenance activities performed on October 7, 1982 included repacking of the shaft area of the hatch. However, the maintenance procedure incorrectly only required seal leak testing of the door. All maintenance procedures were then reviewed to ensure that the proper post maintenance test was being performed. The failure to perform post maintenance testing was not modeled since this does not indicate that the hatch is inoperable, only that the maintenance activity may not have resolved the initial problem. If this were the case, additional failure events would be found in the plant-specific data analysis task indicating a high component failure rate.

83-022 On July 25, 1983 while at 100% power, AOV 846, containment isolation valve for nitrogen supply to the accumulators, was found seized in the mid position. The valve was disassembled and galling was found on the stem plug in the cage assembly. The assembly has a very tight clearance and any scratch on the surfaces could have caused the galling. A new stem plug and cage assembly was installed and the valve seat was replaced. In addition, a seismic support located on the valve operator was modified. This event is addressed in the model by failure of 846 to close. See LER 82-028.

87-004 On April 24, 1987 while at 100% power, Containment Isolation System Train B actuated after personnel bumped a relay in the safeguards cabinet while performing a field walkdown for the electrical drawing upgrade program. All valves isolated as required and after the cause of the event was discovered, operations reset the system. All personnel who are required to work in safeguards cabinets were then instructed on the precautions which must be used. This event is not included in the Containment Isolation model since this type of personnel error constitutes success of the system. However, the spurious actuation of containment isolation is considered by systems which contain automatic containment isolation valves. In addition, this event demonstrates that spurious actuation of Containment Isolation Train B will not result in a reactor trip.

87-005 On May 14, 1987 while at 100% power, a manufacturing discrepancy caused containment particulate radiation monitor R-11 to register high resulting in a spurious containment ventilation isolation signal. All components that were required to isolate performed their function. This event is not included in the Containment Isolation model since this type of actuation constitutes success of the system. However, the spurious actuation of containment ventilation isolation is considered by systems which contain automatic containment ventilation isolation valves or dampers.

88-007 On August 4, 1988 while at 100% power, an inadvertent containment ventilation isolation occurred due to containment particulate radiation monitor R-11 de-energizing. The cause was determined to be a random failure of an internal bridge rectifier power supply which opened the AC fuse supplying power to the R-11 drawer. All components that were required to isolate performed their function. This event is not included in the containment isolation model since this type of actuation constitutes success of the system. However, the spurious actuation of containment ventilation isolation is considered by systems which contain automatic containment ventilation isolation valves or dampers.

89-011 On September 20, 1989 while at 99% power, a spurious containment ventilation isolation occurred. All components that were required to isolate performed their function and no root cause could be determined. This event is not included in the containment isolation model since this type of actuation constitutes success of the system. However, the spurious actuation of containment ventilation isolation is considered by systems which contain automatic containment ventilation isolation valves or dampers.

89-013 On October 20, 1989 while at 99% power, a containment ventilation isolation occurred due to containment gas radiation monitor R-12 reaching its alarm setpoint. All components that were required to isolate performed their function. The root cause was determined to be a Health Physics technician drawing a local containment sample which interrupted flow to the R-12 monitor. Since the monitor has a pressure compensation input that amplifies the gain to the R-12 RMS monitor, as the pressure in the sensing lines decreased, the gain increased to cause a higher indication. This event is not included in the containment isolation model since this type of actuation constitutes success of the system. However, the spurious actuation of containment ventilation isolation is considered by systems which contain automatic containment ventilation isolation valves or dampers. See LER 89-014.

89-014 On October 23, 1989 while at 99% power, a containment ventilation isolation occurred due to containment gas radiation monitor R-12 reaching its alarm setpoint. All components that were required to isolate performed their function. The root cause was determined to be a Health Physics technician drawing a local containment sample which interrupted flow to the R-12 monitor. Since the monitor has a pressure compensation input that amplifies the gain to the R-12 RMS monitor, as the pressure in the sensing lines decreased, the gain increased to cause a higher indication. This event is not included in the containment isolation model since this type of actuation constitutes success of the system. However, the spurious actuation of containment ventilation isolation is considered by systems which contain automatic containment isolation valves or dampers. See LER 89-013.

3.2.1.3.14 Plant-Specific Data Analysis for the Containment Isolation System

A review was performed of the data analysis task work packages to ensure that all significant events are appropriately addressed by the fault tree models. These events are listed below.

Maintenance and Testing Activities. There were no unusual maintenance or testing activities observed for the Containment Isolation System.

Common Cause Failures. There were two common cause failure events that were discovered in the data analysis task. The first event occurred on October 26, 1983 when the fuses for 1787 and 1728 were found to be blown causing the valves to fail close. Since this is the fail-safe (i.e., success) position for these valves, this type of event is not addressed by the models. The second event occurred on June 18, 1985 when steam generator sample valves 5735 and 5736 both failed to close during an operational check of the steam generator blowdown radiation monitor. The local auto/open switches for both valves had been left in the open position which prevented the radiation monitor from closing the valve. A trouble card was submitted to provide a sign-off adjacent to the auto/open switches to leave them in the auto position. This event is not addressed in the Ginna PRA model since a containment isolation signal would have closed the valve if necessary.

Component Reliabilities. There were several events associated with component reliability for valves in the Ginna PRA Containment Isolation System model. These are briefly described below.

During testing on May 19, 1983, AOVs 1003A and 1003B both failed to close following receipt of a containment isolation signal. However, these valves had been opened for the test using the Waste Disposal Panel control auto/open switch which causes the containment isolation signal contact to be bypassed. An operator tag was placed at the Waste Disposal Panel to prevent future occurrences. This event is addressed in the fault tree model as a latent human error.

On January 18, 1988, only the "A" train of containment ventilation isolation tripped during performance of PT-17.2. The relay K-850-R-12 contact pair associated with the "B" train failed to operate. This event is addressed in the Containment Isolation System model by failure to receive an actuation signal.

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 MOV 313 and AOVs 371 and 5392 to close. 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 AOV 7443 causing AOVs 7443, 7444, 7445, 7970, and 7971 to close. These events are not included in the containment isolation model since this failure mode constitutes success of the system. However, the spurious closing of the subject valves is considered by those systems which require them to remain open.

3.2.1.4 Containment Spray System

3.2.1.4.1 Purpose and Design Basis of the Containment Spray System

The Containment Spray (CS) System, in conjunction with the Containment Recirculation Fan Coolers and the Emergency Core Cooling System, is designed to remove heat from containment during emergency situations, and to thus maintain the containment pressure within structural design limits. The Containment Spray System is also capable of removing airborne iodine and particulate fission product inventories from the containment atmosphere following a postulated accident consequently minimizing fission product leakage to the environment.

The Containment Spray System, in conjunction with the Containment Recirculation Fan Coolers and the Emergency Core Cooling System, is designed to remove sufficient heat from the containment atmosphere following an accident to maintain the containment pressure below the 60 psig limit established by the structural design analysis of the containment. The Containment Spray System is also capable of reducing the iodine and particulate fission product inventories in the containment atmosphere, so that the off-site radiation exposure resulting from a Loss of Coolant Accident (LOCA) is within the guideline values of 10 CFR §100. To this end, sodium hydroxide (NaOH) is added to the borated Containment Spray solution during the injection phase of Containment Spray operation in order to improve the removal of radionuclides from the containment atmosphere. The system is designed to provide a spray solution with a pH of 8.3 to 9.1. The high pH of the spray, together with the design flow rate, will insure adequate particulate removal. The large area to volume ratio of the spray droplets in the containment atmosphere enhances the absorption of iodine from the air.

3.2.1.4.2 Containment Spray System Description

The Containment Spray System delivers borated water, initially drawn from Refueling Water Storage Tank (RWST) TSI01 and blended with sodium hydroxide 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 continued spray is required, the spray pump suction is fed from the discharge of the residual heat removal pumps. The 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 Containment Spray 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 spray pumps and open the spray additive valves and the discharge valves to the spray header. The CS System is also capable of manual initiation and control from the control room.

The Containment Spray System utilizes two 200 hp Ingersoll-Rand horizontal centrifugal pumps (PSI01A and PSI01B) with a design flow rate of 1200 gpm. The system incorporates a liquid jet eductor in each train (SSI01 and SSI02) to entrain the NaOH solution and mix it with the borated water from the RWST. Once the caustic solution leaves the spray pump discharge, it passes through motor operated discharge valves, 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 Spraco Model 1173 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.

A simplified flow diagram of the Containment Spray System is shown in Figure 3.2.1-9.

3.2.1.4.3 Containment Spray System Electrical Dependencies

Table 3.2.1-2 shows the electrical system interfaces for the Containment Spray System. Air operated valves 836A and 836B fail open on loss of electrical power. Loss of power to the RWST level transmitters (LT-920 and LT-921) causes the level transmitter readout on the main control board (MCB) to go to zero which will also cause a lo-lo level annunciator alarm. Loss of power to the transmitter alarms causes a lo-lo annunciator alarm. Only one (LT-931) of the NaOH additive tank level transmitters transmits a readout to the MCB and annunciators. A loss of power to the alarm or to the transmitter will cause an annunciator alarm. A loss of power to the local NaOH level transmitter (LT-932) will cause a local low level readout.

3.2.1.4.4 Containment Spray System Cooling Water Dependencies

The containment spray pump mechanical shaft seals are cooled by water taken from the discharge of the CS pumps and cooled by the Component Cooling Water System [Ref. 18.3.26]. The containment spray pumps require a total of 30 gpm (15 gpm per pump) of cooling water from the Component Cooling System.

3.2.1.4.5 Containment Spray System Instrument Air Dependencies

Spray additive outlet isolation valves 836A and 836B are air operated valves. These valves will fail open on loss of instrument air.

3.2.1.4.6 Containment Spray System Actuation and Control Systems Dependencies

The CS pumps will start and the spray additive valves and the discharge valves to the spray header will open on a signal from the Engineered Safety Features Actuation System when containment pressure reaches 28 psig. Pump PSI02A starts and 836A, 860A and 860C open on a signal from the ESFAS A train. Pump PSI02B starts and 836B, 860B and 860D open on a signal from the ESFAS B safeguards train.

3.2.1.4.7 Containment Spray System Heating, Ventilation and Cooling Dependencies

Service Water System cooling to the CS pump area coolers (AAA03A, AAA03B and AAA03C) is not required for operation of the CS pumps.

3.2.1.4.8 Containment Spray System Controls and Instrumentation

Automatic initiation of the Containment Spray System occurs when at least two of three instruments on both sensing networks in the Engineered Safety Features Actuation System detect a hi-hi containment pressure of 28 psig. Actuation signals generated in the ESFAS start the spray pumps and open the spray additive valves and the discharge valves to the spray header.

CS System operation can be initiated manually from the main control board (MCB) in the control room by depressing two buttons simultaneously. CS pumps PSI02A and PSI02B can be controlled by two pull-stop / stop / auto / start switches located on the main control board. The motor operated RWST outlet valves to the CS pumps (896A and 896B) have key switches and close / auto / open switches on the MCB. In order to change the position of these valves, the key must be inserted and turned and the switch must be turned. The CS pump discharge valves (860A, 860B, 860C and 860D) have close / auto / open switches on the MCB. The air operated spray additive valves (836A and 836B) have off / normal and manual / auto switches on the MCB. The MCB also provides level indications for the RWST and NaOH tank and flow indication for NaOH. The CS reset button will reset the ESFAS logic and cause the spray additive discharge valves to return to the position called for by their controllers.

3.2.1.4.9 Location of Major Containment Spray System Components

The Containment Spray System functional components are located in the Auxiliary Building and in Containment. The centerline of CS pumps PSI02A and PSI02B is 1.5' above the basement floor elevation of 235 ft..

The RWST (TSI01) has its base at the Auxiliary Building basement floor (elevation 235 ft.) and extends through all levels of the Auxiliary Building). The RWST sits on a 6" concrete pad and has a cylinder height of 81 ft..

Spray Additive Tank (NaOH Tank) TSI02 is on the basement floor of the Auxiliary Building at column L, row 10A.

The spray nozzles are located at the top of the containment dome (89 nozzles at an elevation of 361' 8" and 90 nozzles at an elevation of 372' 8".

3.2.1.4.10 Normal Containment Spray System Operation

The Containment Spray System is a standby safety system and has no normal operating function. It is aligned in the standby mode during normal plant operation with the pumps off and in automatic control. The pump discharge valves (860A, 860B, 860C and 860D) and the sodium hydroxide additive valves (836A and 836B) are closed and in automatic control. The charcoal filter dousing valves (875A, 875B, 876A and 876B) are closed with the breakers locked open. All other valves in the system flow path are open. A head of at least 20 feet of water is maintained in the CS lines to keep the time delay from CS actuation to initiation within prescribed limits.

3.2.1.4.11 Containment Spray System Performance During Accident Conditions

During accident conditions the Containment Spray System is automatically actuated by the ESFAS if containment pressure reaches 28 psig. If a loss of offsite power or bus undervoltage condition occurs coincident with the accident initiator, the CS pumps load onto the diesel generators anytime after the buses are energized and the ESFAS signal is present. The CS system can also be manually initiated from the control room. Upon receiving a manual or automatic signal, both CS pumps start and the motor operated discharge valves open. The same coincident signal opens the air operated spray additive valves from the sodium hydroxide tank. Operators will manually reset containment spray, ensure that the NaOH tank outlet valves close, close the pump discharge valves and put the CS pumps in automatic control per procedures if containment pressure drops below 4 psig. The pumps take suction from the RWST and deliver the borated water to the spray ring headers. Approximately 5% of the pump discharge is diverted through the additive eductor to provide suction from the spray additive tank. This flow diversion also provides for a minimum recirculation flow path for the containment spray pumps.

When the RWST level reaches 28%, the operators are directed by procedures to transfer suction of the containment spray and safety injection pumps from the RWST to the residual heat removal pump discharge. The residual heat removal pumps are realigned to take a suction from the sump instead of from the RWST. At the 28% RWST level, if any CS pump is idle or if the plant is using the emergency diesel generators, the operators will place the idle pump or the pump on the emergency diesel generator with the maximum load in the pull-stop position. When the RWST level drops to 15%, operators will manually reset the CS System which will cause the spray additive valves to close. The remaining pump(s) will then be placed in the pull-stop position and the pump discharge valves will be closed. The operators will then close the RWST outlet valves and shift the spray pump suction to either Residual Heat Removal (RHR) suction train. If containment spray had actuated prior to the switch to recirculation, it may be restarted if the Technical Support Center determines that it is needed. If containment pressure is greater than 37 psig, one CS pump will then be manually restarted and one CS pump discharge valve and NaOH additive valve will be opened. When containment pressure is less than 32 psig, the operating CS pump will be placed in the pull-stop position and the pump discharge and NaOH additive valves will be closed. For more detailed information concerning RHR alignment for recirculation see Section 3.2.1.11.

3.2.1.4.12 Containment Spray System Test and Maintenance

The Containment Spray System is a principal plant safeguard system that is normally in standby during reactor operation. Complete system tests cannot be performed when the reactor is operating because a CS System test requires the system to be temporarily disabled. The method of assuring operability of the system is therefore to combine annual system tests with more frequent component tests. System tests are performed during annual plant shutdowns and component tests are performed periodically during plant operation. There is no regularly scheduled maintenance for the CS System during periods of power operation.

During their routine plant tours, conducted per procedures every four hours, the operators check, among other things, the NaOH tank room, the CS pumps and the general pump area. The operators are also required by procedures to check certain plant parameters every eight hours when the reactor is at power. These checks include verfying RWST level and NaOH tank level as indicated on the MCB; verifying the positions of valves and breaker switches as indicated on the MCB; verifying that the A and B containment spray pump breaker switches are in the automatic position; and, verfying that CS pump discharge valves 860A, 860B, 860C and 860D are closed, RWST outlet valves 896A and 896B are open with the key switches in the off position and NaOH valves 836A and 836B are closed with the controls in the normal and auto positions.

3.2.1.4.13 Containment Spray System Operating Experience

The following is a listing of Licensee Event Reports (LERs) which have been generated against the Containment Spray System. These LERs were reviewed to ensure failure modes which have been historically observed have been addressed in the Ginna PRA Containment Spray System model.

82-014 On June 24, 1982 with the reactor at 100% power, check valve 862B failed to close at the required differential pressure during surveillance testing of the CS System. The valve had shown wear on the pin and swing arm but spare part delivery had been delayed, resulting in the valve repair being scheduled for the following outage. Inspection at that time seemed to indicate that the valve may have been slightly rotated during initial installation. Check valve failure has been modeled.

82-016 On July 22, 1982 with the reactor at 100% power, check valve 862B failed to seat at the required differential pressure during surveillance testing of the CS System. The valve had shown wear on the pin and swing arm but spare part delivery had been delayed, resulting in the valve repair being scheduled for the following outage. Check valve failure has been modeled.

82-021 On September 23, 1982 check valve 862B failed to promptly close during surveillance testing of the CS System. Repairs consisted of machining the seat and disc assembly of the valve to assure proper closure. Check valve failure has been modeled.

82-026 On October 26, 1982 check valve 862B failed to close promptly during surveillance testing of the CS System. Maintenance was performed and the valve was retested successfully. PT-3 underwent a review to determine if the success criteria were too stringent and as a result, the procedure was revised. Check valve failure has been modeled.

83-004 On January 14, 1983 check valve 862B failed to close promptly during surveillance testing of the CS System. The valve also failed the leakage test with the revised success criteria. Maintenance was performed and the valve was retested successfully. A revised test method was developed to more effectively demonstrate valve operability. Check valve failure has been modeled.

83-019 On June 13, 1983 while in the process of changing modes from cold shutdown to hot shutdown, the CS pumps were found to be in the pull-stop position at RCS temperature of 207°F. This is contrary to direction given in Operating Procedure 0-1.1D (*Pre-Heatup Plant Requirement Check List*) which requires CS System operability. The procedure was changed to give specific instructions addressing the necessity of having the CS pumps operable. This type of failure is imbedded in the pump common cause failure probability.

87-007 On December 18, 1987 a design flaw was discovered showing that a common power supply was utilized to power a motor operated valve on each train of high head recirculation. A postulated failure of the electrical power supply prior to opening of the valves would result in both flow paths leading to the safety injection and containment spray pumps being blocked. Power sources for the valves have since been changed. Failure of a single power source failing both trains of high head recirculation has not been modeled since it can no longer occur.

3.2.1.4.14 Containment Spray System Plant Specific Data Analysis

The Ginna PRA data analysis task work packages were reviewed to ensure that all significant events not already described in the Ginna PRA model were properly addressed. These events are listed below.

The *Common Cause Failure Data Work Package* contains a number of failures of Containment Spray System components.

On December 22, 1981, MOVs 876A and 876B failed to open during their respective stroke tests. The cause of the failure for 876A was slack in the wires interfering with the proper operation of the torque switch. The cause of the failure of 876B was the valve sticking in the closed position until manual operation freed it. MOVs 876A and 876B are not required to open for proper operation of the Containment Spray System so this failure is not modeled.

On June 8, 1987, MOVs 860A and 860B failed to fully close during their respective stroke tests. 860A apparently failed to close because of metal chips found around the stem to stem nut area. No cause was identified for the failure of 860B. The failure of these valves to close has been modeled.

The *Plant Specific Data Work Package* contains a number of failures of the Containment Spray System components.

On March 12, 1986, CS pump PSI02B was declared inoperable when the discharge pressure of the pump only reached 234.57 psi during a test (the acceptable limit was 240 psi). This was not considered to be a failure since 235 psi was considered to be adequate for the pump to perform its function due to system design margins.

On May 31, 1988 with CS pump PSI02B running, flames were observed emitting from the outboard pump bearing area. The back-up packing gland and shaft sleeve were making contact resulting in excessive heat and galling, which caused the pump to seize up. This event is considered a failure to run.

There were numerous failures of MOVs 860A, 860B, 860C and 860D to open or close on demand. These were primarily due to torque switch problems. One event involved loose packing and the others had no root cause identified. These events are modeled as failures of the valves to open and close.

There were five functional failures of AOVs 836A and 836B. The failure causes were primarily due to controller component failures. Failure of the AOVs to open has been modeled.

On September 23, 1982, the breaker for valve 860B was found to be unlocked but in the correct position (closed). This event was not considered to be a failure.

3.2.1.5 Chemical and Volume Control System

3.2.1.5.1 Purpose and Design Basis of the Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) is intended to control the quantity and chemistry of the Reactor Coolant System (RCS) inventory, to provide seal injection flow to the reactor coolant pump (RCP) seals, to process reactor coolant for reuse, and to supply water for auxiliary pressurizer spray. By supplying the RCS with boric acid solution, a neutron poison, the CVCS also can provide an alternate means for reactivity control. However, not all of these functions are relevant to the accident sequence top events. The functions of importance to the Ginna PRA model are briefly described below.

The RCPs circulate coolant through the reactor to the steam generators and, accordingly, operate at the RCS pressure of approximately 2235 psig. They are motor-driven and the motor shafts penetrate the reactor coolant pump casings to drive the pump impellers. The points at which the shafts penetrate the casings are sealed to prevent the escape of reactor coolant; this function is performed by the RCP seal assemblies. Each seal assembly requires a supply of cooling water from the Component Cooling Water (CCW) System and 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.

Pressure in the RCS is maintained by the pressurizer, a reservoir at the high point in the system. This reservoir is kept approximately half-full of reactor coolant; the remaining space is occupied by steam. Electric heaters immersed in the liquid volume create steam to increase RCS pressure. Relatively cool reactor coolant can be sprayed into the steam volume to condense steam and reduce RCS pressure. Normal pressurizer spray is supplied from the discharges of the reactor coolant pumps. An alternate supply is provided from the CVCS so that pressurizer pressure can be controlled during cooldown when the RCPs are not operating.

The coolant mass requirements of the RCS will vary with operating conditions. The CVCS will normally maintain a relatively constant letdown flow from the system and will vary the amount of continuous makeup as required to meet changing RCS needs. This is accomplished by varying the speed of one of the charging pumps. The charging flow also serves to replace seal leakoff and other losses from the RCS.

In the event that a reactor trip is demanded and reactor shutdown is not properly provided by the reactor protection system, the CVCS provides an alternate means of shutting down the reactor and ensuring that it remains shut down. A specified quantity (as controlled by Technical Specifications) of boric acid solution is maintained in two boric acid storage tanks and can be supplied by the boric acid transfer pumps to the suction of the charging pumps for this purpose. Alternately, borated water from the RWST may be used.

The design basis for the CVCS is to provide redundancy of reactivity control. The CVCS regulates the concentration of boric acid solution neutron absorber in the reactor coolant system and is designed to prevent, under anticipated system malfunction, uncontrolled or inadvertent reactivity changes which might stress the system beyond allowable limits.

The system meets design requirements for one of two independent reactivity control systems and for reactivity holddown capability. In addition, the CVCS maintains the reactor coolant water chemistry within limits specified in Technical Specifications.

3.2.1.5.2 Chemical and Volume Control System Description

Three positive displacement Charging Pumps (PCH01A, PCH01B, and PCH01C) provide flow through the CVCS. The Charging Pumps can each pump 60 gpm each at 2385 psig. Their normal suction supply is from Volume Control Tank (VCT) TCH04, while alternate suction supply is from Refueling Water Storage Tank (RWST) TSI01. In addition, the Charging Pumps can be supplied from Boric Acid Storage Tanks (BASTs) TCH07A and TCH07B, or the reactor makeup water system via the Boric Acid Blender (KCH01 / TCH06). The Charging Pumps discharge to a common pulsation dampener (SCH11) from which flow is directed either to the RCP seal injection sub-system or to the RCS via one of the Regenerative Heat Exchangers (ECH02A, ECH02B, or ECH02C).

The RCP seal supply is routed through a 5-micron filter (FCH08 and FCH09) to the thermal barriers of both RCP seal assemblies. Approximately 8 gpm of the injection supply is delivered in each RCP, with 1 - 3 gallons leaking away from the RCP and the balance entering the RCS.

Approximately 30 gpm of the CVCS flow is directed from the pulsation dampener, through a backpressure control valve, to one of the Regenerative Heat Exchangers. The backpressure control valve (air operated valve 142) is adjusted to ensure that RCP seal injection supply pressure is 1 - 2 psi higher than RCS pressure. The Regenerative Heat Exchanger warms the water being supplied to the RCS by removing heat from RCS letdown flow. Charging flow exiting the Regenerative Heat Exchanger can be directed to either loop B cold leg (normal alignment) or to loop B hot leg (alternate alignment). Flow from the Regenerative Heat Exchanger may also be directed to the auxiliary pressurizer spray line through air operated valve 296. An additional charging path exists from the seal injection supply line to the loop A cold leg, but this is normally kept isolated.

The constant makeup to the RCS is balanced by a continuous letdown stream. Water is removed from the B loop crossover pipe and routed to the shell side of the Regenerative Heat Exchanger. From there, flow is routed through a system of orifices and valves to reduce pressure and then to a non-regenerative heat exchanger cooled by flow from the Component Cooling Water (CCW) System. After filtration and purification, the water is normally returned to the Volume Control Tank. If VCT level is high, it may be diverted to one of the three CVCS Holdup Tanks (TCH09A, TCH09B, or TCH09C).

An additional letdown path exists from the loop A crossover pipe. Flow from this point can be routed through Excess Letdown Heat Exchanger ECH03 where it will be cooled by CCW. Flow exiting the Excess Letdown Heat Exchanger can be directed to Reactor Coolant Drain Tank TWD01A or to the RCP seal water return line.

The CVCS also serves to adjust RCS boric acid concentration for reactivity control. Relatively high concentrations of boric acid can be supplied to the Charging Ppump suctions from the Boric Acid Storage Tanks in order to increase the RCS boron concentration. In a similar fashion, unborated water from Reactor Makeup Water Tank TCH15 can be supplied to the RCS to reduce boric acid concentration.

A simplified flow drawing of relevant portions of the CVCS is provided in Figure 3.2.1-10.

3.2.1.5.3 Chemical and Volume Control System Electric Power Dependencies

Motor operated valves 313 (MCCC / DCPDPAB01A) and 350 (MCCD / DCPDPAB01B) and pumps PCH01A (BUS14/23B / DCPDPAB01A), PCH01B (BUS16/15B / DCPDPAB01B), PCH01C (BUS16/15C / DCPDPAB01B), PCH03A (MCCC / DCPDPAB01A), PC03B (MCCD / DCPDPAB01B), PCH08A (MCCC / DCPDPAB01A), and PCH08B (MCCD / DCPDPAB01B) require 125 VDC control power and 480 VAC motive power for operation. The air operated valves discussed above also require 125 VDC power for normal operation.

3.2.1.5.4 Chemical and Volume Control System Cooling Water Dependencies

No cooling water support is required for the CVCS in the Ginna PRA fault tree models.

3.2.1.5.5 Chemical and Volume Control System Instrument Air Dependencies

In the Ginna PRA CVCS model, instrument air is required to support valves 110A, 110B, 110C, 111, 112B, 112C, 142, 392A, 294, 270A, and 270B. The Charging Pump speed controllers also require instrument air; air is used to increase the speed of these positive displacement pumps. When air pressure goes to zero, the pumps fall back to thier minimum speed settings. The Ginna PRA CVCS model requires availability of instrument air to the Charging Pumps in situations where more than minimum speed is required (i.e., whenever the model success criteria call for more than minimal flow to the RCP seals).

3.2.1.5.6 Chemical and Volume Control System Actuation and Control Dependencies

On an undervoltage concurrent with a safety injection signal, charging pumps PCH01A, PCH01B and PCH01C would be shed from their respective 480 VAC vital buses. These pumps are not automatically reloded when the buses are re-energized; operator action would be required to reload and restart a charging pump.

Motor operated valve 313 in the reactor coolant pump seals water return line receives a containment isolation signal.

3.2.1.5.7 Chemical and Volume Control System Heating, Ventilation and Air Conditioning Dependencies

The three Charging Pumps are in a room located in the basement of the Auxiliary Building. Cooling of this room is provided by Charging Pump Cooling Units A and B (AAP07 and AAP08). This ventilation system is described in Section 3.2.1.8.

3.2.1.5.8 Chemical and Volume Control System Control and Instrumentation

The CVCS is controlled from the control room. Two Charging Pumps will normally be in service with one under automatic control and the other under manual control. The flow rate of the charging pump under automatic control is adjusted to maintain pressurizer level.

The CVCS supplies approximately 8 gpm to each RCP seal assembly. Labyrinth seal differential pressure is monitored to ensure proper seal supply. Normal seal differential pressure is about 2 psi. A low differential pressure alarm sounds at 15" water dP. Seal temperatures are also monitored.

The Boric Acid Storage Tanks each contain between 2000 and 3600 gallons of 12-13 weight percent boric acid. Each has level indication and control room alarms. Alarms are set at 75% (high), 40% (low) and 10% (low-low). Tank temperature is indicated and alarmed. The high temperature alarm is set at 175°F and the low temperature alarm at 155°F. The Boric Acid Transfer Pumps are controlled from the main control room and flow indication is provided there.

3.2.1.5.9 Location of Major Chemical and Volume Control System Components

The Chemical and Volume Control system is comprised of a diverse group of subsystems which are located throughout the Auxiliary Building and Containment. The Volume Control Tank and associated equipment are located on the operating floor of the Auxiliary Building at an elevation of 271 ft.. Components relating to the RCP seal supply / return are located in Containment, as are components relating to the Regenerative, Non-Regenerative, and Excess Letdown Heat Exchangers.

Major system components are controlled from the control room. Some local controls exist as well. Most components, except those in Containment, are readily accessible during normal operation. During accident conditions with elevated RCS radiation levels, access to these components could be difficult.

3.2.1.5.10 Normal Operation of the Chemical and Volume Control System

During normal power operation, the CVCS is continually letting down, purifying, and returning reactor coolant to the RCS. Typical letdown flow is around 46 gpm. This flow is cooled by one of the Regenerative Heat Exchangers, reduced in pressure and further cooled by Non-Regenerative Heat Exchanger ECH05, which is cooled with CCW. This flow is then directed through a filtration / purification system to the Volume Control Tank.

Two of the three Charging Pumps are normally in service, taking suction from the VCT. Usually, one will be operating under manual control and one will be in automatic to provide pressurizer level control. The discharge from the Charging Pumps is routed through a filter to the RCP seals (typically, 8 gpm each) and through one of the Regenerative Heat Exchangers back to the RCS (typically, 30 gpm).

3.2.1.5.11 Chemical and Volume Control System Performance Under Accident Conditions

Chemical and Volume Control System functions modeled for Ginna PRA accident sequences are the provision of water to the RCP seals, supply to the auxiliary pressurizer spray valve, provision of charging flow by one or two pumps, and supply of concentrated boric acid to the RCS.

However, these functions are not part of the engineered safeguards for the plant. While the CVCS remains in service following a routine reactor trip, normal charging flow and auxiliary pressure spray capability will be interrupted in event of a safety injection (SI) signal. The Charging Pumps are not automatically aligned to emergency power sources in the event that normal sources are lost; however, they may be manually aligned. In event of an anticipated transient without scram (ATWS), the CVCS will be used to shut down the reactor. The Charging Pumps can be aligned to supply borated water from the RWST to the RCS. Alternately, Boric Acid Transfer Pumps PCH03A and PCH03B can pump 13% boric acid solution from the Boric Acid Storage Tanks (TCH07A or TCH07B) to the suction of the Charging Pumps. The Charging Pumps may then inject this into the RCS. At least 1800 gallons of boric acid solution are maintained in the Boric Acid Storage Tanks at all times for this purpose.

3.2.1.5.12 Chemical and Volume Control System Test and Maintenance

The operating Charging Pumps are exercised three times weekly to verify correct operation of the speed control system. This exercise requires that the speed of each running pump be varied to ensure that pump speed controllers are functioning and that the pump correctly responds to changing conditions under automatic control. Once a week, the standby charging pump will be placed in service and one of the operating pumps returned to standby.

Air operated valves 112B and 112C (charging pumps' suction from RWST and VCT) are tested annually, while the plant is at cold shutdown.

The contents of the Boric Acid Storage Tanks are recirculated three times weekly to facilitate sampling. This practice also serves to verify correct operation of the Boric Acid Transfer Pumps and associated valves.

3.2.1.5.13 Chemical and Volume Control System Operating Experience

Licensee Event Reports (LERs) were reviewed to identify failures experienced by CVCS components and subsystems. No new potential failure modes relevant to the Ginna PRA CVCS model were identified.

Technical Specifications requirements for the CVCS center on its boration functions. Accordingly, most LERs describe problems with components required for boration. These include:

80-006	On July 11, 1980, the boric acid concentration in storage tanks was discovered to be too low (11.7% - 11.8%). The drop in concentration level was due to Ascanite that had been saturated with water. Reagent checks are now made along with more frequent sampling.
81-003	On January 15, 1981, a loss of borated water supply resulted from a valve which had been partially closed. The valve was locked open to prevent future incidents.
81-006	On March 23, 1981, a leak was found on a boric acid line. The break was caused by corrosion. The pipe was isolated and repaired.
81-013	On July 14, 1981, a leak was found on a boric acid suction line, caused by corrosion. The flow was rerouted and the pipe repaired.
82-027	On October 11, 1982, during startup from cold shutdown, a leak was found on a boric acid pump discharge line. The leak was caused by inter-granular stress corrosion cracking (IGSCC). The leaking pipe, along with other suspect piping and fittings, was replaced.
83-009	On January 19, 1983, a boric acid transfer pump tripped on start due to failed fuses. The fuses were replaced and the pump was restarted.
83-026	On September 15, 1983, it was discovered that the boric acid concentration in the storage tanks was too low. This was caused by make-up water leaking into the solution and diluting it. The leak was repaired and the concentration level returned to normal.
83-028	On September 16, 1983, a bad weld on a valve outlet was found to be the source of a boric acid leak. The weld was ground out and the leak stopped.
85-015	On June 20, 1985, two boric acid flowpaths were closed unexpectedly when control logic resulted in the closure of critical valves. The logic was reset.
86-006	On August 16, 1986, due to an inadvertently closed valve, a boric acid transfer pump failed to function. The valve was reopened and pump discharge pressure returned to normal.

88-002 On March 8, 1988, a lower than normal level of boric acid was detected in the storage tanks. It was discovered that a level indication inaccuracy existed due to plugged sensing lines. The sensing lines were cleared.

3.2.1.5.14 Plant Specific Data Analysis for the Chemical and Volume Control Systems

There were four ovserved instances of CVCS piping being plugged over the nine-year period of the Ginna PRA data window. The majority of these incidents were in the boric acid blender and boric acid tanks portion of the CVCS. See Section 3.3.2.3.1.6 for details.

There have been numerous failures reported of the relief valves to the volume control tank from charging pumps PCH01B and PCH01C. See Section 3.3.2.3.1.7 for details.

3.2.1.6 Electric Power Systems

3.2.1.6.1 Purpose and Design Basis of the Electric Power Systems

The Electric Power Systems support the operation of front-line systems and other support systems. Requirements for Electric Power Systems models in the Ginna PRA were dictated by the electric power requirements of components included in other Ginna PRA system models.

The Electric Power Systems may be broken up into the following sub-systems for the purposes of discussion and modeling: The off-site power distribution system; the on-site power distribution system; the 4160 VAC Electrical Distribution System; the 480 VAC Electrical Distribution System; the Emergency Power System; the 125 VDC Power System; the 120 VAC Instrument Power System; and, the AC Power Panel System.

The Electric Power Systems provide separated uninterruptible sources of power for selected 125 VDC and 120 VAC loads. They also provide separated sources of 4160 VAC and 480 VAC power for safety-related loads, including emergency backup with automatic sensing of loss of normal supply and emergency diesel generator start and load. The Electric Power Systems also provide for the automatic transfer of non-safety related loads from their normal onsite supply (from Main Generator KCD01 through Unit Auxiliary Transformer PXYD011) to off-site supplies in the event of a turbine / generator trip.

The Electric Power Systems were initially designed in accordance with the Atomic Industrial Forum (AIF) version of proposed AEC design criteria issued for comment on July 10, 1967. This design criteria required an emergency power source to be provided to permit the functioning of engineered safety features and protection systems, assuming a single active failure.

The Electric Power Systems also conform to NRC General Design Criteria (GDC) 17, *Electrical Power Systems*. Both an on-site and off-site electric power systems are provided to permit the proper functioning of systems important to safety, assuming the other system is not functioning. On-site electric power supplies, including the batteries, emergency power supplies, and electrical distribution system, have sufficient independence, redundancy and testability to ensure that plant safety functions are provided, assuming a single failure.

The off-site electric power system from the transmission network of the on-site electrical distribution system is supplied by two physically independent circuits which are designed to minimize the likelihood of simultaneous failure.

3.2.1.6.2 Electric Power Systems Description

The Ginna Electric Power Systems consist of an on-site distribution system supplied by three power sources: Off-site power from the transmission system through Station Auxiliary Transformers 12A (PXYD012A) and 12B (PXYD012B); on-site power from the Main Generator (KCD01) through Transformer No. 6 in the Ginna switchyard (RG&E Transmision & Distribution Substation 13A), throuth Circuit 767 to Unit Auxiliary Transformer 11 (PXY0D11); and emergency on-site power from two emergency diesel generators (KDG01A and KDG01B).

Station Auxiliary Transformers PXYD012A and PXYD012B are used to supply auxiliary power during plant startup and shutdown. During normal power operation, Station Auxiliary Transformers PXYD012A and PXYD012B supply safety-related (class 1E) loads. Plant auxiliary power is supplied from the Main Generator via Circuit 767 to Unit Auxiliary Transformer PXYD011. Following a turbine / generator trip with off-site power not available, the principle source of power for vital loads is Emergency Diesel Generators KDG01A and KDG01B.

Simplified drawings of the Electric Power Systems are shown in Figures 3.2.1-11 through 13.

Off-Site Power Transmission System Description: Five 115 kVAC transmission circuits are connected to the Ginna switchyard (RG&E Transmision & Distribution Substation 13A): Circuits 911 and 913 connect to the main RG&E transmission network via RG&E Substation 42; Circuits 908 and 912 connect to the 115 kVAC transmission network at RG&E Substations 121 and 122, respectively; and Circuit 909 supplies nearby distribution demand.

Four 115 kVAC lines (Circuits 908, 911, 912 and 913) are connected using a "breaker-and-a-half" arrangement for added reliability for fault isolation. The breaker-and-a-half layout provides the versatility of dual feed for each line and the ability to remove any breaker or transmission line without deenergizing any other part of the substation. The individual capacity of Circuits 908, 911, 912, and 913 exceeds the power requirements of engineered safety features, the requirements of auxiliary plant loads, and the requirements of Circuits 751 and 767, which deliver 34.5 kVAC power to the plant when the Main Generator is not operating.

Circuit 767, one of the 34.5 kVAC off-site sources, is fed from 115 / 34.5 kVAC Transformer No. 6 at RG&E Substation 13A (the Ginna switchyard, accross Lake Road from the plant) and is routed underground to Station Auxiliary Transformer PXYD012B. Circuit 751 from RG&E Transmision & Distribution Substation 204 (located at the intersection of Route 104 and Slocum Road in Ontario Center), the second 34.5 kVAC off-site source that feeds into the plant via Station Auxiliary Transformer PXYD012A, is run on wooden poles over a different route (along North Slocum Road and Lake Road to the site) than the four 115 kVAC lines associated with Substation 13A.

Station Auxiliary Transformers PXYD012A and PXYD012B step down 34.5 kVAC from off-site Circuits 767 (Station Auxiliary Transformer PXYD012B) and 751 (Station Auxiliary Transformer PXYD012A) to 4160 VAC for use by the 4160 VAC electrical distribution system. Station Auxiliary Transformer PXYD012A normally supplies Bus 12A with power through 4160 VAC circuit breaker 52/12AY and is capable of providing backup power to Bus 12B via 4160 VAC breaker 52/12AX. Transformer 12B supplies normal power to Bus 12B through 4160 VAC breaker 52/12BX, with a backup supply to Bus 12A via 4160 VAV breaker 52/12BY. In the event of loss of power from either transformer, the lost bus may be supplied from the other transformer by manually closing the alternate feed breaker to the deenergized bus from the Main Control Board (MCB). Station Auxiliary Transformers PXYD012A and PXYD012B are cooled by oil to air heat exchangers.

On-Site Power System Description: Normal on-site power to non-safety related loads is provided from Main Generator KCD01 when the plant is at power. The Main Generator supplies electrical power rated at 520 megawatts and 19 kVAC to Unit Main Transformer PXYDGSU and back through Unit Auxiliary Transformer PXYD011. The Main Generator ratings are 520 MW, 608.4 MVA at a power factor of 0.85; 60 Hz at 1800 rpm, with 60 psig hydrogen pressure.

Unit Main Transformer PXYDGSU is rated at 578 MVA with a primary voltage of 19 kVAC and a secondary voltage of 115 kVAC. It is oil cooled with an oil-to-air heat exchanger system. Unit Auxiliary Transformer PXYD011 steps down voltage from the output of the Unit Main Generator for use in the station's 4160 VAC distribution system. It also supplies normal power to 4160 VAC Buses 11A and 11B. Unit Auxiliary Transformer PXYD011 is oil-cooled. A disconnect link is located in the supply line to Unit Auxiliary Transformer PXYD011; the disconnect link may be removed to allow maintenance.

4160 VAC Electrical Distribution System Description: The 4160 VAC Electrical Distribution System provides power to non-safety 4160 VAC loads. It also provides normal power to the 480 VAC Electrical Distribution System. Power is supplied to the 4160 VAC distribution system via Station Auxiliary Transformers PXYD012A and PXYD012B and Unit Auxiliary Transformer PXYD011 through associated feeder breakers and power lines. These feeder breakers may be opened, closed, or tripped locally at the switchgear and from the Main Control Board in the control room. The feeder breakers trip automatically on bus undervoltage or transformer faults; these faults also prevent normal closing.

There are four 4160 VAC buses: 11A, 11B, 12A, and 12B. Buses 11A and 11B are normally supplied from Unit Auxiliary Transformer 11 when the main generator is on line. During shutdown, Bus 11A receives power from Bus 12A and Bus 11B receives power from Bus 12B. Buses 12A and 12B are normally supplied from station auxiliary transformers 12A and 12B, respectively.

Loads supplied from 4160 VAC Buses 11A, 11B, 12A and 12B are shown in Table 3.2.1-8.

During normal operations, bus tie breakers 52/BTA-A (Bus 11A to Bus 12A at BUS12A/12) and 52/BTB-B (Bus 11B to Bus 12B at BUS12B/20) are open. These will automatically close on a generator trip if there are no faults on the associated bus, if breakers for circuit 767 or circuit 751 are closed, and if the associated bus's synchro verifier relay (25AX/11T-12A and 25BX/11T-12B for Bus 11A and Bus 11B, respectively) is satisfied. For most turbine trips there is a time delay between turbine trip and generator trip of approximately 60 seconds generated by Turbine Auto Stop Timer Relay 62AST.

480 VAC Electrical Distribution System Description: The 480 VAC electrical distribution system supplies power for the plant's 480 VAC loads and is a power source for the 125 VDC Power System, the 120 VAC Instrument Power system and the AC Power Panel System. The system consists of six buses with associated station service transformers, breakers, and motor control centers. The station service transformers receive power from the 4160 VAC buses and step it down to 480 VAC to supply both safety-related and non-safety-related loads. Power for non-safety Buses 13 and 15 is provided from Buses 11A and 11B. Power for safety-related Buses 14, 16, 17, and 18 is provided from Buses 12A and 12B. If a loss of voltage occurs on a safety-related 480 VAC bus, its associated diesel generator will start and re-energize the bus.

There are four undervoltage (UV) relays on each safeguards bus which sense either a loss of voltage or degraded voltage on the safety-related buses. Two of the relays sense a no voltage (~93 VAC) condition and two sense a variable degraded voltage over a set period of time. Operation of any one relay will cause the associated diesel to start, while operation of either both UV or both degraded voltage relays will trip the normal supply to the vital bus and place it on the diesel.

Bus breakers are located in their respective 480 VAC switchgear. The breakers can be operated from the main control board or locally. The breakers will trip automatically on bus undervoltage, load shed signal (safeguard buses), respective station service transformer fault, or transformer feeder breaker fault. DC control power is required for proper automatic and / or remote manual operation of these breakers. DC control power for Buses 14, 16, 17, and 18 is either battery A (Buses 14, 18) or battery B (Buses 16, 17) depending on which safeguards train the bus belongs to. An emergency control power supply is provided from the battery supplying the opposite safeguards train for the undervoltage circuits, diesel generators, and Buses 13-18. If a fault interrupts the normal DC supply, the DC control power for these loads will automatically shift to the emergency source. When the normal source of DC control power is restored, the control power will shift back to normal. Motor control centers do not have alternate emergency DC control power sources.

An undervoltage signal will trip the following loads: On a loss of offsite power (LOOP) without a safety injection (SI) signal, only the selected service water and running CCW pumps automatically restart. Other major loads on 480 VAC Buses 14, 16, 17, and 18 must be manually loaded.

Loads shed from 480 VAC Motor Control Center C and 480 VAC Motor Control Center D under these circumstances are shown in Table 3.2.1- 9.

Load shed relays 86/MCCC and 86/MCCD remove 125 VDC control power from all shed loads, except in the case of the boric acid evaporator package, where the supply breaker is tripped. After the SI signal has been reset, these loads can be reset by pushing the 86/MCCC reset push rod on 480 VAC Motor Control Center C for MCC C loads, or the 86/MCCD push rod on 480 VAC Motor Control Center D for MCC D loads. In addition, the boric acid evaporator package requires that the breaker on 480 VAC Motor Control Center D be closed to reset this load after the reset push rod for 86/MCCD on MCC D has been pressed.

The SI sequencer energizes selected loads which are necessary to mitigate the effects of design basis accidents and safely shut down the unit. If a SI signal is not accompanied by a loss of voltage, only the loads that are not already running are sequenced (no safety-related load shedding). Loads that are sequenced on to the safety-related buses are shown in Table 3.2.1- 9.

Emergency Power System Description: Emergency AC power to 480 VAC Buses 14, 16, 17, and 18 is supplied by two diesel generators. Diesel Generator KDG01A can provide power to 480 VAC Buses 14 and 18 while Diesel Generator KDG01B can provide power to 480 VAC Buses 16 and 17. If there is not a normal supply of power to these safeguard buses from Unit Main Generator KCD01 or from off-site power, the emergency diesel generators will automatically start and power their buses.

Each emergency diesel generator is driven by an Alco V-type, 16 cylinder, turbocharged, 4-cycle engine. Normal operating speed is 900 rpm and full rated load is 2725 hp continuous, 3142 hp for 2 hours, and 3212 hp for 30 minutes. Speed control is provided by a Woodward governor.

The generator for each emergency diesel generator is rated for 1950 kW continuous service, 3 phase, 60 Hz, 480 VAC at a power factor of 0.8 to 1.0. The generator can be loaded to 2300 kW for .5 hour and 2250 kW for 2 hours prior to continuous duty at 1950 kW.

Each emergency diesel generator has an associated air system for diesel engine starting and initial positioning of the Woodward governor. The diesel air start sub-systems also provide air to their respective fuel oil intake atomizer. [Ref. 18.1.6, Pages 2-3].

Fuel oil is provided by a 350 gallon day tank (TDG04A for KDG01A and TDG04B for KDG01B) located on the skid with each of the diesel engines. When the diesel engine starts, a gear type, engine-driven fuel pump (PDG04A for KDG01A and PDG04B for KDG01B) provides fuel from the day tank to the diesel engine.

During emergency diesel generator operation, each day tank is refilled using a fuel oil transfer pump (PDG02A for KDG01A and PDG02B for KDG01B). Fuel oil is transferred from two 6000 gallon underground storage tanks (TDG01A for KDG01A and TDG01B for KDG01B) located in the plant yard adjacent to the diesel generator building. The lines between the fuel oil storage tanks and the transfer pumps are heat traced to prevent the fuel oil from becoming too viscous in cold weather. A duplex strainer in the fuel oil transfer pump suction line removes any particulate impurities and improves the reliability of the system.

The emergency diesel generators are supplied with cooling water from the Service Water System. Service water is directed to the lube oil cooler and jacket water coolers for each diesel engine. To improve reliability, the service water crossover valves between the two diesel engines are kept open at all times. This ensures that both emergency diesel generators will receive cooling water independent of the selected service water pumps.

Each diesel generator room is equipped with two ventilation supply fans (ADF01A and ADF01B for KDG01A; ADF02A and ADF02B for KDG01B). One fan in each room starts when the associated diesel's jacket water pressure exceeds 11 psig. The second fan in the room is provided with a thermostat which allows the fan to run only when room temperature is greater than 90°F. This provides protection against jacket water pressure sensing line freezing. Each fan is equipped with a downstream air-operated damper (ADD01A for ADF01A; ADD01B for ADF01B; ADD02A for ADF02A; and, ADD02B for ADF02B). Each of these dampers is configured to open on start of the appropriate related diesel generator, and to fail open on loss of instrument air pressure.

Two additional diesel generators are located on-site and can be manually aligned to provide limited power: The Technical Support Center (TSC) Emergency Diesel Generator (KED02): and, Security Diesel SEP-1.

125 VDC Power System Description: The 125 VDC Power System provides control power for the 4160 VAC and 480 VAC Electrical Systems. It also supplies electrical power to inverters INVTA and INVTB, which are the normal supplies to 120 VAC Instrument Buses A (IBPDPCBAR) and C (IBPDPCBCB).

The main components of the 125 VDC Power System are the two Main DC Distribution Panels (DCPDPCB03A and DCPDPCB03B), two sets of batteries (BTRYA and BTRYB), and four battery chargers (BYCA, BYCA1, BYCB and BYCB1). Additional DC distribution panels which supply loads in the main control board (DCPDPCB04A and DCPDPCB04B), the Auxiliary Building (DCPDPAB01A, DCPDPAB02A, DCPDPAB03A, DCPDPAB01B and DCPDPAB02B), the Screen House (DCPDPSH01A and DCPDPSH01B), the Turbine Building (DCPDPTB01B), and the Diesel Generator Building rooms (DCPDPDG01A and DCPDPDG01B) are fed from the Main DC Distribution Panels or the Main DC Battery Fuse Cabinets (DCPDPCB02A and DCPDPCB02B).

125 VDC Trains A and B are supplied by their battery chargers under normal conditions (with their batteries "floating" on the system) and by their batteries whenever normal power is lost to their battery chargers. Alternate battery chargers BYCA1 and BYCB1 are operated in parallel with chargers BYCA and BYCB.

BTRYA and BTRYB are 60 cell, lead-acid batteries that normally operate at 130 VDC. They each have a 1200 amp hour capacity. In the event of a loss of battery BTRYA or battery BTRYB, Technical Support Center (TSC) battery BTRYTSC may be manually cross-tied to one of the trains of the 125 VDC Power System through TSC / Batteries A & B Manual Throwover Switch DCPDPCD02 (located in the Turbine Building basement), TSC / Battery A Fused Disconnect Switch DCPDPCB05A (located in the A Battery Room) and TSC / Battery B Fused Disconnect Switch DCPDPCB05B (located in the B Battery Room). Battery BTRYTSC has a 2420 amp hour capacity.

The Vital Battery Monitoring System provides information on the status of batteries BTRYA, BTRYB, and BTRYTSC. The system consists of voltage and current flow local indicators (EI/BCSA and EI/BCSB, located in the respective battery rooms) and remote current flow indicators (EI/PG for Train A and EI/PA for Train B) located on the subcooling panel in the control room. An annunciator is provided to indicate abnormal battery status. It will alarm on high (145 VDC) or low voltage (110 VDC), battery discharging, loss of battery continuity, or a problem with the monitoring system. Power for the Vital Battery Monitoring System is from non-battery-backed Instrument Bus B (IBPDPCBBW) Distribution Panel B (IBPDPCBB).

Battery chargers BYCA and BYCB are supplied with power from 480 VAC Motor Control Centers C and D, respectively. The chargers have 480 VAC, 3 phase, 60 Hz input; and 150 amps, 130 VDC output; and utilize an equalizing voltage of 140 VDC.

The BYCA1 and BYCB1 battery chargers are normally operating in parallel with and serve as backups for the BYCA and BYCB chargers. Charger BYCA1 is supplied from 480 VAC Motor Control Center C; charger BYCB1 is supplied from 480 VAC Motor Control Center D. Each charger has a 480 VAC, 3 phase, 60 Hz input and 200 amp, 130 VDC output.

120 VAC Instrument Power System Description: The 120 VAC Instrument Power System provides power to the instrumentation for the Reactor Protection System .and Engineered Safeguards Features Actuation System (ESFAS) cabinets. There are four Istrument Buses: Instrument Bus A (IBPDPCBAR), Instrument Bus B (IBPDPCBBW), Instrument Bus C (IBPDPCBCB) and Instrument Bus D (IBPDPCBDY). Power is supplied to Instrument Bus A by inverter INVTA, and to Instrument Bus C by inverter INVTB.

A third inverter, MQ483, is powered from Main Control Board DC Distribution Panel A (DCPDPCB04A). This inverter supplies power to components supporting pressure transmitter PT-479 (Steam Generator EMS01B Pressure) and pressure transmitter PT-950 (Containment Pressure) which are located in yellow protection rack 2 (Y2). This power supply ensures that containment spray will not be inhibited following a loss of off-site power (LOOP). This power supply arrangement also prevents an inadvertent SI signal following a LOOP.

120 VAC Instrument Bus B receives power from 480 VAC Motor Control Center C (MCC C) via 480 VAC / 120 VAC constant voltage transformer CVTA2. 120 VAC Instrument Bus D receives power from 480 VAC Motor Control Center B (MCC B) via 480 VAC / 120 VAC constant voltage transformer CVT1B. Instrument Buses A and C can be supplied by similar transformers (CVTA and CVTB) from 480 VAC Motor Control Centers C and D (MCC C and MCC D), respectively, through static switch transfer devices (Static Switch SCICBAR for IBPDPCBAR and Static Switch SCICBCB for IBPDPCBCB).

The inverters for Instrument Buses A and C are both rated at 7.5-kVA. The inverters utilize silicon-controlled rectifiers (SCRs) in a bridge network in conjunction with a transformer to convert the 125 VDC input to a 118 VAC, 60 Hz, single phase output.

Instrument Buses A and C are provided with automatic static switches which transfer these buses to their alternate supply from 480 VAC Motor Control Centers C and D, respectively, on a loss of inverter output. Static Switches SCICBAR and SCICBCB are solid-state devices which use semiconductors for switching. They provide a maximum transfer time of 1/4 cycle, thereby assuring uninterruptible power to Instrument Buses A and C.

A maintenance power supply may be connected to any of the 120 VAC Instrument Buses. The maintenance power supply receives power from 480 VAC Motor Control Center A, Position 4K (MCCA/04K) through constant voltage transformer CVTAUX.

Each Instrument Bus feeds either one or two Twinco regulated power supplies. Each regulated power supply, in turn, feeds a Distribution Panel. Some components receive power directly from an Instrument Bus breaker while other more voltage-sensitive loads receive power from a Distribution Panel breaker. The relationship between Instrument Buses, regulated power supplies and Distribution Panels is shown in Table 3.2.1- 10.

AC Power Distribution Panels System Description: AC Power Distribution Panels are located throughout the plant to serve miscellaneous loads of 480 VAC or less. They receive power either from 480 Buses and Motor Control Centers (through power transformers), or from other AC panels.

3.2.1.6.3 Electric Power Systems Electrical Dependencies

All electric power interfaces are internal to the fault trees constructed for the Ginna PRA Electrical Power Systems model.

3.2.1.6.4 Electric Power Systems Cooling Water Dependencies

Diesel Generators KDG01A and KDG01B require cooling water flow from the Servic Water System for engine jacket cooling. In the event of a loss of service water flow to the diesels, the operators are procedurally instructed to connect hoses from the Fire Service Water System outlets in the diesel rooms to existing fixtures on the service water inlet lines of the cooling jackets. Diesel Driven Fire Pump PFP01, located in the Screen House, would then be used to cool the emergency diesels.

3.2.1.6.5 Electric Power Systems Instrument Air Dependencies

The electric power system does not require compressed air for success as modeled. Compressed air is required for starting the diesel generators; however, failure to start the diesels due to unavailability of starting air is included in the diesel generator failure-to-start probability.

3.2.1.6.6 Electric Power Systems Actuation and Control Systems Dependencies

Diesel generator start, load shed, and diesel generator-backed bus loading is initiated on undervoltage on 480 VAC Buses 14, 16, 17, and 18. These functions are explicitly included in the Ginna PRA systems models. Diesel generators KDG01A and KDG01B are also started (but not loaded) on an SI signal, but this is not addressed in the model. Failure of diesel generator control and protective features are addressed in the diesel generator failure-to-start and failure-to-run probabilities.

3.2.1.6.7 Electric Power Systems Heating, Ventilation and Air Conditioning Dependencies

Cooling of the diesel generator rooms is required. This is modeled as a part of the electric power fault tree.

3.2.1.6.8 Electric Power Systems Control and Instrumentation

Annunciation is provided on the main control board for the electric power off-normal conditions as specified in Table 3.2.1- 11.

Two pairs of relays monitor voltage on 480 VAC Buses 14, 16, 17, and 18. These relays are designated 27/XX, 27B/XX, 27D/XX, and 27D/B/XX; where XX indicates the particular bus. Low voltage sensed by any of these relays will start the associated diesel generator. Coincidence of both instantaneous undervoltage relays or both time delay undervoltage relays will initiate a stripping of unnecessary loads, tripping of normal bus feeders, diesel start, and closure of the diesel generator output breaker to the affected bus, once the diesel has reached rated speed and voltage. In 1992, this logic was modified. The modification now requires low voltage sensed by two relays from different trains to start the associated diesel and initiate load stripping and sequencing. This modification is not yet reflected in the Ginna PRA model.

3.2.1.6.9 Location of Major Electric Power Systems Components

Locations for major components in the Electrical Power System components are as follows:

Component	Location
Battery BTRYA	Control building, Battery Room A, elevation 253
Battery BTRYB	Control building, Battery Room B, elevation 253
Bus 11A	Turbine building, mezanine level, elevation 271
Bus 11B	Turbine building, mezanine level, elevation 271
Bus 12A	Turbine building, mezanine level, elevation 271
Bus 12B	Turbine building, mezanine level, elevation 271
Bus 13	Turbine building, mezanine level, elevation 271
Bus 14	Auxiliary building, operating level, elevation 271
Bus 15	Turbine building, mezanine level, elevation 271
Bus 16	Auxiliary building, operating level, elevation 253
Bus 17	Screen house east side, elevation 271
Bus 18	Screen house east side, elevation 271
Diesel Generator KDG01A	Diesel generator building, Room A, elevation 253
Diesel Generator KDG01B	Diesel generator building, Room B, elevation 253
Transformer PXYD012A	Transformer yard, south of the turbine building, elevation 271

Transformer PXYD012B	Transformer yard, south of the turbine building, elevation 271
Transformer PXTBSS013	With Bus 13
Transformer PXABSS014	With Bus 14
Transformer PXTBSS015	With Bus 15
Transformer PXABSS016	With Bus 16
Transformer PXSHSS017	With Bus 17
Transformer PXSHSS018	With Bus 18
Transformer PXYD011	Transformer yard, south of the turbine building, elevation 271

3.2.1.6.10 Normal Electric Power Systems Operation

During power operation, 4160 VAC Buses 11A and 11B are fed by main generator output, via Unit Auxiliary Transformer 11. 4160 VBus 12A is normally fed from off-site RG&E Station 204 via Station Auxiliary Transformer PXYD012A. 4160 VAC Bus 12B is normally fed from off-site RG&E Station 13A, via Station Auxiliary Transformer PXYD012B. 4160 VAC Bus 12B normally feeds 480 VAC Buses 16 and 17 via Station Service Transformers PXABSS016 and PXSHSS017. 4160 VAC Bus 12A normally feeds 480 VAC Buses 14 and 18 via Station Service Transformers PXABSS014 and PXSHSS018. Emergency diesel generators KDG01A and KDG01B are maintained in a state of standby readiness.

Battery chargers BYCA and BYCA1 provide power to loads on 125 VDC Train A and maintain battery BTRYA charged. Battery chargers BYCB and BYCB1 similarly power 125 VDC Train B.

120 VAC Instrument Bus A is powered by inverter INVTA through static transfer switch SCICBAR. 120 VAC Instrument Bus C is powered by inverter INVTB through static transfer switch SCICBCB. 120 VAC Instrument Buses B and D are powered by constant voltage transformers CVTA1 and CVTA2 from 480 VAC Motor Control Centers C and B, respectively.

3.2.1.6.11 Electric Power Systems Performance Under Accident Conditions

Following a turbine / generator trip, 4160 VAC Buses 12A and 12B continue to be powered from their normal off-site sources. 4160 VAC Buses 11A and 11B automatically transfer from Unit Auxiliary Transformer 11 and are powered from Buses 12A and 12B through tie breakers 52/BTA-A (BUS12A/12) and 52/BTB-B (BUS12B/20), respectively. Loss of voltage on any of the 480 VAC safety buses (14, 16, 17 or 18) will trip two degraded-voltage relays and two undervoltage relays. Operation of any of these relays initiates a start of the associated diesel generator. Coincidence of two degraded-voltage or undervoltage relays for a particular bus will trip normal feeders to that bus, initiate a load-shed, and permit closure of the diesel generator output breakers.

Four DC battery chargers are available to feed the plant DC loads and maintain a charge on the two 125 VDC plant batteries, provided 480 VAC Motor Control Centers C and D are available. If these 480 VAC motor control centers are lost, vital plant 125 VDC loads are then carried by the batteries until the chargers are restored.

Inverters INVTA and INVTB are supplied from Main DC Distribution Panel A (DCPDPCB03A) and B (DCPDPCB03B), respectively. Loss of AC voltage from the inverters results in a high-speed transfer to the respective alternate supplies, provided these supplies (480 VAC Motor Control Centers C and D) are available.

3.2.1.6.12 Electric Power Systems Test and Maintenance

The Electric Power System is a support system which provides power to plant components during both normal and accident conditions. The AC Emergency Power System (diesel generators and associated breakers) is in standby. A complete test of the entire Electric Power System cannot be performed while at power. Annual testing during refueling (on a train basis), combined with monthly tests of emergency power system components and daily confirmation of component status, as described below, is used to provide indication of system operability.

Ginna Technical Specifications [Ref. 18.1.2, pp 4.6.1 - 4.6.4] require monthly operability demonstrations for the diesel generators. Battery cell voltage and pilot cell specific gravity and temperature are also confirmed monthly. More extensive testing is required on a less frequent basis.

For the Electric Power System, when the plant is above cold shutdown, the following are checked at least once per shift per procedures:

- Emergency diesel generator air start solenoid indicating lights ASV-1 and ASV-2 illuminated

- Emergency diesel generator start relays R1 and R2 indicating lights illuminated

- Emergency diesel generator MAN-AUTO switch is in the AUTO position

- Emergency diesel generator UNIT-PARALELL switch is in the UNIT position

- Emergency diesel generator start circuit breaker control switches are in the AUTO position

- Emergency diesel generator tie breaker W-2 switches for 480 VAC Buses 14, 16, 17 and 18 are in the AUTO position

- Emergency diesel generator fuel supply >5,300 gals (second shift only)

Undervoltage and underfrequency relays and associated annunciators are tested monthly to ensure that they will actuate when their input devices are tripped. During these tests , each tested device is tripped. Undervoltage protection remains available, although with increased likelihood of spurious actuation.

The station batteries are tested yearly during shutdown to verify that the battery system can power emergency loads. The test demonstrates that the batteries will carry the expected emergency load profile for two hours without battery terminal voltage falling below 105 volts. During this test the TSC battery is used to power the 125 VDC train which is in test.

The automatic throw over switches for safety-related switchgear are tested yearly during shutdown to ensure that they will transfer to their alternate source on loss of the normal 125 VDC supply.

Diesel Generators KDG01A and KDG01B are tested once every 31 days to verify operability by:

- Verifying the fuel level in the day tank;

- Verifying the diesel starts from normal standby conditions;

- Verifying the generator can be synchronized, loaded to at least 1950 KW but less than the 2 hour rating of 2250 KW and operate for at least 60 minutes but less than 120 minutes;

- Verifying the diesel generator is aligned to provide standby power to the associated emergency buses; and

- Verifying that electrical and mechanical parameters which assess diesel generator operability are monitored, recorded and evaluated during performance of the test.

The test procedure loads the diesel generator undergoing test and runs it for 1-2 hours. There is a caution statement in the procedure which notes that if an SI signal occurs, the normal bus source breakers will open (this would also occur on LOOP). In this case, the possibility of a diesel generator breaker trip exists.

Diesel generator loading and sequencing tests are conducted yearly during shutdown. This test is performed during each refueling and verifies that each diesel generator will automatically start upon loss of all normal AC station service power together with a simulated SI signal, and, subsequent to diesel generator start, safeguards equipment will load in accordance with the required loading sequence. Each diesel generator must start and restore power to its respective safeguards buses in approximately 10 seconds from initial bus deenergization. Non-essential diesel generator trips are also verified to be blocked during the safeguards loading sequence.

3.2.1.6.13 Electric Power Systems Operating Experience

The following is a list of Licensee Event Reports (LERs) that are related to operation of the Electric Power Systems. These LERs were reviewed to ensure that failure modes which have been historically observed are addressed in the fault tree. Based on this review, it is concluded that all such events which could have occurred at power and impacted post-trip response can be addressed using the models developed for the Ginna PRA:

80-001 On January 18, 1980, KDG01A governor load setting was determined to be incorrectly adjusted. A Dynotape sticker with the incorrect load setting had not been removed following annual overhaul. Unavailability of KDG01A is addressed in the fault tree model.

80-008 On September 10, 1980, KDG01B breaker to Bus 16 (BUS16/11C, 52/EG1B1) did not close during testing because of a binding control relay guide pin. Failure of this breaker to close is included in the fault tree model.

80-009 A barring device was left engaged on KDG01A. When KDG01A was tested on October 3, 1980, the device failed and parts flew out from the diesel. It was determined that KDG01A was operable with the barring device engaged and after it failed.

80-011 On December 11, 1980, KDG01B breaker for Bus 17 (BUS17/25C, 52/EG1B2) failed to close during surveillance testing. Failure of this breaker to close is included in the fault tree model.

81-001 On January 5, 1981, an KDG01B jacket cooling water return line to expansion tank leak occurred from a broken bushing. Unavailability of KDG01B is addressed in the fault tree model.

81-007 Loss of 34.5 kVAC supply to the station auxiliary transformer PXYD12A on April 18, 1981, resulted in a loss of power to 480 VAC Buses 12A and 12B and safeguards 480 VAC Buses 14, 16, 17 and 18. KDG01A and KDG01B started on the undervoltage signal and supplied power to their respective buses. The cause of the event was a fault in the B phase vacuum breaker switch for the PXYD12B spare transformer. Unavailability of power to PXYD12A is addressed both as a LOOP initiator and unavailability of power given trip (basic event).

82-009 On March 20, 1982, safeguards 480 VAC Bus 17 was taken out of service for more than seven days when the plant was shutdown. The event was caused by installation and testing problems. This event is considered shutdown-related and was not specifically addressed in the model.

83-008 On January 25, 1983, KDG01A start relay indicating lights were found off. This caused a loss of the permissive start relays. KDG01A was declared inoperable but KDG01B was not run as required. The event was caused by a failure to follow procedures. Unavailability of KDG01A is addressed in the fault tree.

83-011 Breaker to Battery Charger CVTA1 was inadvertently opened on March 11, 1983 while a QC inspector was checking fire seals. Breaker-transfers-open faults are addressed in the fault tree. Open breakers and fuses prior to an initiating event are assumed to be quickly detectable and correctable, and are not included in the fault tree model.

83-027 A trip occurred on September 16, 1983, during a power reduction when an operator inadvertently lost his place in the procedure and opened a switch from Station Auxiliary Transformer PXYD011 to 4160 VAC Bus 11A before cross-tying the bus to the incoming feed via 4160 VAC Bus 12A. (This did not impact safety-related buses and has not been addressed in the model.)

84-009 Inadvertent start of KDG01A during testing on August 17, 1984. This was caused by an intermittent 12 V power supply for a control logic board. Neither KDG01A nor the safeguards bus was unavailable during the event. This power supply failure is explicitly included in the Ginna undervoltage model.

85-002 Both KDG01A and KDG01B were started and tied to their safeguards buses on January 21, 1985, as required by procedure because of low system frequency caused by an extremely cold weather condition.

85-004 Momentary loss of 120 VAC Instrument Bus C during maintenance on March 26, 1985, because of a defective procedure. Unavailability of 120 VAC Instrument Bus C is addressed in the fault tree model.

85-013 KDG01A was started and tied to its safeguards bus on May 31, 1985, as required by procedures following declaration of a tornado warning by the U.S. Weather Bureau.

85-014 One cycle undervoltage condition occurred on 120 VAC Instrument Bus D on June 6, 1985, during repair of ex-core nuclear power range channel N-41 selector switch. This resulted in completion of a two-out-of-four logic and a reactor/turbine trip. Unavailability of 120 VAC Instrument Bus D is addressed in the fault tree model.

87-001 Plugging of the suction strainers for both diesel generators' fuel oil transfer pumps occurred on February 20, 1987. The diesel generators were in use providing all station power during cold shutdown with all off-site power unavailable due to maintenance. Both diesel generator day tanks indicated low level within 30 minutes of each other. The event was caused by particulate matter in the diesel fuel oil and incorrectly designed and maintained fuel oil transfer pump suction strainers. An onsite portable fuel oil tank was used to provide short-term makeup to the day tanks. Common cause failures in the diesel generator fuel oil transfer systems are included in the fault tree model.

88-006 A failed bushing on one of the main electrical substation 115 kVAC oil circuit breakers on July 16, 1988, caused a loss of normal off-site power, including power to the four 480 VAC safeguards buses. Both diesel generators started and supplied power to safeguards loads. Loss of normal power is addressed in the fault tree model.

88-008 Unexpected start of KDG01B due to a failure of undervoltage system solid state switch #1 on September 3, 1988. The solid state switch is an interface mechanism between the solid state undervoltage monitoring relays and the mechanical actuation relays. Unavailability of the undervoltage monitoring relays and failure of the solid state switches are addressed in the Ginna PRA undervoltage model.

89-002 Undervoltage condition on 480 VAC safeguards Bus 14 and KDG01A start caused by an error during performance of a station modification procedure on May 6, 1989. Lockout relay trip contacts for a breaker had not been blocked because of a typographical error in the procedure. The reactor was in cold shutdown for the modification. During the event, the breaker to 480 VAC Bus 14 (BUS14/18B, 52/14) tripped, and KDG01A started and provided provided power to Bus 14 loads. Unavailability of this breaker is addressed in the fault tree.

89-010 Spurious KDG01B initiation from 480 VAC Bus 16 undervoltage monitoring system on July 30, 1989, a result of a loose connection. In the event of an actual bus undervoltage condition, KDG01B would have been capable of providing bus loads.

3.2.1.6.14 Plant-Specific Data Analysis for the Electric Power Systems

Electric power-related events identified in the Ginna PRA plant-specific data task were reviewed to insure that failure modes which have been historically observed are addressed in the fault tree. The following is a list of events which were not reported as LERs but which impacted electric power system operability. Based on a review of these events, it is concluded that all which could have occurred at power, with the exception of item 10 (which can be addressed by adding this failure to those for KDG01B failure to start), can be addressed using the existing fault tree structure.

1) On December 8, 1988, KDG01A tripped on overspeed while performing PT-12.1, due to air start solenoid valve 5933B failing to close. Failure of the diesel generator to start is included in the fault tree model.

2) On August 17, 1988, the KDG01A governor was not responsive and the governor control motor-driven potentiometer was replaced. The diesel generator was believed still capable of performing its safety-related function.

3) On June 17, 1981, while performing PT 12.1 and PT 12.2 on KDG01A and KDG01B, respectively, KDG01A was sluggish for several minutes before attaining the minimum acceptable test loads. KDG01B also failed the test. Post-maintenance testing revealed improper governor settings for both diesel generators. Common cause failure of the diesel generators is included in the fault tree model.

4) On April 21, 1982, 480 VAC Bus 17 tripped on undervoltage when Reactor Coolant Pump PRC01B was started. The fault tree model addresses diesel generator start and load on sensed bus undervoltage.

5) In March 1988, an undervoltage relay for 4160 VAC Bus 11B was found to be stuck. Failure of bus undervoltage relays is addressed in the fault tree model.

6) In 1987-88 there were four failures of DC throwover relays for safety-related buses. Failure of these relays to transfer on loss of control power is included in the fault tree.

7) On April 14, 1981, normal feed to switchyard transformer No. 6 was lost. This caused loss of Buses 12A, 12B, 14, 16, 17, and 18. Both diesel generators started and loaded as required. (This event may be the same as the event identified in LER 244/81-007 as occurring on April 18, 1981.)

8) On July 23, 1982, an electrician inadvertently tripped the feeder breaker for 480 VAC Motor Control Center A (BUS13/08B, 52/MCCA) while troubleshooting 480 VAC Bus 13. He immediately reset the breaker. Total loss of 480 VAC Motor Control Center A (for example, through a bus fault) is addressed in the fault tree model.

9) A loss of power on 4160 VAC Bus 11B occurred on March 30, 1985, when the door to the Reactor Coolant Pump B (PRC01B) breaker cabinet (BUS11B/24, 52/RCP1B) was closed. Bus 11B Differential Lockout Relay 86/11B tripped the bus; this caused loss of power on 480 VAC Bus 15 and 480 VAC Motor Control Center B. This resulted in loss of 120 VAC Instrument Bus D, which is powered from 480 VAC Motor Control Center B. Loss of 120 VAC Instrument Bus D on loss of its 480 VAC source is addressed in the fault tree model.

10) On March 1, 1988, during performance PT-12.2, the breakers from KDG01B to Buses 16 (BUS16/12A, 52/EG1B1) and 17 (BUS17/25C, 52/EG1B2) were found in the TEST position instead of the NORMAL position. This would have prevented KDG01B from tying onto these two buses. Common cause failure of the two breakers is not currently included in the model. This event can be considered addressed by basic events associated with failure of KDG01B to start and load, or unavailability of the diesel generator following test and maintenance.

11) On December 3, 1985, battery charger BYCA1 failed due to a control circuit failure. Failure of battery charger BYCA1 is addressed in the fault tree model.

12) On February 24, 1987, battery charger BYCA1 was found failed due to a blown output fuse (either FUDCPDPCB02A/1N or FUDCPDPCB02A/1P). Failure of battery charger BYCA1 and the associated output fuses are explicitly addressed in the fault tree model.

13) On July 6, 1981, inverter INVTB switched to its alternate power supply and could not be switched back. The failure involved the inverter switch, and not the inverter itself. The fault tree model has been developed under the assumption that, at the moment before an initiating event, power is supplied to 120 VAC Buses A and C from inverters INVTA and INVTB. Upon loss of either inverter, the fault tree model addresses failure to provide power from the alternate source. A similar event occurred on February 11, 1986.

14) On December 8, 1980, water from a spilled mop bucket in the relay room leaked through a bolt hole onto battery charger BYCA1, causing it to fail. All holes in the relay room floor leading to the battery rooms were subsequently plugged. Failure of battery charger BYCA1 is addressed in the fault tree model.

3.2.1.7 Engineered Safety Features Actuation System

3.2.1.7.1 Purpose and Design Basis of the Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System (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.

Engineered Safety Features (ESFs) are specifically used to provide protection against the release of radioactive materials in the event of a loss of coolant accident (LOCA) or a steamline break accident. They also provide sufficient core cooling to limit the extent of fuel and fuel cladding damage and to insure the integrity of the containment structure. The specific functions that rely on the ESFAS are: safety injection (SI), containment isolation (CI), containment vent isolation (CVI), steamline isolation (MSI), containment spray (CS) and feedwater isolation, automatic diesel start, auxiliary feedwater pump start, and containment air recirculation cooling and filtration.

The Ginna PRA ESFAS model addresses only the sensing and actuation features of the system.

The ESFAS is designed to actuate the engineered safety features to cope with any size reactor coolant, steam line, or feedwater line break.

The ESFAS provides a high degree of reliability such that a single failure or credible malfunction will not prevent the system from performing its intended function. To insure this reliability, its design incorporates redundancy, independence, diversification, failsafe, and testability features.

Bypass removal of one trip circuit is accomplished by placing that circuit in a half-tripped mode; i.e., a two-out-of-three circuit becomes a one-out-of-two circuit. Testing does not trip the system unless a trip condition exists in another channel.

3.2.1.7.2 Description of the Engineered Safety Features Actuation System

The ESFAS actuates appropriate safety-related components whenever reactor coolant system, containment, and secondary-side parameters 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 (i.e., T_{avg}) contain <u>two</u> 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 four analog instrumentation channels associated with the ESFAS. A minimum of two-out-of-three (2/3) logic is used for most measurements. 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. The SI portion only uses two of the four channels; the RPS uses the others.

There are four ESFAS relay cabinets (SIA1, SIA2, SIB1, and SIB2) located in the Relay Room of the Control Building at an elevation of 271 ft.. 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 containment spray (CS), the bistable in each analog circuit is energized when the measured parameter is in an acceptable region. CS bistables use the reverse of this action. When the measured parameter deviates from its acceptable region and reaches its setpoint, the bistable in the analog circuit trips. Once this occurs, safeguards logic auxiliary relays (one for train A and one for train B) deenergize (energize for CS), shutting 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 SI 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 buses (A and C) are supplied by constant voltage transformers and two (B and D) are supplied by inverters.

Manual reset of the SI actuation relay may be accomplished at any time following their operation; CS, CI, and CVI can reset after the initiating signal clears and main steamline isolation (MSI) and feedwater line isolation (FWI) do not have a reset function. 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 VAC 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. The sequence is described in Table 3.2.1-9. On a loss of normal power to 480 VAC Buses 14 and 16, the sequence would be triggered by the closure of the 27X6/14 or 27BX6/14 (or /16) relays following bus reenergization.

3.2.1.7.3 Engineered Safety Features Actuation System Electrical Dependencies

The ESFAS instruments receive 120 VAC Instrument Power from Instrument Buses A (IBPDPCBAR), B (IBPDPCBBW), and C (IBPDPCBCB), Distribution Panels A (IBPDPCBA) and B (IBPDPCBB), and Inverter MQ483. The ESFAS buses themselves receive 125 VDC power from Batteries A (BTRYA) and B (BTRYB). Failure of either train of DC power fails the actuation of that train.

3.2.1.7.4 Engineered Safety Features Actuation System Cooling Water Dependencies

ESFAS does not require any cooling water to operate.

3.2.1.6.5 Engineered Safety Features Actuatio System Instrument Air Dependencies

ESFAS does not requireany compressed air to operate.

3.2.1.7.6 Engineered Safety Features Actuation System Control System Dependencies

Pressurizer low pressure signals for ESFAS come from the same pressure transmitter instruments (PT- 429, 430, and 431) used in the Primary Pressure Control system (see Section 3.2.1.10).

3.2.1.7.7 Engineered Safety Features Actuation System Controls and Instrumentation

This system is an instrumentation system; as such, the instrumentation and control aspects are discussed in the previous sections.

3.2.1.7.8 Engineered Safety Features Actuation System Heating, Ventilation and Air Conditioning Dependencies

ESFAS does not require any HVAC support to operate.

3.2.1.7.9 Location of Major Engineered Safety Features Actuation System Components

The four ESFAS relay cabinets are located in the Relay Room of the Control Building at an elevation of 271 ft.. Instrument loop components feeding ESFAS are located throughout the plant.

3.2.1.7.10 Normal Engineered Safety Features Actuation System Operation

ESFAS is normally actively monitoring safety-related parameters. Pumps and / or valves are signaled via a "slave" relay. The "slave" relay is actuated via an SI auxiliary relay (SI-10X, etc.). The SI auxiliary relays are actuated via two of the four master relays (SIA-1, SIA-2). The other two master relays are for indication (SIB-1, SIB-2). The master relays are actuated via auxiliary relays associated with a given instrumentation loop (e.g., TC-401AX1 off of TE-401A and TE-401B). The auxiliary relays for SI are completely separate from the auxiliary relays that are associated with the RPS other than relying on the same detector string. The signal comes from bistables to auxiliary relays to SI master relays to SI auxiliary relays or the slave relays (most of which are Agastat relays) then to the components.

3.2.1.7.11 Engineered Safety Features Actuation System Performance During Accident Conditions

Response of the ESFAS during accident conditions is dependant on the nature of the initiating event. Monitored variable combinations which result in actuation of safety-related components are identified in Table 3.2.1-14. If these combinations occur, tripped protection bistables will complete a logic matrix path for a train. This will energize the associated master relay, which will, in turn, energize slave relays to actuate applicable safety-related components.

3.2.1.7.12 Engineered Safety Features System Test and Maintenance

Each protection channel in service at power is capable of being calibrated and tripped independently by simulated signals for test purposes to verify its operation. This includes checking through to the trip breakers which necessarily involves the trip logic. Thus, the operability of each trip channel can be determined conveniently and without ambiguity.

Each Reactor Protection System (RPS) protection rack includes a test panel containing switches, test jacks and related equipment necessary for testing the channels contained in the rack. A hinged cover encloses the signal injection switch and signal injection jack of the test panel. Opening the cover or placing the test-operate switch in the TEST position will initiate an alarm identifying the rack under test. Closing the test panel cover will mechanically return the test switches to the NORMAL position. Administrative procedures require that the bistable in the

channel under test be placed in the tripped mode prior to test. This places a proving lamp across the bistable output so that the bistable trip setting can be checked during channel calibration. The bistable trip switches must be manually reset after completion of a test. Closing the test panel cover will not restore these switches to the untripped mode. To prevent safety injection trip, procedures limit bistable testing to one circuit at a time. Testing of the logic matrices channels, A and B, is done one channel at a time. Each auxiliary relay also has an associated test switch.

In general, when an instrument channel test selector switch is placed in TEST, the signal to the associated master relay (SIA-1, MS1, etc.) from like instruments is blocked. The single exception is for the pressurizer low pressure signal to SI actuation (PC-429C, PC-430E, and PC-431G). For these instruments, the test switch effectively changes the logic from 2 of 3 instruments required to 2 of 2.

Tests of the SI and CS Systems actuations are performed at each refueling.

Test frequencies of ESFAS-related instrumentation are shown in Table 3.2.1-16. Logic (or auxiliary) relays are tested monthly, but the master relays are only tested annually.

3.2.1.7.13 Engineered Safety Features Actuation System Operating Experience

80-002 March 31, 1980 -- SI accumulator sample time between tests exceeded Technical Specification limits. The procedure was changed.

81-008 April 2, 1981 -- The pump supplying air to R-11 and R-12 failed, rendering R-11 and R-12 inoperable without backup. Procedure modified to place R-10A into service as backup.

81-012 May 4, 1981 -- SI functional test caused satellite Station RAS to lose power. Procedure changed.

83-014 March 29, 1983 -- steam generator level transmitters low due to drift. Recalibrated.

84-006 May 22, 1984 -- SI due to low steam line pressure due to operator error compounded by procedural inadequacy.

85-004 March 26, 1985 -- SI actuation signal due to momentary loss of Instrument Bus 1C.

86-001 January 18, 1986 -- Procedure performance caused a violation of minimum degree of redundancy for the containment pressure ESFAS channels. Caused by inadequate procedure. Procedure changed.

87-004 April 24, 1987 -- Train B Containment Isolation occurred due to operator bumping a relay in the safeguards cabinets.

87-005 May 14, 1987 -- Containment Ventilation Isolation occurred due to spurious signal from R-11 due to frayed conductor. Re-soldered conductor.

88-007 August 4, 1988 -- Containment Ventilation Isolation due to R-11 de-energizing due to failed power supply.

88-010 December 11, 1988 -- All Steam Generator pressure channels drifted high due to freezing of pressure transmitter sensing lines. To resolve this, RG&E closed off outside vents near the sensing lines with plywood.

89-003 May 18, 1989 -- Inadvertent SI train A, no Containment Ventilation Isolation signal. All A train equipment not in pull stop, other equip did not operate.

89-006 June 16, 1989 -- R-11 and R-12 not set to monitor correct air.

89-011 September 20, 1989 -- Containment Ventilation Isolation occurred due to a spurious event.

89-013 October 20, 1989 -- Containment Ventilation Isolation due to R-12 due to flow/pressure fluctuations in the sensing lines.

89-014 October 23, 1989 -- Containment Ventilation Isolation due to R-12 due to flow/pressure fluctuations in the sensing lines.

89-016 November 17 1989 -- Possible problem with SI block/unblock switch that could render some features of both trains inoperable. It was temporarily fixed by a procedure change; final resolution is to replace these switches with two switches (one per train).

3.2.1.7.14 Plant-Specific Data Analysis for the Engineered Safety Features Actuation System

No interesting failures of ESFAS-related components were reported in the plant specific data analyses.

3.2.1.8 Heating, Ventilation and Air Conditioning Systems

3.2.1.8.1 Purpose and Design Basis of the Heating, Ventilation and Air Conditioning Systems

The Heating, Ventilation and Air Conditioning (HVAC) Systems are located throughout Ginna Station to control the environment under both normal and accident conditions for both human and hardware operations. Each building at Ginna has a separate HVAC system. These systems consist of fans or blowers that move air, coolers that transfer heat to a cooling system, such as component cooling water (CCW) or service water (SW), and electrical heaters. Ventilation equipment failures can cause the failure of operating equipment due to overheating and/or the failure of standby equipment due to freezing. The following is a summary of HVAC performance in areas containing equipment required for a safe shutdown:

> <u>Diesel Generator Building:</u> Each diesel generator is located in a separate room of the Diesel Generator Building. Each room is ventilated by two inlet fans supplying outside air, with one fan in each room discharging a supply of air directly on the instrument and control cabinets. Excess air is discharged through automatic, pressure-actuated roof vents. No refrigeration or service water-to-air cooling is used. Freezing could be a concern if vents are left open.
>
> <u>Turbine Building:</u> The Turbine Building uses roof vent fans, wall vent fans, windows, and unit heaters for ventilation and temperature control. The fans are not supplied by vital power; the loss of these fans would not be critical to a safe shutdown. Freezing of equipment in the Turbine Building is not likely to affect a safe plant shutdown, but could upset the operation of a plant (i.e., initiate a plant transient). This concern was addressed in the Ginna-specific initiating event frequency calculations.
>
> <u>Service Building:</u> The Service Building ventilation system consists of five air handling units. Air from uncontaminated areas is exhausted through roof exhaust fans. Air from areas of potential contamination, such as laboratories equipped with hoods, are exhausted through the Auxiliary Building controlled access area exhaust fans. Service Building HVAC is not required for safe shutdown. Freezing of equipment in the Service Building is not likely to affect a safe plant shutdown or initiate a plant transient.

Technical Support Center: The HVAC system provides personnel protection from airborne radiological contaminants, maintains a positive pressure relative to the outside, and provides cooling, heating, and ventilation required by the Technical Support Center (TSC). Technical Support Center ventilation is not required for safe shutdown. Although freezing of equipment in the Technical Support Center is a concern, it is not likely to affect a safe plant shutdown.

Screen House: The Screen House does not require the HVAC system for equipment operation, but utilizes roof vent fans, wall vent fans, windows and unit heaters for control of the environment. In the event of a loss of power to the fans, there would be no significant temperature rise, since it is a large volume building with sufficient openings to adequately circulate outside air. If temperatures in the Screen House should drop to and remain well below freezing, water in gauge root lines (for Service or Circulating Water) could freeze, but only indications, not controls would be hampered.

Intermediate Building

The Intermediate Building ventilation system is connected to the Auxiliary Building system. Two Intermediate Building exhaust fans pull air through dampers that are located on the east wall (north side) of the building and discharge into the intake of the Auxiliary Building Exhaust fans. Additionally, a single recirculation fan blows air from the north (clean) side to the south (hot) side of the building.

Auxiliary Feedwater (AFW) Pump Area: The one turbine driven and two motor driven auxiliary feedwater pumps are located on the 253 ft. level (basement) of the north portion of the Intermediate Building. An analysis was performed in support of the Station Blackout (SBO) rule to determine the steady state air temperature of the area during a four hour SBO event. The analysis concluded that the area will reach 157.5°F if the door to the Turbine Building in left closed and 145°F if the door is opened. However, the room has not been analyzed for an extended period (> 4 hours) of operation without ventilation. Freezing is not a concern during normal plant operation due to the heat generated from operating equipment.

Atmospheric Relief Valve (ARV) Area: The ARVs are located on the upper level of the Intermediate Building, in the north portion of the Intermediate Building. The area was analyzed to determine the steady state ambient temperature during a four-hour SBO event, and the steady state air temperature was determined to reach 186°F with the door open and 178.9°F with the door closed. The equipment is designed for high energy line break conditions that exceed these temperatures, but the HVAC is modeled because these temperature could hamper the local manual operation of ARVs. (Operation of ARVs is possible wearing environmental suits; this is considered in the recovery analysis.)

Standby Auxiliary Feedwater (SAFW) Building: The SAFW System, which consists of two motor driven pump trains, is located in a building that abuts the Auxiliary Building. The SAFW Building was added to the station well after initial construction. The room cooling system consists of two Service Water System-cooled HVAC units (one unit dedicated to each SAFW pump area) that are automatically started whenever the pumps are started. The cooling units are safety-related and required to be available during all modes of operation. An assessment has been performed which indicates that with one pump running and no ventilation available, the maximum SAFW room temperature over a 72 hour period is 115°F, which is below the maximum design temperature of 120°F.

Although normal operator walk-throughs (≤ 12 hours) should prevent the loss of room temperature control, since the SAFW Building is separated from other plant operating spaces, undetected freezing of water in the AFW or SW dead-legs is a concern. The room heating is not safety related. Service Water System pipes enter the building from underground while AFW piping travels into the Auxiliary Building above ground.

Auxiliary Building

The Auxiliary Building HVAC system provides clean, filtered and tempered air to the Auxiliary and Intermediate Buildings and to the surface of the decontamination pit and spent fuel pool. The same system also exhausts air from the Auxiliary and Intermediate Buildings. The exhaust system includes a 100% capacity bank of HEPA filters and redundant 100% capacity fans. Additional, localized cooling is supplied for the Residual Heat Removal, Charging, Safety Injection and Containment Spray pumps.

Auxiliary Building Sub-Basement: The two RHR pumps are located in the Auxiliary Building sub-basement area at an elevation of 219 ft. on the west side of the Auxiliary Building. The sub-basement is provided with two SW-cooled cooling units. The RHR pumps have been analyzed for performance in the following conditions: Emergency cooldown with no cooling coils; LOCA with no cooling coils; emergency cooldown with one cooling coil; and, LOCA with one cooling coil. The only major components in the Auxiliary Building sub-basement are the RHR pumps. The analysis concludes that both RHR pumps, one of which has received an insulation upgrade and one which has not, are fully qualified for the calculated environment. Freezing is not a concern during normal plant operation.

Auxiliary Building Basement, Safety Injection / Containment Spray Pump Area: The Safety Injection (SI) and Containment Spray (CS) pumps are located in the east end of the Auxiliary Building basement at an elevation of 235 ft.. Each SI / CS pump arrangement has a dedicated cooler and a cooling duct with its flow directed on to the pump and motor. Like the Auxiliary Building sub-basement, the area temperature was evaluated for conditions during a LOCA and an emergency cooldown with no ventilation available. The analysis concludes that all pumps and motor operated valves in this area are fully qualified for the calculated environment. Freezing is not a concern during normal plant operation.

Auxiliary Building Basement, Charging Pump Room: The Charging Pumps are located in a small room in the Auxiliary Building basement. Based on room heat load, at least one of two redundant coolers is required for operation of these pumps. Room heat load does not vary considerably with accidents (i.e., LOCAs). Freezing is not a concern during normal plant operation.

Control Building

HVAC in the Control Building is provided and controlled on a room-by-room basis.

Battery Rooms: Battery rooms A and B are located on the lower level (253 ft.) of the Control Building and are accessible from the Turbine Building basement. Since the battery chargers and inverters are located in the Battery Rooms, they can be expected to heat up if ventilation should fail during operation. The inverters are supplied with attached fans to cool their internals. RG&E analysis indicates that equipment will remain operational without any Battery Room HVAC. Freezing is not a concern during normal plant operation.

Control Room / Relay Room: The Control Room is located on the upper level (elevation 289 ft.) and the Relay Room is located on the middle level (elevation 271 ft.) of the Control Building adjacent to the Turbine Building. The Control Room and Relay Room ventilation and associated chilled water systems are required for habitability and equipment operability. Since both rooms contain safeguards equipment, HVAC is needed for this area to ensure long-term plant control. Freezing is not a concern during normal plant operation due to heat generated by equipment in the rooms.

Containment: The Containment Ventilation (CV) System removes the normal heat loss from the equipment and piping in the containment during plant operation and maintains a normal ambient temperature of about 120°F and a 50% relative humidity. Under accident conditions, containment ventilation is one of two means of removing energy from containment to ensure against containment overstress and to remove the portion of the residual heat and chemical reaction heat released to containment. Freezing is not a concern during normal plant operation due to heat generated by equipment in the rooms.

The function of the Containment HVAC System is to remove heat generated in containment during normal operation and non-LOCA transients. Additionally, it provides sufficient air circulation and filtering throughout all containment areas to permit safe and continuous access to containment within 2 hours after reactor shutdown, assuming defects exist in 1% of the fuel rods. The CV System provides for positive circulation of air across the refueling water surface to ensure personnel access and safety during shutdown; and provides a minimum containment ambient temperature of 50°F during reactor shutdown. The CV System also provides for purging of containment to the plant vent for dispersion to the environment, as allowed by applicable regulations, and provides for backup purging of containment following an accident. During accidents, its function is to remove heat, including both air cooling and steam condensation, and to remove radioactive particulate via charcoal filters.

The charging pump, relay, control and SAFW room and IB HVAC systems function to remove equipment-generated heat from the respective area for habitability and equipment operation. These systems function to control temperature and humidity during both normal and off-normal operational periods. Control Room HVAC also isolates the inhabited area upon the receipt of high radiation or chemical level signals.

The design basis for the Containment Ventilation System as it relates to the Ginna PRA model is as follows:

- To maintain containment ambient conditions of about 120°F and 50% relative humidity during normal operation; and,

- To remove sufficient heat from containment following the initial design basis accident containment pressure transient to keep the containment pressure from exceeding the design pressure;

The design basis for the Control Room and Intermediate Building HVAC Systems is to ensure adequate heat removal such that ambient temperature limits are not exceeded and to control the direction of flow of airborne radioactivity. For the purposes of the Ginna PRA analysis, the design basis for all other HVAC Systems was assumed to be to control temperatures such that equipment will operate and, when required, to maintain the areas habitable.

3.1.2.8.2 Description of the Heating, Ventilation and Air Conditioning Systems

This section describes the HVAC systems included in the Ginna PRA models. Simplified drawings for these systems are found in Figures 3.2.1-14 through 3.2.1-19.

<u>Containment HVAC System</u>

The Containment air recirculation system consists of four air handling systems (ACA01A, ACA01B, ACA01C, and ACA01D, and fans ACF08A, ACF08B, ACF08C, and ACF08D), each including 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 systems (Units A and C) are equipped with activated charcoal filter units, normally isolated from the main air recirculation stream, which serve to remove volatile iodine following an accident. The filter units are located on a platform above the operating floor. 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 air recirculation cooling function during normal operation is accomplished using three of the four air handling units (less during the winter) with common, headered 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 Containment ventilation cooling units are supplied by individual lines from the Service Water 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 train valve. This allows each cooler to be isolated for draining or maintenance.

During normal plant operation, cooling water flow through the units is throttled for Containment temperature control purposes by valve 4561 on the common discharge header from the cooling units. An independent full-flow valve (4562) opens automatically in the event of a high-containment-pressure 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

Containment recirculating 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 service water 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.

Two of the Containment recirculating fan cooler units are required during the post-accident period for depressurization of containment (along with the Containment Spray System).

Charging Pump Room HVAC

The charging pump room is located at an elevation of 235 ft. in the Auxiliary Building basement. It is cooled by redundant fan-driven air coolers (coils AAA01A and AAA01B and fans AAF01A and AAF01B) using service water as the cooling medium. Electrical power for the fan motors is provided from 480 VAC Motor Control Centers C and D. The capacity of each unit is sufficient to maintain acceptable room-ambient temperatures when the minimum number of Charging Pumps required for system operation are in service. Hence, one cooler is normally operating.

Main Control Room

The control room air handling unit (AKF03) and circulation fans (AKF07, AKF08, and AKF09) for the Control Room are powered from 480 VAC Motor Control Center K, which receives power from 480 VAC Bus 14 through 480 VAC Motor Control Center C. The following is the control room environment service conditions for equipment designed to mitigate design-basis events:

Normal Operation:		
	Temperature	50°F to 104°F (usually 70°F to 78°F)
	Pressure	0 psig
	Humidity	60% (nominal)
	Radiation	Negligible
Accident Conditions:		
	Temperature	Less than 104°F
	Pressure	0 psig
	Humidity	60% (nominal)
	Radiation	Negligible
	Flooding	Not applicable

The Control Room HVAC System is normally operating with 2000 cfm of fresh air coming into the system. However, radiation, toxic gas, fire or smoke alter this flow path to ensure Control Room habitability. A spurious shift to any of these HVAC system configurations does not constitute a Control Room HVAC failure.

The single-train Control Room HVAC System (i.e., no redundancy) is necessary to keep the Control Room habitable. Control Room temperature will stabilize around 120°F with the door open and around 140°F with the door closed following loss of Control Room HVAC. These conditions will be reached in less than 24 hours. Without ventilation, an unpredictable set of equipment failures may be expected which may result in Control Room evacuation and local equipment monitoring and operate. The most limiting piece of equipment is the Advanced Digital Feedwater Control System (ADFCS) which, although located in a separate room (commonly known as the Mux Room) off the Relay Room, is cooled by Control Room HVAC. Without cooling, this area will quickly exceed the 90°F operating limit of the ADFCS.

Relay Room:

The relay room is cooled by two non-safety, Service Water-cooled air conditioning units (AKF01 and AKF02). Each consists of a fan, compressor and condenser, filter and dampers. The room will be modeled as requiring one of the two air conditioning units.

Standby Auxiliary Feedwater (SAFW) Building:

The SAFW building HVAC units provide cooling and heating as required to maintain the room temperature within the design temperature range of 60°F to 120°F. A room cooling unit (AFA01A or AFA01B) is automatically started whenever its associated pump is started. These cooling units are safety-related and powered from separate Class 1E 480 VAC buses. The cooling units can also be manually started from a local control panel, using a control switch that has RUN-AUTO-OFF positions. Service Water flow to the SAFW room coolers is controlled by a two-way valve in the discharge line from the coil.

The SAFW Building electrical heating system operates whenever the temperature in the room falls below the thermostat setting of 60°F to 65°F. The heating system is not safety related or 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.

Intermediate Building:

The AFW pumps and the ARVs are located in the north (sometimes refered to as the "clean side") sector of the Intermediate Building, which is divided between north and south sectors by a fire wall. The Intermediate Building has no tempered air supply system. The building relies on the Intermediate Building exhaust fans to draw air through intake dampers and discharge the air into the Auxiliary Building exhaust system. Additionally, the Intermediate Building has an internal fan that draws air from the AFW pump area in the basement (elevation of 253 ft.) of the north sector and discharges it to the south sector. 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.

3.1.2.8.3 Heating, Ventilation and Air Conditioning Systems Electrical Dependencies

All HVAC equipment requires electrical power for operation.Containment recirculating fan coolers fans ACF08A (BUS14/23C), ACF08B (BUS16/13C), ACF08C (BUS16/14C) and ACF08D (BUS14/20C); charging pumps room cooling units fans AAF01A (MCCC/16F) and AAF01B (MCCD/15F); fans AKF03 (MCCK) and AKF08 (MCCK) in the control room cooling loop; intermediate building recirculation fans AIF02, AIF04A and AIF04B (all MCCF/04B); intermediate building exhaust fans AIF01A (MCCF04B) and AIF01B (MCCD/03F); and, auxiliary building exhaust fans AAF08A (BUS11A/09) and AAF08B (BUS11B/23) all require either 480 VAC or 4160 VAC power and 125 VDC control power. Relay room cooling units fans AKF01A (MCCB/02F) and AKF01B (MCCB/02MM) require only 480 VAC power. Standby auxiliary pump building cooling units fans AFF01A (MCCL/02M) and AFF01B (MCCM/02M) require 480 VAC power and DC control power, but they generate this DC power via small AC / DC transformers located in their breaker cubicles.

3.1.2.8.4 Heating, Ventilation and Air Conditioning Systems Cooling Water Dependencies

Service water cools all four of the containment recirculating fan coolers cooling coils; the charging pump room coolers; the relay room coolers; and, the standby auxiliary feedwater pump building cooling units.

3.1.2.8.5 Heating, Ventilation and Air Conditioning Systems Instrument Air Dependencies

Instrument air is require to shift the air-operated dampers in the containment recirculating fan coolers ducting to divert flow through the charcoal filters in post-accident situations. It is also required to hold open dampers in the controll room cooling ductwork.

3.1.2.8.6 Heating, Ventilation and Air Conditioning Systems Cooling Actuation and Control Dependencies

ESFAS signals start the idle containment recirculating fan cooling units; shift flow through the post-accident charcoal filters in containment; and, to fully open service water valves 4561 and 4562.

3.1.2.8.7 Heating, Ventilation and Air Conditioning Systems Heating, Ventilation and Air Conditioning Dependencies

The HVAC Systems do not require HVAC to operate.

3.1.2.8.8 Heating, Ventilation and Air Conditioning Systems Controls and Instrumentation

When the high-containment-pressure or automatic safety injection (SI) signal is received, the butterfly valves in the containment recirculation systems are tripped to the accident or fail-safe position. In this position, air would pass through the fan and be directed through an alternative post accident path containing charcoal filters and then to the supply header for containment distribution.

A SAFW HVAC malfunction alarm in the Control Room is actuated upon high or low temperature in the Control Room, or loss of ventilation flow when the coolers are supposed to be running.

3.1.2.8.9 Location of Major Heating, Ventilation and Air Conditionong Systems Components

All major components of the Containment HVAC System are located inside Containment. The Control Room HVAC System and the Battery Rooms HVAC unit are located in the Control Building Air Handling Room at an elevation of 253 ft.. The two Relay Room HVAC units are located in the Relay Room. The two main Auxiliary Building exhaust fans are located in the south (hot) sife of the Intermediate Building at an elevation of 293 ft.. Intermediate Building Exhaust Fans AIF01A and AIF01B are located next to the Auxiliay Building exhaust fans. Intermediate Building Supply Fan AIF02 is located in the basement of the Intermediate Building north (clean) side, on a platform above the motor driven auxiliary feedwater pumps.

3.1.2.8.10 Normal Operation of the Heating, Ventilation and Air Conditioning Systems

The Ginna UFSAR states that three of four containment ventilation trains are normally in operation, with the charcoal filters in standby. Operating experience indicates that only two trains are normally operated in the winter. One of the two HVAC trains is normally operational in the Charging Pump rooms. All HVAC equipment is normally operating in the control room and relay room. Ventilation in the SAFW Building is normally not operating.

3.1.2.8.11 Heating, Ventilation and Air Conditioning Systems Performance Under Accident Conditions

In the event of an accident, Containment recirculation fan coolers butterfly valves 5871, 5872, 5874, and 5876 automatically open on the SI signal, which also closes valves 5873 and 5875 to block the normal discharge path from the fan. The flow sequence for accident conditions is the same as during normal operation except that the fan discharge of two fans is directed through an alternative bypass line to the charcoal filters before entering the discharge header for distribution. Two of the four fans and coolers plus one Containment spray pump have sufficient capacity to maintain Containment pressure. Procedures provides the operators with specific guidance to check the operation of Containment HVAC.

The Containment recirculation fan collers butterfly valves have two positions: Full open or full closed. These valves are air operated and spring loaded. Upon loss of control signal or control air, the spring actuates the valve to the accident position (fail-safe operation) which directs flow to the charcoal filters. Redundant electrically operated three-way solenoid valves are used at each butterfly valve to control the instrument air supply. These valves are arranged so that failure of a single solenoid valve to respond to the accident signal will not prevent actuation of the butterfly valve to the accident position (fail-safe operation).

Following a LOOP, all containment fans are started, two of the four can be secured during the recirculation phase.

The control room HVAC system is normally operated in MODE-1, with dampers D10 and D01 open to allow 2000 CFM fresh air to mix into the air flow. The system exhausts the same amount of air through dampers AKD05 and AKD04, and through the toilet exhaust fan and damper AKD02.

The next condition is MODE-2, post-accident with outside air available, is triggered by the existence of a high area radiation alarm. This condition will close damper AKD10, open dampers AKD08 and AKD07, and starts emergency return (via charcoal filter) fan AKF07. Dampers AKD09, AKD08 an AKD04 will be variable to maintain a constant air volume in the room.

MODE-3, post-accident with no outside air available, is the same as MODE-2 except for dampers AKD10, AKD08 and AKD04 are closed allowing no exchange of air with the environment.

MODE-4, initiated for control room purging following a fire, uses both the filters and intake/exhaust to filter air much like MODE-2. MODE-5 uses the filter system without any intake or exhaust to clean the air following a fire. MODE-6 is initiated by chlorine, ammonia or radiation in the fresh air inlet pipe. Dampers AKD01, AKD02, AKD05, AKD01, AKD04, and AKD08 all close, and the filtration portion of the system is initiated by opening dampers AKD09 and AKD07, and starting the emergency return fan AKF07.

The Relay Room and SAFW Room HVAC Systems have no special mode of operation during accidents. The charging pumps and associated ventilation, and the IB ventilation system are stripped following an SI/UV signal, but are available for re-starting when the appropriate EDG is running.

3.1.2.8.12 Test and Maintenance of Heating, Ventilation and Air Conditioning Systems

The only Technical Specification-required tests to HVAC equipment are for containment ventilation filters and control room chemical and radiation detectors. The test identified in Section 4.5.2.3 of the Technical Specification [Ref. 18.1.5] is performed once every 18 months or after 720 hours of operation of the containment ventilation filters. The test is oriented toward filter performance rather than system reliability. Table 4.1.1 of the Technical Specification shows that Control Room chlorine, ammonia and radiation detectors are calibration checked by routine monitoring and tested monthly.

All HVAC systems except for the SAFW rooms HVAC units are normally operating or operated on a rotating basis. Maintenance is performed during reactor operation while running the redundant HVAC units, or temporary fans.

3.1.2.8.13 Heating, Ventilation and Air Conditioning Systems Operating Experience

The following is a listing of licensee event reports (LERs) and event dates which have been generated against the HVAC systems. These LERs were reviewed to ensure that failure modes which have historically been observed have been addressed in the fault tree.

81-004 Containment Fan Cooler C Drain Plug Failure, February 11, 1981 -- During normal steady state operation, the C Containment Fan Cooler Unit had a failed drain plug and a second drain plug leaking to the sump. Service Water to the C unit was isolated and the leakage stopped. The probable cause was a galvanic reaction, and all drain plugs were replaced. Containment Fan Cooler in maintenance events are included in the fault tree model.

81-012 Exhaust Fan Damper Fails During Fuel Movement, November 2, 1984.-- During normal reactor operation, an inspection of the duct work of the 1C Auxiliary Building Exhaust Fan revealed that the discharge damper was failed in the closed position. Since fuel was moved with this damper failed, a Technical Specifications LCO was violated. The damper was repaired and fuel handling procedures were modified. Damper failures are included in the HVAC models. This exhaust fan is not in the PRA model.

87-006 Inadvertent Attendant Cooling Unit Inoperability Due to Open Breaker Causes 1D SAFW Pump to be Deemed Inoperable Beyond the Technical Specification Limit, November 30, 1987 -- The breaker for the SAFW Pump Room 1B Cooling Unit was found to be in the off position. The cause of the problem was not precisely determined. Locks were added to the breakers to prevent recurrence of the problem. Latent human errors are included in the SAFW HVAC model.

88-010 Simultaneous Loss of Two "B" Steam Generator Pressure Channels, Due to Sensing Line Freezing, Causes a Common Mode Failure Condition, December 11, 1988 -- During normal reactor operation, one of the three 1B steam generator pressure channels began drifting high. Twenty minutes later, a second channel began drifting high. The cause of the problems with both channels was freezing of the pressure transmitters. Outside air louvers were replaced, and the temperature monitoring of the area was improved with the installation of more thermometers and requirements to read them during normal rounds. Freezing events are included throughout the PRA model.

3.1.2.8.14 Plant-Specific Data Analysis for Heating, Ventilation and Air Conditioning Systems

Reference 18.1.11 discusses major events in the operating history of HVAC systems. Numerous Control Room failures to isolate and spurious isolations were noted, but these are not considered to be HVAC system failures for the purposes of this system model.

3.2.1.9 Instrument Air System

3.2.1.9.1 Purpose and Design Basis of the Instrument Air System

The IA System is designed to supply clean, dry air for valve operators, and piping penetration pressurization. The Service Air (SA) System is a backup source of compressed air to the IA system and supplies air for maintenance and service use. The IA System consists of three air compressors with an associated aftercooler and air reservoir for each compressor. The SA System consists of one air compressor with an associated aftercooler and air receiver. The Ginna UFSAR specifically states that air supply failure does not affect the safe operation of the plant; it affects only the means of positioning air controlled equipment. However, the availability of IA significantly enhances the ability to operate equipment.

The critical function of the IA System is to supply compressed air to the pneumatic instruments and apparatus of safely systems through IA headers. The IA headers deliver the clean and dry air to a Turbine Building header. The Turbine Building header then distributes compressed air to headers in the:

- Intermediate Building;
- Containment;
- Service Building;
- Auxiliary Building; and,
- All-Volatile Treatment Building.

The IA System, although supplying operating air to safety-related, is not a safety-related system. The safety-related systems using IA are designed such that upon loss of air pressure each served component will fail in the safe position.

3.2.1.9.2 Description of the Instrument Air System

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 (CIA02A, CIA02B, and CIA02C) with an associated aftercooler and air reservoir for each compressor. Air from the receivers is supplied to the IA header through filters and an air dryer. The instrument air header delivers air to the various valve actuators, piping penetration pressurization system, containment air and proof test system, and turbine lube-oil system.

The SA System produces 115 to 125 psig unfiltered air used in the maintenance air connections throughout the station, and for fire water storage tank pressurization. The SA System consists of one air compressor (CSA02) with an associated aftercooler and air receiver. No filtration or drying of SA is required, and the SA compressor is not completely oil free; an oil filter is supplied. Cross-connections between SA and IA allow the service air 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 instrument air header will always pass through the filters and dryer.

The following describes the key IA components:

Air Compressors CIA02A, CIA02B, CIA02C and CSA02

- Flow Capacity: 300 cfm

- Switches: CONSTANT SPEED-OFF-AUTO
  START-STOP
- Type: Vertical, canned, non-lubricated, single stage, double acting, reciprocating
- Observed Oil Pressure: 45 psig
- Observed Water Pressure: >= 10 psig
- Air Outlet Temperature: between 100°F and 110°F

Aftercoolers EIA01A, EIA01B, EIA01C and ESA01

- Type: Counterflow shell and tube
- Operating Temperature: less or equal to 90F

Air Receivers TIA04A, TIA04B, TIA04C, and TSA01

The air receivers 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 supply a common air header to the filters and air dryers.

- IA Air Receivers TIA04A, TIA04B and TIA04C
  - Design pressure: 140 psig
- SA Air Receivers TSA01
  - Design pressure: 130 psig

Dryers TIA05A, TIA05B, TIA05C, TIA05D

Two heaterless air dryers are normally in operation in the IA header to reduce the dew point of the air to -70°F at atmospheric pressure. Each of the two dryer units 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.

Filters FIA70, FIA72, FIA52 AND FIA53

The prefilter (FIA70 or FIA71) before each dryer removes entrained moisture and oil to prevent fouling of the dehydration towers. The afterfilter (FIA52 or FIA53) of each dryer removes any desiccant dust which may be present in the air.

Simplified diagrams of the Instrument Air and Service Air Systems are shown in Figures 3.2.1-20, 3.2.1-21 and 3.2.1-22. A diagram illustrating the air distribution headers is shown in Figure 3.2.1-23.

3.2.1.9.3 Instrument Air System Electrical Dependencies

The compressors are powered from non-emergency buses 13 (CIA02A and CSA02) and 15 (CIA02B and CIA02C). The air dryer for Train A is powered from Bus 13, andthe air dryer for Train B is powered from Bus 15.

3.2.1.9.4 Instrument Air System Cooling Water Dependencies

The compressors are cooled by the Service Water (SW) System. Following an SI signal, this portion of the SW system is isolated. Simplified diagrams of Service Water flow to the Instrument Air and Service Air compressors are shown in Figures 3.2.1-24 and 3.2.1-25.

3.2.1.9.5 Instrument Air System Instrument Air Dependencies

The Instrument Air System does not require instrument air to operate.

3.2.1.9.6 Instrument Air System Actuation and Control Dependencies

The actuation and control power for the IA system is provided from the Bus 13 and 15 DC control power as described in the above sub-section on electrical power. Additionally, a containment isolation signal from the Engineered Safeguards Actuation System will shut containment isolation valve 5392 and isolate the IA supply to containment.

3.2.1.9.7 Instrument Air System Heating, Ventilation, and Air Conditioning Dependencies

The Instrument Air System does not require any HVAC to operate.

3.2.1.9.8 Instrument Air System Controls and Instrumentation

Each IA compressor has a local CONSTANT-OFF-AUTO selector switch and a START-STOP control switch located on the back of the Main Control Board (MCB). When the compressor selector switch is placed in the CONSTANT (constant run) position, the motor runs constantly. The compressor is loaded and unloaded by a pair of redundant pressure switches that control the air inlet valve. The compressor is loaded when receiver pressure drops to 113 psig and unloaded when receiver pressure reaches 125 psig. A compressor with its selector switch placed in the AUTO position will automatically start when air pressure drops to 105 psig.

Compressor running/secured/locked out indication is provided in the control room. A compressor is locked out following a bus undervoltage condition or a compressor overload trip. The lock out condition is reset by turning the selector switch to the OFF position.

The following compressor alarms and trips are provided:

- Low Lube Oil Pressure Trip (30 psig)
- High Aftercooler SW Outlet Temperature Alarm (95°F)
- High Compressor SW Outlet Trip (130°F)
- High Compressor Aftercooler Air Outlet Temperature Trip (100°F)
- High Compressor Air Outlet Temperature Alarm (475°F for A and B, 500°F for C)
- Dryer Transfer Failure Alarm (60 seconds after switch failure)

These alarms give an IA Compressor Alarm on the MCB. Additionally, IA System pressure below 100 psi will give an Instrument Air Low Pressure alarm on the MCB.

3.1.2.9.9 Location of Major Instrument Air System Components

The instrument and service air compressors, aftercoolers, air receivers, and filters are located in the east end of the Turbine Building basement at an elevation of 253 ft.. Instrument air headers go to all major buildings that contain reactor equipment (auxiliary, turbine, intermediate, screen house), including containment.

3.1.2.9.10 Normal Operation of the Instrument Air System

Normally, two compressors of IA and both dryers are in operation, with the control switch in the CONSTANT SPEED position. Compressor operation is normally controlled by the local selector switches. The standby compressor selector switch is in AUTO. When a compressor selector switch is placed in the CONSTANT SPEED position, the associated compressor will start and run continuously. In this mode of operation, the compressor is loaded or unloaded based upon discharge pressure. The IA compressors, when operated in AUTO, will automatically start when the instrument air header pressure drops to 105 psig. Once started in automatic, the compressor will run continuously and be loaded and unloaded between 113 and 125 psig. The SA compressor, normally operated in AUTO mode, will automatically start and stop based upon service air pressure.

The minimum operation pressure for compressor motor lubricating oil is 38 psig. An automatic timer controls the air flow such that one tower per unit is in the drying stage while the other is being regenerated.

The IA compressors are alternated every other Wednesday (2 week run period) in accordance with plant procedures.

3.1.2.9.11 Instrument Air System Performance During Accident Conditions

IA compressors will operate as normal in all accidents except for loss of off-site power (LOOP), safety injection (SI) and containment isolation (CI) situations. The system is not normally run following a LOOP because of the 75 kW power requirement, but it can be manually started. Following an SI signal, the non-safety 10" SW header will be isolated causing a loss of SW to the compressor and aftercoolers. The in-containment portions of the system are isolated following a CI signal.

In event of a failure of the IA system air compressors, a cross connection is provided to the SA System. Compressed air flow from the SA System occurs when the IA system pressure decreases to 90 psig or less. The SA System cross connection is located upstream of the drying equipment, thus the air supplied from SA will be essentially oil free, clean and dry when provided to the IA headers. The SA compressor is not oil free; thus, an oil filter is provided.

Procedure AP-IA.1 Provides the actions to be taken during a loss of the IA System function. If the IA pressure should fall below 60 psig, the reactor must be tripped. The 60 psig pressure is based on the minimum pressure required for the satisfactory operation of the Steam Generator Water Level Control System.

The action to restore IA pressure first attempt to obtain additional air from the remaining IA compressors, then the SA compressor, the diesel driven compressor and finally the Breathing Air System. The ability to supply the IA header from the electric breathing (Joy) air compressor or diesel-driven (Gardner Denver) air compressor is proceduralized in Reference 2.2. The diesel-driven compressor is located north of the Turbine Building in the plant yard and is normally connected to the IA System. These compressors would only be used in an emergency so as to prevent oil contamination of the IA System headers. Procedure AP-IA.1 also provides leak isolation procedures.

3.1.2.9.12 Instrument Air System Test and Maintenance

Both air dryers should be in service for normal operation; however, one air dryer can be removed for maintenance for approximately 24 hours, which is apparently based on limiting moisture introduction into the system. Compressors are inspected at least twice per shift. If running after maintenance, a compressor would be inspected every two hours until temperature between running compressors equalizes. The two running compressors are alternated each week, thus a compressor runs for two weeks and then spends a week in standby. Bypass valves 5276 and 8230 on air dryers TIA05A and TIA05B may have to be opened momentarily to charge the header. This opening is brief and does not introduce significant water to the IA System.

3.1.2.9.13 Instrument Air System Operating Experience

One significant event occurred on August 14, 1988, when IA compressor CIA02C tripped due to high ambient air temperature (113°F) with a portable fan running. This event has not repeated itself.

3.1.2.9.14 Plant-Specific Data Analysis for the Instrument Air System

The plant specific data analysis for the IA System is discussed in detail in Section 3.3.2.3.1.8 through 3.3.2.3.1.10.

3.2.1.10 Primary Pressure Control Systems

3.2.1.10.1 Purpose and Design Basis of the Primary Pressure Control Systems

The primary pressure control (PPC) functions of the Reactor Coolant System (RCS) are provided by the pressurizer (including safety relief valves, power-operated relief valves (PORVs), motor operated PORV block valves, spray valves, and pressurizer heaters), piping, and instrumentation necessary for operational control. The pressurizer is connected to the RCS B loop.

The pressurizer and associated components maintain the required RCS pressure during steady-state operation, limit the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevent the pressure in the RCS from exceeding the design pressure. The pressurizer contains replaceable direct immersion heaters, multiple safety and relief valves, a spray nozzle and associated spray valves, interconnecting piping, valves, and instrumentation. The heaters raise, and the spray valves lower, the temperature of the contents in the pressurizer.

The safety relief valves and pilot operated relief valves (PORVs) provide for steam release to prevent RCS overpressurization. Automatic spray valve operation limits the pressurizer pressure following most reactor trips, which minimizes PORV and Safety Relief Valve (SRV) lifts. The PORVs also provide for RCS depressurization if required following a loss of main and auxiliary feedwater or a steam generator tube rupture.

Each of the two pressurizer code safety valves is designed to prevent system pressure from exceeding design pressure by more than 10% for the maximum surge rate resulting from a complete loss of load without direct reactor trip or other control, except that the secondary side safety valves are assumed to be operable.

Two PORVs, with setpoints below the code safety valves, minimize the likelihood of SRV lift during transients. The PORVs are provided with upstream block valves which can be used to isolate a stuck open relief valve. While not in the design basis, the PORVs also provide an RCS blowdown path for use during feed and bleed cooling.

Two spray valves, in conjunction with the pressurizer heaters, provide pressure control for plant load changes during normal operation. The Reactor Coolant System and its components are designed to accommodate, without reactor trip, a change in plant load of 5% of full power/minute or a step change of 10% of full power. In addition, if the turbine bypass and steam dump system are operable, the RCS can accommodate a 50% step load decrease or a turbine trip from below 50% power without reactor trip.

3.2.1.10.2 Description of the Primary Pressure Control Systems

Pressure in the RCS is controlled by the pressurizer (TRC01), where water and steam pressure is maintained through the use of pressurizer heaters and sprays. Steam can either be formed by the pressurizer heaters or condensed by a spray to minimize pressure variations due to contraction and expansion of the coolant. The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line, which is attached to the bottom of the pressurizer, connects the pressurizer to the hot leg of the B RCS loop. During a positive surge, caused by a decrease in plant load, the spray system, which is fed from the cold leg of a coolant loop, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the PORVs.

There is one spray nozzle for the auxiliary spray valve (296) and both normal spray valves (431A and 431B). These power-operated spray valves limit the pressure during load transients. Two separate, automatically controlled spray valves with remote-manual overrides are normally used for pressurizer spray. A manual throttle valve in parallel with each spray valve permits a small continuous flow (1 gpm) through each spray line. (Two separate spray valves and line connections are provided so that the spray will operate when only one RCP is operating.) These spray valves are normally closed. Valve 431A receives flow from RCP A and 431B receives flow from RCP B. Alternate spray can be provided from the Chemical and Volume Control System (CVCS) through air operated valve 296 when neither RCP is operating.

There are 78 electric pressurizer heaters separated into a control/variable (proportional) group and a backup group. The pressurizer heaters are located in the lower section of the vessel and keep the water and steam in the pressurizer at saturation temperature. The pressurizer heaters are necessary for power operation and facilitate post-trip core cooling. The backup group is either fully on or fully off, while the control group's output is controlled inversely proportional to the pressurizer pressure. The backup heaters turn on at 2210 psig while the control heaters are fully on at 2220 psig and off at 2250 psig.

Spring-loaded steam code safety valves and PORVs are connected to the pressurizer. Discharge from these valves is normally contained in pressurizer relief tank (PRT) TRC02, where discharged steam is condensed and cooled by mixing with water. If the relief valve discharge cannot be accommodated by the PRT, a rupture disk on the tank blows. This results in the relief valve discharge being directed to containment. During power operation, the PORVs serve to minimize pressure transients, which could lift the SRVs.

RCS overpressurization protection is provided by two code safety valves. These valves lift at 2485 psig and prevent pressures greater than 110% of design for all transients, including failure to trip.

Two PORVs; set to lift at 2335 psig, prevent SRV lift for non-ATWS transients. The PORVs are operated automatically for pressure control or remote manually when RCS depressurization is required (e.g., for SGTR mitigation or feed and bleed). The PORVs are spring closed and air or nitrogen opened, and receive actuating gas from the plant instrument air system or a backup nitrogen accumulator. The accumulators are sized to provide sufficient actuating nitrogen without operator action following a loss of the instrument air system. During feed and bleed, the instrument air source is bypassed and nitrogen is used to open the PORVs. The control signal to open the PORVs during feed and bleed is provided by arming the Reactor Vessel Overpressure Protection System (LTOP).

The pressurizer discharge lines leading to each PORV contain a motor-operated block valve (516 for 430 and 515 for 431C) to be used if the PORV opens inadvertently or fails to close following an overpressurization transient.

A simplified diagram of the Primary Pressure Control Systems is shown in Figure 3.2.1-26.

3.2.1.10.3 Primary Pressure Control Systems Electrical Dependencies

PORVs 430 and 431C and motor operated block valves 515 and 516 require 125 VDC and 480 VAC power for operation. Spray valves 431A and 431B require 120 VAC for operability.

3.2.1.10.4 Primary Pressure Control Systems Cooling Water Dependencies

The Primary Pressure Control Systems do not require any cooling water to operate.

3.2.1.10.5 Primary Pressure Control Systems Instrument Air Dependencies

Instrument air provides motive power for the PORVs and spray valves. When instrument air is unavailable, or when bypassed during feed and bleed operation, nitrogen gas is available via manual alignment (through the LTOP system) to open the PORVs. Components associated with the backup nitrogen supply are addressed in the PPC fault tree model. Instrument air and nitrogen supply to the PORVs is illustrated in Figure 3.2.1-28.

3.2.1.10.6 Primary Pressure Control Systems Actuation and Control Dependencies

The Primary Pressure Control Systems to not require any inputs from ESFAS or other modeled control systems to operate.

3.2.1.10.7 Primary Pressure Control Systems Heating, Ventilation and Air Conditioning Dependencies

The Primary Pressure Control Systems do not require any HVAC to operate.

3.2.1.10.8 Primary Pressure Control Systems Control and Instrumentation

The pressurizer has four pressure transmitters which provide signals used for indication, control, and protection. These are PT-429, PT-430, PT-431, and PT-449. Each of the four channels may be displayed on recorder PR-429 by selecting the desired channel with the pressurizer pressure recorder selector switch. Pressurizer pressure is displayed on the main control board by four meters, with a combined range of 1700-2500 psig.

To provide control signals for the spray valves and PORVs, pressurizer pressure is compared to a setpoint pressure. The output of this comparison is supplied to a PID circuit, where the signal is conditioned to compensate for the rate of change of the inputs.

The two spray valves operate together on the same control signal from the pressurizer pressure controller (either from PT-449 or PT-429). The nominal opening pressure for the valves is at an error signal of +25 psi (2260 psig), with a gain of 2 percent/psig, so that the valves are fully open at a +75 psi error (2310 psig). The control signals are supplied through a manual-auto hand control station (one for each spray valve), located on the main control board from which manual spray valve operation can be initiated.

Power-operated relief valves 430 and 431C operate at a nominal setpoint of 2335 psig. They are either open or shut. The PORVs are interlocked closed below 2335 psig on a redundant pressure channel to prevent inadvertent depressurization on a single channel failure high. For example, with the switches in the PLP rack in the normal "at power" configuration, to open 430 would require both PT-429 and PT-430 to be greater than 2335 psig. Manual operation of the relief valves below the setpoint is possible from the main control board with a three (3) position switch (OPEN-AUTO-CLOSE).

For sustained RCS depressurization (for example, for steam generator tube rupture mitigation and for feed and bleed cooling), the reactor vessel overpressure protection system (LTOP) is used to provide an open signal to both PORVs. The system is armed by operating the key switches for valves 8604A, 8604B, 8616A, 8616B, 8619A and 8619B on the back of the main control board. This allows nitrogen to be supplied to the nitrogen accumulator via valves 8603A and 8603B, the nitrogen surge tank via 8612A, 8612B, 8616A and 8616B and arms valves 8619A and 8619B such that, since pressure in the RCS exceeds 410 psig (for applicable sequences) as measured on PT-450, PT-451, PT-452 (2/3 logic) 8619A and 8619B will reposition to allow nitrogen to open 430 and / or 431C. When pressure decreases to < 410 psig then valves 8619A and 8619B will shut. The LTOP instrumentation is shown in Figure 3.2.1-29.

Pressurizer heater control is also provided using PT-449 and the same PID device.

PORV and SRV position indication is provided. A thermocouple located in the discharge pipe of each code safety valve provides indication of valve movement or significant seat leakage. Actuation of a safety valve will cause a rapid rise in discharge temperature, which is sensed by the thermocouple and indicated/alarmed in the control room. Also linear voltage differential transducers on the pressurizer safety valves provide a direct indication of valve position. The PORVs have direct stem position indication/alarm in the control room.

Pressurizer pressure indication and control circuitry is shown in Figure 3.1.2-27.

3.2.1.10.9 Location of Major Primary Pressure Control Systems Components

The Primary Pressure Comtrol Systems valves and pressurizer heaters are located in Containment. Instrumentation and control components of the systems are located in racks in either the control room at an elevation of 289 ft. in the Control Building, or the Relay Room at an elevation of 271 ft. in the Control Building.

3.2.1.10.10 Normal Operation of the Primary Pressure Control Systems

During normal system operation both PORVs are closed and both PORV block valves are open. Both RCPs are operating, and hence normal pressurizer spray is available from either spray valve, if required. Alternate pressurizer spray is isolated.

At normal pressure, 2235 psig $\pm$ 15 psig, the RCS is stable with the proportional heaters on at half capacity to compensate for heat losses. If pressure should increase, proportional heater output will decrease until the heaters are completely off at 2250 psig. If pressure continues to increase, the spray valves will start opening at 2260 psig and will be fully open at 2310 psig. A high pressure alarm will actuate at 2310 psig. At 2335 psig, the power-operated relief valves will open and at 2377 psig a reactor trip will occur (see Section 3.2.1.10.11 for post-trip response).

If pressure decreases from normal, the proportional heaters' output will increase until fully on at 2220 psig. The backup heater groups turn fully on at 2210 psig. At 2185 psig, a low pressurizer pressure alarm would actuate. At 1873 psig (interlocked with P-7), a reactor trip is initiated (see Section 7 for post-trip response).

3.2.1.10.11 Primary Pressure Control Systems Performance During Accident Conditions

The PORVs are automatically actuated at 2335 psig (prior to the high pressure reactor trip setpoint). In the event that either PORV fails to close following lift, its associated block valve can be manually closed from the control room.

Following a SGTR and for transients in which main and auxiliary feedwater are unavailable, RCS depressurization and use of either the Condensate System (for SG cooling) or the SI System (for feed and bleed cooling) can provide decay heat removal. For these situations, the PORVs must be blocked open to depressurize the RCS. This is accomplished by arming the reactor vessel overpressure protection system. This system then provides the control signal (since RCS pressure is greater than 410 psig).

The spray valves are proportionally actuated starting at 2260 psig and are fully open at 2310 psig. Proper operation of the pressurizer sprays will prevent PORV lift following reactor trip. Manual operation of pressurizer spray (normal or alternate spray) is required for SGTR mitigation.

3.2.1.10.12 Test and Maintenance of the Primary Pressure Control Systems

Each PORV is demonstrated operable by:

1) Performance of a Channel Functional Test (CFT) on the actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the PORV is required operable and at least once per 31 days thereafter while the PORV is required operable;

2) Performance of a channel calibration on the actuation channel is checked at least once per 18 months;

3) Position indicator and thermocouple position indicator are checked daily (TS limit), min. operable 1-out-of-2; and,

4) Position indicators: primaries are checked monthly and tested every refueling: and backups are checked monthly and tested every refueling.

Each PORV block valve is demonstrated operable by:

1) Verifying the valve is open at least once per 72 hours when the OMS is required to be operable:

2) Except during cold and refueling shutdowns each valve is demonstrated operable at least once per 92 days by operating through one complete cycle, unless the valve is already closed;

3) Position indicators are checked daily: anytime the RCS < 200°F (TS limit), min. operable 0-out-of-1; anytime the RCS > 200°F, (TS limit) min. operable 1-out-of-2; and,

4) Position indicators are checked monthly and tested every refueling.

Applicable pressurizer instrumentation is demonstrated operable by:

1) Pressure channel checks are performed daily anytime the RCS > 200°F: alarm value — high 2310, low 2185, SI 1750; TS limit — saf. limit 2735, saf. vlv 2485, Rx trip 2377, PORV 2335, Rx trip 1873; and,

2) Pressure channels are checked each shift, calibrated each refueling, and tested monthly.

The auxiliary spray valve is demonstrated operable by:

1) AOV 296, the auxiliary spray valve from the regenerative heat exchanger to the pressurizer, is verified daily to be closed.

The safety valves are demonstrated operable by:

1) The equipment and sampling test which tests the setpoint during each refueling;

2) Position indicators (digital and thermocouple) have daily channel checks anytime the RCS > 200°F, (TS limit) min. operable 1-out-of-2; and,

3) Position indicators: primaries, checked monthly and calibrated each refueling; backups, checked monthly and calibrated each refueling.

3.2.1.10.13 Primary Pressure Control System Operating Experience

The following is a list of Licensee Event Reports (LERs) which have been generated against PPC-related components. These LERs were reviewed to ensure that failure modes which have been historically observed are addressed in the fault tree. Based on this review, it is concluded that all such events which could have occurred at power and impacted modeled post-trip response can be addressed using the existing fault tree structure.

80-004 DC switches for both trains of OPPD and the head vent solenoid valve were found in the off position with no RCS vent path open. [OPPD affects the Nitrogen backup of the PORVs and would be reflected in the N2 accumulator failures.] (Determined to be an operator error in maintenance.)

82-005 PORV failed to close following a SGTR. (The restricted vent valve in the PORV air / N2 supply line was then removed and an orificed check valve installed.)

83-023 When PORV-430 attempted to reseat following a manual turbine trip lift, a leak was discovered.

86-008 Ground lead in TWINCO-MQ400C caused failure of PORV-431C to open and sprays to actuate. Caused a reactor trip. (Determined to be human error in maintenance.) [PC-431K and spray controllers both receive power from TWINCO-MQ400C.]

3.2.1.10.14 Plant Specific Data Analysis for the Primary Pressure Control Systems

The plant specific data analyses were reviewed to determine any effect of non-LER reportable events on the existing fault tree structure. The data collection and analysis activities are consistent with the information in the Ginna PRA fault tree models.

3.2.1.11 Residual Heat Removal System

3.2.1.11.1 Purpose and Design Basis of the Residual Heat Removal System

The low pressure injection and low pressure recirculation portions of the RHR System perform functions in support of the Safety Injection (SI) System. The Safety Injection System, as described in the Ginna UFSAR, is intended to assure adequate core cooling following loss-of-coolant and certain other accidents. The functions of the SI System are described in detail in the Safety Injection System Work Package. After a break in the Reactor Coolant System (RCS), passive accumulators inject borated water into the RCS cold legs. Three high-pressure safety injection pumps are available to reflood the RCS using water from the Boric Acid Storage Tanks (BASTs) and the Refueling Water Storage Tank (RWST). The RHR pumps will provide makeup to the RCS from the RWST if RCS pressure decreases below 140 psig.

When the RWST inventory is depleted, the SI pumps and the RHR pumps are realigned to pump water from the containment sump, through heat exchangers cooled by the Component Cooling Water System, back to the RCS. Depending on RCS pressure, the pumps may be aligned to pump directly to the RCS or they may be aligned to the suction of the SI pumps.

Two independent parallel flow paths exist to and from the RHR pumps and heat exchangers with the exception of a shared suction line from the RWST and a shared segment of discharge line to the containment. Power is provided to the pumps from independent safeguards Buses 14 and 16.

The injection and recirculation portion of the RHR System performs the following functions which may be needed to ensure adequate core cooling:

- Refloods the RCS using the RWST inventory, if RCS pressure is below pump shutoff head of 140 psig;

- Recirculates the containment sump "B" inventory through heat exchangers and back to the RCS via the SI pumps, if RCS pressure is below pump shutoff head of 140 psig; and,

- Recirculates the containment sump "B" inventory through heat exchangers and back to the RCS via the SI pumps, if RCS pressure requires (140 psig < RCS pressure < 1515.5 psig).

The Ginna UFSAR indicates that the design basis for the Safety Injection System (including the RHR System) is to automatically deliver cooling water to the reactor core to limit the fuel clad temperature and thereby ensure that the core will remain intact and in place, with its heat transfer geometry preserved, for all break sizes up to and including the hypothetical instantaneous double-ended rupture of the reactor coolant pipe, the rod ejection accident, a steam or feedwater line break, a steam generator tube rupture, and other accidents. The specific function of the SI and RHR pumps is to reflood the reactor vessel and return the core to a subcooled state. The flow from any two SI pumps and any one RHR pump is sufficient to provide the required flow to maintain fuel within required safety limits.

The RHR System is designed so that no single active failure will prevent it from performing its safeguards function. Redundancy has been ensured for all active components. Most parts of the system are rated for a maximum pressure of 600 psig. These portions are protected from full reactor pressure by redundant isolation valves and overpressure protective devices.

3.2.1.11.2 Description of the Residual Heat Removal System

A simplified drawing of the RHR System is provided in Figure 3.2.1-30.

The RHR System consists of two pumps (PAC01A and PAC01B), two heat exchangers (EAC02A and EAC02B), 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 PSI01C.

RHR suction supply to the pumps is from the RWST via a 10-inch line containing a normally open motor-operated valve (856), and a check valve (854). When the system is operating to provide residual heat removal, suction is via a 10-inch line from "A" loop hot leg, containing two motor-operated isolation valves (700 and 701). Recirculation supply 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 motor-operated valves (704A/B). The two pumps are horizontally-mounted centrifugal type, each capable of delivering 1560 gpm at 121 psid. The pumps were manufactured by Pacific Pumps and are of Type "SVC/6L."

After 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 takes off just after each heat exchanger and returns flow to the RWST suction line. There is 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 while on RHR. A 6-inch line connects the trains, connecting to "A" train immediately downstream of the heat exchanger and to "B" train after the heat exchanger outlet check valve. Two motor-operated valves (857A/C) in this line isolate the "A" train from a common supply to SI. One motor-operated valve (857B) isolates train "B" from this line. On the "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 PSI01C.

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. After 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 "B" RCS loop cold leg and is used during RHR.

Component cooling water (CCW) is provided to the RHR pump seal heat exchangers (EAC06A and EAC06B) and to the RHR heat exchangers. CCW supply to the seal heat exchangers is not required for the injection mode of pump operation. CCW supply to the RHR 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 motor-operated valve and a check valve 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 3" 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 safety injection 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. Motor-operated valve 700 (RHR suction isolation from the RCS) cannot be opened unless RCS pressure is below 410 psig and sump suction motor-operated valves 850A and B 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 B are closed. Motor-operated valve 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.

3.2.1.11.3 Residual Heat Removal System Electrical Dependencies

Valves 852A (MCCC / DCPDPAB01A), 852B (MCCD / DCPDPAB01B), 850A (MCCC / DCPDPAB01A), 850B (MCCD / DCPDPAB01B), 738A (MCCC / DCPDPAB01A), 738B (MCCD / DCPDPAB01B), 700 (MCCC / DCPDPAB01A), 701 (MCCD / DCPDPAB01B), 720 (MCCC / DCPDPAB01A), 721 (MCCD / DCPDPAB01B), 856 (MCCC / DCPDPAB01A) and pumps PAC01A (BUS14/22A / DCPDPAB01A) and PAC01B (BUS16/15A / DCPDPAB01B) require DC and 480 VAC for operation.

3.2.1.11.4 Residual Heat Removal System Cooling Water Dependencies

The RHR pump seal coolers are supplied by the Component Cooling Water System. This supply is required for recirculation operation. The RHR heat exchangers must be supplied by component cooling water during recirculation operation. Component cooling valves 738A/B, 769, 707A/B, 708A/B, 780A/B, and 741A/B are included in the RHR model.

3.2.1.11.5 Residual Heat Removal System Instrument Air Dependencies

Instrument air is required to control the RHR heat exchanger flow and bypass control valves. These valves all fail to required safety positions on loss of air. Flow control is required during two pump recirculation operation with only one suction train aligned.

3.2.1.11.6 Residual Heat Removal System Actuation and Control Dependencies

3.2.1.11.7 Residual Heat Removal System Heating, Ventilation and Air Conditioning Dependencies

Containment cooling is required to ensure the structural integrity of containment, thereby maintaining the fluid boundary of Sump B and maintaining adequate NPSH for the RHR pumps during recirculation operation.

3.2.1.11.8 Residual Heat Removal System Controls and Instrumentation

Control and indication is provided in the control room for all motor-operated valves associated with the system, as well as for the RHR pumps. Controllers for the heat exchanger outlet and bypass valves (624, 625 and 626) are also located there. FT-626 provides indication of total system flow to FI-626 on the Main Control Board (MCB). TR-630 provides indication of RHR heat exchanger "A" inlet temperature.

No operator control actions are required to align the system for injection. In order to switch the system to recirculation, operators must have control and indication for the RHR pumps and appropriate valves. These include motor operated valves 856 (RWST suction), 850A and 850B (recirculation sump suction). Indication of RWST level is required as well. RWST instrumentation failures are modeled in the Containment Spray System (see Section 3.2.1.4).

In order to provide a controlled cooldown, operators must have indication and control for valve 626 and must be able to control at least one of the heat exchanger outlet flow control valves, 624 or 625.

Alarms are given by the following conditions in the RHR System:

- Low flow — < 2900 gpm or as set during RHR mode operations;
- High pressure — > 550 psig;
- Low CCW flow — < 15 gpm (pump seal cooler); and,
- Low pressure — < 410 psig.

Important control room indications include:

Valve Position	MOVs 851A, B; 700; 701; 704A, B; 720; 721; 738A, B; 850A, B; 852A, B; 856; 857A, B, C; AOVs 624; 625; 626;.
Pump status	Pumps PAC01A and PAC01B breakers open / closed
RHR flow	FT-626 (FI-626)
RHR HX inlet temp	TT-630 (TR-630)
RHR flow to CS/HPI	FT-931A, B (FI-931A and FI-931B)

3.2.1.11.9 Location of Major Residual Heat Removal System Components

RHR valves 700, 701, 720, 721, 852A, 852B, 853A, 853B (connections to the RCS), 851A, 851B (connections to the containment sump), and associated piping are located in Containment. The balance of the system is located in the Auxiliary Building basement (elevation 235 ft.) and the Auxiliary Building sub-basement (elevation 219 ft.).

The system is controlled from the control room. All components except those connecting the system to the RCS should be readily accessible during plant operation. During accident sequences with elevated RCS radiation levels, accessing these components could be difficult.

3.2.1.11.10 Normal Operation of the Residual Heat Removal System

During normal operation, the RHR System is aligned for the injection mode of operation and is not in service. System suction is aligned to the RWST via valves 704A, 704B, 854, and 856. The discharge path is aligned up to the injection valves, 852A and 852B. Component Cooling Water is aligned to the RHR pump seal coolers but isolated from the RHR heat exchangers.

Under shutdown conditions, the RHR System will be aligned to provide decay heat removal. After the RCS temperature has declined to 350°F following a shutdown, the normally-open (locked open) sump suction valves 851A and 851B are closed as is the RWST suction valve, 856. Valves 851A and B are in series with normally-closed valves 850A and 850B. Valves 738A and 738B are opened to supply the heat exchangers with CCW. Suction is established from the RCS via valves 700 and 701 and flow is returned via valves 720 and 721.

Total system flow is set with the 626 heat exchanger bypass flow control valve. Cooldown rate. is controlled by adjusting heat exchanger outlet flow control valves 624 and 625. RHR inlet temperature is determined from temperature recorder 630, which monitors the temperature at the inlet to RHR heat exchanger EAC02A.

3.2.1.11.11 Residual Heat Removal System Performance During Accident Conditions

Upon receipt of a safety injection signal, the RHR pumps are started and injection valves 852A and 852B are opened. If RCS pressure declines to the RHR pump shutoff head of 140 psig, the pumps begin to inject borated water from the RWST. If injection continues until the RWST inventory is depleted, the operators will shut the system down and realign it for cold leg recirculation. This entails stopping the RHR pumps and closing the RWST suction valve, 856. Containment sump suction "B" valves 850A and 850B are then opened, and CCW is admitted to the heat exchangers via valves 738A and 738B. The pumps are then restarted. If reactor pressure is greater than the pump shutoff head, the system may be aligned to supply the high pressure injection pumps by opening 857A, 857B, and 857C. An alternate path exists to SI pump PSI01C via valves 1816A and 1816B. Operation of these valves is addressed in the SI fault tree model.

3.2.1.11.12 Residual Heat Removal System Test and Maintenance

Technical specifications require that the RHR System be tested monthly to verify satisfactory flow through the minimum flow line and adequate pump discharge pressure. During the test described in procedure PT-2.2M/Q, no major system valves are repositioned and the RHR System is still capable of performing its safety functions. Additional full-system testing is performed during annual outages (RSSP 2.2).

Ginna procedure 0-6.14, *Monthly Surveillance Schedule* [Ref. 18.2.8], indicates that the safeguards valves surveillance procedure, PT-2.3, is to be performed quarterly. Procedure PT-2.3 requires that the following RHR or related system valves be stroked to verify operability: 704A, 704B, 850A, 850B, 851A, 851B, 857A, 857B, 857C. During the time that certain of these valves are tested, one train of the RHR System may not be immediately available to perform its safety function. This time interval is small, but the impact of train unavailability has been included in the model.

3.2.1.11.13 Residual Heat Removal System Operating Experience

A review of Licensee Event Reports relating to the RHR System identified the following items as potentially relevant to system modeling issues. No new potential failure modes were identified for the system.

82-017 On August 3, 1982, during surveillance testing of the RHR pump PAC01B at 100% steady state power, it was noted that the leakage from the mechanical seal exceeded 2 gph. Actual leakage was 2.1 gph. This required the RHR pump PAC01B to be declared inoperable.

84-002 On March 3, 1984, while cooling down the RCS to cold shutdown condition for the annual refueling and maintenance outage, periodic test PT-2.4.1 *Cold/Refueling Motor-Operated Valve Surveillance (RHR System - 700 valves)* was in progress. MOV 700 (RCS Loop A residual heat removal suction stop valve) failed to stroke to the open position when actuated from the Control Room. Following manual unseating of the valve, the valve was retested and stroking times were verified acceptable.

84-003 On March 7, 1984, while the reactor was in the cold shutdown condition, the draindown of the Reactor Coolant System (RCS) was in progress in preparation for the Steam Generators (S/G) annual inspection. In the process of draining the RCS to the CVCS Holdup Tanks, while preparing to shift from draining via the Reactor Coolant Drain Tank (RCDT) pump to the Low Pressure Purification Pump, valves MOV 851A and B (Containment Sump B Suction to RHR) were mistakenly opened prior to shutting valve MOV 850A (downstream of MOV 851A and upstream of RCDT pump suction). This resulted in water being drained from the RCS Loop to sump B, with potential loss of RHR capability.

84-005 On May 14, 1984, while cooling down the RCS to the cold shutdown condition, MOV 700 (RCS Loop-A RHR suction valve) failed to stroke to the open position when actuated from the Control Room. Following manual unseating of the valve, maintenance personnel performed an inspection of the valve exterior. This inspection revealed that the packing gland flange had shifted out of the vertical position to a point where the flange was in contact with the valve stem. This could have caused a mechanical binding in the stem and torque-out of the operator.

87-007 On December 18, 1987, during the review of a Westinghouse Corporation letter entitled *Operating Plant Feedback — Non-Vital Power Supply Used in Valve Interlock Logic*, it was discovered that the potential existed for a loss of core cooling during the high head recirculation phase. The apparent root cause of the event was identified as a design flaw, in that a common power supply, Bus 14, ultimately powered a motor-operated valve on each train of the RHR System (MOVs 857A and 857C). A postulated failure of the electrical power supply prior to opening of the subject valves would result in both flow paths leading to the safety injection and containment spray pumps being blocked, creating potential loss of core cooling. (Electrical power supplies to these valves were reconfigured after this discovery.)

87-008 On December 23, 1987, with the unit at 100% reactor power, RHR pump PAC01B failed to start for testing due to zero clearance between its breaker's amptector actuator arm and the tripper bar. Follow up testing of selected safeguards breakers revealed a second failure of the safety injection pump PSI01B. Because a majority of the safety related breakers are of this same design, a possibility of common mode failure existed. (The breaker trip mechanisms were subsequently adjusted.)

3.2.1.11.14 Plant Specific Data Analysis for the Residual Heat Removal System

There were no remarkable RHR component failures noted in the plant specific data analyses.

3.2.1.12 Safety Injection System

3.2.1.12.1 Purpose and Design Basis of the Safety Injection System

The Safety Injection System, part of the Emergency Core Cooling System, consists of active and passive components which function to provide borated water to cool the core in the case of an accidental depressurization of the Reactor Coolant System (RCS). The system's active components serve three functions. They provide continued makeup for large area ruptures where the initial refill is accomplished by the accumulators. They also provide injection for small area ruptures where the RCS pressure does not rapidly drop below the accumulator pressure. Finally, they provide long-term protection by recirculating spilled reactor coolant and the injected refueling water. The system's passive component (accumulator) function is to rapidly reflood the core following rapid depressurization and core voiding by discharging borated water into the cold legs of the RCS piping, thus assuring core cooling with no dependance on power sources or actuation signals.

The Safety Injection System, as part of the Emergency Core Cooling System, is designed to automatically deliver cooling water to the reactor core to limit the fuel clad temperature (thus limiting the clad metal-water reaction) and thereby ensure that the core will remain intact and in place, with its heat transfer geometry preserved. This protection is provided for all break sizes up to and including a hypothetical instantaneous double-ended rupture of the Reactor Coolant pipe, a rod ejection accident, a steam or feedwater line break, and a steam generator tube rupture. For any rupture of a steam pipe (and the associated uncontrolled heat removed from the core), the SI System adds shutdown reactivity so that with a stuck rod, no off-site power, and minimum engineered safety features, there is no resultant damage to the Reactor Coolant System and the core remains in place.

3.2.1.12.2 Safety Injection System Description

The active function of the Safety Injection System is to deliver borated water, drawn from Refueling Water Storage Tank (RWST) TSI01 to the cold legs of the Reactor Coolant System. If continued injection is required the system will be reconfigured to take suction from the discharge of the Residual Heat Removal pumps. The passive function of the SI System delivers borated water with a minimum boron concentration of 1800 ppm from the accumulators to the cold legs of the Reactor Coolant System. The two train system consists of the RWST, three pumps (one of which can be aligned to either train), two accumulators and the necessary piping, valves, instrumentation and controls.

The accumulators are designed to discharge their contents into the Reactor Coolant System 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 Reactor Coolant loop. Even if some unforseen deposition accumulated, the differential pressure 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 Safety Injection System occurs when pressurizer pressure drops to 1750 psig or lower, steam generator pressure drops to 514 psig or lower, or sensors in containment sense containment pressure of 4 psig or greater. An Engineered Safety Features Actuation System (ESFAS) signal will cause the pumps to start. For more detailed information concerning ESFAS actuation signals see Section 3.2.1.7.

The Safety Injection 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 Safety Injection flow path is passing little or no flow. The three bypass lines discharge to a 2-in. common header and are isolated from the RWST during recirculation.

A simplified flow diagram of the Safety Injection System is shown in Figure 3.2.1-31.

3.2.1.12.3 Safety Injection System Electrical Dependencies

Table 3.2.1-20 shows the electrical system interfaces for the Safety Injection System. PIC-629 (RHR pump A discharge pressure) has no power source of its own but is wired into the DC control power for motor operated valve 857B. For all level and pressure transmitters addressed in the fault tree, the loss of power to the level or pressure transmitter will result in a low signal being generated. The loss of power to the alarms for the BAST level transmitters (LT-102, LT-106, LT-171 and LT-172) will prevent the initiation of a low BAST (<10%) signal. The alarms for the Accumulator level and pressure transmitters (LT-934, LT-935, PT-936, PT-937, LT-938, LT-939, PT-940 and PT-941) are normally energized so that a loss of power to any of the alarms would cause an annunciator alarm in the Control Room.

3.2.1.12.4 Safety Injection System Cooling Water Dependencies

The Safety Injection pump mechanical shaft seals are cooled by water taken from the discharge of the SI pumps and cooled by the Component Cooling Water System. The SI pumps require a total of 75 gpm (25 gpm per pump) of cooling water from the Component Cooling Water System to cool the seal. The oil for the pump bearings is cooled by the Service Water System.

3.2.1.12.5 Safety Injection System Instrument Air Dependencies

The Safety Injection System, as it is modeled in the Ginna PRA, does not require any of the plant air systems to operate.

3.2.1.12.6 Safety Injection System Actuation and Control Dependencies

The SI pumps will start upon receipt of a signal from the Engineered Safety Features Actuation System (ESFAS). Pump PSI01A and pump PSI01C (when powered by 480 VAC Bus 16) will start on a signal from the ESFAS A train. Pump PSI01B and pump PSI01C (when powered by 480 VAC Bus 14) will start on a signal from the ESFAS B train.

Table 3.2.1-19 provides a listing of the various permissives which must be satisfied in order for the Safety Injection System valves to change position. The information for the table was taken was taken from the electrical Control Schematics for the respective valves and from the Ginna UFSAR.

3.2.1.12.7 Safety Injection System Heating, Ventilation and Air Conditioning Dependencies

Service Water cooling to the safety injection pump area coolers is not required for operation of the safety injection pumps.

3.2.1.12.8 Safety Injection System Controls and Instrumentation

Safety Injection is initiated automatically by low pressurizer pressure on two of three detectors, or low steam line loop A or loop B pressure as detected by two of three detectors on each line, or high Containment pressure on two of three detectors. An ESFAS signal will cause the safety injection pumps to start. For more detailed information concerning ESFAS actuation signals see Section 3.2.1.7. The various automatic control permissives for the Safety Injection System valves are described in Table 3.2.1-19.

Safety Injection can be initiated manually from the control room by depressing one of two pushbuttons on the main control board (MCB). The SI pumps can be controlled by two pull out / stop / auto / start switches. PSI01C has indication lights which show if the associated buses are available to power the pump. All of the Safety Injection System motor operated valves have indicating lights on the MCB which show what position the valves are in. The motor operated valves all have close / auto / open switches on the MCB except for valves 897 and 898 which have close / open switches. The MCB also provides BAST level indication, accumulator level and pressure indication, SI flow and pressure to the RCS loop cold legs indication, Safety Injection block switch and reset button, and the BAST lo-lo lockout reset switch. The Safety Injection block switch, among other things, allows automatic actuation of Safety Injection System pumps and valves to be blocked. For more detailed information concerning the SI block switch see Section 3.2.1.7. The Safety Injection reset button allows the operator to resets the initiation logic for Safety Injection one minute or longer after it has initiated. This does not change the state of any equipment but permits the operator to manually control equipment affected by ESFAS. The BAST lo-lo lockout reset switch resets the lo-lo valve actuation logic for the BAST level transmitters. The MCB left rear section contains redundant BAST level and pressure indication. Table 3.2.1-22 lists control room annunciators relevant to operation of the Safety Injection System.

3.2.1.12.9 Location of Major Safety Injection System Components

The Safety Injection System functional components are located in the Auxiliary Building (AB) and in Containment. The specific locations are described in Table 3.2.1-21.

The centerline of safety injection pumps PSI01A, PSI01B and PSI01C is 33 inches above the floor elevation of 235 feet in the Auxiliary Building basement.

3.2.1.12.10 Normal Safety Injection System Operation

The Safety Injection System is a standby safety system and has no normal operating function. It is aligned in the standby mode during normal plant operation with the pumps off and in automatic control. The RWST to SI pump suction motor operated valves (825A and 825B) are both open, with their 480 VAC AC power removed. Valves 826A, 826B, 826C and 826D from the BASTs are closed, also with their 480 VAC AC power removed. The PSI01C discharge to train A and B motor operated valves (871A and 871B) and the PSI01C suction motor operated valves (1815A and 1815B) are both open. The SI pump discharge to cold leg motor operated valves (878B and 878D) are both open and the SI pump discharge to hot leg motor operated valves (878A and 878C) are both closed. The accumulator discharge motor operated valves (841 and 865) are both open. The SI to RWST recirculation motor operated valves (897 and 898) are open. All manual valves in the system flowpath are open. The SI motor operated valves are in automatic control during normal plant operation except for motor operated valves 878A, 878B, 878C, 878D, 841 and 865 which all have their breakers locked open.

3.2.1.12.11 Safety Injection System Performance During Accident Conditions

During accident conditions the active portion of the Safety Injection System is automatically actuated by the ESFAS as a result of low pressurizer pressure of 1750 psig or lower on two of three detectors, or low steam line loop A or loop B pressure of 514 psig or lower as detected by two of three detectors on each line, or high containment pressure of 4 psig or greater on two of three detectors. An ESFAS signal will cause all three pumps to start. PSI01A will start immediately on 480 VAC Bus 14 with PSI01C starting after a 5 second time delay on Bus 14. PSI01B will start immediately on 480 VAC Bus 16 with PSI01C starting after a 7 second time delay on 480 VAC Bus 16 if Agastat time delay relay 2/SIP1C2 (the timer that starts PSI01C on 480 VAC Bus 14) fails to operate or after a 37 second time delay if Agastat time delay relay 2/SIP1C2 operates but breaker BUS14/19A (the breaker for PSI01C on 480 VAC Bus 14) does not close. In the event of an abnormal voltage condition on one or both of the busses, the diesel generators will pick up the 480 VAC bus loads. In this case the Agastat time delay relays will start to time out when the safeguards busses are loaded.

If 480 VAC circuit breaker 52/SIP1A (BUS14/20A) for PSI01A does not close, motor operated valve 871B will receive a signal to close after a 3 second time delay. This will divert the flow from PSI01C to the train A injection line. If 480 VAC circuit breaker 52/SIP1B (BUS16/12A) for PSI01B does not close, motor operated valve 871A will receive a signal to close after a 3 second time delay. This will divert the flow from PSI01C to the train B injection line. Motor operated valves 871A and 871B remain open if the circuit breakers for PSI01A and PSI01B both successfully close or if both circuit breakers remain open. If 480 VAC circuit breaker BUS14/20A fails to close and 400 VAC circuit breaker BUS16/12A closes but then re-opens, if circuit breaker. BUS16/12A reopens before Agastat time delay relay 2/871B times out (3 seconds), motor operated valve 871B will remain open. If 480 VAC circuit breaker 52/SIP1B (BUS16/12A) re-opens after time delay relay 2/871B times out, motor operated valve 871B will close and not re-open automatically. The same situation exists for PSI01B and motor operated valve 871A. Figure 3.2.1-30 contains four simplified diagrams of the configurations for motor operated valves 871A and 871B.

The active function of the Safety Injection System will deliver borated water from Refueling Water Storage Tank TSI01 to the cold legs of the Reactor Coolant System. The system will draw borated water from the RWST until it reaches the 28% level. At that point, if all three SI pumps are running, the operators will place the pump PSI01C in the pull stop position on the MCB. Upon reaching the 15% RWST level, the remaining SI pumps will be placed in the pull stop position and the system will be reconfigured to take suction from the discharge of the Residual Heat Removal pumps. For more detailed information concerning RHR alignment for recirculation see Section 3.2.1.11.

The passive portion of the Safety Injection System delivers borated water from the accumulators to the cold legs of the Reactor Coolant System. Whenever the RCS pressure falls below the accumulator pressure, the check valves open, forcing borated water into the RCS. This is accomplished without dependencies on power sources or actuation signals.

3.2.1.12.12 Safety Injection System Test And Maintenance

The Safety Injection System is a principal plant engineered safeguards system that is normally in standby during reactor operation. Complete system tests cannot be performed when the reactor is operating because an SI signal causes containment isolation. The method of assuring operability of the system is therefore to combine annual system tests with more frequent component tests. System tests are performed during annual plant shutdowns and component tests are performed periodically during plant operation. There is no regularly scheduled maintenance for the SI System during periods of power operation.

Procedures direct the operators to check certain plant parameters by performing a plant tour every four hours. Operators check the SI pumps and the pump area, the BASTs and the heat trace breaker panels for the primary and secondary heat trace for proper alignment and for alarms.

Procedures also direct the operators use to check certain plant parameters every eight hours by observing indicators on the main control board. When the reactor is at power, operators use these procedure to check BAST level and accumulator level and to verify the positions of valves and circuit breaker switches. The procedures verify that the Safety Injection pumps PSI01A, PSI01B and PSI01C circuit breaker switches are in the automatic position, SI accumulator discharge to the cold leg valves (motor operated valves 865 and 841) are open, SI pump PSI01C discharge to SI loop A and B valves 871A and 871B are open, SI pump discharge to cold leg valves 878B and 878D are open, SI pump discharge to hot leg valves 878A and 878C are closed, SI pump suction valves are aligned with valves 852A and 852B open with their 480 VAC power removed and valves 826A, 826B, 826C and 826D closed with their 480 VAC power removed, SI pump recirculation to the RWST valves 897 and 898 are open, SI pump C suction valves 1815A and 1815B are open, SI pump suction from the RWST valves 825A and 825B are closed and the Safety Injection block switch is in the normal position.

SI pumps and valves are tested monthly to meet operability verification requirements. The test line is aligned to flow back to the RWST and a suction valve from the RWST is opened. PSI01A and PSI01B are tested singly by starting each pump and checking the net discharge pressure of the pump for a flow rate of 150 gpm. PSI01C is tested by first closing the discharge valve to train A and then starting the pump. After checking the net discharge pressure for a flow rate of 150 gpm, the pump is stopped and restarted on Bus 16. On completion of the pump testing, the discharge valve to train A is reopened and is independently verified open in accordance with procedures. The procedures also test for leakage past the pump discharge to hot leg check valves. If leakage is detected, the pump discharge to hot leg motor operated valves will be closed one at a time to determine which check valve is leaking. The system will then be returned to operable status and the configuration will be independently verified.

Procedure PT-2.1Q (*Safety Injection System Quarterly Test*) provides instructions for performing For the quarterly SI pump and valve operability verification test, the test line is aligned to flow back to the RWST and a suction valve from the RWST is opened. PSI01A and PSI01B are tested singly by starting each pump and checking the pump bearing vibration and the differential pressure and net discharge pressure of the pump for a flow rate of 150 gpm. PSI01C is tested by first closing the discharge valve to train A and then starting the pump. After checking the pump bearing vibration and the net discharge pressure for a flow rate of 150 gpm, the pump is stopped, aligned to discharge to train B and restarted on 480 VAC Bus 16. On completion of the pump testing, the discharge valve to train B is reopened and both pump discharge to SI train valves are independently verified. The procedure then tests for leakage past the pump discharge to hot leg check valves. If leakage is detected, the pump discharge to hot leg motor operated valves will be closed one at a time to determine which check valve is leaking. The system will then be returned to operable status and the configuration will be independently verified. The quarterly test procedures also do a partial flow exercise and subsequent closure verification of the SI pump discharge check valves and a full flow exercise and subsequent closure of the SI recirculation and test line check valves.

Procedures also provide for exercising, stroke timing and performing position indication testing on various safety related motor operated valves. Testing of motor operated valves 825A, 825B, 826A, 826B, 826C, 826D, 871A, 871B, 897, 898, 1815A and 1815B is accomplished by simply opening and closing each valve in turn and recording the stroke time where required. These valves are also checked to insure that the actual valve stem position agrees with remote position indication. Testing of motor operated valves 1815A and 1815B requires PSI01C to be in pull-stop control prior to beginning the test.

Procedures are also in place to test the operability of some of the SI System check valves. In order to test the accumulator discharge check valves, the test line is aligned to allow flow back to the RWST. The air operated valves on the test lines that tap into the accumulator discharge downstream of the check valves are opened one at a time, reducing pressure against the check valve, allowing the check valve to partially open and allow flow from the accumulator to pass to the RWST. Testing of check valve 1828 (SI suction bypass check valve) is accomplished by first shutting the manual valve upstream of the check valve so that no further flow is available to the valve. After the downstream line has been drained, the upstream manual valve is reopened and the downstream line is checked to insure pressure has returned to pre-test conditions.

3.2.1.12.13 Safety Injection System Operating Experience

The following is a listing of Licensee Event Reports (LERs) which have been generated against the Safety Injection System. These LERs were reviewed to ensure failure modes which have been historically observed have been addressed in the fault tree.

80-002 On March 31, 1980 a review of SI accumulator sample results noted that the time from the previous sample exceeded 75 days. The plant analysis schedule has been changed to require monthly samples. This event does not constitute a failure of the system.

80-005 On June 3, 1980 the loop A accumulator injection valve 865 circuit breaker (MCCD/12C) was found in the ON position. The frequency of breaker position verifications has been increased. This event does not constitute a failure of the system.

80-006 On July 11, 1980 the BAST concentration was found to be too low. Contents of the BASTs were enriched and retested again too low. The titrant was changed and indicated concentrations too high. Proper concentrations were then restored. A reagent check is now being done in conjunction with tank sampling. Improper fluid concentrations have been modeled.

81-002 On January 1, 1981 PSI01C did not start with the 480 VAC Bus 16 circuit breaker (BUS16/13A). The circuit breaker was racked out and then racked in again and the pump operated successfully. The circuit breaker was believed to be not racked in properly. Potential circuit breaker failures have been addressed in the Ginna PRA model.

81-005 On March 2, 1981 PSI01C did not start with the 480 VAC Bus 16 circuit breaker (BUS16/13A). The problem was determined to be a closing circuit malfunction. The faulty circuit breaker was replaced. Potential circuit breaker failures have been addressed in the Ginna PRA model.

81-016 On November 5, 1981 PSI01C did not start with the 480 VAC Bus 16 circuit breaker (BUS16/13A). The problem was determined to be a closing circuit malfunction due to a weak lockout coil. The faulty circuit breaker was replaced. Potential circuit breaker failures have been addressed in the Ginna PRA model.

82-028 On December 19, 1982 air operated valve 846 (nitrogen inlet isolation valve to the accumulators) was found to be opening and closing sluggishly and the total valve stroke was limited due to galling of the stem plug in the cage assembly. The stem plug and cage were removed and redressed by polishing out the galled surfaces and the seat was replaced.

83-022 On July 25, 1983 air operated valve 846 seized in mid position due to galling. A new stem plug and cage assembly were installed and also galled. A previously used stem, plug and cage assembly were redressed and installed, the valve seat was replaced, the valve repacked and a seismic support located on the valve operator was modified. This failure mode has been modeled as failure of a valve to open or close.

83-026 On September 15, 1983 the BAST concentration was found to be too low after reactor make-up water leaked into the storage tanks. This problem has been corrected by closing an in-line manual valve. There was also some difficulty experienced in obtaining accurate samples. To preclude recurrence, whenever significant additions to the storage tanks are made, a mass balance will be done to predict the concentration changes and a sample will be taken to verify the calculations. Improper fluid concentrations have been modeled.

84-001 On February 19, 1984 valve 945 was found to be leaking due to a current to pressure (I/P) transducer being out of calibration because of dirt in the pneumatic portion of the unit. The corrective action included cleaning and calibrating I/P transducer and the valve positioner and replacing the I/P transducer airset and filters. Preventive maintenance schedules were reviewed for similar valves.

84-006 On May 22, 1984 there was an inadvertent SI initiation due to operator error and procedural inadequacy. Procedures were modified. This event does not constitute a failure of the system.

85-004 On March 26, 1985 two inadvertent SI actuation signals were generated (both times the reactor was in cold shutdown with the pumps in pull-stop). The first was caused by a procedural deficiency and the second by a momentary loss of power during the removal of the diesel generator from service coincident with the performance of a maintenance procedure. Procedures have been revised to prevent recurrence. These events do not constitute failures of the system.

85-015 On June 20, 1985 a non-licensed Primary Auxiliary Operator vented both level transmitters on BAST TCH07B (LT-171 and LT-106) contrary to his instructions to vent one level transmitter. This caused a 2 / 2 low level signal which caused the BAST to SI suction valves (motor operated valves 826A and 826B) to close and the RWST to SI suction valves (motor operated valves 825A and 825B) to open. Because the event was immediately detectable and correctable, it has not been modeled.

87-007 On December 18, 1987 a design flaw was discovered showing that a common power supply was utilized to power a motor operated valve on each train of high head recirculation (motor operated valves 857A and 857C). A postulated failure of the electrical power supply prior to opening of the valves would result in both flow paths leading to the Safety Injection and Containment Spray pumps being blocked. Power sources for the valves have since been changed. Failure of a single power source failing both trains of high head recirculation has not been modeled since it can no longer occur.

87-008 On December 23, 1987 follow up testing of circuit breakers for possible common mode failure following a failure on an RHR pump circuit breaker revealed a failure of SI pump PSI01B 480 VAC circuit breaker 52/SIP1B (BUS16/12A). Preventive maintenance has been changed to include checking and resetting, if necessary, the clearance between the amptector actuator arm and circuit breaker trip bar.

88-002 On March 8, 1988 the BAST level was determined to be too low due to level transmitter inaccuracies. Procedures were changed to require sensing lines to be cleaned prior to declaring the tanks operable. Corrective action for this LER was put on hold pending the outcome of an Engineering Evaluation concerning the necessity of the high concentration boric acid solution. This failure mode has been modeled as level transmitter failure.

89-003 On May 18, 1989 SI was inadvertently initiated on the "A" train; however, it did not actuate on the "B" train. The inadvertent SI actuation was due to a procedural inadequacy which has since been corrected. The failure of train "B" to actuate was due to mechanical interference because the installation and inspection requirements of the system modification overlooked the possibility of mechanical interference. Labels have been installed on appropriate latching type relays to warn not to obstruct relay plunger. The first event does not constitute a failure of the system and the second is an ESFAS issue.

89-007 On June 19, 1989 PSI01B and PSI01C were declared inoperable because it was thought that they could not meet their design flow rates. The cause of the event was incorrect calibration data provided by the designer for the newly installed recirculation system flow transmitters. Correct data was obtained, the flow transmitters were correctly calibrated to the flow orifice plates and procedures were changed to reflect correct calibration data. This event was determined to be a lack of adequate information rather than a failure.

89-016 On November 17, 1989 an initial engineering evaluation identified a potential problem with the SI block / unblock switch in that a single failure could render some automatic actuation features of both trains of SI inoperable. The switch was inspected to verify that the switch contacts were in the proper position, procedures were changed to add this check each time the plant heats up from a cold shutdown, an operator aid tag was placed on the MCB adjacent to the switch denoting the step in the procedure, and operators were trained to recognize the difference in plunger positions. During the 1991 outage, a modification was made to separate the block / unblock switches into separate trains.

3.2.1.12.14 Plant Specific Data Analysis for the Safety Injection System

A review was performed of the Data Analysis Task Work Packages to ensure that all significant events not already described in Section 10.1 of this work package are appropriately addressed by the fault tree models. These events are listed below.

The *Common Cause Failure Data Work Package* contains a number of failures of Safety Injection System components.

There were numerous failures of BAST level transmitters (LT-102, LT-106, LT-171 and LT-172). These events were primarily caused by boric acid hardening in the sensing lines and in many cases, more than one transmitter would fail at the same time. BAST level transmitter high and low failures and common cause failures have been modeled in the Safety Injection System fault tree.

On May 5, 1980 during performance of RSSP-2.2 (*Diesel Generator Safeguards Sequence Test*) for train "B" logic, PSI01B and PSI01C failed to start on Diesel Generator B (KDG01B) on a simulated ESFAS signal. The pump breakers were found to be not fully inserted. This is most likely a human error common cause failure and has been modeled as the failure to restore equipment to service after test or maintenance.

On October 13, 1987 the locking devices for motor operated valves 897 and 898 were found to be off; however, the valves were in their required position. This is most likely a human error common cause failure and has been modeled as the failure to restore equipment to service after test or maintenance.

The *Plant Specific Data Work Package* contains a number of failures of Safety Injection System components.

On March 2, 1981, a review of the previous day's test run revealed that the PSI01C thrust bearing temperature 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. This type of failure has been modeled as a failure of the pump to run.

There has been noticeable leakage through the SI System injection check valves causing system pressurization and accumulator dilution problems. The accumulators have not been modeled.

PSI01C experienced six failures to start from 1980 through 1988, all of which involved breaker problems. Four of the event were attributed to 480 VAC circuit breaker 52/SIP1C1 (BUS16/13A), while the other two events were caused by the failure to fully rack in the circuit breaker following test and / or maintenance. All of the events involving 480 VAC circuit breaker BUS16/13A occurred over an 18 month period during 1980-1981. An Engineering modification corrected the problem during the 1983 refueling outage.

The *Test and Maintenance Unavailability Data Work Package* contains no unusual testing or maintenance activities for the Safety Injection System.

3.2.1.13 Service Water System

3.2.1.13.1 Purpose and Design Basis of the Service Water System

The Service Water (SW) System takes suction from Lake Ontario via the Screen House Circulating Water System inlet bay and supplies cooling water to many plant loads. These cooling loads include the Turbine Building, Auxiliary Building, Screen House, and air conditioning chillers. Essential and non-safeguards equipment which is not isolated by a service water isolation signal is also supplied. The Service Water System is designed to provide adequate cooling of essential and nonessential loads, during normal operations and to essential loads during accident conditions. Also, no single failure of the Service Water System should result in a plant shutdown. The Service Water System normally discharges back into Lake Ontario via the discharge canal.

The SW System takes suction from Lake Ontario via the Circulating Water System inlet bay in the Screen House and supplies cooling water to various turbine plant loads and auxiliary reactor plant loads. The SW System supplies seal water circulating water pumps PCW01A and PCW01B; seal water to vacuum pumps PCP01A and PCP01B; flushing water to Circulating Water System traveling screens FSW01A, FSW01B, FSW01C and FSW01D; and, makeup water to fire water storage tank TFS01 via fire booster pump PFP03. The Service Water System is the normal water supply to standby auxiliary feedwater pumps PSF01A and PSF01B, and serves as an alternate water supply to motor driven auxiliary feedwater pumps PAF01A, PAF01B and turbine driven auxiliary feedwater pump PAF03. The SW System is designed to provide adequate cooling to essential and nonessential loads during normal operations, and to essential loads during accident conditions. The SW System discharges back into Lake Ontario via the plant discharge canal, or via alternate discharge structure SSW01 into Deer Creek.

The Service Water System consists of service water pumps PSW01A, PSW01B, PSW01C, and PSW01D; a 20" and a 10" supply header; twelve motor operated isolation valves; a normal discharge header; and, a standby discharge header. All portions of the SW System, such as pumps, piping, etc., serving safeguards equipment are designed as seismic Class I; as a Class I system, it is capable of remaining operable when subjected to the stresses of a design basis earthquake (DBE). All other portions of the SW System serving non-safety loads are designated as Class III and are capable of being isolated from the Class I portion.

3.2.1.13.2 Service Water System Description

The Service Water System provides redundant cooling water supplies to Containment recirculating fan cooler coils ACA01A, ACA01B, ACA01C and ACA01D; various heat exchangers serving the turbine generator plant; emergency diesel generators KDG01A and KDG01B, instrument air compressors CIA02A, CIA02B and CIA02C and service air compressor CSA02; Component Cooling Water (CCW) System heat exchangers EAC01A and EAC01B; and, to other plant cooling loads.

The four service water pumps are located in the Screen House and are powered from 480 VAC Bus 17 (Pumps PSW01B & PSW01D) and 480 VAC Bus 18 (Pumps PSW01A & PSW01C). They are vertical, two-stage, centrifugal pumps from Worthington with Westinghouse motors. They are rated at 5300 gpm each, 1750 rpm, 308 BHP, 480 VAC, a head of 198 feet, and 80° Fahrenheit design temperature. The SW pumps have an efficiency of 85.5 percent and require a minimum flow of 160 gpm. They can be started remotely from hand controllers located on the main control board (MCB) in the Control Room; they will also start automatically under the following conditions:

1) On an undervoltage (UV) condition on 480 VAC Buses 17 and / 18, the running service water pumps will be load shed. The two service water pumps selected in standby via the Screen House selector switches (Switches SSS/SWP1AC and SSS/SWP1BD) will restart after a 40-second time delay following re-energization of the buses by emergency diesel generators KDG01A and KDG01B; or.

2) On a Safety Injection (SI) signal, the two standby service water pumps selected via the Screen House selector switches will start after 15-second and 17-second time delays for trains A and B, respectively, following re-energization of 480 VAC Buses 17 and 18 by emergency diesel generators KDG01A and KDG01B if an undervoltage condition existed, or from the time of the Safety Injection signal, if no undervoltage existed.

Which service water pumps restart is dependent upon the positions of the two service water pump selector switches (Switches SSS/SWP1AC and SSS/SWP1BD) located in the Screen House. The switches each have two positions. On switch SSS/SWP1AC, one position selects pump PSW01A and the other position selects pump PSW01C; on switch SSS/SWP1BD, one position selects pump PSW01B and the other position selects pump PSW01D. The logic is such that on an undervoltage or a safety injection signal, only the two selected pumps will automatically start. The pumps can also be started manually from the control room. Manually restarting a SW pump may require shifting that SW pump's MCB pump switch to STOP (after the pump trips) to clear the logic.

Service Water System requirements dictatee running two or three service water pumps for normal plant operation. Depending on lake temperature, one service water pump is needed for accident conditions during the injection phase; two pumps are required for accident conditions during the recirculation phase. One service water pump is loaded and started on each emergency diesel generator during post-accident emergency diesel generator load sequencing. It should be noted, however, that these operational requirements may be highly conservative; RG&E is in the process of completing new analyses to establish less conservative SW pump requirements during accident conditions.

The service water supply header is a 20" piping loop that supplies the safety loads directly. It supplies turbine plant loads via an inner 10" loop header that isolates from the outer safety loop during accident conditions. Cross-connect valves (manual valves 4611, 4612, 4669, and 4768) are located in the supply loop to split the two service water trains if needed. The loop header is designed so that no single failure will cause a plant shutdown. It is also designed to isolate non-safety loads on a Safety Injection signal coincident with indications of a 480 VAC Buses 14 and / or 16 undervoltage by shutting twelve motor operated SW header isolation valves (motor operated valves 4609, 4613, 4614, 4615, 4616, 4663, 4664, 4670, 4733, 4734, 4735, and 4780) shown in Table 3.2.1-23 to insure adequate service water flow to accident equipment. Four of these motor operated valves (4613, 4614, 4664, and 4670) isolate the 10" turbine plant header; two motor operated valves (4663 and 4733) isolate air conditioning chillers SCI03A and SCI03B; two motor operated valves (4609 and 4780) isolate flow to Circulating Water System travelling screens FSW01A, FSW01B, FSW01C and FSW01D in the Screen House; and, four motor operated valves (4615, 4616, 4734, and 4735) isolate CCW heat exchangers EAC01A and EAC01B, Spent Fuel Pool heat exchangers EAC13 and EAC14 and Spent Fuel Pool standby heat exchanger EAC12, and the supply to standby AFW pumps PSF01A and PSF01B. In addition, on a Safety Injection signal, air operated valves (AOVs) 4561 and 4562 will fail open in the containment recirculating fan cooler return line, increasing cooling water to containment recirculating fan cooler coils ACA01A, ACA01B, ACA01C and ACA01D to improve steam condensing capabilities during accidents.

Of the twelve motor operated valves in the Service Water System supply header, five are gate valves (motor operated valves 4670, 4664, 4663, 4615, and 4616) and seven are butterfly valves (motor operated valves 4780, 4609, 4613, 4614, 4733, 4734, and 4735). They are in pairs (motor operated valves 4780/4609, 4670/4613, 4664/4614, 4616/4735, 4663/4733 and 4615/4734). Each pair except the 4780/4609 pair has one gate valve and one butterfly valve; 4780 and 4609 are both butterfly valves. There are six hand switches on the MCB to operate these SW header isolation valves in pairs.

Service water isolation motor operated valves 4609, 4670, 4614, 4663, 4615, and 4616 receive power from Bus 480 VAC 14. A Safety Injection signal ("A" train) with the normal 480 VAC supply breaker in cubicle BUS14/18B open will close these valves when emergency diesel generator KDG01A energizes the bus. SW isolation motor operated valves 4613, 4664, 4733, 4734, 4735 and 4780 receive their operating power from 480 VAC Bus 16. A Safety Injection signal ("B" train) with the normal 480 VAC supply breaker in cubicle BUS16/11B open will close these valves when emergency diesel generator KDG01B energizes the bus. If a Safety Injection signal occurs coincident with a loss of off-site power or other undervoltage condition, and only one service water pump starts (one emergency diesel generator having failed to start), the closing of these valves would insure adequate service water to the containment fan coolers and emergency diesel generators KDG01A and KDG01B.

There are a total of four separate service water return lines. One serves turbine plant loads and discharges to the plant discharge canal. One serves the containment recirculating fan cooler coils, reactor compartment cooler coils ACA02A and ACA02B, and air conditioning chillers SCI03A and SCI03B, and discharges to the plant discharge canal. The other two SW return lines serve the remaining auxiliary reactor plant loads, such as safety injection pumps PSI01A, PSI01B and PSI01C coolers, residual heat removal (RHR) pumps PAC01A and PAC01B coolers and CCW heat exchangers EAC01A and EAC01B. One SW header is the normal return and discharges into the discharge canal. Alternate SW discharge header SSW01 is normally isolated and would only be used should the normal header be damaged. Alternate header SSW01 discharges via an open concrete discharge structure into Deer Creek. The alternate discharge path has a low flow annunciator on the main control board in the Control Room that is normally energized, since the header is normally not in use.

A simplified flow diagram for the Service Water System is shown in Figures 3.2.1-33 and 3.2.1-34.

3.2.1.13.3 Service Water System Electrical Dependencies

Table 3.2.1-24 shows all AC and DC electrical system interfaces for the Service Water System.

3.2.1.13.4 Service Water System Cooling Water Dependencies

The Service Water System does not require any external cooling water sources with the exception of water from Lake Ontario via the Service Water Bay in the Screenhouse. This water is drawn into the Service Water Bay via the Intake Tunnel from the lake.

3.2.1.13.5 Service Water System Instrument Air Dependencies

Air operated valves 4561 and 4562 in the service water discharge line from the containment recirculating fan coolers are modeled in the Ginna PRA *Heating, Ventilation And Air Conditioning (HVAC) Systems* model (see Section 3.2.1.8). There are, therefore, no air operated components in the Service Water System model.

3.2.1.13.6 Service Water System Actuation and Control Dependencies

The Service Water System receives Safety Injection signals from the Engineered Safety Features Actuation System (ESFAS). SW pumps PSW01A and PSW01C receive signals from the "A" train of ESFAS via slave time delay relay 2/SWP1AC, SI signal auxiliary relay SI-10X, and SI master relay SIA-1; SW pumps PSW01B and PSW01D receive SI signals from the "B" train of ESFAS via slave time delay relay 2/SWP1BD, SI signal auxiliary relay SI-20X, and SI signal master relay SIA-2. Motor operated valves 4609, 4614, 4615, 4616, 4663, and 4670 receive signals from the "A" train of ESFAS via auxiliary relays SI-16X and SI-17X, while motor operated valves 4613, 4664, 4733, 4734, 4735, and 4780 receive signals from the "B" train of ESFAS via auxiliary relays SI-26X and SI-27X.

3.2.1.13.7 Service Water System Heating, Ventilation and Air Conditioning Dependencies

The Service Water System does not require any HVAC support to operate, with the exception of the Circulating Water Intake Heaters (EHTRCW01A, EHTRCW01B, EHTRCW01C and EHTRCW01D) located on the intake structure in Lake Ontario. These heaters are required during severely cold weather (when lake water temperature is about 33°F) to prevent the buildup of frazil ice on the intake screens.

3.2.1.13.8 Service Water System Controls and Instrumentation

Automatic temperature control is provided for turbine lube oil coolers ESW05A and ESW05B, and for containment recirculating fan coolers coils ACA01A, ACA01B, ACA01C and ACA01D. A bypass around turbine lube oil coolers control valve 4538 provides an alternate flow path. Another line is used to cool steam generator blowdown sample tank heat exchangers ESW01A and ESW01B. Automatic bypass valve 4562 is provided to allow flow around containment recirculating fan coolers coils temperature control valve 4561; this bypass is activated by a Safety Injection (SI) signal. Both the control valve and the automatic bypass valve are of the fail open type. Manual globe valves are provided on the outlet side of all cooling services, except the containment recirculating fan coolers (which have butterfly valves) for flow adjustment and balancing.

Radiation monitor R-16 is located in the service water discharge line from the four containment recirculating fan coolers and reactor compartment coolers ACA02A and ACA02B. Individual coolers may be manually isolated to determine which unit is leaking if R-16 alarms. Radiation monitor R-20 is located in the service water discharge line from the spent fuel pool heat exchangers.

On a loss of off-site power, the two service water pumps selected on the Screen House selector switches restart automatically 40 seconds after re-energization of the buses by emergency diesel generators KDG01A and KDG01B. A detailed list of loads supplied by the Service Water System is shown in Table 3.2.1-25. Those loads considered to be safeguards equipment are preceded by an asterisk in Table 3.2.1-25.

Major service water loads and approximate design flow rates are shown in Table 3.2.1-26.

There are hand switches on the MCB in the Control Room for operating the four service water pumps, the twelve SW header isolation motor operated valves, and the SW supply motor operated valves to the three auxiliary feedwater pumps. In addition, there are hand switches on the back of the MCB for standby AFW pump suction valves 9629A and 9629B should the operators ever need to use the Standby AFW System per procedures to feed the steam generators. The turbine lube oil temperature controller is also on back center section of the MCB.

Other indications available on the MCB in the Control Room include Service Water System header pressure for both trains (PT-2027 / PI-2160 for SW train A and PT-2028 / PI-2161 for SW train B), Screen House water level (LT-3006), and various annunciators to warn the operators of possible problems with the Service Water System. A listing of these annunciators is shown in Table 3.2.1-27.

3.2.1.13.9 Location of Major Service Water System Components

Service Water System major components are located as follows:

PSW01A	Screen House, Column CC, Row 6, Elevation 253'6"
PSW01B	Screen House, Column CC, Row 6, Elevation 253'6"
PSW01C	Screen House, Column BB, Row 6, Elevation 253'6"
PSW01D	Screen House, Column BB, Row 6, Elevation 253'6"
4609	Screen House, Column CC, Row 6, Elevation 253'6"
4613	Turbine Building, Column A, Row 12, Elevation 253'6"
4614	Intermediate Building, Column G, Row 4, Elevation 253'6"
4615	Auxiliary Building, Column Q, Row 9A, Elevation 253'6"
4616	Auxiliary Building, Column Q, Row 9A, Elevation 253'6"
4663	Intermediate Building, Column G, Row 4, Elevation 253'6"
4664	Intermediate Building, Column G, Row 4, Elevation 253'6"
4670	Diesel Building, Column A, Row 12, Elevation 253'6"
4733	Intermediate Building, Column G, Row 4, Elevation 253'6"
4734	Auxiliary Building, Column Q, Row 7A, Elevation 271'0"
4735	Auxiliary Building, Column Q, Row 8A, Elevation 253'6"
4780	Screen House, Column CC, Row 6, Elevation 253'6"

3.2.1.13.10 Normal Service Water System Operation

The operators are directed by procedures to start service water pumps as necessary. Normally, at full load during peak warm weather summer conditions, three service water pumps will be running with the fourth service water pump being a spare; during cold weather conditions in the winter, two pumps will normally be running. Running service water pumps are rotated in and out of service each month. Ginna station administrative controls require that three of four service water pumps be operable when the reactor is above 350°F.

3.2.1.13.11 Service Water System Performance During Accident Conditions

On receipt of a Safety Injection signal coincident with an undervoltage on 480 VAC Buses 14 and / or 16, the twelve SW header isolation motor operated valves will shut, isolating non-safety loads. The SW pumps selected in standby via Screen House SW pump selector switches SSS/SWP1AC and SSS/SWP1BD will sequence onto 480 VAC Buses 17 and 18 at 15 seconds and 17 seconds. In addition, the two air operated valves on the Containment recirculating fan cooler coils service water discharge line will fail to their full open position, increasing cooling water flow to the Containment coolers.

On an undervoltage on 480 VAC Buses 17 and 18 with no Safety Injection signal, the two running SW pumps will be shed, the two service water pumps selected in standby via Screen House SW pump selector switches SSS/SWP1AC and SSS/SWP1BD will sequence onto their respective buses 40 seconds after bus re-energization.

On receipt of a Safety Injection signal with no undervoltage, the running service water pumps will continue running; the two SW pumps selected in standby via Screen House SW pump selector switches SSS/SWP1AC and SSS/SWP1BD will start on their respective 480 VAC buses after 15 and 17 seconds for the two trains, and the two Containment recirculating fan cooler coils air operated valves will fail to their full open positions.

If the Standby Auxiliary Feedwater (SAFW) System is needed to inject service water into the steam generators, the operators would open SAFW pump suction valves 9629A and 9629B, open (or verify open) Service Water System header isolation motor operated valves 4615 and 4616, and start the SAFW pumps per procedures.

On a loss of condensate storage tanks (CSTs) TCD02A and TCD02B during operation of the Auxiliary Feedwater (AFW) System, service water can be lined up to supply the AFW pumps by opening service water supply motor operated valves 4013, 4027, and 4028 to the AFW pump suction, and by dispatching an operator to unlock and open three manual valves in series with these motor operated valves per procedures.

If the Service Water System return line outside the Auxiliary Building serving Component Cooling Water heat exchangers EAC01A and EAC01B and the Safety Injection / Containment Spray pumps coolers fails, then procedures direct both lining up the affected SW loads to alternate service water return SSW01 to Deer Creek, and isolating the normal service water return line to the plant discharge canal.

Should the entire Service Water System lose pressure due to some catastrophic failure, such as a pipe break, procedures direct the operators to split the SW safety header trains by shutting valves 4669 and 4760 in the 4" cross-tie in the diesel room, valves 4756 and 4639 in the 14" crosstie to the containment recirculation fan coolers, and valves 4625 and 4626 in the 2½" cross-tie to the containment recirculating fan coolers. This action splits the system in two, and effectively doubles the chances of isolating the pipe break and returning at least half of the system to service.

3.2.1.13.12 Service Water System Test And Maintenance

Testing and maintenance for the Service Water System are summarized in Table 3.2.1-28.

3.2.1.13.13 Service Water System Operating Experience

The following two Licensee Event Reports filed through 1989 pertain to the Service Water System:

82-009 From March 20, 1982, to March 26, 1982, 480 VAC Bus 17 was out of service for the planned installation of a new undervoltage system. The plant was in cold shutdown for refueling at the time of this modification work. The bus was returned to service without incident.

83-006 On January 20, 1983, with the plant at 100% power, the operators received an alarm that indicated low water level in the Screen House Service Water Bay. The problem was traced to frazil ice buildup in the intake tunnel and the circulating water pump suction. Water level in the Service Water Bay reached a low of 12.5 feet before the operators were able to correct the situation. The root cause of the frazil ice buildup was a modification that had reduced voltage to the intake heaters from 480 VAC to 240 VAC. As a result of this incident, the intake heater voltage was returned to 480 VAC.

3.2.1.13.14 Plant Specific Data Analysis for the Service Water System

A review was performed of the three Ginna PRA plant specific data work packages to ensure that all significant events are properly addressed in the Service Water System model.

Service Water System events reported in the *Plant Specific Data Work Package* were reviewed. The events described in this reference are accounted for in the fault tree shown in Appendix C of this work package with the following exceptions:

1) Failures of Circulating Water System components such as the traveling screens are not considered to be within the defined scope of the Service Water System as analyzed in this work package; and,

2) The SOVs for the service water strainer bypass valves for turbine driven AFW pump PAF03 are not considered to be within the defined scope of the Service Water System as analyzed in this work package.

The Service Water System fault tree model shown in Appendix C of this work package was found to reflect the testing and maintenance events and data presented in the *Test And Maintenance Unavailability Data Work Package* without exception.

The *Common Cause Failure Data Work Package* contained two Service Water System events. Neither event (failure of traveling screens FSW01B and FSW01D, and failure of the four manual isolation valves on the inlet lines to containment recirculating fan cooler cooling coils ACA01A, ACA01B, ACA01C and ACA01D) involved components that are considered to be within the defined scope of the Service Water System as analyzed in this work package.

3.2.1.14 Turbine Generator Plant Systems

3.2.1.14.1 Purpose and Design Basis of the Turbine Generator Plant Systems

One atmospheric relief valve (ARV) is provided on each steam generator outlet line. The valve has two functions. It offers overpressure protection to the steam generator at a setpoint below the safety valve setpoints and it can be used to maintain no-load T_{avg} or perform a plant cooldown in the event the steam dump to the condenser is not available. With respect to PRA-modeled accident sequences, the valves are required for plant cooldown following a steam generator tube rupture. The ARV is the only controllable method for releasing steam from the intact steam generator and thus cooling down and depressurizing the reactor. In other accident scenarios, where other energy release mechanisms are preferred, the ARVs are not modeled.

The ARVs are Seismic Category I as part of the main steam line pressure boundary. The piping and restrains necessary to ensure functioning of the valves after a seismic event are also Seismic Category I. Pneumatic supply to the valves is provided by the non-seismic Instrument Air (IA) System and two non-seismically designed nitrogen systems. Backup supply from the nitrogen supply systems is expected to be operable following a loss of offsite power. One ARV is sufficient for maintaining hot shutdown or to achieve cooldown of the reactor coolant system below hot shutdown conditions.

3.2.1.14.2 Turbine Generator Plant Systems Description

The ARVs (3411 and 3410) are air-operated valves with 329,000 lbm/hr normal and 890,000 lbm/hr maximum relief capacities. They can be operated remotely or manually and can be isolated by a manual valve located upstream of the valves. The pneumatic supply to the valves is provided by the Instrument Air (IA) System, and backup supply is provided by the nitrogen supply systems. Twelve nitrogen bottles (6 for valve 3411 and 6 for valve 3410) are located in the Turbine Building outside the door to the control room. This is a very high traffic area, which has two potential effects. First, in a high traffic area, an incipient problem is likely to be noticed. Second, the traffic could induce a problem (i.e., break a component, spill a corrosive material). Neither effect is likely to affect the system, and probabilisticly, the two effects tend to negate one another. Therefore, these rather interesting phenomena are not considered in the fault tree model.

During remote operation the valve 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 solenoid valve will energize causing the power-operated valve to open at 1060 psig. When pressure decreases to 1005 psig, the solenoid will deenergize causing the valve to close. The valves can also be manually operated with a handwheel mounted on each valve. Figures 3.2.1-35 and 3.2.1-36 contain simplified drawings of the ARV portion of the Main Steam System.

3.2.1.14.3 Turbine Generator Plant Systems Electrical Dependencies

The ARV opening solenoid valves (3411S and 3410S) are powered from RA-1, Train A and RA-2 Train B, respectively. The valves are energized to open, and fail closed on deenergization.

3.2.1.14.4 Turbine Generator Plant Systems Cooling Water Dependencies

The ARVs do not require any external cooling water sources.

3.2.1.14.5 Turbine Generator Plant Systems Instrument Air Dependencies

The ARVs are pneumatically operated by either the dedicated nitrogen system or the plant IA System. The dependency on the IA System is included in the model, including a model of the backup nitrogen.

3.2.1.14.6 Turbine Generator Plant Systems Actuation and Control Dependencies

The ARVs have both an electrical and mechanically actuated pressure relief capability. They do not receive any signals from ESFAS.

3.2.1.14.7 Turbine Generator Plant Systems Heating, Ventilation and Air Conditioning Dependencies

The ARVs are expected to be remotely operated without requiring room cooling from the Heating, Ventilation and Air Conditioning (HVAC) Systems. However, based on the *ARV Area Ambient Temperature Rise During SBO* calculation, the area will not be accessible for local manual operation by unprotected operators without Intermediate Building HVAC. Environmental suits are required and available for local-manual operation of the ARVs according to the supporting documentation to station blackout submittal.

3.2.1.14.8 Turbine Generator Plant Systems Controls and Instrumentation

The ARVs are normally controlled and the valve position monitored from the Main Control Board and input to the Plant Computer.

3.2.1.14.9 Location of Major Turbine Generator Plant Systems Components

The ARVs are located on the upper level of the Intermediate Building, with valve 3411 at elevation 278' 4" Column G Row 4 and valve 3410 at elevation 278' 4" Column F Row 7. The nitrogen tanks for the ARV are located on the Turbine Building operating floor (elevation 289 ft.).

3.2.1.14.10 Normal Turbine Generator Plant Systems Operation

The system is normally in the automatic standby mode. During remote operation the valve positioner will control the air pressure to the top and bottom of the operating piston of the ARVs. In the automatic mode of operation the ARVs are set to lift at 1050 psig (corresponds to a primary T_{avg} of 547°F). In manual control the valve position can be controlled by the operator in the control room. In the event the automatic controller fails, is set wrong, or the controller is in manual, a solenoid valve will energize at 1060 psig admitting air to the bottom of the operating piston. This will cause the ARV to open. When pressure decreases to less than 1060 psig the solenoid will de-energize, air will escape and the relief valve will close. (If ARV lifts due to 1060 psig, it will take awhile to reclose.)

3.2.1.14.11 Turbine Generator Plant Systems Performance During Accident Conditions

Following a SGTR and associated isolation, the desired method of cooldown is by supplying AFW to the intact steam generator, and releasing energy in the form of steam via the ARV. When the Reactor Coolant System is cooled and depressurized, the Residual Heat Removal (RHR) System is used for inventory control and heat removal.

3.2.1.14.12 Turbine Generator Plant Systems Test And Maintenance

The ARVs are exercised using air, nitrogen and manually during each annual refueling shutdown in accordance with established maintenance procedures.

3.2.1.14.13 Turbine Generator Plant Systems Operating Experience

Licensee Event Reports were reviewed, and no reports that pertain to the ARVs were found.

3.2.1.14.14 Plant-Specific Data Analysis for the Turbine Generator Plant Systems

ARV-3411 was found to be sticking open in 1980, but has experienced no further problems since the repairs. In 1987, ARV-3410 failed to operate and was found to be steam cut.

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
2	5	NA	10	CT	N(2)	Flange(8)	NA	NA	NA	NA	NA	None
		NA	10	CT	N(2)	Flange(8)	NA	NA	NA	NA	NA	None
29	5	SAC05	24	CT	N(2)	Flange(8)	NA	NA	NA	NA	NA	1248
		8152	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1248
100	3b	370B	2	CV	N(3)	Check	NA	NA	NA	NA	NA	1265-1
		CLOC	NA	CV	N(3)	NA	NA	NA	NA	NA	NA	1265-2
101	3b	870B	3	SI	Y	Check	NA	NA	NA	NA	NA	1262-1
		889B	4	SI	Y	Check	NA	NA	NA	NA	NA	1262-1
		CLOC	NA	SI	Y	NA	NA	NA	NA	NA	NA	1262-1
		885B	0.75	SI	N(1)	Manual	NA	NA	NA	NA	NA	1262-1
		12407	0.75	SI	N(1)	Manual	NA	NA	NA	NA	NA	1262-1
		PI-923A	0.75	SI	N(1)	NA	NA	NA	NA	NA	NA	1262-1
		PT-923	0.75	SI	N(1)	NA	NA	NA	NA	NA	NA	1262-1
102	3b	383B	2	CV	N(3)	Check	NA	NA	NA	NA	NA	1265-1
		CLOC	NA	CV	N(3)	NA	NA	NA	NA	NA	NA	1265-2
103	5	NA	2	CT	N(2)	Cap	NA	NA	NA	NA	NA	1991
		5129	2	CT	N(2)	Manual	NA	NA	NA	NA	NA	1991
105	3b	862A	6	CS	Y	Check	NA	NA	NA	NA	NA	1261
		CLOC	NA	CS	Y	NA	NA	NA	NA	NA	NA	1261
		869A	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2856	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2825	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2825A	0.50	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		864A	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859A	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859B	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859C	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
106	3b	304A	2	CV	N(3)	Check	NA	NA	NA	NA	NA	1265-1
		CLOC	NA	CV	N(3)	NA	NA	NA	NA	NA	NA	1265-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System [3]	Modeled[4]	Valve Type	Actuation Signal [5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header [7]	Drawing
107	2	1723	3	CT	Y	AOV	T	S1	NA	FUBRWDP1/F9-P, F10-N	AB	1279
		1728	3	CT	Y	AOV	T	S1, S2	NA	FUBRWDP1/F1-P, F2-N	AB	1279
108	1	313	3	CV	Y	MOV	T	S1, S2	MCCC/13J	DCPDPAB01A/02	NA	1265-2
		CLOC	NA	CV	Y	NA	NA	NA	NA	NA	NA	1265-2
109	3b	862B	6	CS	Y	Check	NA	NA	NA	NA	NA	1261
		CLOC	6	CS	Y	NA	NA	NA	NA	NA	NA	1261
		869B	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2858	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2826	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		2826A	0.50	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		864B	0.75	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859A	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859B	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
		859C	2	CS	N(1)	Manual	NA	NA	NA	NA	NA	1261
110a	3b	304B	2	CV	N(3)	Check	NA	NA	NA	NA	NA	1265-1
		CLOC	NA	CV	N(3)	NA	NA	NA	NA	NA	NA	1265-2
110b	1	879	0.75	CT	N(1)	Manual	NA	NA	NA	NA	NA	1262
111	3b	720	10	RH	N(2)	MOV	No	NA	MCCC/7C	DCPDPAB01A/02	NA	1247
		959	0.37	RH	N(1)	AOV	T	S1, S2	NA	FUNSP/F13-P, F14-N	AB	1247
		371	5	CV	Y	AOV	T	S1, S2	NA	FUMCB/XCB-P,N	NA	1264
		2840	2	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		2847	0.75	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		2848	0.75	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		2853	0.75	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		CLOC	0.75	RH	N(2)	NA	NA	NA	NA	NA	NA	1247
			NA									

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System[3]	Modeled[4]	Valve Type	Actuation Signal[5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header[7]	Drawing
112	1	200A	2	CV	Y	AOV	T	S1, S2	NA	FUMCB/XTD-P,N	CNMT	1264
		200B	2	CV	Y	AOV	T	S1, S2	NA	FUMCB/XTE-P,N	CNMT	1264
		202	2	CV	Y	AOV	T	S1, S2	NA	FUMCB/XTF-P,N	CNMT	1264
		371	2	CV	Y	AOV	T	S1, S2	NA	FUMCB/XCB-P,N	AB	1264
		203	2	CV	N(4)	Relief	NA	NA	NA	NA	NA	1264
		CLOC	NA	CV	N(3)	NA	NA	NA	NA	NA	NA	1264
113	3b	870A	3	SI	Y	Check	NA	NA	NA	NA	NA	1262-1
		889A	4	SI	Y	Check	NA	NA	NA	NA	NA	1262-1
		CLOC	NA	SI	Y	NA	NA	NA	NA	NA	NA	1262-1
		885A	0.75	SI	N(1)	Manual	NA	NA	NA	NA	NA	1262-1
		12406	0.75	SI	N(1)	Manual	NA	NA	NA	NA	NA	1262-1
		Cap	0.37	SI	N(1)	NA	NA	NA	NA	NA	NA	1262-1
		PI-922A	5	SI	N(1)	NA	NA	NA	NA	NA	NA	1262-1
		PT-922	0.75	SI	N(1)	NA	NA	NA	NA	NA	NA	1262-1
			0.75									
119	4	9704A	3	AF	N(8)	MOV	No	NA	MCCL/1J	NA	NA	1238
		9723	0.75	AF	N(7)	Manual	NA	NA	NA	NA	NA	1238
		CLIC	NA	SG	Y	NA	NA	NA	NA	NA	NA	1238
120a	3a	846	1	SI	N(1)	AOV	T	S1, S2	NA	FUMCB/XJF-P,N	AB	1262-1
		8623	1	SI	N(1)	Check	NA	NA	NA	NA	NA	1262-2
120b	2	539	0.37	CT	N(1)	AOV	T	S1, S2	NA	FUGACP/F11-1P, F21-1N	AB	1258
		546	5	CT	N(1)	Manual	NA	NA	NA	NA	NA	1258
			0.37									
			5									
121a	3a	508	2	RC	N(5)	AOV	T	S1, S2	NA	FUMCB/XHH-P,N	AB	1258
		529	2	RC	N(5)	Check	NA	NA	NA	NA	NA	1258
121b	3a	528	0.75	CT	N(1)	Check	NA	NA	NA	NA	NA	1258
		547	0.75	CT	N(1)	Manual	NA	NA	NA	NA	NA	1258

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
121c	2	PT945 1819A PT946 1819B	0.37 5 0.37 5 0.37 5 0.37 5	CT CT CT CT	N(1) N(1) N(1) N(1)	NA Manual NA Manual	NA NA NA NA	NA NA NA NA	NA NA NA NA	NA NA NA NA	NA NA NA NA	1261 1261 1261 1261
123a	2	1655 1789	0.75 0.75	CT CT	N(1) N(1)	Manual AOV	NA T	NA S1	NA NA	NA FUGACP/F1-2P, F2-2N	NA AB	1272-2 1272-1
123b	4	9704B 9724 9725 CLIC	3 0.75 0.75 NA	AF AF AF SG	N(8) N(7) N(7) Y	MOV Manual Manual NA	No NA NA NA	NA NA NA NA	MCCM/1J NA NA NA	NA NA NA NA	NA NA NA NA	1238 1238 1238 1238
124a	4	743 CLIC	2 NA	CC CC	N(3) N(3)	Check NA	NA NA	NA NA	NA NA	NA NA	NA NA	1246-1 1246-1
124b	5	1572 1573 1574	0.37 5 0.37 5 0.37 5	CT CT CT	N(1) N(1) N(1)	Manual Manual Manual	NA NA NA	NA NA NA	NA NA NA	NA NA NA	NA NA NA	1863 1863 1863
124c	4	745 CLIC	2 NA	CC CC	N(3) N(3)	AOV NA	No NA	NA NA	NA NA	FUMCB/XCC-P,N NA	AB NA	1246-1 1246-1
124d	5	1569 1570 1571	0.37 5 0.37 5 0.37 5	CT CT CT	N(1) N(1) N(1)	Manual Manual Manual	NA NA NA	NA NA NA	NA NA NA	NA NA NA	NA NA NA	1863 1863 1863

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
125	2	759B	3	CC	N(3)	MOV	No	NA	MCCD/12F	DCPDPAB01B/02	NA	1246-1
		CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
126	2	759A	3	CC	N(3)	MOV	No	NA	MCCC/12J	DCPDPAB01A/02	NA	1246-1
		CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
127	3b	CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
		749A	3	CC	N(3)	MOV	No	NA	MCCC/10J	DCPDPAB01A/02	NA	1246-1
128	3b	CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
		749B	3	CC	N(3)	MOV	No	NA	MCCD/10J	DCPDPAB01B/02	NA	1246-1
129	3a	1713	1	CT	N(1)	Check	NA	NA	NA	NA	NA	1272-2
		1786	1	CT	N(1)	AOV	T	S1	NA	FUBRWDP1/F7-P, F8-N	AB	1272-2
		1787	1	CT	N(1)	AOV	T	S2	NA	FUBRWDP1/F19-P, F20-N	AB	1272-2
		1793	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1272-2
130	4	814	6	CC	N(3)	MOV	T	S2	MCCD/10F	DCPDPAB01B/02	NA	1246-1
		CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
131	4	813	6	CC	N(3)	MOV	T	S1	MCCC/10F	DCPDPAB01A/02	NA	1246-1
		CLIC	NA	CC	N(3)	NA	NA	NA	NA	NA	NA	1246-1
132	5	7970	6	HV	Y	AOV	T,CVI	S1, S2	NA	FURA3/V39F-P,N	CNMT	1870
		7971	6	HV	Y	AOV	T,CVI	S1, S2	NA	FURA3/V39F-P,N	AB	1870
		Cap	0.37 5	HV	N(1)	NA	NA	NA	NA	NA	NA	1870
140	1	701	10	RH	N(2)	MOV	No	NA	MCCD/7F	DCPDPAB01B/02	NA	1247
		2763	0.75	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		2786	0.75	RH	N(1)	Manual	NA	NA	NA	NA	NA	1247
		CLOC	NA	RH	N(2)	NA	NA	NA	NA	NA	NA	1247
141	5	850A	10	RH	N(6)	MOV	No	NA	MCCC/6J	DCPDPAB01A/02	NA	1247
		1813A	6	RH	Y	MOV	No	NA	MCCC/13M	DCPDPAB01A/02	NA	1247
		CLOC	NA	RH	N(6)	NA	NA	NA	NA	NA	NA	1247

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System [3]	Modeled[4]	Valve Type	Actuation Signal [5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header [7]	Drawing
142	5	850B	10	RH	N(6)	MOV	No	NA	MCCD/6J	DCPDPAB01B/02	NA	1247
		1813B	6	RH	Y	MOV	No	NA	MCCD/13M	DCPDPAB01B/02	NA	1247
		CLOC	NA	RH	N(6)	NA	NA	NA	NA	NA	NA	1247
143	2	1003A	3	CT	Y	AOV	T	S1	NA	FUBRWDP1/F11-P, F12-N	AB	1272-2
		1003B	3	CT	Y	AOV	T	S2	NA	FUBRWDP1/F17-P, F18-N	AB	1272-2
		1721	3	CT	Y	AOV	T	S1, S2	NA	FUBRWDP1/F21-P, F22-N	AB	1272-2
		1722	3	CT	Y	Manual	NA	NA	NA	NA	NA	1272-2
		1709G	0.75	CT	N(1)	Manual	NA	NA	NA	NA	NA	1272-2
201a	4	4757	2.5	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4775	0.75	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
201b	4	4636	2.5	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4658	0.5	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		4776	0.75	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		PI-2141	0.75	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		Cap	0.37 5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
202a	5	1076B	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1275-1
		10211S1	1	CT	N(1)	SOV	T	S1, S2	NA	DCPDPAB02B/01	NA	1275-1
202b	5	1084B	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1275-1
		10213S1	1	CT	N(1)	SOV	T	S1, S2	NA	FUHZRCPB/13P, 14N	NA	1275-1
203a	2	PT947	0.37 5	CT	N(1)	NA	NA	NA	NA	NA	NA	1261
		PT948	0.37 5	CT	N(1)	NA	NA	NA	NA	NA	NA	1261
		1819C	0.37 5	CT	N(1)	Manual	NA	NA	NA	NA	NA	1261
		1819D	0.37 5	CT	N(1)	Manual	NA	NA	NA	NA	NA	1261

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System [3]	Modeled[4]	Valve Type	Actuation Signal [5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header [7]	Drawing
203b	5	1563	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
		1564	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
		1565	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
203c	5	1566	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
		1567	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
		1568	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1863
204	5	ACD93	48	CT	N(2)	Flange[8]	NA	NA	NA	NA	NA	1865
205	1	956D	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1278-1
		966C	0.375	CT	N(1)	AOV	T	S1, S2	NA	FUNSP/F7-P, F8-N	SB	1278-1
206a	1	956E	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1278-1
		966B	0.375	CT	N(1)	AOV	T	S1, S2	NA	FUNSP/F9-P, F10-N	SB	1278-1
206b	4	5735	0.75	CT	Y	AOV	T	S1, S2	NA	FUNSP/15-P, 16-N	SB	1277-1
		5749	0.375	CT	N(7)	Manual	NA	NA	NA	NA	NA	1277-1
		CLIC	NA	CT	Y	NA	NA	NA	NA	NA	NA	1277-1
207a	1	956F	0.375	CT	N(1)	Manual	NA	NA	NA	NA	NA	1278-1
		966A	0.375	CT	N(1)	AOV	T	S1, S2	NA	FUNSP/1-P, 2-N	SB	1278-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System[3]	Modeled[4]	Valve Type	Actuation Signal[5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header[7]	Drawing
207b	4	5736	1	CT	Y	AOV	T	S1, S2	NA	FUNSP/19-P, 20-N	SB	1277-1
		CLIC	NA	CT	Y	NA	NA	NA	NA	NA	NA	1277-1
209a	4	4635	2.5	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4637	0.75	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
209b	4	4638	2.5	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4758	0.75	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		4759	0.5	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		PI-2232	0.75	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		Cap	0.37	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	5	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
			NA									
210	5	1080A	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1275-1
		10214S1	1	CT	N(1)	SOV	T	S1, S2	NA	DCPDPAB02A/01	NA	1275-1
		10215S1	1	CT	N(1)	SOV	T	S1, S2	NA	DCPDPAB02B/01	NA	1275-1
300	5	ACD92	48	CT	N(2)	Flange[8]	NA	NA	NA	NA	NA	1866
301	4	6151	2	CT	N(2)	Manual	NA	NA	NA	NA	NA	1915
		6165	2	CT	N(2)	Manual	NA	NA	NA	NA	NA	1915
303	4	6152	0.75	CT	N(1)	Manual	NA	NA	NA	NA	NA	1915
		6175	0.75	CT	N(1)	Manual	NA	NA	NA	NA	NA	1915
304a	5	1076A	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1275-1
		10205S1	1	CT	N(1)	SOV	T	S1, S2	NA	DCPDPAB02B/01	NA	1275-1
304b	5	1084a	1	CT	N(1)	Manual	NA	NA	NA	NA	NA	1275-1
		10209S1	1	CT	N(1)	SOV	T	S1, S2	NA	DCPDPAB02B/01	NA	1275-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve[1]	Size (in)[2]	System [3]	Modeled[4]	Valve Type	Actuation Signal [5]	Safeguard Train	AC Power Source[6]	DC Power Source[6]	I/A Header [7]	Drawing
305a	5	1554 1555 1556	0.375 0.375 0.375	CT CT CT	N(1) N(1) N(1)	Manual Manual Manual	NA NA NA	NA NA NA	NA NA NA	NA NA NA	NA NA NA	1863 1863 1863
305b	3a	1598 1599	1 1	CT CT	N(1) N(1)	AOV AOV	T, CVI T, CVI	S1 S2	NA NA	FUMCB/XDA-P,N FUMCB/XEG-P,N	IB IB	1866 1866
305c	5	1557 1558 1559	0.375 0.375 0.375	CT CT CT	N(1) N(1) N(1)	Manual Manual Manual	NA NA NA	NA NA NA	NA NA NA	NA NA NA	NA NA NA	1863 1863 1863
305d	5	1560 1561 1562	0.375 0.375 0.375	CT CT CT	N(1) N(1) N(1)	Manual Manual Manual	NA NA NA	NA NA NA	NA NA NA	NA NA NA	NA NA NA	1863 1863 1863
305e	2	1596 1597	1 1	CT CT	N(1) N(1)	Manual AOV	NA T, CVI	NA S1, S2	NA NA	NA FUMCB/XDB-P,N	NA IB	1866 1866
307	5	9227 9229	4 4	CT CT	N(2) N(2)	AOV Check	T NA	S1, S2 NA	NA NA	FUMCB/XHJ-P,N NA	IB NA	1991 1991

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
308	4	4629 4633 4655 FIA-2033 TIA-2010 Caps CLIC	8 1 0.5 0.5 0.5 0.37 5 NA	SW SW SW SW SW SW SW	N(3) N(1) N(1) N(1) N(1) N(1) N(3)	Manual Manual Relief NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	1250-3 1250-3 1250-3 1250-3 1250-3 1250-3 1250-3
309	5	7445 7478	6 6	HV HV	Y Y	AOV AOV	T, CVI T, CVI	S1 S2	NA NA	FURA3/V6F-P,N FURA3/V6F-P,N	IB CNMT	1865 1865
310a	3a	5392 5393	2 2	IA IA	Y Y	AOV Check	T NA	S1, S2 NA	NA NA	FURA3/V37R-P,N NA	IB NA	1893 1893
310b	3a	7141 7226	2 2	CT CT	N(2) N(2)	Manual Check	NA NA	NA NA	NA NA	NA NA	NA NA	1886-2 1886-2
311	4	4630 4634 4656 FIA-2034 TIA-2011 Caps CLIC	8 1 0.5 0.5 0.5 0.37 5 NA	SW SW SW SW SW SW SW	N(3) N(1) N(1) N(1) N(1) N(1) N(3)	Manual Manual Relief NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	1250-3 1250-3 1250-3 1250-3 1250-3 1250-3 1250-3
312	4	4642 4646 12500K PI-2144 CLIC	8 1 0.5 0.5 NA	SW SW SW SW SW	N(3) N(1) N(1) N(1) N(3)	Manual Manual Manual NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	NA NA NA NA NA	1250-3 1250-3 1250-3 1250-3 1250-3
313	5	7444 Cap NA	6 0.37 56	CT CT CT	N(2) N(1) N(2)	MOV NA Flange	T, CVI NA NA	S1, S2 NA NA	ACPDPCB03 NA NA	NA NA NA	NA NA NA	1882 1882 1882

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
315	4	4643	8	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4647	1	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		4659	0.5	SW	N(1)	Relief	NA	NA	NA	NA	NA	1250-3
		FIA-2035	0.5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		TIA-2012	0.5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		Caps	0.37	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	5	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
			NA									
316	4	4628	8	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4632	1	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		PI-2138	0.5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
317	5	7443	6	CT	N(2)	MOV	T, CVI	S1, S2	ACPDPCB03	NA	NA	1882
		Cap	0.37	CT	N(1)	NA	NA	NA	NA	NA	NA	1882
		SAT01	5	CT	N(2)	Flange	NA	NA	NA	NA	NA	1882
			6									
319	4	4627	8	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4631	1	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		PI-2142	0.5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
320	4	4641	8	SW	N(3)	Manual	NA	NA	NA	NA	NA	1250-3
		4645	1	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		12500H	0.5	SW	N(1)	Manual	NA	NA	NA	NA	NA	1250-3
		PI-2136	0.5	SW	N(1)	NA	NA	NA	NA	NA	NA	1250-3
		CLIC	NA	SW	N(3)	NA	NA	NA	NA	NA	NA	1250-3
321	4	5738	2	CT	Y	AOV	T	S1, S2	NA	FUSNP/17-P, 18-N	IB	1277-1
		5752	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1277-1
		CLIC	NA	CT	Y	NA	NA	NA	NA	NA	NA	1277-1
322	4	5737	2	CT	Y	AOV	T	S1, S2	NA	FUNSP/21-P, 22-N	IB	1277-1
		5756	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1277-1
		CLIC	NA	CT	Y	NA	NA	NA	NA	NA	NA	1277-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
323	4	4644 4648 4660 FIA-2036 TIA-2013 Caps CLIC	8 1 0.5 0.5 0.5 0.37 5 NA	SW SW SW SW SW SW SW	N(3) N(1) N(1) N(1) N(1) N(1) N(3)	Manual Manual Relief NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	NA NA NA NA NA NA NA	1250-3 1250-3 1250-3 1250-3 1250-3 1250-3 1250-3
324	5	8418 8419	2 3	CT CT	N(2) N(2)	AOV Check	T NA	S1, S2 NA	NA NA	FUMCB/XTR-P,N NA	IB NA	1908-3 1908-3
332a	5	922 924 7452 Cap CLOC	0.37 5 0.37 5 0.37 5 0.37 5 NA	CT CT CT CT CT	N(1) N(1) N(1) N(1) N(1)	SOV SOV Manual NA NA	T T NA NA NA	S1, S2 S1, S2 NA NA NA	NA NA NA NA NA	FUMCB/XIB-P,N FUMCB/XID-P,N NA NA NA	NA NA NA NA NA	1278-1 1278-1 1278-1 1278-1 1278-1
332b	5	923 7456 Cap CLOC	0.37 5 0.37 5 0.37 5 NA	CT CT CT CT	N(1) N(1) N(1) N(1)	SOV Manual NA NA	T NA NA NA	S1, S2 NA NA NA	NA NA NA NA	FUMCB/XIC-P,N NA NA NA	NA NA NA NA	1278-1 1278-1 1278-1 1278-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
332c	2	PT944 PT949 PT950 1819E 1819F 1819G	0.37 5 0.37 5 0.37 5 0.37 5 0.37 5 0.37 5	CT CT CT CT CT CT	N(1) N(1) N(1) N(1) N(1) N(1)	NA NA NA Manual Manual Manual	NA NA NA NA NA NA	NA NA NA NA NA NA	NA NA NA NA NA NA	NA NA NA NA NA NA	NA NA NA NA NA NA	1261 1261 1261 1261 1261 1261
332d	5	921 7448 Cap CLOC	0.37 5 0.37 5 0.37 5 NA	CT CT CT CT	N(1) N(1) N(1) N(1)	SOV Manual NA NA	T NA NA NA	S1, S2 NA NA NA	NA NA NA NA	FUMCB/XIA-P,N NA NA NA	NA NA NA NA	1278-1 1278-1 1278-1 1278-1

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
401	4	3411	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3413A	0.50	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		3455	0.50	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3505A	6	MS	Y	MOV	No	NA	NA	DCPDPCB03A/M-P,N	NA	1231
		3505C	1.5	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3509	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3511	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3513	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3515	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3517	30	MS	Y	AOV	No	NA	NA	RA1/RA3	IB	1231
		3521	2	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		3615	3	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3669	1	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		11027	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		11029	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		11031	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		PS-2092	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-468	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-469	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-469A	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-482	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		Caps	0.37	CT	N	NA	NA	NA	NA	NA	NA	1231
		CLIC	5 NA	CT	Y	NA	NA	NA	NA	NA	NA	1231

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing

Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System(3)	Modeled(4)	Valve Type	Actuation Signal(5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header(7)	Drawing
402	4	3410	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3412A	0.50	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		3456	0.50	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3504A	6	MS	Y	MOV	No	NA	NA	DCPDPCB03B/17	NA	1231
		3504C	1.5	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3508	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3510	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3512	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3514	6	MS	Y	Relief	NA	NA	NA	NA	NA	1231
		3516	30	MS	Y	AOV	No	NA	NA	RA1/RA3	IB	1231
		3520	2	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		3614	3	CT	N	Manual	NA	NA	NA	NA	NA	1231
		3668	1	CT	Y	Manual	NA	NA	NA	NA	NA	1231
		11021	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		11023	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		11025	1	CT	N	Manual	NA	NA	NA	NA	NA	1231
		PS-2093	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-478	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-479	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		PT-483	1	CT	N	NA	NA	NA	NA	NA	NA	1231
		Caps	0.37	CT	N	NA	NA	NA	NA	NA	NA	1231
		CLIC	5	CT	Y	NA	NA	NA	NA	NA	NA	1231
			NA									
403	4	3993	18	MF	Y	Check	NA	NA	NA	NA	NA	1236-2
		3995X	0.5	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		4000C	3	AF	Y	Check	NA	NA	NA	NA	NA	1237
		4003	3	AF	N(8)	Check	NA	NA	NA	NA	NA	1237
		4003A	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1237
		4011A	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1237
		4099E	1	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		8651	1	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		CLIC	NA	NA	Y	NA	NA	NA	NA	NA	NA	1236-2

Table 3.2.1-1 - Mechanical Penetration Isolation Boundary Listing												
Pen #	Type	Boundary/ Valve(1)	Size (in)(2)	System (3)	Modeled(4)	Valve Type	Actuation Signal (5)	Safeguard Train	AC Power Source(6)	DC Power Source(6)	I/A Header (7)	Drawing
404	4	3992	18	MF	Y	Check	NA	NA	NA	NA	NA	1236-2
		3994E	1	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		3994X	0.50	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		4000D	3	AF	Y	Check	NA	NA	NA	NA	NA	1237
		4004	3	AF	N(8)	Check	NA	NA	NA	NA	NA	1237
		4004A	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1237
		4012A	0.75	CT	N(7)	Manual	NA	NA	NA	NA	NA	1237
		8650	1	CT	N(7)	Manual	NA	NA	NA	NA	NA	1236-2
		CLIC	NA	NA	Y	NA	NA	NA	NA	NA	NA	1236-2
1000	NA	NA	116	CT	N(2)	Hatch	NA	NA	NA	NA	NA	NA
2000	NA	NA	168	CT	N(2)	Hatch	NA	NA	NA	NA	NA	NA

<u>General Notes to Table 3.2.1-X:</u>

(1) The following abbreviations are used:

CLIC Closed Loop Inside Containment
CLOC Closed Loop Outside Containment

(2) Valve size was taken from drawing identified in Drawing column with the exception of some blind flanges. GMEDB [Ref. 18.4.2] was used in these cases when drawings were not identified.

(3) System designations are consistent with those provided in [Ref. 18.1.2].

(4) This column is completed using either Y (yes) or N (no). The basis for not modeling the identified containment boundary is provided in the parenthesis following the "N" as follows:

(1) Boundary does not meet the modeling criteria of 1.5 inches or is preceeded by piping which does not meet this criteria.

(2) Loss of penetration integrity requires failure of two passive boundaries (e.g., blind flanges, locked-closed valves) which are not affected by any core damage sequence.

(3) Loss of penetration integrity requires failure of a containment isolation valve <u>and</u> a piping system not affected by any core damage sequence which has a relief valve setting > 150 psig.

(4) The relief valve is located inside containment between two containment barriers in a system which is normally operating. Since containment pressure would assist in maintaining the relief valve closed, it is not modeled as a release path.

(5) This penetration contains two normally closed containment isolation valves which are open less than 1% of the time at power [Ref. 18.1.24, Appendix A]. Since neither containment isolation valve requires motive power to perform its function (i.e., AOV and check valve), and neither is affected by any accident sequence, this penetration was not modeled.

(6) This penetration is normally isolated by two passive boundaries and is only open during the recirculation phase of the accident. During recirculation, a pipe rupture could release sump fluid into the Auxiliary Building. However, this penetration was not modeled due to the low probability of this occurring (pipe rupture = 6.64E-06 [RHPPJINJLN] and small-break LOCA frequency = 1.0E-03/year).

(7) Loss of penetration integrity requires failure of this small, normally closed passive boundary in addition to a Steam Generator Tube Rupture event. Since the integrity of this boundary is continuously verified during power operations, it was not modeled.

(8) This valve was not modeled due to expected system lineups. Instead, an associated in-series valve was modeled (9705A replaced 9704A, and 9705B replaced 9704B).

(5) A "T" identifies that the component receives a containment isolation signal while "CVI" identifies a containment ventilation isolation signal. This information was taken from UFSAR Table 6.2-15 [Ref. 18.1.5].

(6) The Ginna Flooding Data Base was used to initially identify the AC and DC power sources. The power sources for penetrations which were modeled was further confirmed by review of applicable electrical drawings and control schematics.

(7) The following abbreviations are used for instrument air headers:

AB	Auxiliary Building	SB	Service Building
CNMT	Containment	TB	Turbine Building
IB	Intermediate Building		

Table Notes:

(a) This blind flange utilizes two gland seals or O-rings; consequently, both seals or O-rings must fail in order to challenge containment integrity.

Table 3.2.1-2
Containment Spray System Electrical Dependencies

Component	AC Power Source	DC Power Source
PSI02A	Bus 14 Unit 20B	Aux Bldg DC Dist Pnl 1A, Sw #4
PSI02B	Bus 16 Unit 13B	Aux Bldg DC Dist Pnl 1B, Sw #4
AOV 836A	Inst. Bus 1A	Not required
AOV 836B	Inst. Bus 1C	Not required
MOV 860A	MCC C Pos. 8J	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 860B	MCC D Pos. 8J	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 860C	MCC C Pos. 11F	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 860D	MCC D Pos. 11F	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 875A	MCC C Pos. 14C	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 875B	MCC D Pos. 14C	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 876A	MCC C Pos. 14F	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 876B	MCC D Pos. 14F	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 896A	MCC C Pos. 8M	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 896B	MCC D Pos. 8M	Aux Bldg DC Dist Pnl 1B, Sw #2
LQ-920 (LT-920 power supply)	Inst Dist Pnl MQ-400C	Not required
LC-920A/B (LT-920 alarm)	Inst Dist Pnl C	Not required
LC-920C (LT-920 alarm)	Inst Dist Pnl C	Not required
LC-921 (LT-921 alarm)	Fox 1 Rack	Not required

Table 3.2.1-2
Containment Spray System Electrical Dependencies

Component	AC Power Source	DC Power Source
LC-931 (LT-931 alarm)	Inst Dist Pnl C	Not required
LT-931 power supply	Inst Dist Pnl MQ-400C	Not required
LT-932 power supply	Inst Dist Pnl B	Not required

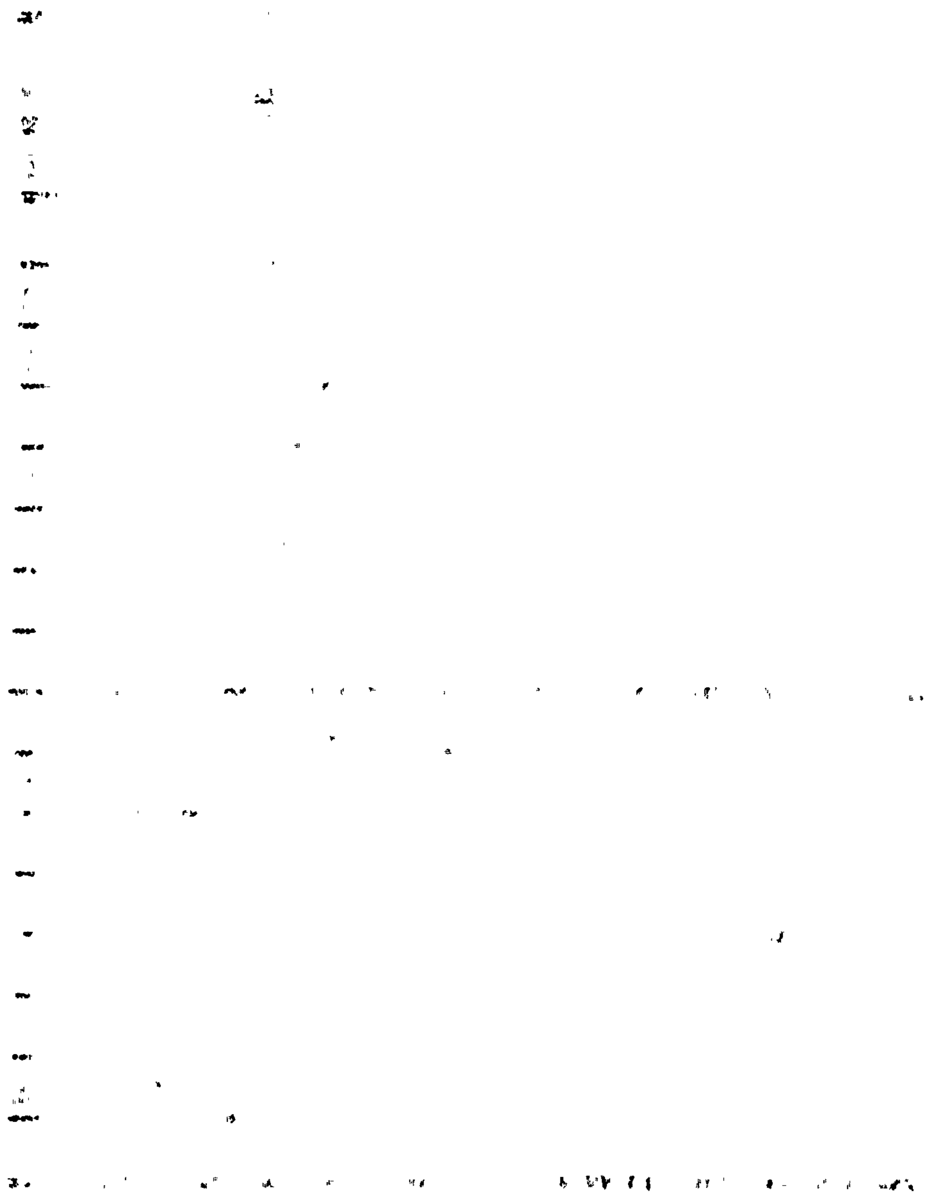


Table 3.2.1-3
Locations of Major Containment Spray System Components

EIN	Building	Elevation	Column	Row
PSI02A	AB	235' 8"	L	8A
PSI02B	AB	235' 8"	L	8A
TSI01	AB	235' 8"	N	7A
TSI02*	AB	235' 8"	L	10A
MV 831A	AB	235' 8"	L	8A
MV 831B	AB	235' 8"	L	8A
AOV 836A	AB	235' 8"	L	11A
AOV 836B	AB	235' 8"	L	11A
CV 847A	AB	235' 8"	L	8A
CV 847B	AB	235' 8"	L	8A
MV 858A	AB	235' 8"	L	8A
MV 858B	AB	235' 8"	L	8A
MOV 860A	AB	235' 8"	L	8A
MOV 860B	AB	235' 8"	L	8A
MOV 860C	AB	235' 8"	L	8A
MOV 860D	AB	235' 8"	L	8A

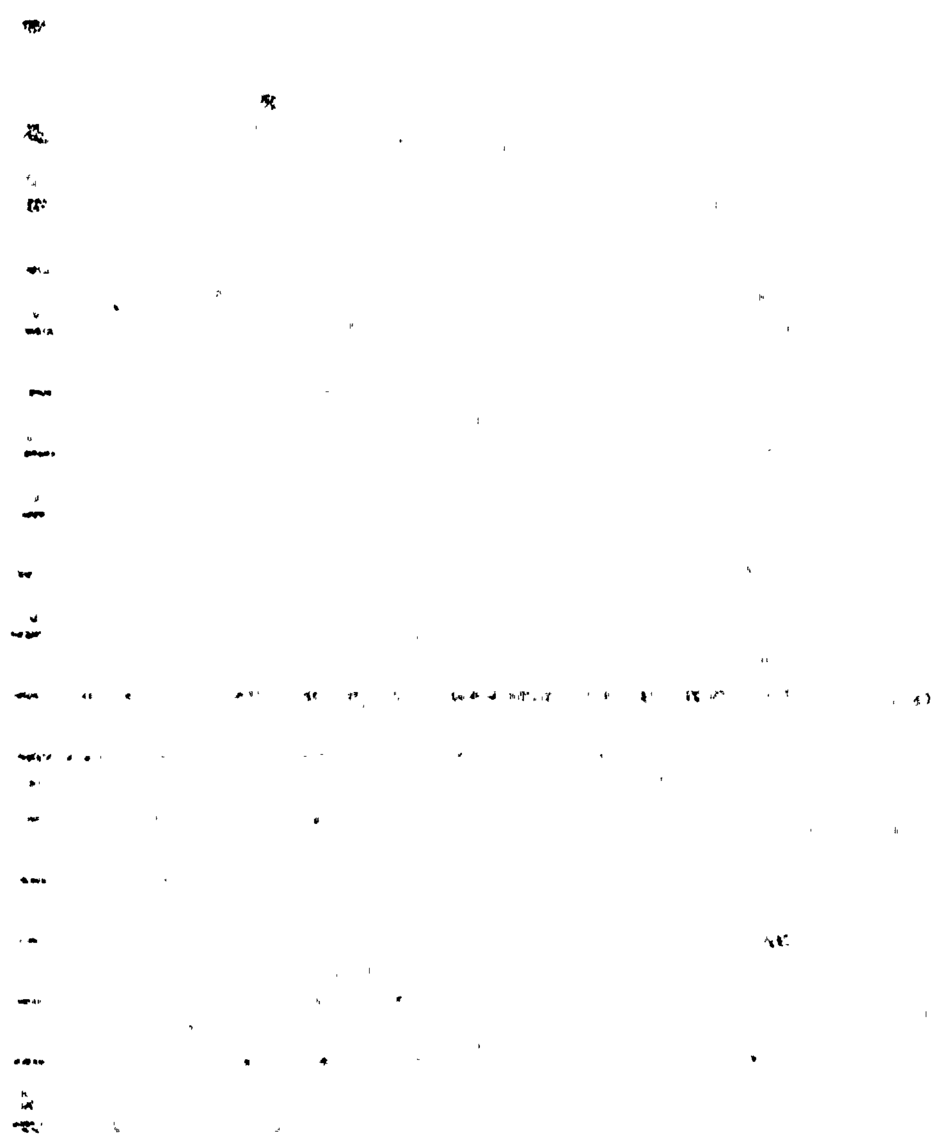


Table 3.2.1-3
Locations of Major Containment Spray System Components

EIN	Building	Elevation	Column	Row
CV 862A	AB	235' 8"	L	8A
CV 862B	AB	235' 8"	L	8A
MV 868A	AB	235' 8"	L	8A
MV 868B	AB	235' 8"	L	8A
MV 873A	AB	235' 8"	L	10A
MV 873B	AB	235' 8"	L	11A
MOV 875A	CNMT	300' 4"	NE	OMB
MOV 875B	CNMT	300' 4"	NE	OMB
MOV 876A	CNMT	300' 0"	NE	OMB
MOV 876B	CNMT	300' 0"	NE	OMB
MV 881B	AB	235' 8"	L	11A
MV 881C	AB	235' 8"	L	8A
MV 881D	AB	235' 8"	L	8A
MOV 896A	AB	235' 8"	N	8A
MOV 896B	AB	235' 8"	N	8A

CV indicates a check valve.
MV indicates a manual valve.
AOV indicates an air operated valve.
MOV indicates a motor operated valve.

Table 3.2.1-4
Containment Spray System Control Room Annunciators

ANNUNCIATOR	DESCRIPTION
A-6	CS Pump Cooling Water Out Low Flow 15 gpm
A-27	Containment Spray, 2/3 & 2/3 > 28 psi
A-28	Containment Spray Channel Alert, 2/3 > 28 psi
B-8	RWST Hi-Lo Level, 95 % 28
B-16	RWST Lo-Lo Level, 15 %
B-24	Spray Additive Tank Lo Level, 90 %
J-9	Safeguard Breaker Trip
J-25	Safeguards Equipment Locked Off
L-30	Safeguard Test Switch on Test
L-31	Safeguard DC Failure

Table 3.2.1-5

Control Room Indicators and Controllers for CVCS

EIN	Description
TC-130	Non-regenerative Hx Letdown Line Outlet temperature controller
TI-120	Seal water heat exchanger outlet temperature
PR-420	RCP running pressure
FI-610	Flow indicator, CCW flow to thermal barrier cooling coil - RCP A
FI-614	Flow indicator, CCW flow to thermal barrier cooling coil - RCP B
HCV-142	Charging line control valve controller
TI-122	Excess Letdown Hx Outlet temp
TI-126	Regenerative Hx Charging Line Outlet temp
TI-127	Regenerative Hx Letdown Line Outlet temp
PI-121	Excess Letdown Hx Outlet pressure
PI-139	VCT pressure
HIC-104	Boric Acid Tank Recirculation controller
HIC-105	Boric Acid Tank Recirculation controller
HIC-123	Excess Letdown Hx Outlet flow controller
FI-128	Charging Line flow indicator
HIC-133	RHR loop bypass flow controller

Table 3.2.1-6

CVCS Valve Control and Position Indication

EIN	Description
AOV 200A	Loop B letdown orifice outlet AOV
AOV 200B	Loop B letdown orifice outlet AOV
AOV 202	Loop B letdown orifice outlet AOV
AOV 371	Letdown containment isol AOV
AOV 294	Charging line inlet AOV to loop B cold leg (RCS)
AOV 745	Excess letdown HX CCW outlet cnmt isol AOV (aux bldg)
AOV 310	Loop A inlet isol AOV to excess letdown HX
AOV 312	Loop A excess letdown division AOV
AOV 270A	RCP A seal return AOV
AOV 270B	RCP B seal return AOV
AOV 392B	Alternate charging line control AOV to Loop A
AOV 386	RPC A & B seal #1 bypass control AOV
AOV 296	Charging line aux spray isol AOV to pressurizer (OMB)
SOV 258	VCT solenoid vlv to vent header
AOV 244	Letdown deborating diversion AOV
AOV 754A	RCP A thermal barrier CCW outlet AOV (in cnmt)
AOV 754B	RCP B thermal barrier CCW outlet AOV (in cnmt)
AOV 745	Excess letdown HX CCW outlet cnmt isol AOV (aux bldg)
AOV 110A	Boron flow control AOV to boric acid blender
AOV 110B	Boric acid blender makeup control AOV to charging pumps
AOV 110C	Boric acid blender makeup control AOV to VCT
AOV 111	Makeup control, water to blender
AOV 371	RMW AOV to boric acid blender
AOV 427	Loop B letdown AOV to regenerative heat exchanger
MOV 749A	CCW cnmt inlet isol MOV to RCP A (aux bldg)
MOV 749B	CCW cnmt inlet isol MOV to RCP B (aux bldg)
MOV 759A	RCP A CCW outlet cnmt isol MOV (aux bldg)
MOV 759B	RCP B CCW outlet cnmt isol MOV (aux bldg)
MOV 313	Seal water return isol MOV
PCH03A	Start / stop
PCH03B	Start / stop
PCH01A	Start / stop / speed control
PCH01B	Start / stop / speed control
PCH01C	Start / stop / speed control
PCH08A	Start / stop
PCH08B	Start / stop

Table 3.2.1-7

Alarm Indications for CVCS

EIN	Description
PC-135	Letdown line pressure controller
TI-140	VCT outlet temperature
TIC-103	Boric Acid Tank A temperature controller
TI-125	RC Pump Lower Bearing Water temp - B
TI-132	RC Pump Lower Bearing Water temp - A
TC-145	Letdown to Mixed Bed Demineralizer
TI-181	No. 1 Seal Outlet temp, RCP A
TI-182	No. 1 Seal Outlet temp, RCP B
PI-124	RCP Loop B Labyrinth Seal, Lo dP
PI-131	RCP Loop A Labyrinth Seal, Lo dP
PI-173	RCP A, dP across No. 1 Seal
PI-174	RCP B, dP across No. 1 Seal
PI-183	Seal Injection Filter dP
FR-110	Concentrated Boric Acid flow controller
FR-111	RMW to Blender flow controller
FI-134	Letdown Line flow indicator
FR-175	RCP A, Controlled Leakage Flow, low range
FR-176	RCP B, Controlled Leakage Flow, low range
FR-177	RCP A, Controlled Leakage Flow, high range
FR-178	RCP B, Controlled Leakage Flow, high range
LI-101	Batching Tank level
LI-102	Boric Acid Tank A level
LI-106	Boric Acid Tank B level
LI-112	VCT level
LI-157	RMW Tank level
LI-171	Boric Acid Tank B level
LI-172	Boric Acid Tank A level

[illegible]

Table 3.2.1- 8
Major Loads Supplied By 4160 and 480 VAC Buses

Bus 11A

BUS11A/08 Reactor Coolant Pump PRC01A
BUS11A/07 Main Feed Pump PFW01A
BUS11A/06 Condensate Pump PCD02A
BUS11A/05 Condensate Pump PCD02C
BUS11A/04 Heater Drain Pump PCD03A
BUS11A/03 Circulating Pump PCW01A
BUS11A/09 Auxiliary Building Exhaust Fan AAF08A
BUS11A/02 Condensate Booster Pump PCD01C
BUS11A/01 480 VAC Bus 13 (via Station Service Transformer PXTBSS013)
Cross-tie to Bus 11B

Bus 11B

BUS11B/24 Reactor Coolant Pump PRC01B
BUS11B/25 Main Feed Pump PFW01B
BUS11B/26 Condensate Pump PCD02B
BUS11B/27 Heater Drain Pump PCD03B
BUS11B/28 Circulating Pump PCW01B
BUS11B/23 Auxiliary Building Exhaust Fan AAF08B
BUS11B/29 Condensate Booster Pump PCD01B
BUS11B/30 480 VAC Bus 15 (via Station Service Transformer PXTBSS015)
BUS11B/31 Cross-tie to Bus 11A

Bus 12A

BUS12A/15 480 VAC Bus 14 (via Station Service Transformer PXABSS014)
BUS12A/14 480 VAC Bus 18 (via Station Service Transformer PXSHSS018)
BUS12A/16 Condensate Booster Pump PCD01A
BUS12A/12 Cross-tie to Bus 11A

Bus 12B

BUS12B/17 480 VAC Bus 16 (via Station Service Transformer PXABSS016)
BUS12B/18 480 VAC Bus 17 (via Station Service Transformer PXSHSS017)
BUS12B/20 Cross-tie to Bus 11B

Table 3.2.1- 8
MajorLoads Supplied By 4160 and 480 VAC Buses

Bus 14

Containment Fan ACF08D
Auxiliary Building Exhaust Fan AAF04
Pressurizer heater Control Group
Charging Pump PCH01A
CCW Pump PAC02A
(coincident with SI signal)
MCC C non-vital loads (coincident with SI signal) via relay 86/MCCC

Bus 16

Containment Fan ACF08B
Containment Fan ACF08C
Charging Pump PCH01B
Charging Pump PCH01C
Pressurizer Backup Heaters
CCW Pump PAC02B (coincident with SI signal)
MCC D non-vital loads (coincident with SI signal) via relay 86/MCCD

Bus 17

Motor-Driven Fire Pump PFS02
Intake Heater EHTRCW01B
Intake Heater EHTRCW01D
Service Water Pump PSW01B
Service Water Pump PSW01D
MCC G Feed

Bus 18

Intake Heater EHTRCW01A
Intake Heater EHTRCW01C
Service Water Pump PSW01A
Service Water Pump PSW01C
MCC G Feed

MCC C (SI Train A) Loads

Penetration Cooling Fan ACF07A
Boric Acid Transfer Pump PCH03A
Reactor Compartment Cooling Fan ACF09A
Reactor Coolant Drain Tank Pump PWD10A
Reactor Water Makeup Pump PCH08A
RWST Purification Pump PAC05
Spent Fuel Pool Cooling Pump PAC07A

MCC D (SI Train B) Loads

Penetration Cooling Fan ACF07B
Boric Acid Transfer Pump PCH03B
Reactor Compartment Cooling Fan ACF09B
Reactor Coolant Drain Tank Pump PWD10B
Reactor Water Makeup Pump PCH08B
Auxiliary Building Exhaust Fan AAF07
(Spent Fuel Pool Area)

Table 3.2.1- 9
Safety Injection (SI) Signal Load Sequencing

Time (sec)	Bus 14 and 18 - Train A (Generator KGD01A)	Time (sec)	Bus 16 and 17 - Train B (Generator KDG01B)
0	Safety Injection signal	0	Safety Injection signal
10	Safeguards buses energized	10	Safeguards buses energized
15	Safety Injection Pump PSI01A	15	Safety Injection Pump PSI01B
20	Safety Injection Pump PSI01C	22	Safety Injection Pump PSI01C (If breaker BUS14/18A does not close)
25	Residual Heat Removal Pump PAC01A	27	Residual Heat Removal Pump PAC01B
30	Service Water Pump PSW01A or PSW01C, preselected	32	Service Water Pump PSW01B or PSW01D, preselected
35	Containment Fan ACF08A	37	Containment Fan ACF08B
40	Containment Fan ACF08D	42	Containment Fan ACF08C
45	Auxiliary Feedwater Pump PFW02A	47	Auxiliary Feedwater Pump PFW02B
(a)	Containment Spray Pump PSI02A	(a)	Containment Spray Pump PSI02B

(a) May be loaded onto safeguards buses anytime after buses are energized.

Table 3.2.1-10
Instrument Buses, Regulated Power Supplies And Distribution Panels

120 VAC Instrument Bus A (IBPDPCBAR)

- 118 VAC Twinco Regulated Power Supply MQ400A
  - 118 VAC Distribution Panel A (IBPDPCBA)
- 118 VAC Twinco Regulated Power Supply MQ400E
  - 118 VAC Distribution Panel E (IBPDPCBE)
  - 118 VAC Dist Panel GH(IBPDPCBGH)[Spare]

120 VAC Instrument Bus C (IBPDPCBCB)

- 118 VAC Twinco Regulated Power Supply MQ400C
  - 118 VAC Distribution Panel C (IBPDPCBC)
- 118 VAC Twinco Regulated Power Supply MQ400G [Spare]
- 118 VAC Twinco Regulated Power Supply MQ400H [Spare]

120 VAC Instrument Bus B (IBPDPCBCB)

- 118 VAC Twinco Regulated Power Supply MQ400B
  - 118 VAC Distribution Panel B (IBPDPCBB)

120 VAC Instrument Bus D (IBPDPCBDY)

- 118 VAC Twinco Regulated Power Supply MQ400D
  - 118 VAC Distribution Panel D (IBPDPCBD)

Table 3.2.1-11
Electric Power-Related Annunciator Windows and Locations

Annunciator Window	Window Location
BATTERY ROOMS LOSS OF VENTILATION	C-13
4-KV BUS UNDERVOLTAGE 70% OF NORM	D-8
4-KV BUS UNDERFREQUENCY 57.7 HZ	D-16
INVERTER TROUBLE	E-3
LOSS OF A INSTRUMENT BUS	E-6
LOSS OF B INSTRUMENT BUS	E-14
LOSS OF C INSTRUMENT BUS	E-22
MCC C OR D AUX BKR CAB	E-25
LOSS OF D INSTRUMENT BUS	E-30
GENERATOR STATIC WINDING HI TEMP	J-2
19-KV POTENTIAL TRANSFORMER VOLTAGE	J-3
GENERATOR ISO PHASE BUS COOLING SYSTEM	J-4
#11 OR #12 TRANSFORMER OUT OF SYNCH .	J-5
4-KV MAIN OR TIE BREAKER TRIP	J-6
480 V MAIN OR TIE BREAKER TRIP	J-7
480 V MCC SUPPLY BREAKER TRIP	J-8
SAFEGUARD BREAKER TRIP	J-9
GENERATOR VOLTAGE REGULATOR MANUAL	J-10
GENERATOR REVERSE POWER	J-11
GENERATOR MAIN TRANSFORMER ANNUNCIATOR	J-12
#11 OR #12 TRANSFORMER LOW SIDE PARALLELED	J-13
480 V BUS 14-16 OR 17-18 TIE BKR CLOSED	J-14
BATTERY CHARGER FAILURE OR PA INVERTER TROUBLE	J-15
GENERATOR VOLTAGE REGULATOR FIELD FORCING	J-18
GENERATOR FIELD FAILURE	J-19
GENERATOR TRANSFORMER OVEREXCITATION	J-20
1A OR 1B BATTERY UNDERVOLTAGE	J-21
GENERATOR PIPE CABLE PILOT WIRE MONITOR	J-22
BATTERY BANK GROUND	J-23
EMERGENCY DIESEL GENERATOR 1A PANEL	J-24
GENERATOR EXCITER FIELD BREAKER TRIP	J-26
GENERATOR VOLTAGE REGULATOR POWER UNIT BIAS	J-27
STATION 13A TROUBLE	J-28
480 V TRANSFORMER BREAKER TRIP	J-29
GENERATOR FIELD GROUND	J-30
VITAL BATTERY MONITORING SYSTEM	J-31
EMERGENCY DIESEL GENERATOR 1B PANEL	J-32

Table 3.2.1-11
Electric Power-Related Annunciator Windows and Locations

Annunciator Window	Window Location
11A OR 11B BUS UNDERFREQUENCY	L-2
11A OR 11B BUS UNDERVOLTAGE	L-3
SAFEGUARD BUS MAIN BREAKER OVERCURRENT TRIP	L-5
BUS 13 UNDERVOLTAGE NONE-SAFEGUARD	L-6
BUS 16 UNDERVOLTAGE SAFEGUARDS	L-7
480 V GROUND	L-8
SAFEGUARD BUS D/G BREAKER OVERCURRENT TRIP	L-13
BUS 14 UNDERVOLTAGE - SAFEGUARDS	L-14
BUS 17 UNDERVOLTAGE - SAFEGUARDS	L-15
AUXILIARY TRANSFORMER #11	L-19
12A TRANSFORMER OR 12A BUS TROUBLE	L-20
BUS 15 UNDERVOLTAGE NON-SAFEGUARDS	L-22
BUS 18 UNDERVOLTAGE SAFEGUARDS	L-23
34-KV BREAKER LO AIR PRESSURE 110 PSI	L-25
34-KV LINE 767 PILOT WIRE MONITOR	L-26
34-KV BREAKER TRIP	L-27
12B TRANSFORMER OR 12B BUS TROUBLE	L-28
4-KV BUS DIFFERENTIAL LOCKOUT	L-29
SAFEGUARD DC FAILURE	L-31

Table 3.2.1-12
Undervoltage Auxiliary Relay Functions

27X1/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #1
27BX1/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #1

- Trips Circuit Breaker 52/14
- Trigger Diesel Generator start Logic
- Trips Circuit Breaker 52/SIPC2
- Trips Circuit Breaker 52/BT14-13

27X2/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #2
27BX2/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #2

- Trips Circuit Breaker 52/SIP1A (PSI01A)
- Trips Circuit Breaker 52/CF1D (ACF08D)
- Trips Circuit Breaker 52/ABEF-1G
- Trips Circuit Breaker 52/FUT

27X3/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #3
27BX3/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #3

- Trips Circuit Breaker 52/MAFP1A (PAF01A)
- Trips Circuit Breaker 52/RHRP1A (PAC01A)
- Trips Circuit Breaker 52/PHCG
- Trips Circuit Breaker 52/CCP1A (PAC02A)
- Triggers Diesel Generator Starting Logic

27X4/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #4
27BX4/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #4

- Trips Circuit Breaker 52/CHP1A (PCH01A)
- Trips Circuit Breaker 52/CF1A (ACF08A)
- Trips Circuit Breaker 52/SPARE
- Trips Circuit Breaker 52/SAFWP1C (PSF01A)

Table 3.2.1-12
Undervoltage Auxiliary Relay Functions

27X5/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #5
27BX5/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #5
	- Trips Circuit Breaker 52/BT16-14 - Trips Circuit Breaker 52/18 - Trips Circuit Breaker 52/14SS
27X6/14	480 VAC Bus 14 Undervoltage Auxiliary Relay #6
27BX6/14	480 VAC Bus 14 Undervoltage Auxiliary Backup Relay #6
	- Close Circuit Breaker 52/MAFP1A (PAF01A) - Trigger Safety Injection Signal Train A Agastats & slave relays in conjunction with SI Slave Relay SI-10X (27X6/14 only; wiring for 27BX6/14 is not connected)
27X1/16	480 VAC Bus 16 Undervoltage Auxiliary Relay #1
27BX1/16	480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #1
	- Trips Circuit Breaker 52/16 - Triggers the Diesel Generator starting logic - Trips Circuit Breaker 52/SIP1B (PSI01B) - Trips Circuit Breaker 52/BT16-15
27X2/16	480 VAC Bus 16 Undervoltage Auxiliary Relay #2
27BX2/16	480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #2
	- Trips Circuit Breaker 52/BT16-14 permissive - Trips Circuit Breaker 52/SIP1C1 (PSI01C) - Trips Circuit Breaker 52/CF1B (ACF01B) - Trips Circuit Breaker 52/CF1C (ACF01C)

Table 3.2.1-12
Undervoltage Auxiliary Relay Functions

27X3/16 480 VAC Bus 16 Undervoltage Auxiliary Relay #3
27BX3/16 480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #3

- Trips Circuit Breaker 52/FUT (Spare Breaker)
- Trips Circuit Breaker 52/MAFP1B (PAF01B)
- Trips Circuit Breaker 52/RHRP1B (PAC01B)
- Trips Circuit Breaker 52/CHP1B (PAC02B)
- Trips Circuit Breaker 52/CHP1C (PAC02C)

27X4/16 480 VAC Bus 16 Undervoltage Auxiliary Relay #4
27BX4/16 480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #4

- Trip Circuit Breaker 52/PHBG
- Trip Circuit Breaker 52/CCP1B (PAC02B)
- Trip Circuit Breaker 52/SFPPB
- Trip Circuit Breaker 52/SPARE
- Trip Circuit Breaker 52/SAFWP1D (PSF01B)

27X5/16 480 VAC Bus 16 Undervoltage Auxiliary Relay #5
27BX5/16 480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #5

- Trip Circuit Breaker 52/17
- Trip Circuit Breaker 52/16SS
- Trigger Diesel Generator starting logic

27X6/16 480 VAC Bus 16 Undervoltage Auxiliary Relay #6
27BX6/16 480 VAC Bus 16 Undervoltage Auxiliary Backup Relay #6

- Trigger Safety Injection Signal Train B Agastats & slave relays in conjunction with SI Slave Relay SI-20X (27X6/16 only: wiring for 27BX6/16 is not connected)
- Close Circuit Breaker 52/MAFP1B (PAF01B)

Table 3.2.1-12
Undervoltage Auxiliary Relay Functions

27X1/17	480 VAC Bus 17 Undervoltage Auxiliary Relay #1
27BX1/17	480 VAC Bus 17 Undervoltage Auxiliary Backup Relay #1

- Trip Circuit Breaker 52/17
- Trigger Diesel Generator starting logic
- Trip Circuit Breaker 52/FUT
- Trip Circuit Breaker 52/MCC1G2 (Motor Control Center G)

27X2/17	480 VAC Bus 17 Undervoltage Auxiliary Relay #2
27BX2/17	480 VAC Bus 17 Undervoltage Auxiliary Backup Relay #2

- Trip Circuit Breaker 52/FP
- Trip Circuit Breaker 52/IH1B
- Trip Circuit Breaker 52/IH1D
- Trip Circuit Breaker 52/SWP1B
- Trip Circuit Breaker 52/SWP1D

27X3/17	480 VAC Bus 17 Undervoltage Auxiliary Relay #3
27BX3/17	480 VAC Bus 17 Undervoltage Auxiliary Backup Relay #3

- Trip Circuit Breaker 52/BT17-18
- Trip Circuit Breaker 52/16
- Trip Circuit Breaker 52/17SS
- Trigger Diesel Generator start logic

27X4/17	480 VAC Bus 17 Undervoltage Auxiliary Relay #4
27BX4/17	480 VAC Bus 17 Undervoltage Auxiliary Backup Relay #4

- Wired to trigger Safety Injection Signal Train B Agastats & slave relays in conjunction with SI Slave Relay SI-20X, but wiring is not connected

Table 3.2.1-12
Undervoltage Auxiliary Relay Functions

27X1/18	480 VAC Bus 18 Undervoltage Auxiliary Relay #1
27BX1/18	480 VAC Bus 18 Undervoltage Auxiliary Backup Relay #1
	- Trip Circuit Breaker 52/18 - Trigger Diesel Generator start logic - Trip Circuit Breaker 52/MCC1G1 (Motor Control Center G) - Trip Circuit Breaker 52/FUT
27X2/18	480 VAC Bus 18 Undervoltage Auxiliary Relay #2
27BX2/18	480 VAC Bus 18 Undervoltage Auxiliary Backup Relay #2
	- Trip Circuit Breaker 52/SWP1C (PSW01C) - Trip Circuit Breaker 52/SWP1A (PSW01A) - Trip Circuit Breaker 52/IH1C - Trip Circuit Breaker 52/IH1A
27X3/18	480 VAC Bus 18 Undervoltage Auxiliary Relay #3
27BX3/18	480 VAC Bus 18 Undervoltage Auxiliary Backup Relay #3
	- Trip Circuit Breaker 52/14 - Trip Circuit Breaker 52/BT17-18 - Trip Circuit Breaker 52/18SS - Trigger Diesel Generator start logic
27X4/18	480 VAC Bus 18 Undervoltage Auxiliary Relay #4
27BX4/18	480 VAC Bus 18 Undervoltage Auxiliary Backup Relay #4
	- Wired to trigger Safety Injection Signal Train A Agastats & slave relays in conjunction with SI Slave Relay SI-10X, but wiring is not connected

Table 3.2.1-13
ESFAS System Relay Functions

Master Relay SIA-1:

Is an input to RPS Channel A
Is an input to RPS Channel B
Trips Auxiliary Relay SI-10X
Trips Auxiliary Relay SI-11X
Trips Auxiliary Relay SI-12X

Master Relay SIA-2:

Is an input to RPS Channel A
Is an input to RPS Channel B
Trips Auxiliary Relay SI-20X
Trips Auxiliary Relay SI-21X
Trips Auxiliary Relay SI-22X

Master Relay SIF-1:

Trips Auxiliary Relay F10X
Trips Auxiliary Relay F30X

Master Relay SIF-2:

Trips Auxiliary Relay F20X
Trips Auxiliary Relay F40X

Auxiliary Relay SI-10X:

Trips Auxiliary Relay SI-13X
Trips Auxiliary Relay SI-14X
Trips Auxiliary Relay SI-15X
Trips Auxiliary Relay SI-16X
Trips Auxiliary Relay SI-17X
Trips Auxiliary Relay SI-18X
Trips Steam Line Isolation Master Relay MS1
Trips Steam Line Isolation Master Relay MS3
Trips Containment Ventilation Isolation Master Relay V1
Trips Feedwater Isolation Master Relay F1
Trips Feedwater Isolation Master Relay F3
Triggers Motor Control Center C Load Shedding
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/871A
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C2
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/RHRP1A
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SWP1AC

Auxiliary Relay SI-10X: (continued)

Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/CF1A
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/MAFP1A
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/1C2X
Trips Safety Injection Signal Slave Relay SISP1A
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SF1
Trips Safety Injection Signal Slave Relay 871X

Auxiliary Relay SI-11X:

Trips the feed breaker to Station Service Transformer PXABSS014
Trips the breaker to Main Feedwater Pump PFW01A
Trips the breaker to Main Feedwater Pump PFW01B
Trips the breaker to Charging Pump PCH01A
Trips Agastat time delay relay 2/BLA [KDG01A/Bus 18]
Closes the breaker for AFW Pump PAF01A
Opens AOV 4561 [Containment Fan Coolers SW Discharge]
Triggers AFW MOV 4007 flow control bypass valve 4480

Auxiliary Relay SI-12X:

Trips Auxiliary Relay SI-13X
Trips Auxiliary Relay SI-14X
Trips Auxiliary Relay SI-15X
Trips Auxiliary Relay SI-16X
Trips Auxiliary Relay SI-17X
Trips Auxiliary Relay SI-18X
Trips the breaker to CCW Pump PAC02A
Trips the breaker for the Pressurizer Heaters Control Group
Trips the breaker for Circ. Water Inlet Heaters Group A

Auxiliary Relay SI-13X:

Trips Auxiliary Building Exhaust Fan G
Trips the breaker from Bus 18 to Motor Control Center G
Trips the breaker for Circ. Water Inlet Heaters Group C

Auxiliary Relay SI-14X:

Trips the breaker for Standby AFW Pump PSF01A
Triggers RWST To PSI01C MOV 1815A
Triggers RWST To PSI01C MOV 1815B
Trips the supply breaker to Station Service Transformer PXSHSS018

Table 3.2.1-13
ESFAS System Relay Functions

Auxiliary Relay SI-15X:

Triggers RWST To SI Pumps Suction Isolation MOV 825A
Triggers BAST To SI Pumps Suction MOV 826A
Triggers BAST To SI Pumps Suction MOV 826B
Triggers Accumulator Discharge MOV 841
Triggers RHR Pumps Discharge To RV MOV 852A

Auxiliary Relay SI-16X:

Closes Service Water header isolation MOV 4609
Triggers PSI01A To Loop B Hot Leg MOV 878A
Triggers PSI01B To Loop A Hot Leg MOV 878C
Closes Service Water header isolation MOV 4616

Auxiliary Relay SI-17X:

Closes Service Water header isolation MOV 4615
Closes Service Water header isolation MOV 4663
Closes Service Water header isolation MOV 4614
Closes Service Water header isolation MOV 4670
Triggers Containment Ventilation Fan Relay CF1AL

Auxiliary Relay SI-18X:

Opens the tie breaker between 480 VAC Buses 13 and 14
Opens the tie breaker between 480 VAC Buses 16 and 15
Trips the output breaker from Station Service Transformer PXABSS014
Trips the output breaker from Station Service Transformer PXSHSS018
Opens the tie breaker between 480 VAC Buses 16 and 14
Opens the tie breaker between 480 VAC Buses 17 and 18
Is an input to diesel generator KDG01A's starting circuit

Auxiliary Relay SI-20X:

Trips Auxiliary Relay SI-23X
Trips Auxiliary Relay SI-24X
Trips Auxiliary Relay SI-25X
Trips Auxiliary Relay SI-26X
Trips Auxiliary Relay SI-27X
Trips Auxiliary Relay SI-28X
Trips Steam Line Isolation Master Relay MS2
Trips Steam Line Isolation Master Relay MS4
Trips Containment Ventilation Isolation Master Relay V2Is an input to Safety Injection Sequence Slave Relays Train B

Table 3.2.1-13
ESFAS System Relay Functions

Auxiliary Relay SI-20X (continued):

Trips Feedwater Isolation Master Relay F2
Trips Feedwater Isolation Master Relay F4
Triggers Motor Control Center D Load Shedding

Auxiliary Relay SI-21X:

Trips the feed breaker to Station Service Transformer PXABSS016
Trips the breaker to Main Feedwater Pump PFW01A
Trips the breaker to Main Feedwater Pump PFW01B
Trips the breaker to Charging Pump PCH01B
Trips the breaker to Charging Pump PCH01C
Trips Agastat time delay relay 2/BLB [KDG01B/Bus 17]
Closes the breaker for AFW Pump PAF01B
Opens AOV 4562 [Containment Fan Coolers SW Discharge]
Triggers AFW MOV 4008 flow control bypass valve 4481

Auxiliary Relay SI-22X:

Trips Auxiliary Relay SI-23X
Trips Auxiliary Relay SI-24X
Trips Auxiliary Relay SI-25X
Trips Auxiliary Relay SI-26X
Trips Auxiliary Relay SI-27X
Trips Auxiliary Relay SI-28X
Trips the breaker to CCW Pump PAC02B
Trips the breaker to the motor driven Fire Water Pump
Trips the breaker for the Pressurizer Heaters Backup Group

Auxiliary Relay SI-23X:

Trips the breaker from Bus 17 to Motor Control Center G
Trips the breaker for Circ. Water Inlet Heaters Group B
Trips the breaker for Circ. Water Inlet Heaters Group D

Auxiliary Relay SI-24X:

Trips the breaker for Standby AFW Pump PSF01B
Triggers RWST To PSI01C MOV 1815A
Triggers RWST To PSI01C MOV 1815B
Trips the supply breaker to Station Service Transformer PXSHSS017

Table 3.2.1-13
ESFAS System Relay Functions

Auxiliary Relay SI-25X:

Triggers RWST To SI Pumps Suction Isolation MOV 825B
Triggers BAST To SI Pumps Suction MOV 826C
Triggers BAST To SI Pumps Suction MOV 826D
Triggers Accumulator Discharge MOV 841

Auxiliary Relay SI-26X:

Triggers RHR Pumps Discharge To RV MOV 852B
Closes Service Water header isolation MOV 4780
Triggers Loop A Accumulator B Discharge MOV 865
Triggers PSI01A To Loop B Cold Leg MOV 878B
Triggers PSI01B To Loop A Cold Leg MOV 878D

Auxiliary Relay SI-27X:

Closes Service Water header isolation MOV 4735
Closes Service Water header isolation MOV 4734
Closes Service Water header isolation MOV 4733
Closes Service Water header isolation MOV 4664
Closes Service Water header isolation MOV 4613
Triggers Containment Ventilation Fan Relay CF1CL

Auxiliary Relay SI-28X:

Opens the tie breaker between 480 VAC Buses 14 and 13
Opens the tie breaker between 480 VAC Buses 16 and 15
Trips the output breaker from Station Service Transformer PXABSS016
Trips the output breaker from Station Service Transformer PXSHSS017
Opens the tie breaker between 480 VAC Buses 16 and 14
Opens the tie breaker between 480 VAC Buses 17 and 18
Is an input to diesel generator KDG01B's starting circuit

Safety Injection Signal Agastat Time Delay Slave Relay 2/871A:

Triggers MOV 871A

Safety Injection Signal Agastat Time Delay Slave Relay 2/871B:

Triggers MOV 871B

Table 3.2.1-13
ESFAS System Relay Functions

Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C1: [Gate SI363]

Closes the Bus 16 circuit breaker for Safety Injection Pump PSI01C
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C2

Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C2:

Closes the Bus 14 circuit breaker for Safety Injection Pump PSI01C
Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C1

Safety Injection Signal Agastat Time Delay Slave Relay 2/RHRP1A:

Closes the Bus 14 circuit breaker for RHR Pump PAC01A

Safety Injection Signal Agastat Time Delay Slave Relay 2/RHRP1B:

Closes the Bus 16 circuit breaker for RHR Pump PAC01B

Safety Injection Signal Agastat Time Delay Slave Relay 2/SWP1AC:

Closes the Bus 18 circuit breaker for Service Water Pump PSW01A
Closes the Bus 18 circuit breaker for Service Water Pump PSW01C

Safety Injection Signal Agastat Time Delay Slave Relay 2/SWP1BD:

Closes the Bus 17 circuit breaker for Service Water Pump PSW01B
Closes the Bus 17 circuit breaker for Service Water Pump PSW01D

Safety Injection Signal Agastat Time Delay Slave Relay 2/CF1A:

Closes the Bus 14 circuit breaker for Containment Reci. Fan Cooler Fan ACF08A

Safety Injection Signal Agastat Time Delay Slave Relay 2/CF1B:

Closes the Bus 16 circuit breaker for Containment Reci. Fan Cooler Fan ACF08B

Safety Injection Signal Agastat Time Delay Slave Relay 2/CF1C:

Closes the Bus 16 circuit breaker for Containment Reci. Fan Cooler Fan ACF08C

Safety Injection Signal Agastat Time Delay Slave Relay 2/CF1D:

Closes the Bus 14 circuit breaker for Containment Reci. Fan Cooler Fan ACF08D

Table 3.2.1-13
ESFAS System Relay Functions

Safety Injection Signal Agastat Time Delay Slave Relay 2/MAFP1A:

Closes the Bus 14 circuit breaker for AFW Pump PAF01A

Safety Injection Signal Agastat Time Delay Slave Relay 2/MAFP1B:

Closes the Bus 14 circuit breaker for AFW Pump PAF01B

Safety Injection Signal Agastat Time Delay Slave Relay 2/1C2X:

Trips Safety Injection Signal Agastat Time Delay Slave Relay 2/SIP1C2

Safety Injection Signal Agastat Time Delay Slave Relay 2/SF1:

Is an input to the reset coil of Safety Injection Signal Master Relay SI-A1
Is an input to the reset coil of Safety Injection Signal Manual Activation Relay SI-M1

Safety Injection Signal Agastat Time Delay Slave Relay 2/SF2:

Is an input to the reset coil of Safety Injection Signal Master Relay SI-A2
Is an input to the reset coil of Safety Injection Signal Manual Activation Relay SI-M2

Safety Injection Signal Slave Relay SISP1A:

Closes the Bus 14 circuit breaker for Safety Injection Pump PSI01A
Trips Agastat Time Delay Relay 2/AB on MOV 825A

Safety Injection Signal Slave Relay SISP1B:

Closes the Bus 16 circuit breaker for Safety Injection Pump PSI01B
Trips Agastat Time Delay Relay 2/CD on MOV 825B

Safety Injection Signal Slave Relay 871X:

Is an input to MOV 871A in conjunction with SI SIgnal Agastat Relay 2/871A
Is an input to MOV 871B in conjunction with SI SIgnal Agastat Relay 2/871B

Steam Line Isolation Loop A Master Relay MS1:

Triggers SG A MSIV Solenoid Valve 3517C (Vent)
Triggers SG A MSIV Solenoid Valve 3517A (Air Supply)

Table 3.2.1-13
ESFAS System Relay Functions

Steam Line Isolation Loop A Master Relay MS2:

Triggers SG A MSIV Solenoid Valve 3517D (Vent)
Triggers SG A MSIV Solenoid Valve 3517B (Air Supply)

Steam Line Isolation Loop B Master Relay MS3:

Triggers SG B MSIV Solenoid Valve 3516C (Vent)
Triggers SG B MSIV Solenoid Valve 3516A (Air Supply)

Steam Line Isolation Loop B Master Relay MS4:

Triggers SG B MSIV Solenoid Valve 3516D (Vent)
Triggers SG B MSIV Solenoid Valve 3516B (Air Supply)

Containment Isolation Master Relay C1:

Triggers Containment Isolation Auxiliary Relay C15X

Containment Isolation Master Relay C2:

Triggers Containment Isolation Auxiliary Relay C25X

Containment Isolation Auxiliary Relay C15X:

Is an input to Containment Isolation Rack CI-A1
Is an input to Containment Isolation Rack CI-A2

Containment Isolation Auxiliary Relay C25X:

Is an input to Containment Isolation Rack CI-B1
Is an input to Containment Isolation Rack CI-B2

Containment Spray Master Relay S1:

Triggers Containment Spray Auxiliary Relay S10X

Containment Spray Master Relay S2:

Triggers Containment Spray Auxiliary Relay S20X

Table 3.2.1-13
ESFAS System Relay Functions

Containment Spray Auxiliary Relay S10X:

Triggers CS Pump PSI02A Discharge MOV 860A
Triggers CS Pump PSI02B Discharge MOV 860C
Closes the breaker to CS Pump PSI02A
Triggers Spray Additive Tank Discharge AOV 836A

Containment Spray Auxiliary Relay S20X:

Triggers CS Pump PSI02A Discharge MOV 860B
Triggers CS Pump PSI02B Discharge MOV 860D
Closes the breaker to CS Pump PSI02B
Triggers Spray Additive Tank Discharge AOV 836B

Containment Ventilation Isolation Master Relay V1:

Triggers Containment Ventilation Isolation Auxiliary Relay V11X

Containment Ventilation Isolation Master Relay V2:

Triggers Containment Ventilation Isolation Auxiliary Relay V21X

Containment Ventilation Isolation Auxiliary Relay V11X:

Is an input to Containment Isolation Rack CI-A2

Containment Ventilation Isolation Auxiliary Relay V21X:

Is an input to Containment Isolation Rack CI-B2

Steam Generator A Feedwater Isolation Master Relay F1:

Triggers Steam Generator A Feedwater Isolation Auxiliary Relay F10X

Steam Generator A Feedwater Isolation Master Relay F2:

Triggers Steam Generator A Feedwater Isolation Auxiliary Relay F20X

Steam Generator A Feedwater Isolation Auxiliary Relay F10X:

Triggers the solenoid to Main Feedwater Control AOV 4269 (SG A)
Triggers the solenoid to Main Feedwater Control Bypass AOV 4271 (SG A)

Table 3.2.1-13
ESFAS System Relay Functions

Steam Generator A Feedwater Isolation Auxiliary Relay F20X:

Triggers the solenoid to Main Feedwater Control AOV 4269 (SG A)
Triggers the solenoid to Main Feedwater Control Bypass AOV 4271 (SG A)

Steam Generator B Feedwater Isolation Master Relay F3:

Triggers Steam Generator B Feedwater Isolation Auxiliary Relay F30X

Steam Generator B Feedwater Isolation Master Relay F4:

Triggers Steam Generator B Feedwater Isolation Auxiliary Relay F40X

Steam Generator B Feedwater Isolation Auxiliary Relay F30X:

Triggers the solenoid to Main Feedwater Control AOV 4270 (SG B)
Triggers the solenoid to Main Feedwater Control Bypass AOV 4272 (SG B)

Steam Generator B Feedwater Isolation Auxiliary Relay F40X:

Triggers the solenoid to Main Feedwater Control AOV 4270 (SG B)
Triggers the solenoid to Main Feedwater Control Bypass AOV 4272 (SG B)

Table 3.2.1-14
Engineered Safety Feature Actuation System Instrumentation Setpoints
(As Quoted From Technical Specifications Table 3.5-4)

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES*
1. SAFETY INJECTION AND FEEDWATER ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. High Containment Pressure	$\leq$ 4.0 psig	$\leq$ 5.0 psig
c. Low Pressurizer Pressure	$\geq$ 1723 psig	$\geq$ 1715 psig
d. Low Steam Line Pressure	$\geq$ 514 psig	$\geq$ 500 psig
2. CONTAINMENT SPRAY		
a. Manual	Not Applicable	Not Applicable
b. High-High Containment Pressure	$\leq$ 28 psig	
3. CONTAINMENT ISOLATION		
a. Containment Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable	Not Applicable
b. Containment Ventilation Isolation		
1. Manual	Not Applicable	Not Applicable
2. High Containment Radioactivity	Note 3	Not Applicable
3. From Safety Injection	Not Applicable	Not Applicable
4. Manual Spray	Not Applicable	Not Applicable
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. High Containment Pressure	$\leq$ 18 psig	$\leq$ 20 psig
b. High Steam Flow, Coincident with Low T_{avg} and SI	dp corresponding to $\leq$ 0.49 psig x 106 lbs/hr at 755 psig $T_{avg} \geq 545°F$	dp corresponding to $\leq$ 0.55 x 106 lbs/hr at 755 psig $T_{avg} \geq 543°F$
c. High-High Steam Line Flow Coincident with SI2	dp corresponding to $\leq$ 3.6 x 106 lbs/hr at 755 psig	dp corresponding to < 3.7 x 10^6 lbs/hr at 755 psig

Table 3.2.1-14
Engineered Safety Feature Actuation System Instrumentation Setpoints
(As Quoted From Technical Specifications Table 3.5-4)

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES*
5. FEED WATER ISOLATION		
a. High Steam Generator Water Level	≤ 67% of narrow range instrument span each steam generator	≤ 68% of narrow range instrument span each steam generator
6. AUXILIARY FEEDWATER		
a. Low-Low Steam Generator Water Level	≥ 17% of narrow range instrument span each steam generator	≥ 16% of narrow range instrument span each steam generator See Note 1.
b. From Safety Injection	Not Applicable	Not Applicable
c. Loss of 4-kV Voltage Start TAFP)	62% of 4160 volts Note 2	Note 2
d. Feedwater Pump Breakers Open (Start TAFP)	Not Applicable	Not Applicable
7. LOSS OF VOLTAGE		
a. 480 V Safeguards Bus Under-voltage (Loss of Voltage)	see Figure 2.3-1	
a. 480 V Safeguards Bus Under-voltage (Degraded Voltage)	see Figure 2.3-1	
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS		
a. Pressurizer Pressure (block, unblock SI)	2000 psig	2000 psig

Note 1: A positive 11% error has been included in the setpoint to account for errors which may be introduced into the steam generator level measurement system at a containment temperature of 286°F as determined by an evaluation performed on temperature effects on level systems as required by IE Bulletin 79-21.

Note 2: This setpoint value is from inverse time curve for CVT relay (406C883) with tap setting of 82 volts and time dial setting of 1. Delay at 62% voltage is 3.6 seconds. The allowable values are 15% of the trip setpoint.

Table 3.2.1-14

Engineered Safety Feature Actuation System Instrumentation Setpoints

(As Quoted From Technical Specifications Table 3.5-4)

Note 3: The trip setpoints for containment ventilation isolation while purging shall be established to correspond to the limits of 10 CFR Part 20 for unrestricted areas. The setpoints are determined procedurally in accordance with Technical Specification 3.9.2 by calculating effluent monitor count rate limits, which take into account appropriate factors for detector calibration, ventilation flow rate, and average site meteorology.

*Allowable Values are those values assumed in accident analysis.

Table 3.2.1-15

Engineered Safety Feature Actuation Instrumentation

(As Quoted From Technical Specifications Table 3.5-2)

No. Functional Unit	1 Total No. of Channels	2 No. of Channels To Trip	3 Min. Operable Channel	4 Permissible Bypass Conditions	5 Operator Action If Conditions Of Column 1 or 3 Cannot Be Met	6 Channel Operable Above
1. SAFETY INJECTION						
a. Manual	2	1	2		8	T_{RCS}=350°F
b. High Containment Pressure	3	2	2		9	T_{RCS}=350°F
c. Steam Generator Low Steam Pressure/Loop	3	2	2	Primary pressure less than 2000 psig	9	T_{RCS}=350°F
d. Pressurizer Low Pressure	3	2	2	Primary pressure less than 2000 psig	9	T_{RCS}=350°F
2. CONTAINMENT SPRAY						
a. Manual	2	2**	2		10	Cold Shutdown
b. Hi-Hi Containment Pressure (Containment Spray)	2 sets of 3	2 of 3 in both sets	2 per set in either set		11	Cold Shutdown
3. AUXILIARY FEEDWATER Motor and Turbine Driven						
a. Manual	1/pump	1/pump	1/pump		8	T_{RCS}=350°F
b. Stm. Gen. Water Level-low-low						
i. Start Motor Driven Pumps	3/SG	2/SG either gen.	2/SG both gen.		9	T_{RCS}=350°F
ii. Start Turbine Driven Pump	3/SG	2/SG both gen.	2/SG either gen.		12	T_{RCS}=350°F
c. Loss of 4-KV Voltage Start Turbine Driven Pump	2/bus	1/bus (both buses)	2/bus (either bus)		12	T_{RCS}=350°F
d. Safety Injection Start Motor Driven Pumps		(See Table 3.5-2, Item 1)				

**Must actuate 2 switches simultaneously.

Table 3.2.1-15
Engineered Safety Feature Actuation Instrumentation
(As Quoted From Technical Specifications Table 3.5-2)

	1	2	3	4	5	6
No. Functional Unit	Total No. of Channels	No. of Channels To Trip	Min. Operable Channel	Permissible Bypass Conditions	Operator Action If Conditions Of Column 1 or 3 Cannot Be Met	Channel Operable Above
e. Trip of both Feed-water Pumps starts Motor Driven Pumps Standby Motor Driven	2/pump	1/pump both pumps	2/pump either pump		6	5% power
a. Manual	1/pump	1/pump	1/pump		8	TRCS=350°F
4. CONTAINMENT ISOLATION						
4.1 Containment Isolation						
a. Manual	2	1	2		10	Cold Shutdown
b. Safety Injection (Auto Actuation)		(See Table 3.5-2, Item 1)				
4.2 Containment Ventilation Isolation						
a. Manual	2	1	1		13	Cold Shutdown
b. High Containment Radioactivity	2	1	2		13	Cold Shutdown
c. Safety Injection		(See Table 3.5-2, Item 1)				
5. STEAM LINE ISOLATION						
a. Hi-Hi Steam Flow with Safety Injection	2 Hi-Hi SF w/ SI for each loop	1 SF w/ SI in each loop	***		12	*T_{RCS}=350°F w/MSIV's open
b. Hi Steam Flow & 2 of 4 Low T_{avg} with Safety Injection	2 Hi SF & 4 low T_{avg} with SI for each loop	1 Hi SF & 2 low T_{avg} with SI for each loop	***		12	*T_{RCS}=350°F w/MSIV's open
c. Containment Pressure	3	2	2		2	*T_{RCS}=350°F w/MSIV's open

Table 3.2.1-15

Engineered Safety Feature Actuation Instrumentation

(As Quoted From Technical Specifications Table 3.5-2)

No.	Functional Unit	1 Total No. of Channels	2 No. of Channels To Trip	3 Min. Operable Channel	4 Permissible Bypass Conditions	5 Operator Action If Conditions Of Column 1 or 3 Cannot Be Met	6 Channel Operable Above
d.	Manual	1/loop	1/loop	1/loop		8	$*T_{RCS}$=350°F w/MSIV's open
6.	FEEDWATER LINE ISOLATION						
a.	Safety Injection		(See Table 3.5-2, Item 1)				
b.	Hi Steam Generator Level	3/loop	2/loop in either loop	2/loop in both loops		9	$**T_{RCS}$=350°F w/FW Isol valves open

ACTION STATEMENTS (labeled consistently with Technical Specifications Table 3.5-2)

6. With the number of operable channels less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the tripped condition within 1 hour. Should the next Channel Functional Test require the bypass of an inoperable channel to avoid the generation of a reactor trip signal, operation may proceed until this Channel Functional Test. At the time of this next Channel Functional Test, or if at any time the number of operable channels is less than the Minimum Operable Channels, be at a condition where channel operability is not required according to Column 6 of Table 3.5-1 within the next 6 hours.

8. With the number of operable channels one less than the Minimum Operable Channels required, restore the inoperable channel to operable status within 48 hours or be in Hot Shutdown with the next 6 hours and at an RCS temperature less than 350°F within the next 6 hours.

9. With the number of operable channels one less than the Total Number of Channels required, operation may proceed until the next Channel Functional Test provided the inoperable channel is placed in the tripped position within 1 hour. At the next Channel Functional Test, or at any time the number of operable channels is less than the Minimum Operable Channels required, be at Hot Shutdown within the next 6 hours and at an RCS temperature less than 350°F within the following 6 hours.

10. With the number of operable channels one less than the Minimum Operable Channels required, restore the inoperable channel to operable status within 48 hours or be in Hot Shutdown with the next 6 hours and at cold shutdown within the next 30 hours.

11. With the number of operable channels less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the tripped condition within 1 hour. Should the next Channel Functional Test require the bypass of an inoperable channel to avoid the generation of an actuation signal, operation may proceed until this Channel Functional Test. At the time of this Channel Functional Test, or if at any time the number of operable channels is less than the Minimum Operable Channels required, be at Hot Shutdown within 6 hours and at Cold Shutdown within the following 30 hours.

12. With the number of operable channels less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the tripped condition within 1 hour. Should the next Channel Functional Test require the bypass of an inoperable channel to avoid the generation of an actuation signal, operation may proceed until this Channel Functional Test. At the time of this Channel Functional Test, or if at any time the number of operable channels is less than the Minimum Operable Channels required, be at hot shutdown within 6 hours and at an RCS temperature less than 350°F within 6 hours.

13. With the number of operable channels less than the Minimum Operable Channels required, operation may continue provided the containment purge and exhaust valves are maintained closed.

Table 3.2.1-16
ESFAS Instrument Test Frequencies
(As Quoted from Technical Specifications Tables 4.1-1 and 4.1-5 and FSAR Figure 7.3-1)

Measurement	Instrument	Check	Calibration	Test
CR area radiation Hi	RC-1 K9750-R1	D	R	M
Cnmt Air particle Hi	RC-11 K850-R11	channel check -W source check -N.A.	R	Q
Cnmt Radiogas Hi	RC-12 K850-R12	channel check -D source check -PR	R	Q
Cnmt Pressure Hi	PC-945A	S	R	M
	PC-947A	S	R	M
	PC-949A	S	R	M
Cnmt Pressure Hi-Hi	PC-946A	S	R	M
	PC-948A	S	R	M
	PC-950A	S	R	M
	PC-945B	S	R	M
	PC-946B	S	R	M
	PC-947B	S	R	M
	PC-948B	S	R	M
	PC-949B	S	R	M
	PC-950B	S	R	M
Pzr Pressure Lo	PC-429C	S	R	M
	PC-429D	S	R	M
	PC-430E	S	R	M
	PC-430F	S	R	M
	PC-431G	S	R	M
	PC-431I	S	R	M
Steam Line Flow Loop A Hi	FC-464A	S	R	M
	FC-465A	S	R	M

Table 3.2.1-16
ESFAS Instrument Test Frequencies
(As Quoted from Technical Specifications Tables 4.1-1 and 4.1-5 and FSAR Figure 7.3-1)

Measurement	Instrument	Check	Calibration	Test
Steam Line Flow				
Loop A Hi-Hi	FC-464B	S	R	M
	FC-465B	S	R	M
Steam Line Flow				
Loop B Hi	FC-474A	S	R	M
	FC-475A	S	R	M
Steam Line Flow				
Loop B Hi-Hi	FC-474B	S	R	M
	FC-475B	S	R	M
Steam Line Pressure				
Loop A lo	PC-468A	S	R	M
	PC-469A	S	R	M
	PC-482A	S	R	M
Steam Line Pressure				
Loop B lo	PC-478A	S	R	M
	PC-479A	S	R	M
	PC-483A	S	R	M
Lo T_{avg} Loop A	TC-401A	S	R	M
	TC-402A	S	R	M
Lo T_{avg} Loop B	TC-403A	S	R	M
	TC-404A	S	R	M

Table 3.2.1-16

ESFAS Instrument Test Frequencies

(As Quoted from Technical Specifications Tables 4.1-1 and 4.1-5 and FSAR Figure 7.3-1)

Notation	Frequency
S, each shift	At least once per 12 hours
D, daily	At least once per 24 hours
W, weekly	At least once per 7 days
M, monthly	At least once per 31 days
Q, quarterly	At least once per 92 days
R, refueling	At least once per 18 months
N.A.	Not Applicable
PR	Within 12 hours prior to each release

Table 3.2.1-17
SI Sequencing Relays

Time from Safeguards Bus Energized (sec)	Equipment Started	Agastat Relay Designator
TRAIN A EQUIPMENT		
0	Safety Injection Pump A	SISP1A
3	MOV 871A opened	2/871A
5	Safety Injection Pump C*	2/SIP1C2
10	Residual Heat Removal Pump A	2/RHRP1A
15	Service Water Pump A or C**	2/SWP1AC
20	Containment Fan A	2/CF1A
25	Containment Fan D	2/CF1D
30	Auxiliary Feedwater Pump A	2/MAFP1A
30	Safety Injection Pump C*	2/1C2X
TRAIN B EQUIPMENT		
0	Safety Injection Pump B	SISP1B
3	MOV 871B opened	2/871B
7	Safety Injection Pump C*	2/SIP1C1
12	Residual Heat Removal Pump B	2/RHRP1B
17	Service Water Pump B or D**	2/SWP1BD
22	Containment Fan B	2/CF1B
27	Containment Fan C	2/CF1C
32	Auxiliary Feedwater Pump B	2/MAFP1B

* *Safety Injection Pump C will first try to start on Train A power. If the Train A Agastat relay fails it will start on Train B power at time = 7 seconds. If the Train A Agastat operates, but the Train A breaker fails, the pump will start on Train B power at time = 30 seconds.*

** *The Service Water Pump that starts is dependent on the position of the two Service Water Pump Selector Switches.*

Table 3.2.1-18
Valve Failure Modes Following Loss of Instrument Air Event

Valves (by location)	Failure Mode
Containment	
Letdown AOV-427FO	
Excess Letdown AOV-310	FC
RCP Seal Return AOV-270B	FO
RCP Thermal Barrier CCW AOV-754B	FO
Letdown Orifices AOV-200A, 200B, 202	FC
Charging AOV-294, 392A	FC
Aux. Spray AOV-296	FC
PRZR Spray PCV-431A, 431B	FC
PRZR PORV PCV-430, 431C	FC
RCP Thermal Barrier CCW AOV-754A	FO
Charging AOV-392B	FC
RCP Seal Return AOV-386	FC
PRZR Sample Valves AOV-951, 953	FC
Auxiliary Building	
Letdown Valve LCV-112A	Fail to VCT
Letdown Valve AOV-371	FC
Charging Line Valve HCV-142	FO
RHR Flow Valves HCV-624, 625	FO
RHR Hx Bypass Flow Valve FCV-626	FC
VCT Makeup Valves AOV-110B, 110C, 111	FC
Charging Pump Suction AOV-112B	FC
Charging Pump Suction AOV-112C	FO
Charging Pump Speed Control	Fails to minimum speed
NaOH Tank Outlet Valves AOV-836A, 836B	FO
Letdown Valve TCV-145	Fails to VCT
Letdown Valve PCV-135	FO
VCT Makeup Valve AOV-110A	FO

Failure Modes: FO - Fails Open FC - Fails Closed

Table 3.2.1-18
Valve Failure Modes Following Loss of Instrument Air Event

Valves (by location)	Failure Mode
Turbine Building	
Heater Drain Pump Recirc Valve 3365	FO (HDT pumps trip if recirc. Valve full open for 1 minute)
Condensate Trim Valves 9508D, 9508G	FC
Condensate Makeup Valve 4316	FC
Steam Dump Valves 3349, 3351, 3353, 3355	FC
H_2 Cooler Inlet Valve 4230	FO
Condensate Makeup Valve 4315	FC
Reheater 2nd Pass Level Control Valves to #5 Heater 3333A, 3333B, 3334A, 3334B	FC
MFW Regulating Valves and Bypass Valves 4269, 4270, 4271, 4272	FC
Condensate Bypass Valve 3959	FO
Reheater 2nd Pass Hi Level Dump Valves to Condenser 3336A, 3336B, 3338A, 3338B	FO
Steam Dump Valves 3350, 3352, 3354, 3356	FC
H_2 Cooler Bypass Valve 4229	FO
Intermediate Building	
S/G Blowdown Valves 5737, 5738	FC

Failure Modes: FO - Fails Open FC - Fails Closed

Table 3.2.1-19
Safety Injection Valve Interlocks

MOV	REFERENCE	NORMAL POSITION	AUTOMATIC ACTION	AUTOMATIC CONTROL PERMISSIVE
825A	18.3.26	closed	open	[(ESFAS signal on train A) and (MOV 826A or 826B closed) and (MOV 826C or 826D closed)] will open MOV 825A after a 5 second time delay or [BAST level of 10% or less as indicated by (LT-102 or LT-171) and (LT-172 or LT-106)] will open MOV 825A immediately
825B	18.3.27	closed	open	[(ESFAS signal on train B) and (MOV 826A or 826B closed) and (MOV 826C or 826D closed)] will open MOV 825B after a 5 second time delay or [BAST level of 10% or less as indicated by (LT-102 or LT-171) and (LT-172 or LT-106)] will open MOV 825B immediately
826A	18.3.28 18.3.29	open	close	(BAST level of 10% or less as indicated by [LT-102 or LT-171] and [LT-172 or LT-106]) and (MOV 825A or 825B has left the closed position)
			open	(ESFAS signal on train A) and (BAST level greater than 10% as indicated by LT-102 or LT-172) and (BAST level greater than 10% as indicated by LT-171 or LT-106)
826B	18.3.30 18.3.31	closed	close	(BAST level of 10% or less as indicated by [LT-102 or LT-171] and [LT-172 or LT-106]) and (MOV 825A or 825B has left the closed position)
			open	(ESFAS signal on train A) and (BAST level greater than 10% as indicated by LT-102 or LT-172) and (BAST level greater than 10% as indicated by LT-171 or LT-106)
826C	18.3.32 18.3.33	open	close	(BAST level of 10% or less as indicated by [LT-102 or LT-171] and [LT-172 or LT-106]) and (MOV 825A or 825B has left the closed position)
			open	(ESFAS signal on train B) and (BAST level greater than 10% as indicated by LT-102 or LT-172) and (BAST level greater than 10% as indicated by LT-171 or LT-106)

Table 3.2.1-19
Safety Injection Valve Interlocks

MOV	REFERENCE	NORMAL POSITION	AUTOMATIC ACTION	AUTOMATIC CONTROL PERMISSIVE
826D	18.3.34 18.3.35	closed	close	(BAST level of 10% or less as indicated by [LT-102 or LT-171] and [LT-172 or LT-106]) and (MOV 825A or 825B has left the closed position)
			open	(ESFAS signal on train B) and (BAST level greater than 10% as indicated by LT-102 or LT-172) and (BAST level greater than 10% as indicated by LT-171 or LT-106)
841	18.3.36	open	open	(Switch on MCB in auto position) and (ESFAS signal on train A)
865	18.3.37	open	open	(Switch on MCB in auto position) and (ESFAS signal on train B)
857A	18.3.80 18.3.81	closed	open	[Operator action] and [(850A is closed and 850B is closed) or ({897 is closed or 898 is closed} and {896A is closed or 896B is closed} and {850A is open or 850B is open})]
857B	18.3.82 18.3.83	closed	open	[Operator action] and [PIC-629 is less than 250 psi] and [(850A is closed and 850B is closed) or ({897 is closed or 898 is closed} and {896A is closed or 896B is closed} and {850A is open or 850B is open})]
857C	18.3.84	closed	open	[Operator action] and [(850A is closed and 850B is closed) or ({897 is closed or 898 is closed} and {896A is closed or 896B is closed} and {850A is open or 850B is open})]
871A	18.3.38	open	close	[PSI01B breaker (BUS16/12A) not closed or MOV 871A test switch mispositioned] and [ESFAS signal on train A] *The automatic closing is inhibited by an ESFAS signal on train A and PSI01A breaker (BUS14/20A) open and PSI01B breaker (BUS16/12A) open.
871B	18.3.39	open	close	[PSI01A breaker (BUS14/20A) not closed or MOV 871B test switch mispositioned] and [ESFAS signal on train B] *The automatic closing is inhibited by an ESFAS signal on train B and PSI01A breaker (BUS14/20A) open and PSI01B breaker (BUS16/12A) open.

Table 3.2.1-19
Safety Injection Valve Interlocks

MOV	REFERENCE	NORMAL POSITIO N	AUTOMATIC ACTION	AUTOMATIC CONTROL PERMISSIVE
878A	18.3.42	closed	open	(Switch on MCB in auto position) and (ESFAS signal on train A)
878B	18.3.43	open	open	(Switch on MCB in auto position) and (ESFAS signal on train B)
878C	18.3.44	closed	open	(Switch on MCB in auto position) and (ESFAS signal on train A)
878D	18.3.45	open	open	(Switch on MCB in auto position) and (ESFAS signal on train B)
1815 A	18.3.48	open	open	(Switch on MCB in auto position) and (ESFAS signal on train A or train B)
1815 B	18.3.49	open	open	(Switch on MCB in auto position) and (ESFAS signal on train A or train B)

Table 3.2.1-20
Safety Injection System Power Sources

Component	AC Power Source	DC Power Source
PSI01A	Bus 14 Unit 20A	Aux Bldg DC Dist Pnl 1A, Sw #4
PSI01B	Bus 16 Unit 12A	Aux Bldg DC Dist Pnl 1B, Sw #4
PSI01C (2)	Bus 14 Unit 19A	Aux Bldg DC Dist Pnl 1A, Sw #4
PSI01C (1)	Bus 16 Unit 13A	Aux Bldg DC Dist Pnl 1B, Sw #4
BATH1A (2 Htrs.)	MCC C Pos. 4B	Aux Bldg DC Dist Pnl 1A, Sw #2
BATH1B (2 Htrs.)	MCC D Pos. 4K	Aux Bldg DC Dist Pnl 1B, Sw #2
P Heat Trace	Heat Trace Dist Pnl 14	No DC required
S Heat Trace	Heat Trace Dist Pnl 16	No DC required
MOV 825A	MCC C Pos. 9J	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 825B	MCC D Pos. 9J	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 826A	MCC C Pos. 9C	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 826B	MCC C Pos. 9F	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 826C	MCC D Pos. 9C	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 826D	MCC D Pos. 9F	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 841	MCC C Pos. 12F	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 865	MCC D Pos. 12C	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 871A	MCC C Pos. 11C	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 871B	MCC D Pos. 11C	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 878A	MCC C Pos. 8C	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 878B	MCC D Pos. 8C	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 878C	MCC C Pos. 8F	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 878D	MCC D Pos. 8F	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 897	MCC L Pos. 1B	MCB Dist Pnl 1A, Pos #XND-6
MOV 898	MCC D Pos. 16FF	MCB Dist Pnl 1B, Pos #2

Table 3.2.1-20
Safety Injection System Power Sources

Component	AC Power Source	DC Power Source
MOV 1815A	MCC C Pos. 15M	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 1815B	MCC D Pos. 16J	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 857A	MCC C Pos. 7M	Aux Bldg DC Dist Pnl 1A, Sw #2
MOV 857B	MCC D Pos. 7M	Aux Bldg DC Dist Pnl 1B, Sw #2
MOV 857C	MCC C Pos. 15J	Aux Bldg DC Dist Pnl 1A, Sw #2
LQ-102 (LT-102 power supply)	TWINCO Dist. Panel MQ-400B	No DC required
LC-102C (LT-102 Lo-Lo BAST alarm)	TWINCO Dist. Panel MQ-400B	No DC required
LC-102A/B (LT-102 Hi-Lo BAST alarm)	Instrument Dist. Panel 1B	No DC required
LQ-106 (LT-106 power supply)	TWINCO Dist. Panel MQ-400C	No DC required
LC-106C (LT-106 Lo-Lo BAST alarm)	Instrument Dist. Panel 1C	No DC required
LC-106A/B (LT-106 Hi-Lo BAST alarm)	Instrument Dist. Panel 1C	No DC required
LQ-171 (LT-171 power supply)	TWINCO Dist. Panel MQ-400C	No DC required
LC-171C (LT-171 Lo-Lo BAST alarm)	Instrument Dist. Panel 1C	No DC required
LC-171A/B (LT-171 Hi-Lo BAST alarm)	Instrument Dist. Panel 1C	No DC required

Table 3.2.1-20
Safety Injection System Power Sources

Component	AC Power Source	DC Power Source	Reference
LQ-172 (LT-172 power supply)	TWINCO Dist. Panel MQ-400B	No DC required	18.3.97 18.3.150 18.3.153
LC-172C (LT-172 Lo-Lo BAST alarm)	Instrument Dist. Panel 1B	No DC required	18.3.97 18.3.150 18.3.151
LC-172A/B (LT-172 Hi-Lo BAST alarm)	Instrument Dist. Panel 1B	No DC required	18.3.97 18.3.150 18.3.151

Table 3.2.1-21
Location of Major Safety Injection System Components

EIN	Building	Elevation	Column	Row
PSI01A	AB	235' 8"	N1	8A
PSI01B	AB	235' 8"	N	9A
PSI01C	AB	235' 8"	N1	9A
TCH07A	AB	271' 0"	L	10A
TCH07B	AB	271' 0"	L	10A
825A	AB	235' 8"	N1	9A
825B	AB	235' 8"	N1	9A
826A	AB	253' 0"	L	10A
826B	AB	253' 0"	L	10A
826C	AB	253' 0"	L	10A
826D	AB	253' 0"	L	10A
827A	AB	271' 0"	L	10A
827B	AB	271' 0"	L	10A
841	CNMT	235' 8"	NE	OMB
842A	CNMT	235' 8"	SW	OMB
842B	CNMT	235' 8"	SW	OMB
857A	AB	235' 8"	N	8A
857B	AB	235' 8"	N	8A
857C	AB	235' 8"	N	8A

Table 3.2.1-21
Location of Major Safety Injection System Components

EIN	Building	Elevation	Column	Row
865	CNMT	235' 8"	SW	OMB
867A	CNMT	235' 8"	SE	IMB
867B	CNMT	235' 8"	NW	IMB
870A	AB	235' 8"	N1	7A
870B	AB	235' 8"	N1	7A
871A	AB	235' 8"	N1	7A
871B	AB	235' 8"	N1	9A
878A	CNMT	235' 8"	SE	OMB
878B	CNMT	235' 8"	SE	OMB
878C	CNMT	235' 8"	SW	OMB
878D	CNMT	235' 8"	SW	OMB
878E	CNMT	235' 8"	SW	OMB
878G	CNMT	235' 8"	NE	OMB
878J	CNMT	235' 8"	SW	OMB
888A	AB	235' 8"	N1	8A
888B	AB	253' 8"	N1	9A
889A	AB	235' 8"	N1	9A
889B	AB	235' 0"	N1	9A

Table 3.2.1-21
Location of Major Safety Injection System Components

EIN	Building	Elevation	Column	Row
890A	AB	235' 8"	N1	8A
890B	AB	235' 8"	N1	9A
891A	AB	235' 8"	N1	8A
891B	AB	235' 8"	N1	9A
891C	AB	235' 8"	N1	9A
897	AB	235' 0"	N	8A
898	AB	253' 0"	N	8A
1815A	AB	235' 8"	N1	9A
1815B	AB	235' 8"	N1	9A
1816A	AB	235' 8"	N	9A
1816B	AB	235' 8"	N	9A
1820A	AB	235' 8"	N1	8A
1820B	AB	235' 8"	N1	8A
1820C	AB	235' 8"	N1	9A
TSI03A	CNMT	235' 8"	NE	OMB
TSI03B	CNMT	235' 8"	SW	OMB

Table 3.2.1-22
Safety Injection System Control Room Annunciators

ANNUNCIATOR	DESCRIPTION
A-14	SI Pumps Cooling Water Out Lo Flow 25 gpm
B-15	Boric Acid Tank Hi-Lo Level, 60 % 90
B-23	Boric Acid Tank Lo-Lo Level
B-31	BAST Temp or Lo Nitrogen Pressure, 155°F 175°F
C-3	Accumulator A (Loop B) Level, 57 % 75
C-4	Accumulator B (Loop A) Level, 57 % 75
C-11	Accumulator A (Loop B) Pressure, 720 psi 760
C-12	Accumulator B (Loop A) Pressure, 720 psi 760
C-25	Containment Pressure Channel Alert, 4 psi
C-27	Pressurizer Lo Pressure SI Channel Alert, 1750 psig
C-28	Pressurizer Lo Pressure SI Channel Alert, 1750 psig
D-19	Pressurizer Lo Pressure SI, 1750
D-21	Steam Line Loop A Lo-Lo Pressure, 514 psi
D-22	Steam Line Loop B Lo-Lo Pressure, 514 psi
D-28	Containment Pressure, 4 psi
D-31	Manual Safety Injection
G-27	Steam Line A Lo-Lo Pressure Channel Alert, 514 psi
G-29	Steam Line B Lo-Lo Pressure Channel Alert, 514 psi
J-9	Safeguard Breaker Trip
J-25	Safeguards Equipment Locked Off
K-22	Heat Tracing System
L-30	Safeguard Test Switch on Test
L-31	Safeguard DC Failure

Table 3.2.1-23
Service Water Isolation Valves

FUNCTION	DESIGNATOR	NUMBER	VALVE TYPE
Chiller Isolation	1A1	4663	Gate
Chiller Isolation	1A2	4733	Butterfly
Screen Wash Isolation	1A1	4609	Butterfly
Screen Wash Isolation	1A2	4780	Butterfly
Aux. Building Isolation	1A1	4616	Gate
Aux. Building Isolation	1A2	4735	Butterfly
Aux. Building Isolation	1B1	4615	Gate
Aux. Building Isolation	1B2	4734	Butterfly
Turbine Building Isolation	1A1	4614	Butterfly
Turbine Building Isolation	1A2	4664	Gate
Turbine Building Isolation	1B1	4670	Gate
Turbine Building Isolation	1B2	4613	Butterfly

[illegible]

Table 3.2.1-24
Service Water System Electrical Dependencies

EIN	AC Power	DC Power
PSW01A	Bus 18, Unit 29C (BUS18/29C)	FUDCPDPSH01A/2-P,N FUBUS18/29C-P,N
PSW01B	Bus 17, Unit 27C (BUS17/27C)	FUDCPDPSH01B/7-P,N FUBUS17/27C-P,N
PSW01C	Bus 18, Unit 29D (BUS18/29D)	FUDCPDPSH01A/2-P,N FUBUS18/29D-P,N
PSW01D	Bus 17, Unit 27D (BUS17/27D)	FUDCPDPSH01B/7-P,N FUBUS17/27D-P,N
4609	MCC H, Unit 2M (MCCH/02M)	FUDCPDPCB03A/C-P,N FUMCCH/2M-P,N
4613	MCC D, Unit 11J (MCCD/11J)	FUDCPDPAB01B/2-P,N FUMCCD/11J-P,N
4614	MCC C, Unit 14M (MCCC/14M)	FUDCPDPAB01A/2-P,N FUMCCC/14M-P,N
4615	MCC C, Unit 14J (MCCC/14J)	FUDCPDPAB01A/2-P,N FUMCCC/14J-P,N

Table 3.2.1-24
Service Water System Electrical Dependencies

EIN	AC Power	DC Power
4616	MCC C, Unit 6F (MCCC/06F)	FUDCPDPAB01A/2-P,N FUMCCC/6F-P,N
4663	MCC C, Unit 11M (MCCC/11M)	FUDCPDPAB01A/2-P,N FUMCCC/11M-P,N
4664	MCC D, Unit 13F (MCCD/13F)	FUDCPDPAB01B/2-P,N FUMCCD/13F-P,N
4670	MCC H, Unit 2J (MCCH/02J)	FUDCPDPCB03A/C-P,N FUMCCH/2J-P,N
4733	MCC C, Unit 14J (MCCC/14J)	FUDCPDPAB01B/2-P,N FUMCCC/14J-P,N
4734	MCC D, Unit 6F (MCCD/06F)	FUDCPDPAB01B/2P-N FUMCCD/6F-P,N
4735	MCC D, Unit 13C (MCCD/13C)	FUDCPDPAB01B/2-P,N FUMCCD/13C-P,N
4780	MCC J, Unit 2M (MCCJ/02M)	FUDCPDPCB03B/D-P,N FUMCCJ/2M-P,N

Table 3.2.1-25
Service Water System Loads

*	Diesel generator coolers and expansion tank makeup (2)
	Condensate pump motor coolers (3)
	Heater drain pump motor coolers (2)
	Instrument air compressors (3)
	Generator exciter (1)
	Bus duct coolers (2)
	Seal oil coolers (2)
	Main feed pump lube oil coolers (2)
	EHC oil coolers (2)
	Turbine lube oil coolers (2)
	Steam generator blowdown sample coolers (2)
	Sample cooler and chiller (2)
	Blowdown tank drain cooling (1)
	Vacuum priming pumps (2)
	Fire service water booster pump supply (1)
	Traveling screen flushing valves supply (4)
	Seal water to circulating water pumps (2)
	Relay room air conditioning (2)
	Battery room air conditioning (1)
	CV air test after cooler (1)
	Air conditioning chillers (2)
*	Containment coolers and fan motors (4)
	Reactor compartment coolers (2)
*	Component cooling water heat exchangers (2)
	Spent fuel pool heat exchangers
*	Safety injection pump thrust and radial bearing housing oil cooling (3)
	RHR pump area coolers (2)
	Charging pump room coolers (2)
	Penetration cooling
	Degassifier and I & C Shop
*	Alternate supply to Auxiliary Feedwater System (3)
*	Normal supply to Standby Auxiliary Feedwater System (2)
*	Standby auxiliary pump building area coolers (2)
*	Motor driven auxiliary feedwater pump oil coolers (2)
*	Turbine driven auxiliary feedwater pump oil cooler

* *Classified as critical loads as they have either a post-accident function or a function significant to safety*

Table 3.2.1-26
Major Service Water Loads And Flow Requirements

SERVICE (NUMBER)	DESIGN FLOW EACH (GPM)	TYPICAL 2 PUMP FLOW AT POWER (GPM)	TYPICAL 3 PUMP FLOW AT POWER (GPM)
Containment Cooling Coils (4)	946	5,004	5,738
CCW Coolers (2)	5,070	2,642	4,200
Reactor Cavity Cooler (1)	45	98	115
Diesel Generators (2)	320	751	865
Motor-driven Auxiliary FW Pump (2)	7	14	14
Turbine-driven Aux. FW Pump (1)	15	15	15
Turbine Oil Coolers (2)	600	651	735
Penetration Cooler	20	34	40
EHC Oil Coolers (2)	20	39	45
Seal Oil Unit Air/H2 (1)	100/70	259	290
Exciter (1)	90	308	350
Pump Area Coolers,			
Charging (2)	9	32	40
Residual Heat Removal (2)	12.5	33	40
SI Pumps Bearings (3)	3	9	9
Air Compressors (3)	12	36	36
Air Conditioning (1)	525	270	310
Sample Coolers & Chillers (4)	15	41	50
Bus Duct Coolers	70	162	180
MFWP Lube Oil Coolers (2)	35	82	95
Spent Fuel Pit HXs (2)	700/1600	474 / 661	530 / 840
Screen Wash (4)	320	505	570
Total Flow		12,120	15,095
Number Pumps Required		2	3
Required Pump Capacity		6,060	5,355 / 4870*
Actual Pump Capacity	5300 gpm		
Actual Pump Head	198 feet		
Actual Pump BHP	308 hp		

* The lower value represents flow per pump on the SW header that has two operating pumps

Table 3.2.1-27
Service Water Related Control Room Annunciators

AA-1	SW Redundant Return Line Low Flow (1000 gpm) [Normally on at power]
A-29	Reactor CAV Cooling Fan Cooler Water Outlet Hi Temperature 150°F
C-2	Containment Recirculation Coolers Water Outlet Hi Temperature 217°F
C-10	Containment Recirculating Coolers Water Outlet Lo Flow 920 gpm
E-16	RMS Process Monitor High Activity - caused by: a. R-16 Rad Monitor for SW return from Containment Coolers (100 cpm) b. R-20 Rad Monitor for SW return from Spent Fuel Heat Exchangers (30,000 cpm)
H-6	CCW Service Water Lo Flow 1000 gpm H-9 Auxiliary Feed Pump Cooling Water Filter Hi Differential Pressure
I-1	Screen House Low Level 17'
I-2	CW Pump Seal Water Filter Hi Differential Pressure 3 psi
I-9	Screen House Lo-Lo Level 15'
I-10	CW Pump Seal Water Low Flow
I-11	Temperature Recorders
J-4	Gen Iso Phase Bus Cooling System (Low SW flow or > 75°F)
J-7	480V Main or Tie Breaker Trip
J-9	Safeguard Breaker Trip (switch - breaker mismatch)
J-14	480V Bus 14/16 or 17/18 Tie Breaker Closed
J-25	Safeguards Equipment Locked Off (Switch in Pull-stop)
K-14	Emergency Shutdown Local Control
K-29	Spent Fuel Pit Hi Temperature 125°F
L-15	Bus 17 Undervoltage Safeguards - according to curve in Technical Specifications
L-23	Bus 18 Undervoltage Safeguards - according to curve in Technical Specifications

Table 3.2.1-28
Service Water System Testing & Maintenance

Components	Procedure	Interval	Test/Maintenance
MOVs	PT-2.7	Monthly	Valves stroked for pump test
		Quarterly	Check operability & stroke time
		Refueling	Verify stem position vs. indication
	M-1007	5 Years	PM and diagnostic testing
Chk. Valves	PT-2.7	Monthly	Ensure open with pump operation
	RSSP-2.5	Refueling	Verify closure tightness
Pumps	PT-2.7	Monthly	Ensure pump operability
	A-1011	Quarterly	Lubrication & inspection
	M-1010 M-11.10.1	Yearly	Minor inspection
	M-1010 M-11.10	4 Years	Major overhaul
Man. Valves	None	NA	NA

Figure 3.2.1-1
Auxiliary Feedwater System Simplified Flow Daigram (1 of 3)

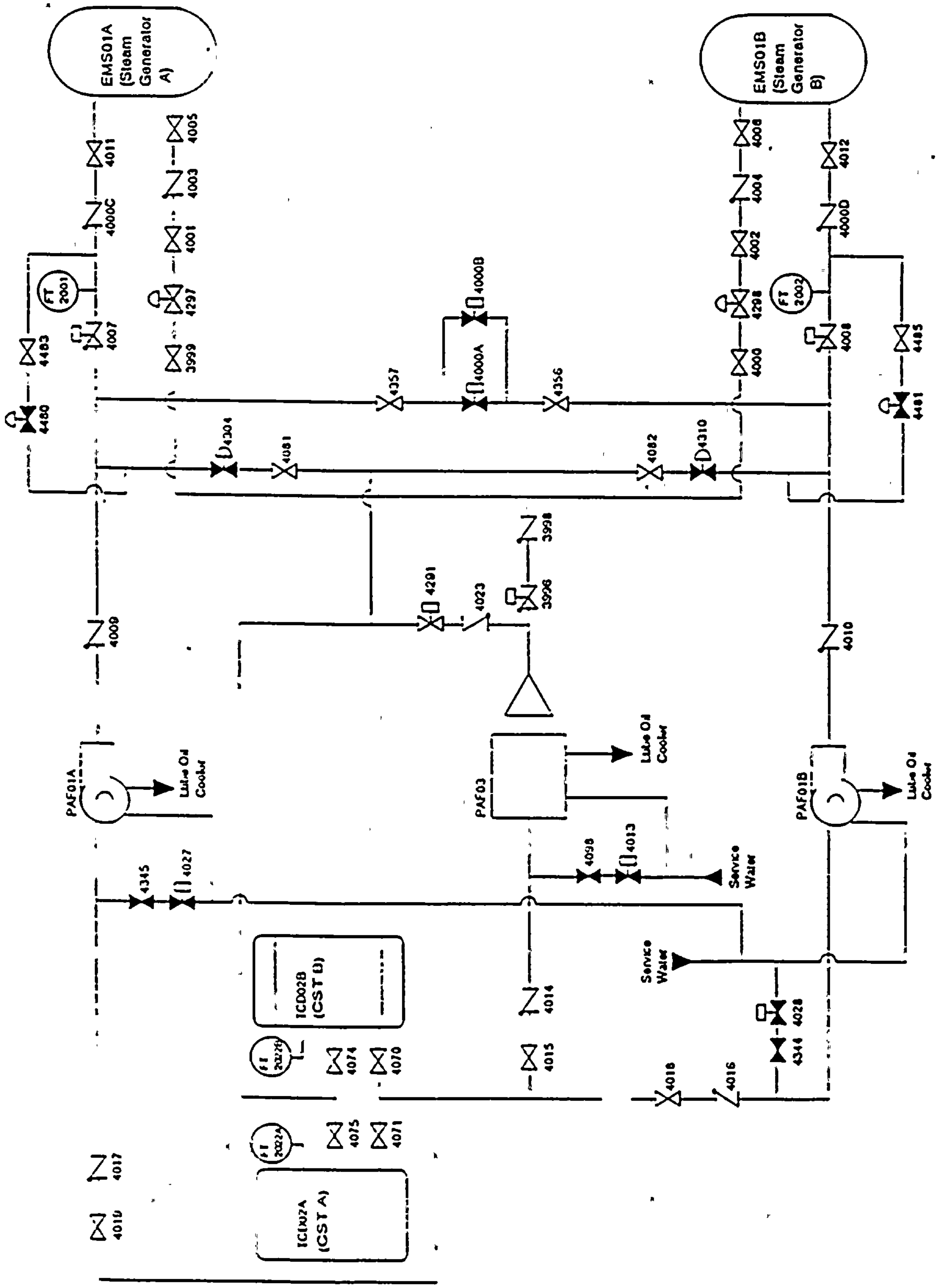


Figure 3.2.1-2
Auxiliary Feedwater System Simplified Flow Diagram (2 of 3)

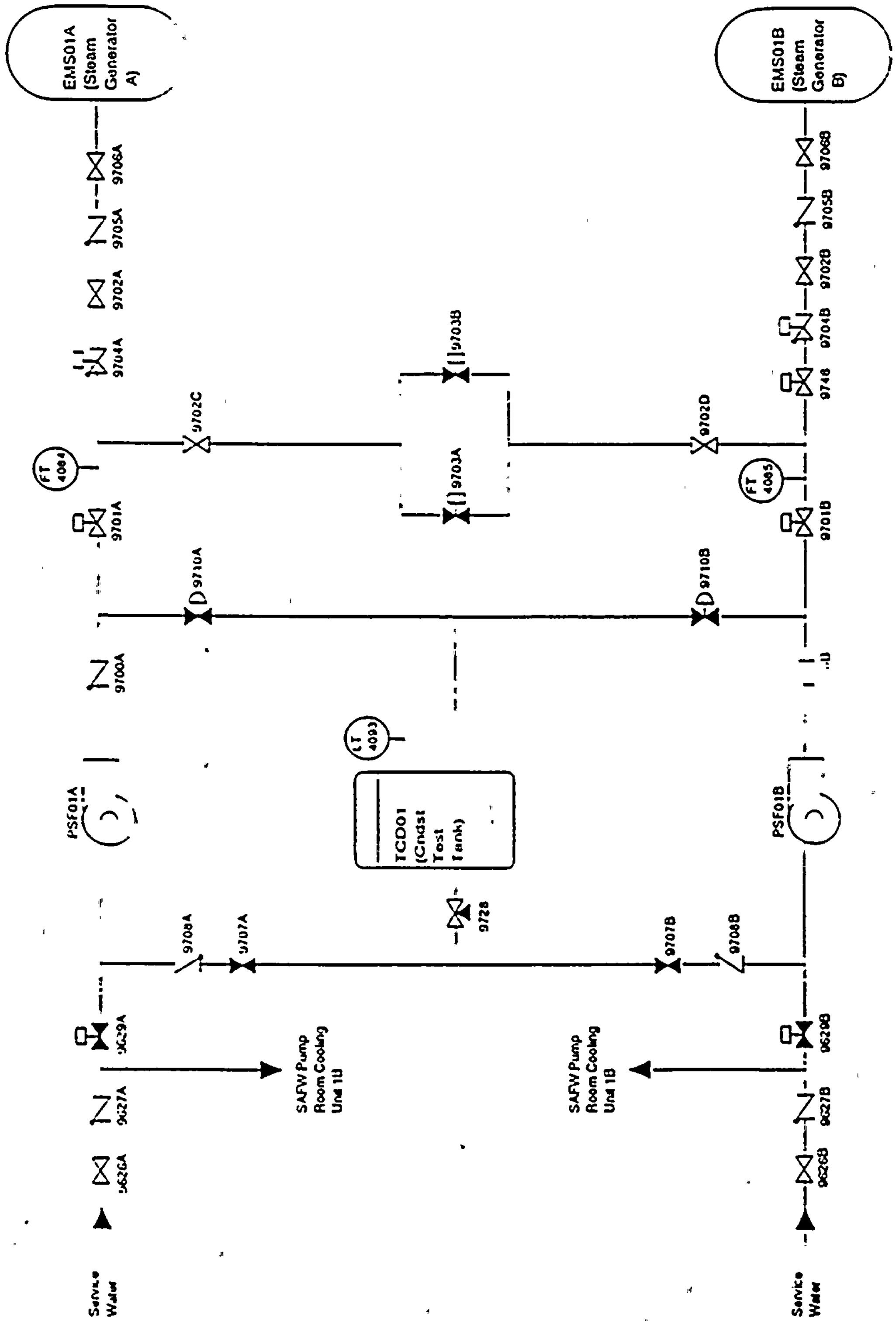


Figure 3.2.1-3
Auxiliary Feedwater System Simplified Flow Diagram (3 of 3)

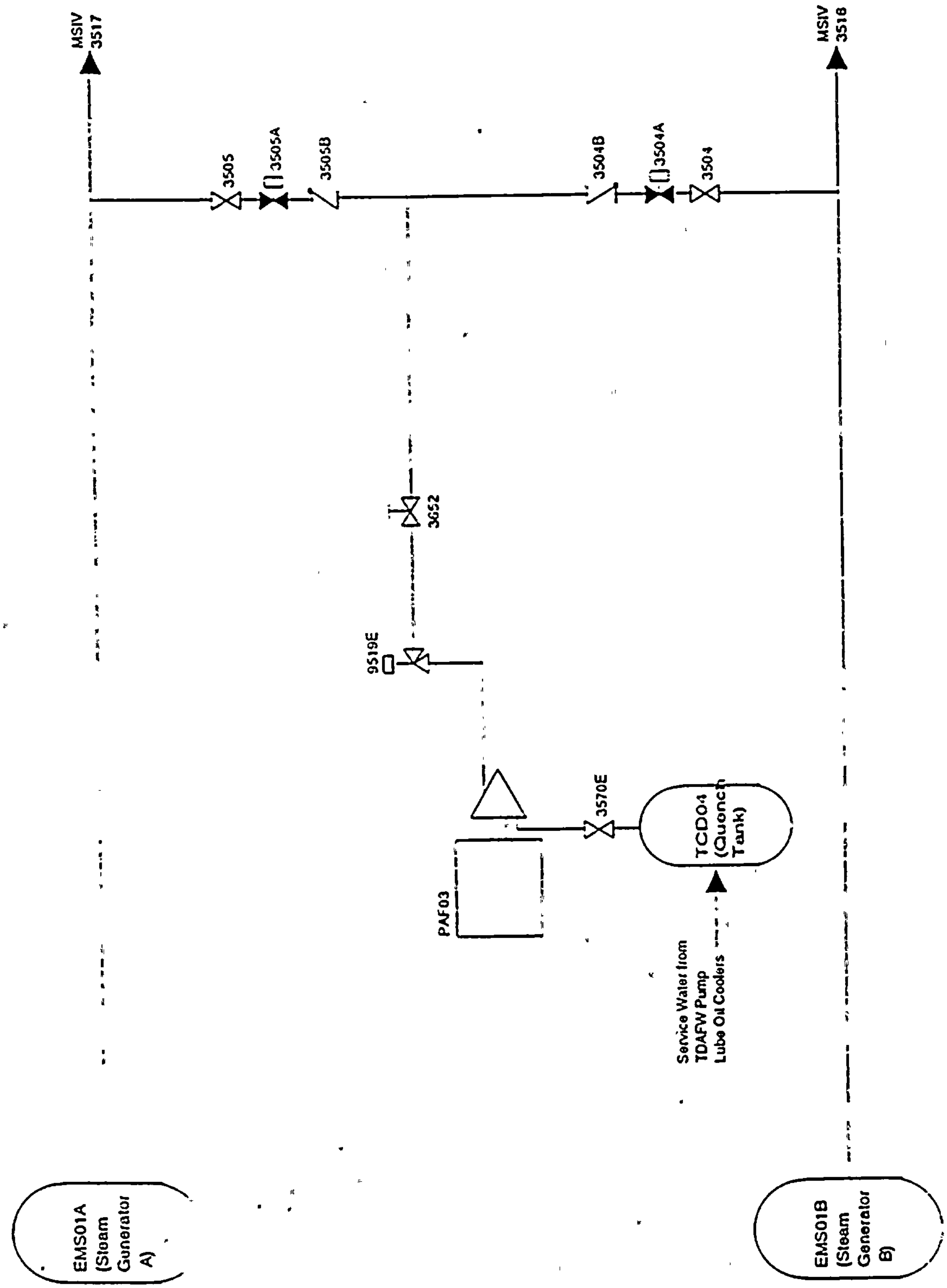


Figure 3.2.1-4
Motor Driven Auxiliary Feedwater Pump PAF01A Starting Logic

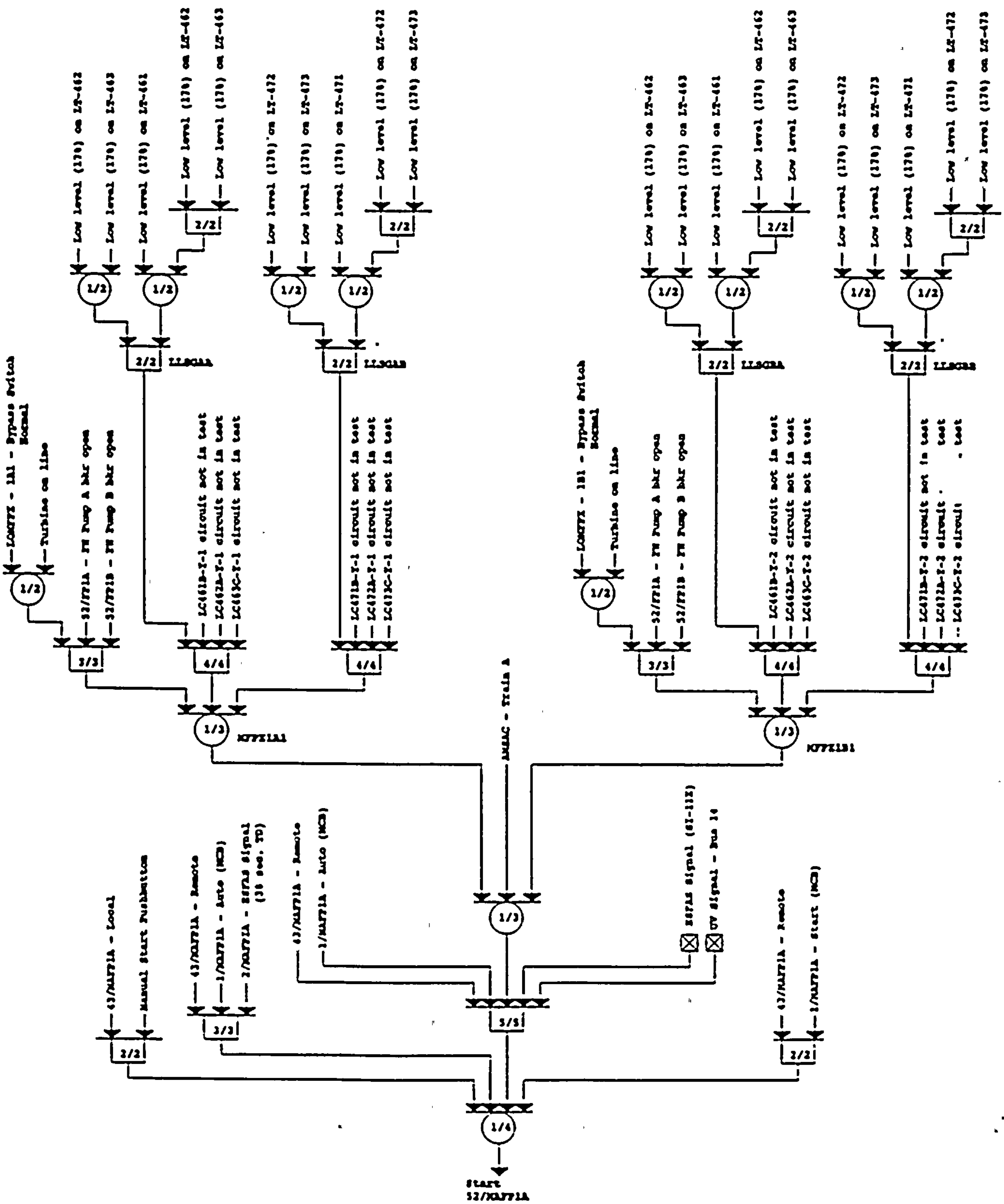


Figure 3.2.1-5
Motor Driven Auxiliary Feedwater Pump PAF01B Starting Logic

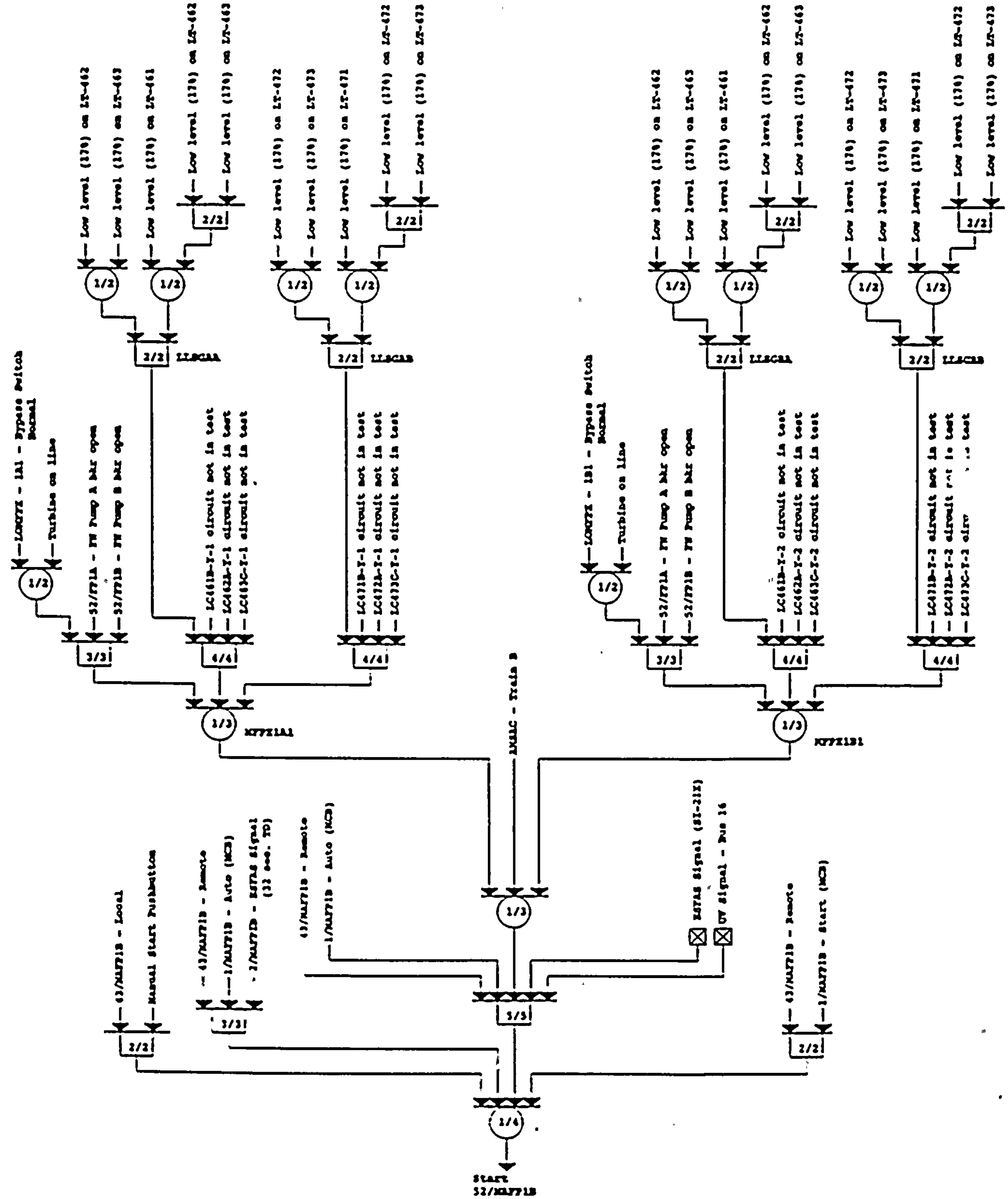


Figure 3.2.1-6
Component Cooling Water System Simplified Flow Diagram

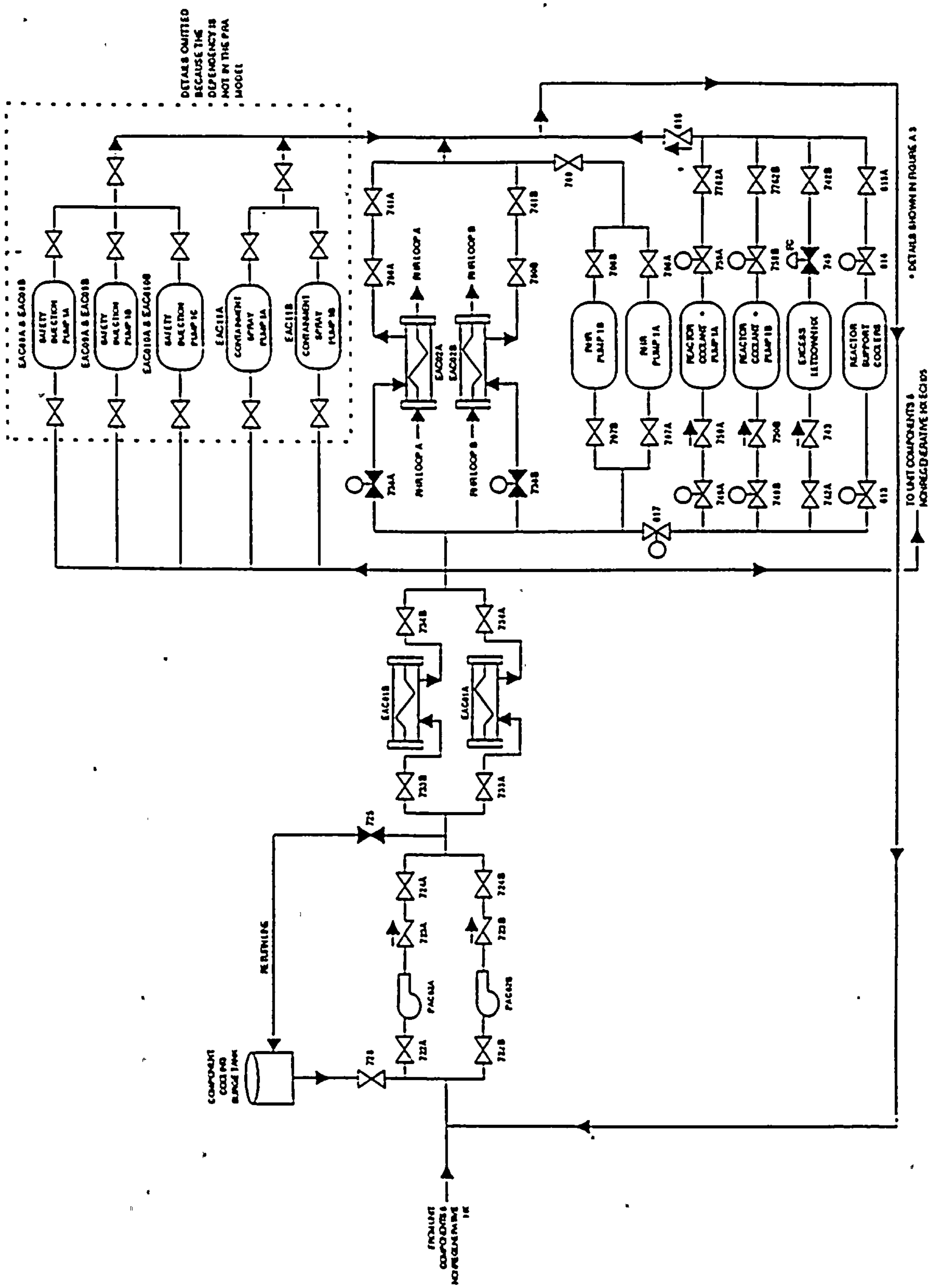


Figure 3.2.1-7
CCW to the Reactor Coolant Pumps

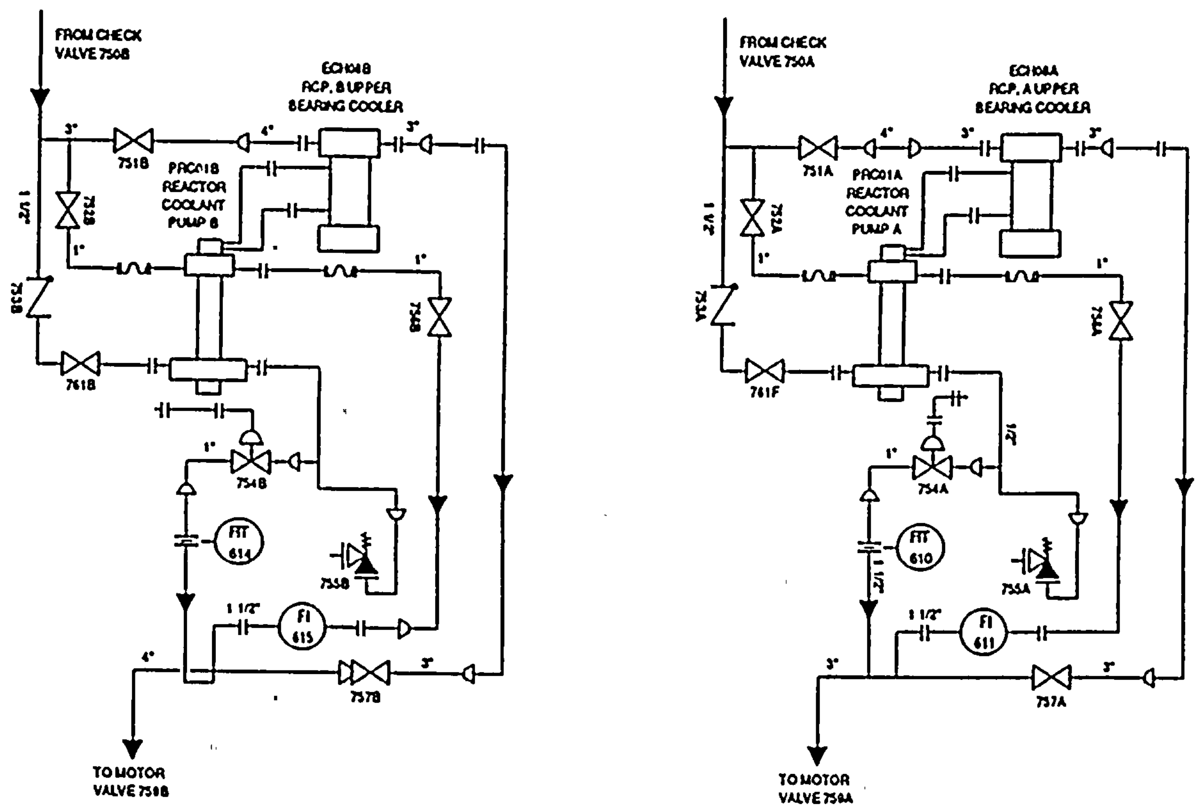


Figure 3.2.1-8
Assumption: Heat Exchanger EAC01B In Standby

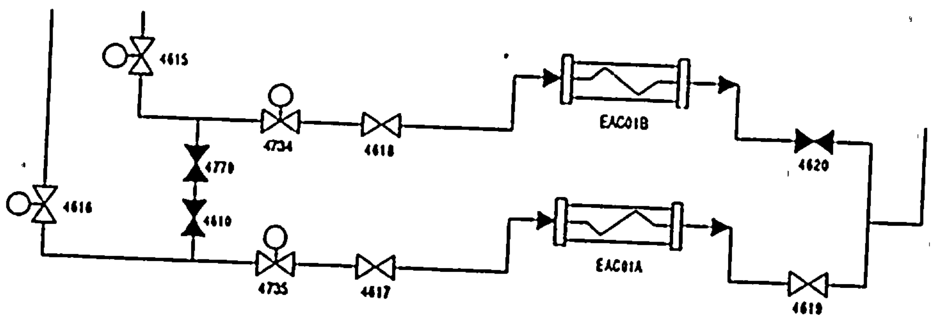


Figure 3.2.1-9
Containment Spray System Simplified Flow Diagram

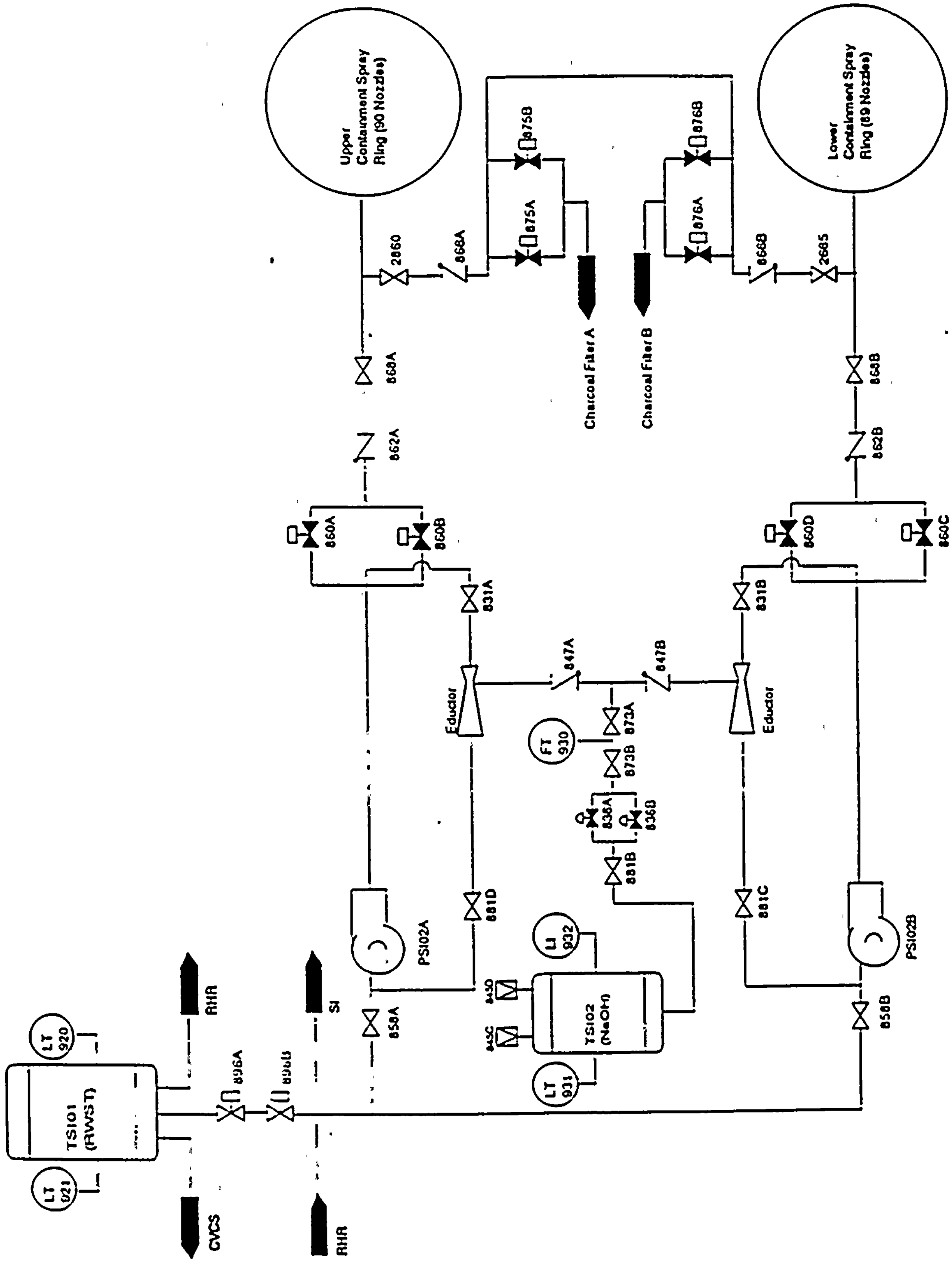


Figure 3.2.1-10
Chemical and Volume Control System Simplified Flow Diagram

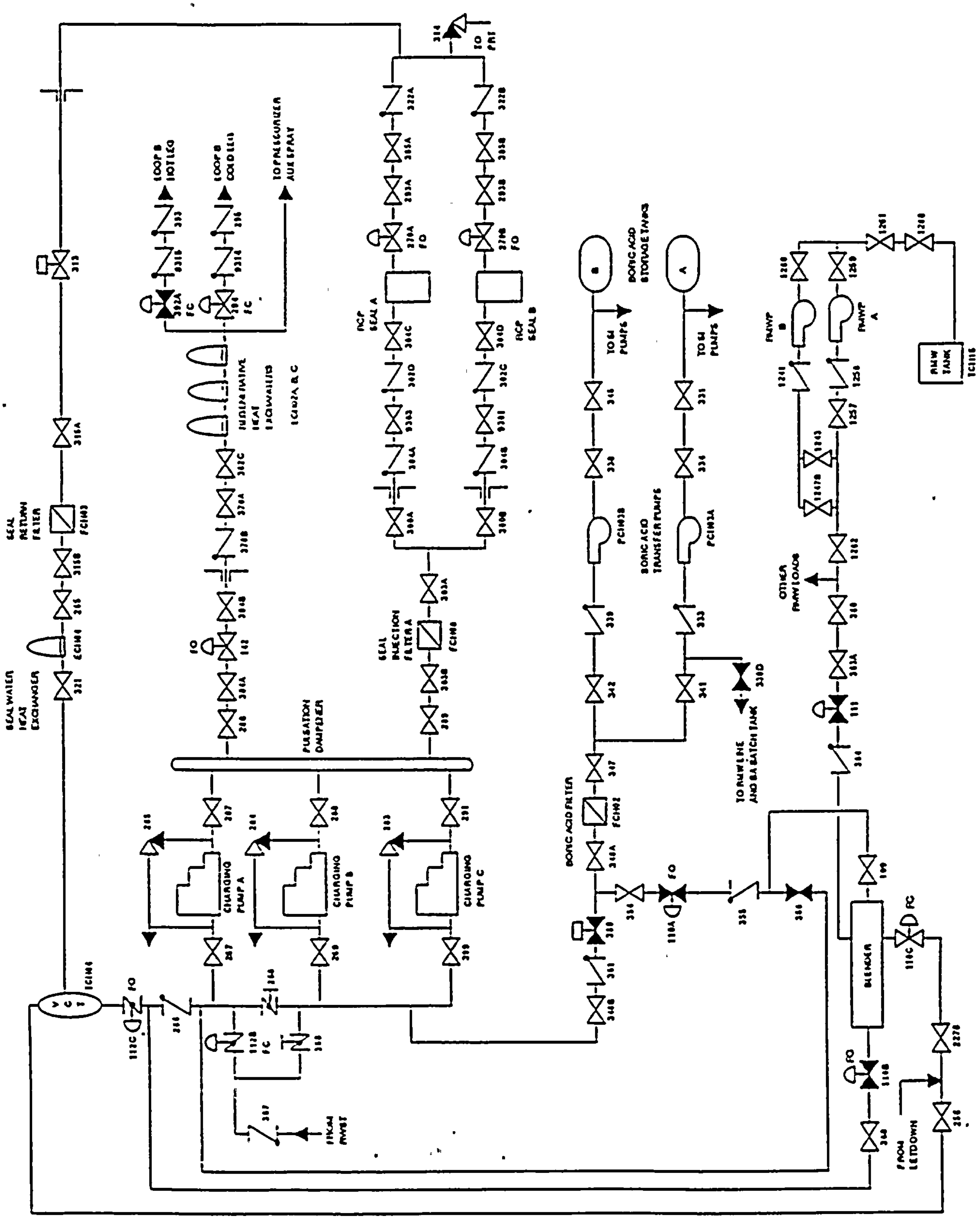


Figure 3.2.1-11
Main Electrical Distribution Systems

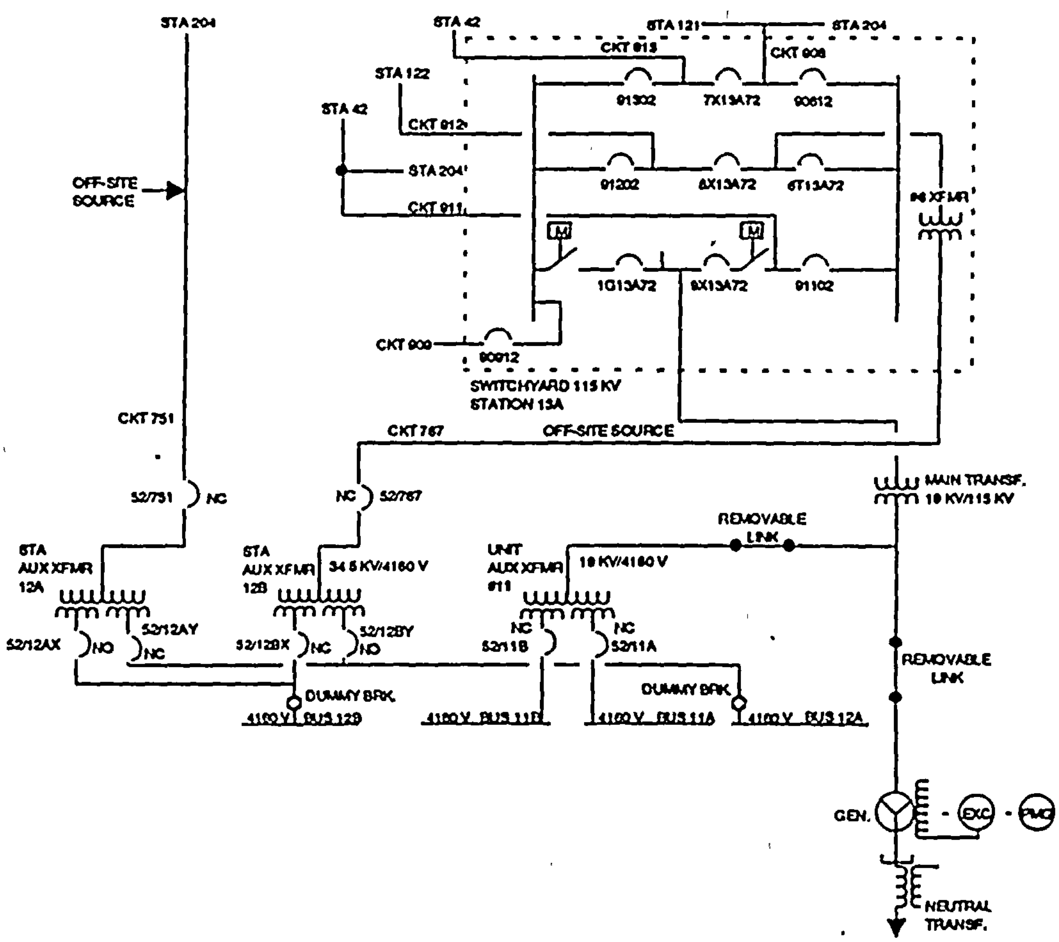
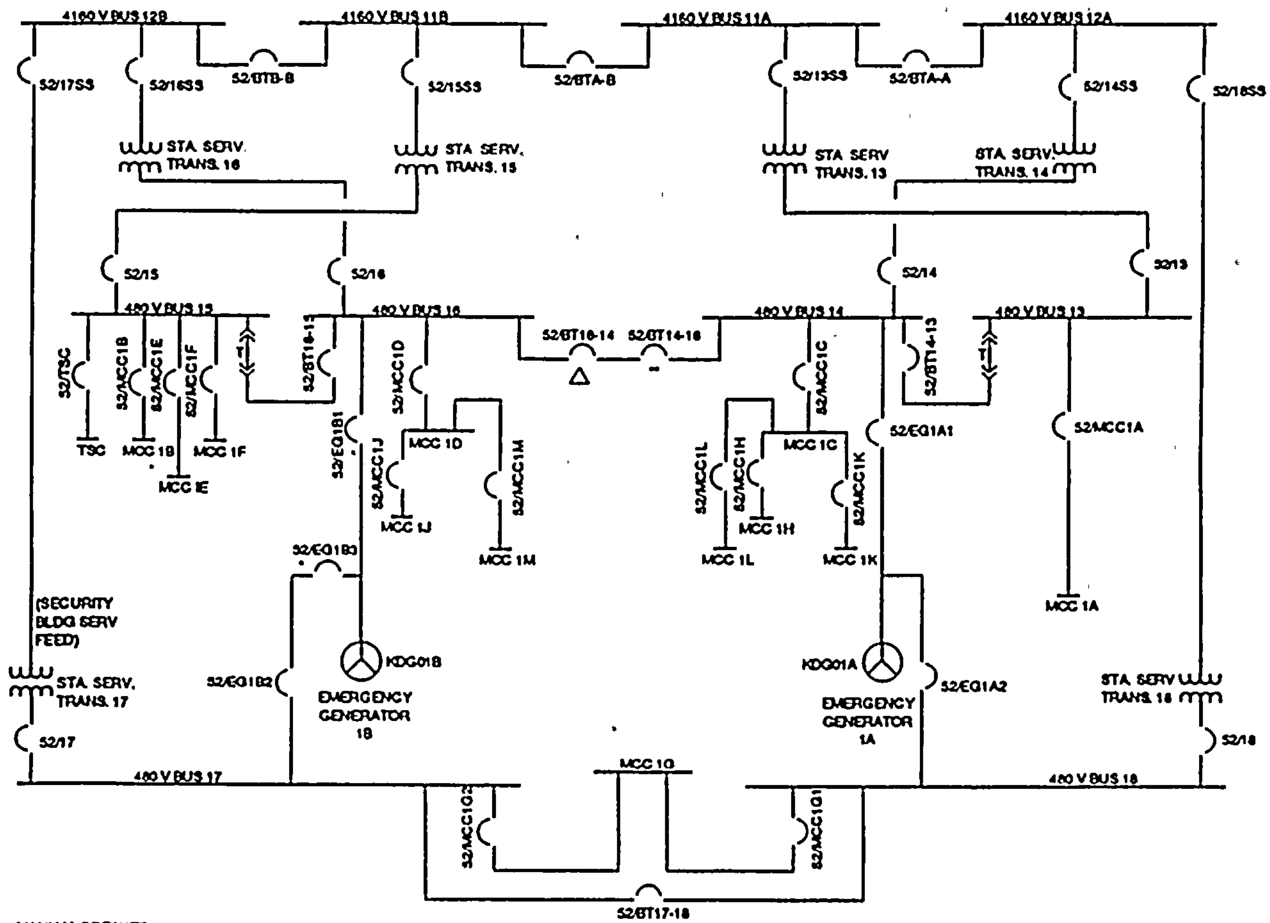


Figure 3.2.1-12
480 VAC Electrical Distribution System



- • MANUAL BREAKER
- •• MANUAL BREAKER (OPEN ABOVE 200 DEGREES F)
- T MANUAL DUMMY TIE, KEY INTERLOCK WITH BUSE TIE, DUMMY MUST BE OPEN AND RACKED OUT BEFORE YOU CAN RACK OUT THE TIE BREAKER
- △ REMOTE CONTROL BREAKER (HELD OPEN ABOVE 200 DEGREES F) PROTECTS FOR FIRE FAULT TAKING OUT BOTH BUSES

Figure 3.2.1-13
125 VDC and 120 VAC Distribution Systems

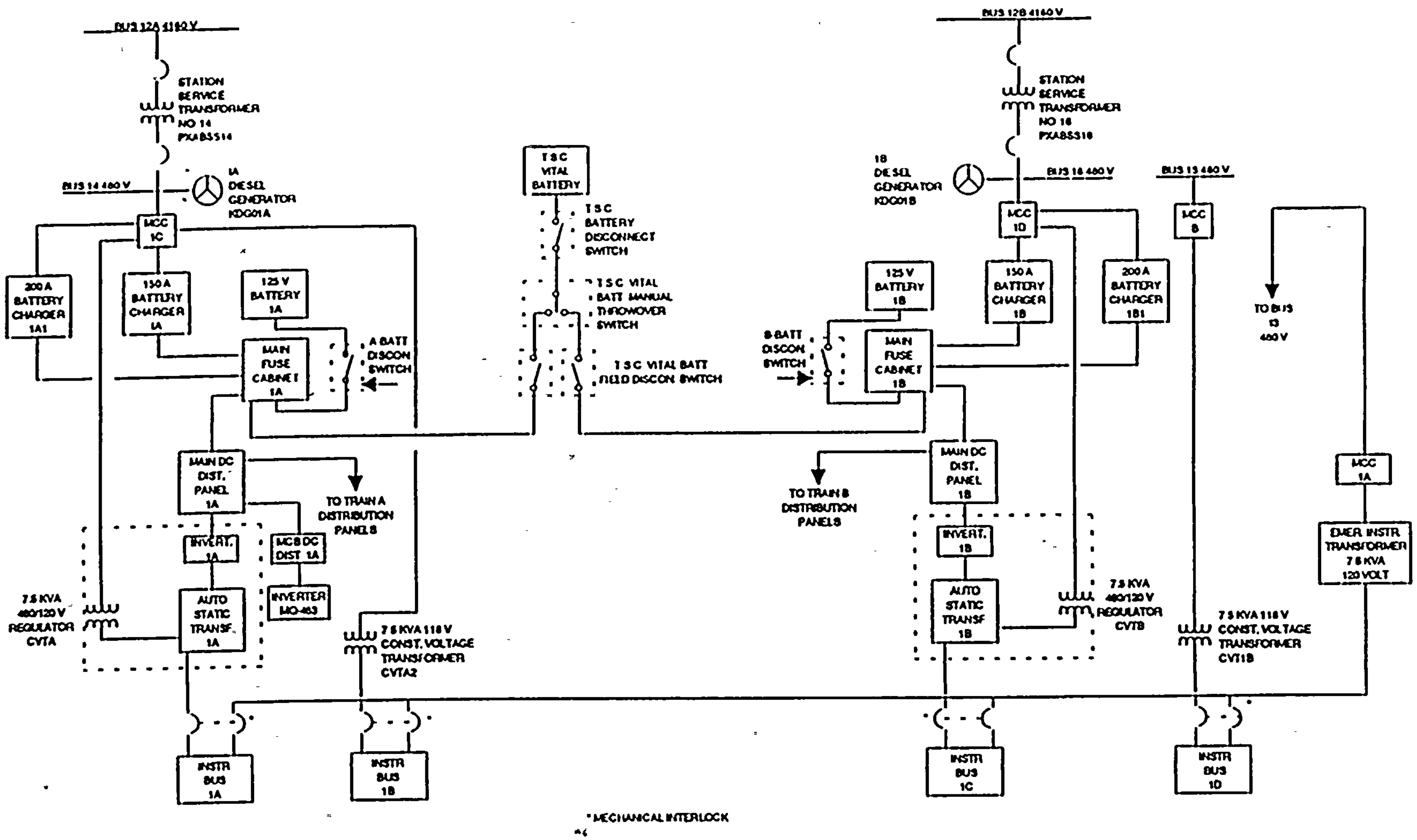


Figure 3.2.1-14
Containment HVAC Systems

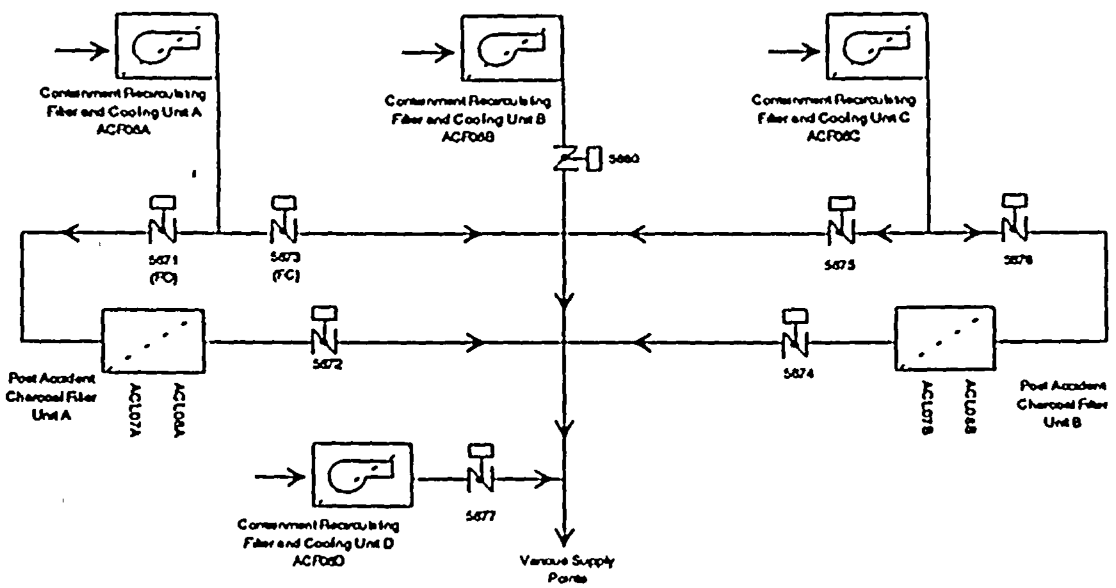


Figure 3.2.1-15
Service Water to Containment HVAC

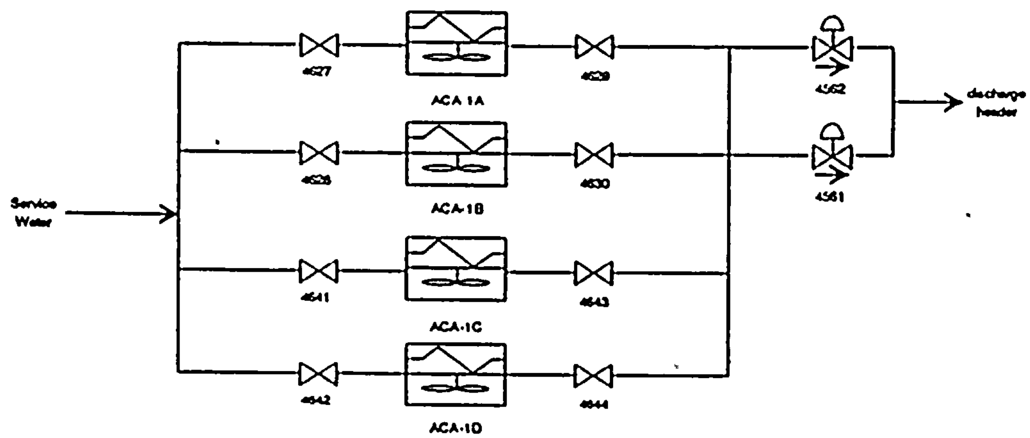


Figure 3.2.1-16
Charging Pumps Room HVAC

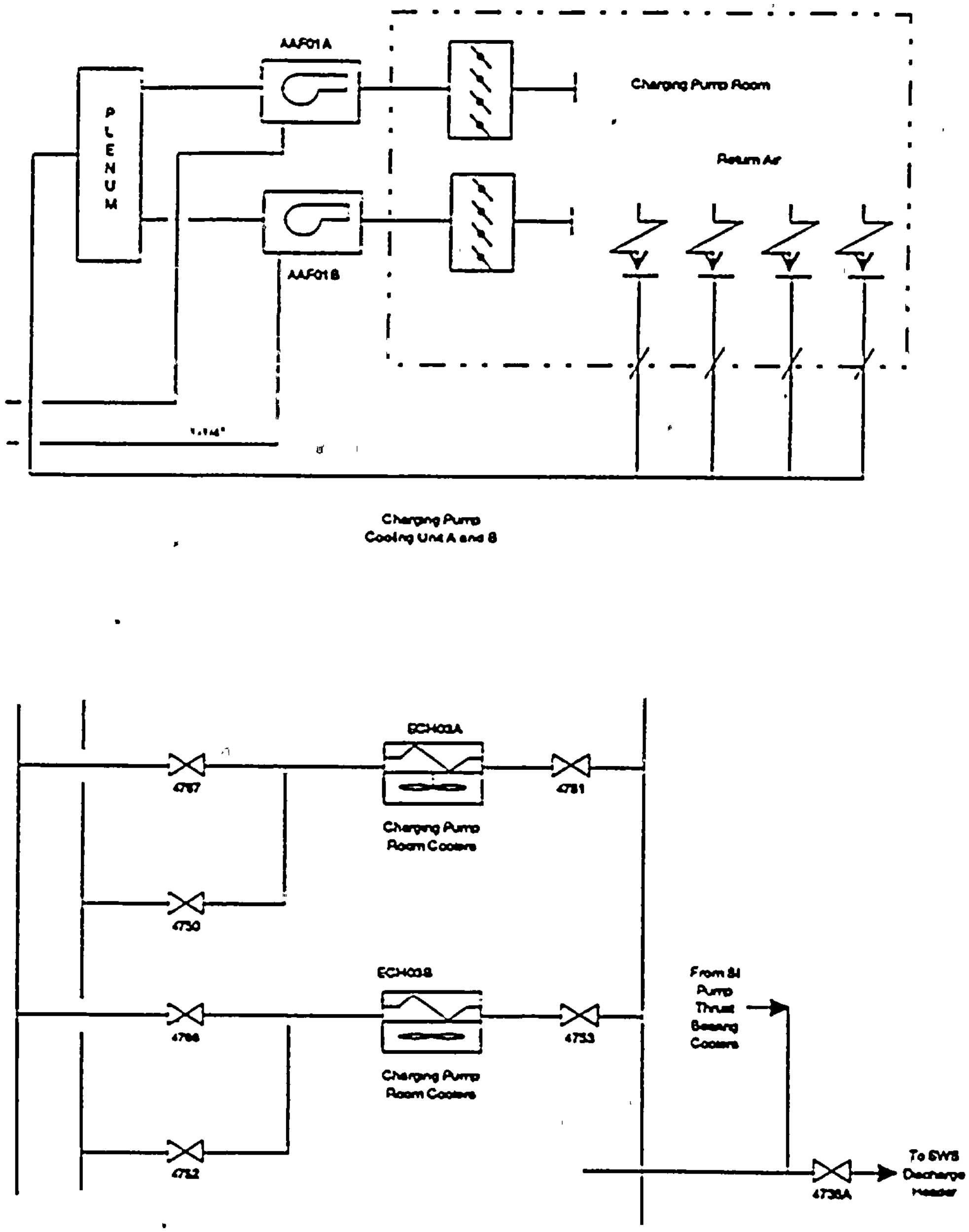
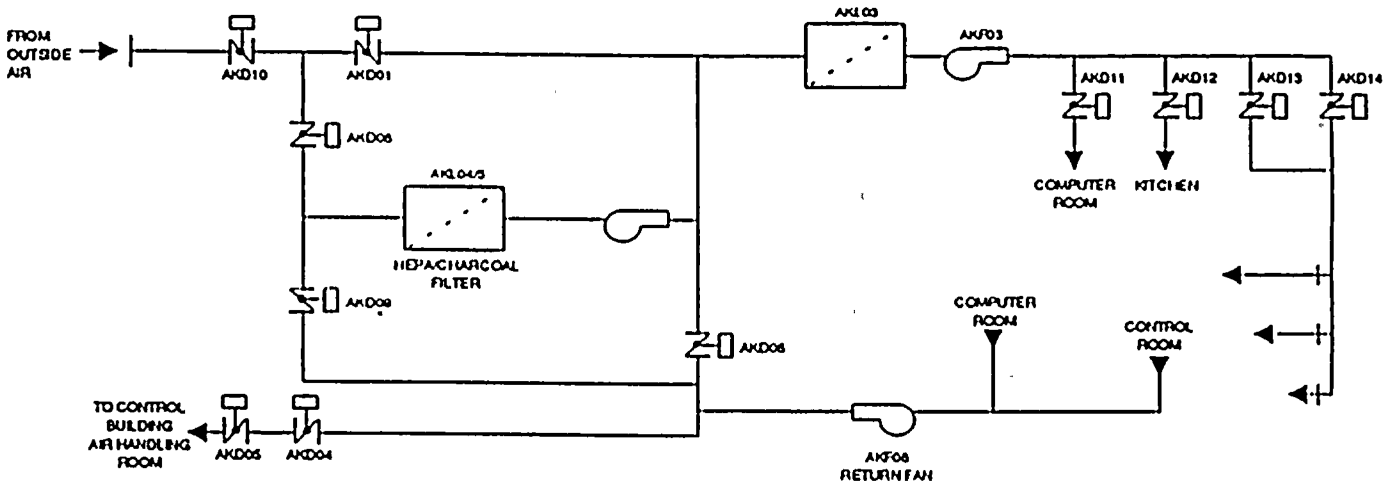


Figure 3.2.1-17
Control Room HVAC



NOTE ALL DAMPERS ARE INSTRUMENT AIR OPERATED

Figure 3.2.1-18
Relay Room HVAC

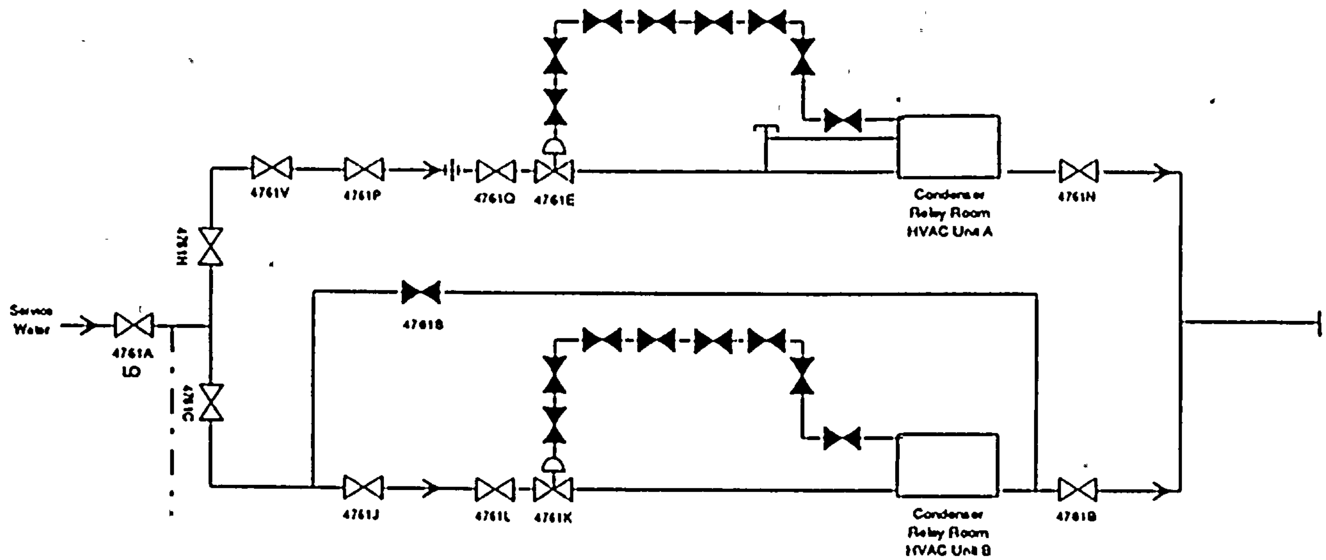
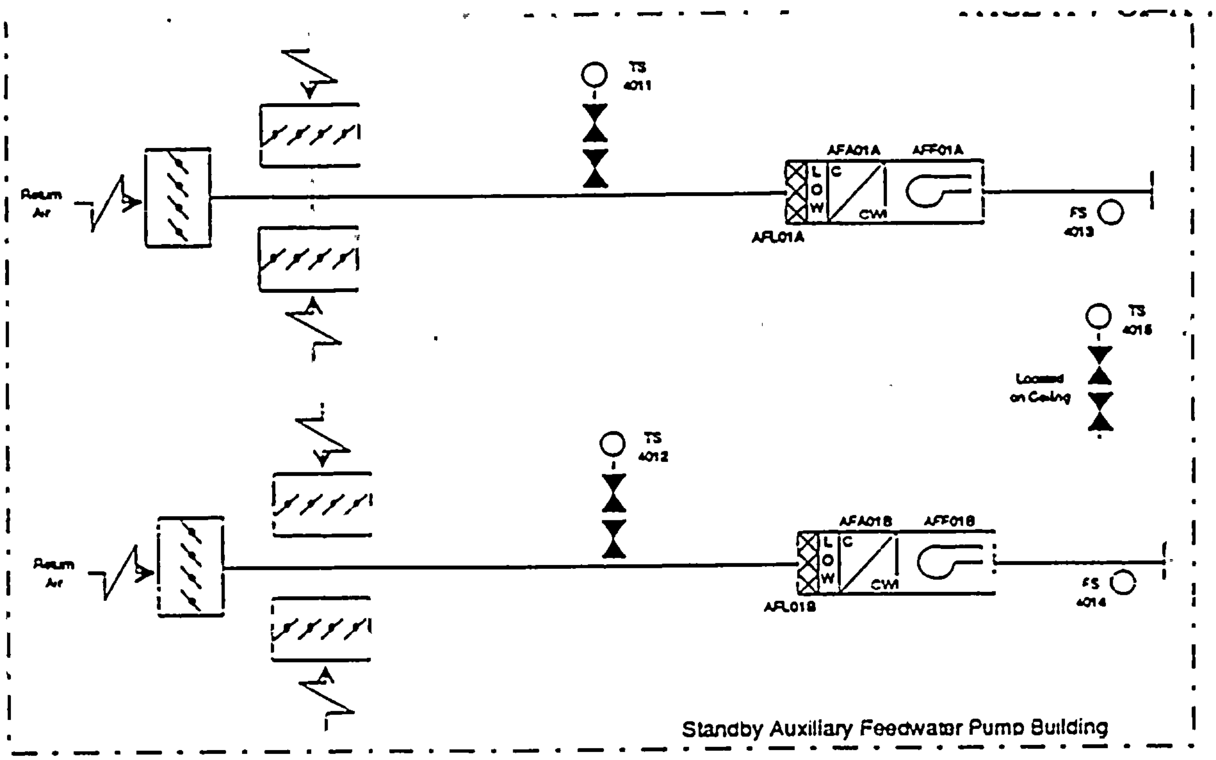


Figure 3.2.1-19
Standby Auxiliary Feedwater Building HVAC



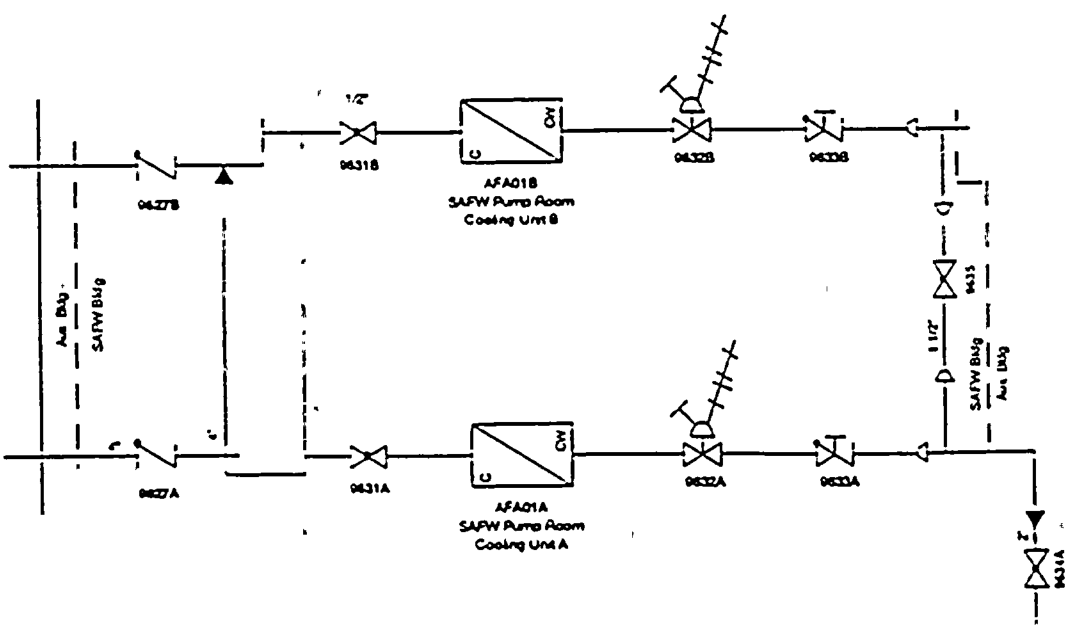


Figure 3.2.1-20
Instrument Air Compressors Simplified Flow Diagram

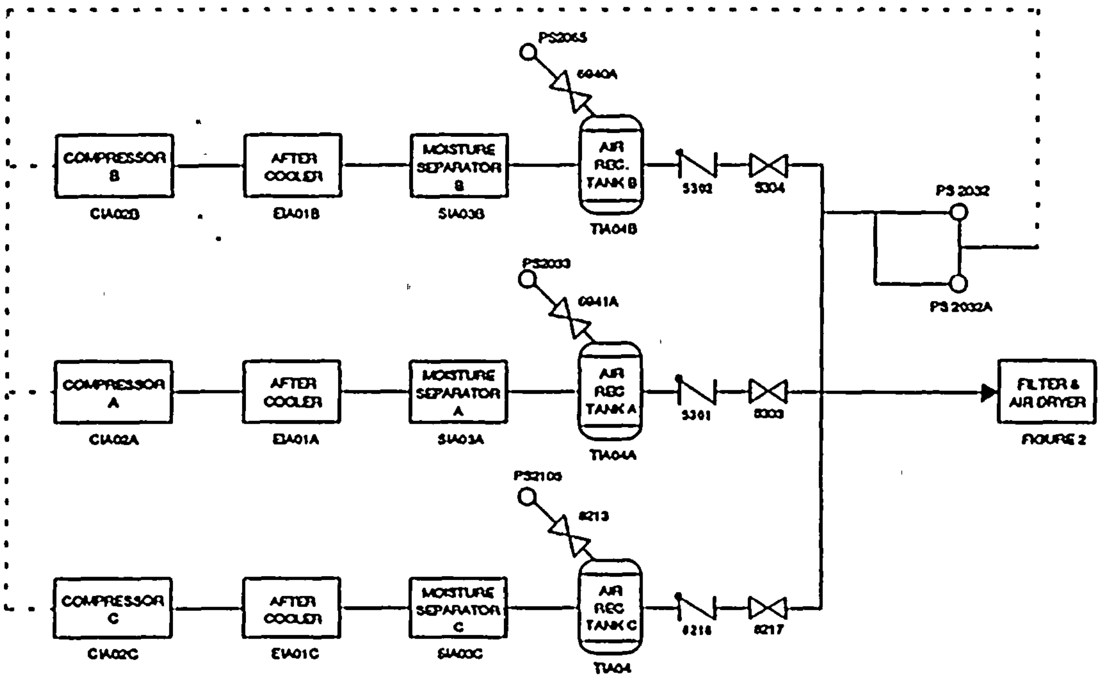


Figure 3.2.1-21
Instrument Air Dryers and Filters Simplified Flow Diagram

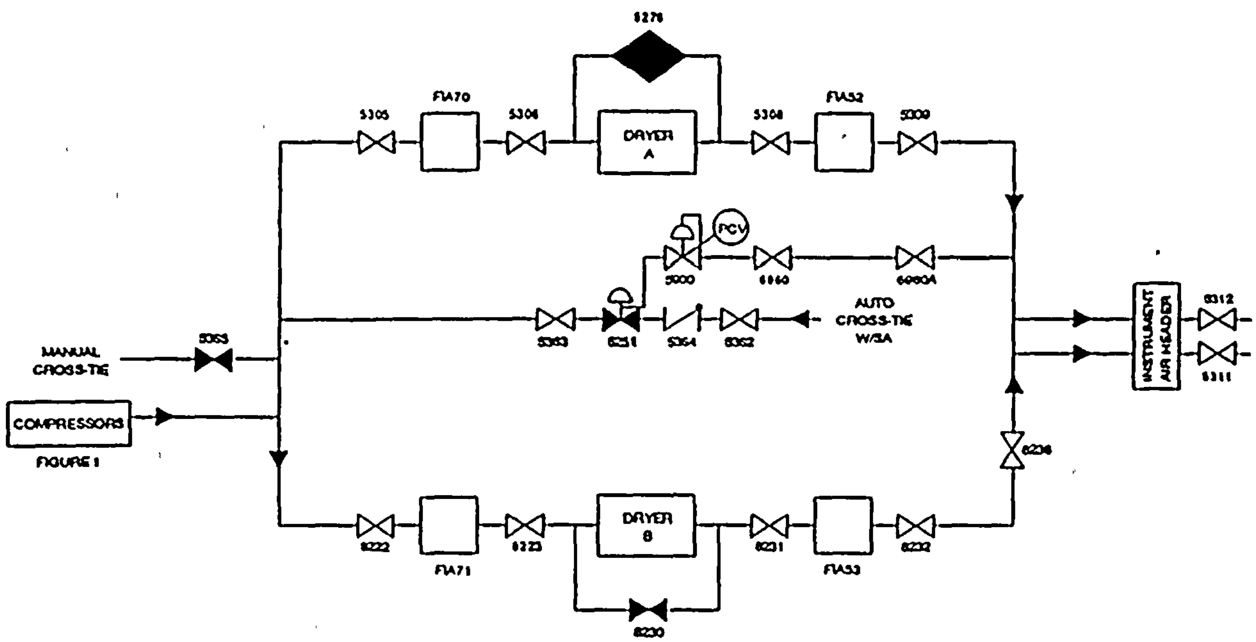


Figure 3.2.1-22
Service Air System Simplified Flow Diagram

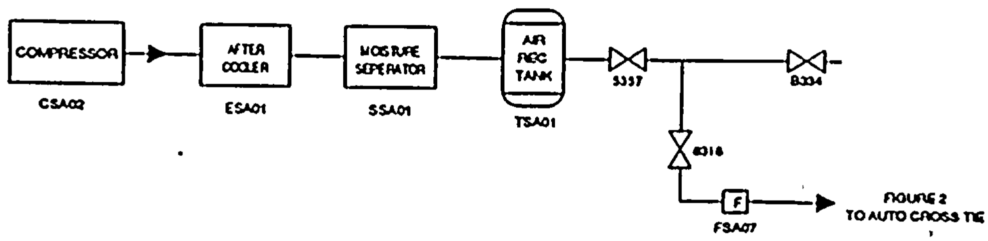


Figure 3.2.1-23
Instrument Air Distribution Headers

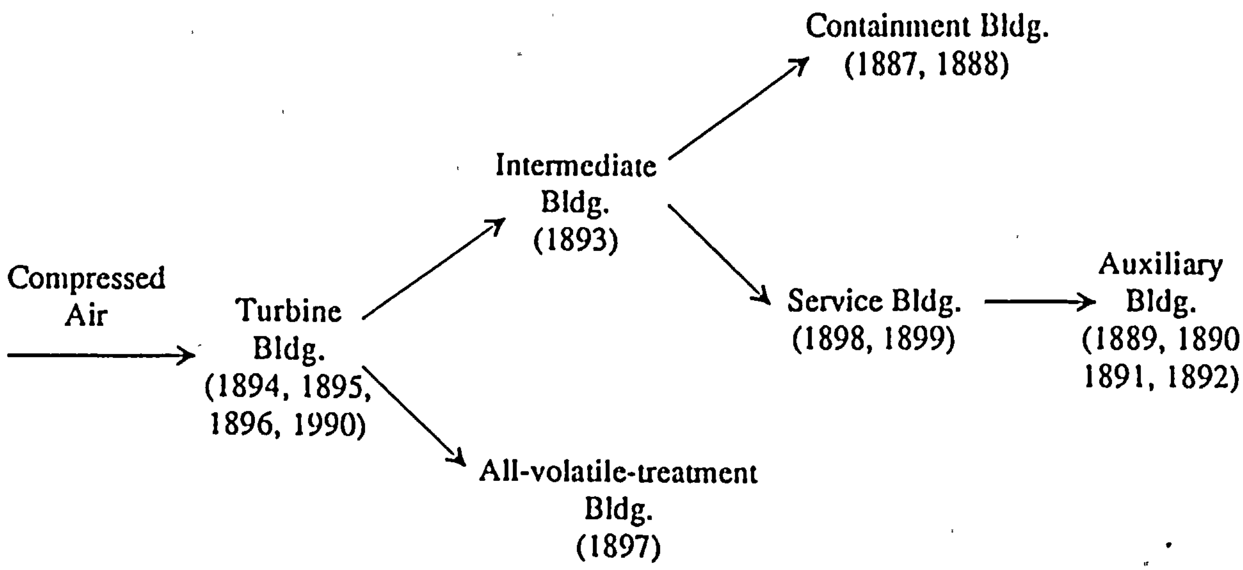


Figure 3.2.1-24
Service Water to the Instrument Air Compressors

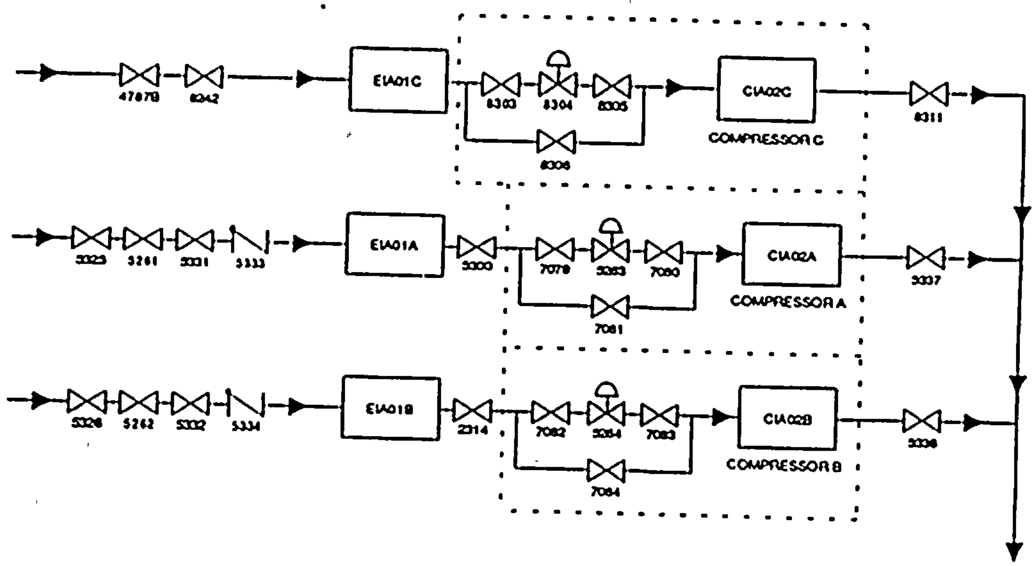


Figure 3.2.1-25
Service Water to the Service Air Compressor

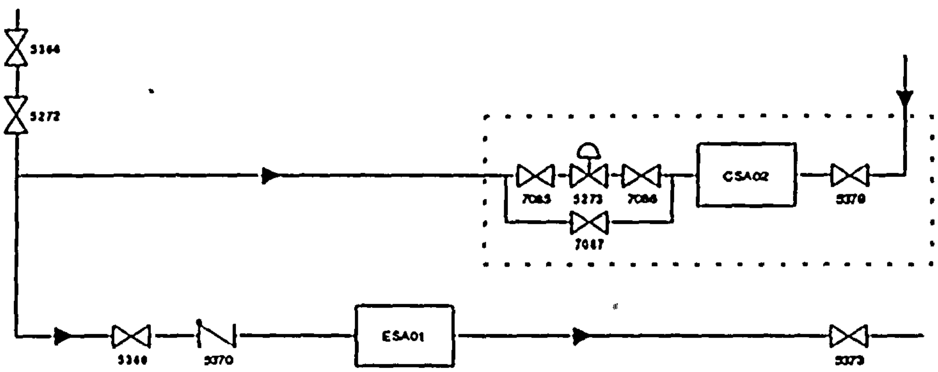


Figure 3.2.1-26
Primary Pressure Control Systems Simplified Diagram

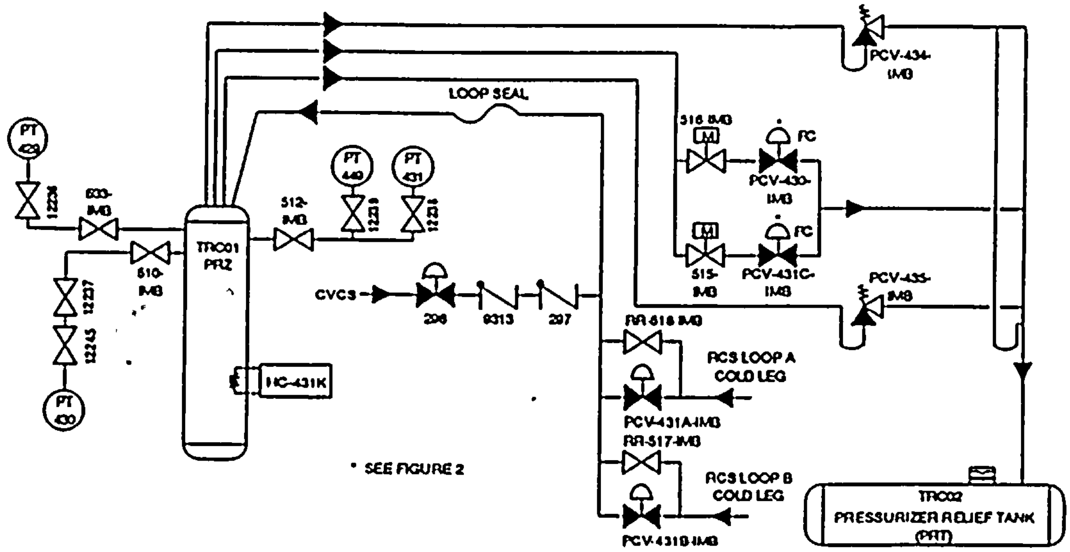


Figure 3.2.1-27
Pressurizer Pressure Instrumentation Circuits

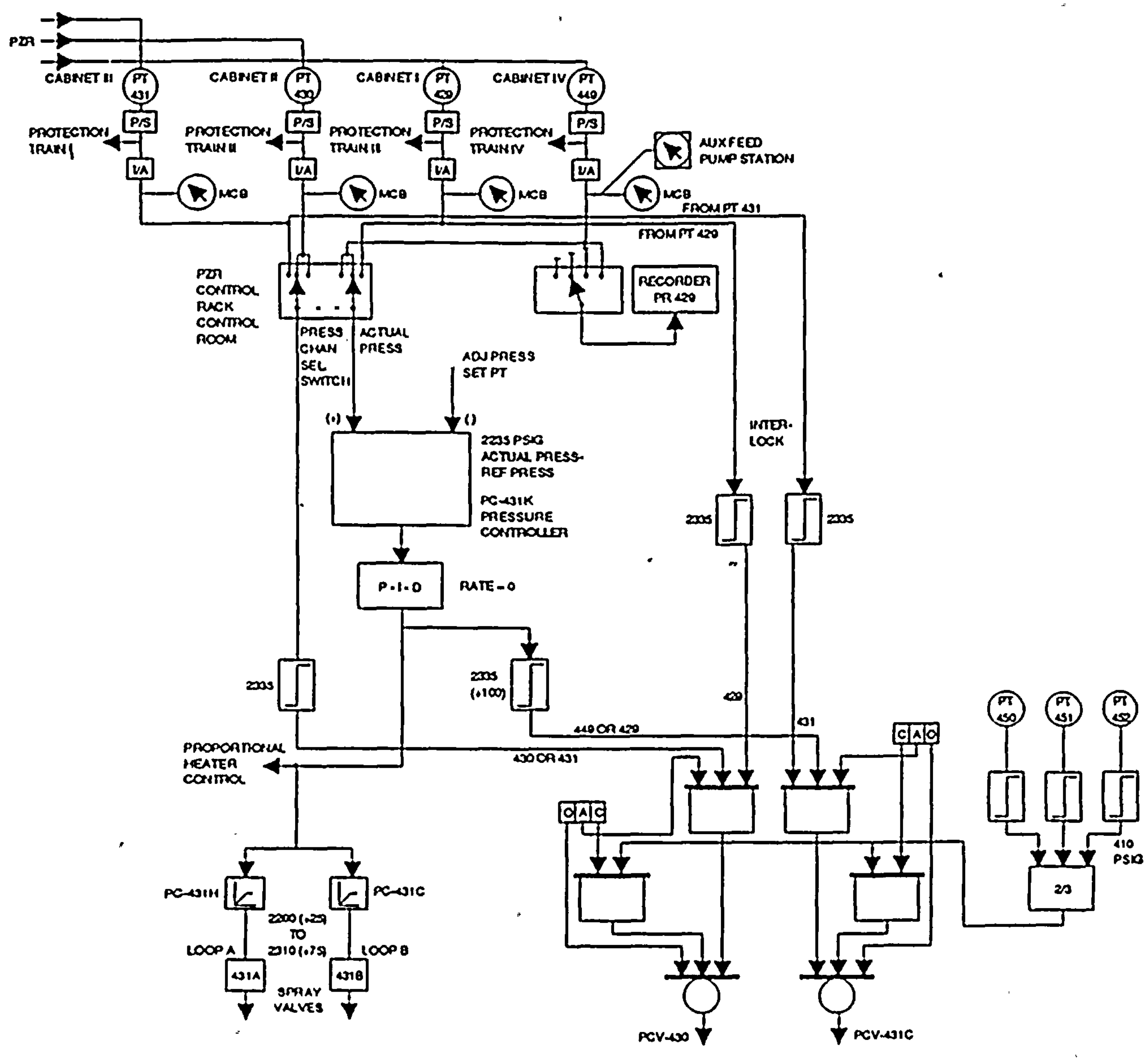


Figure 3.2.1-28
Instrument Air and Nitrogen Supply to the PORVs

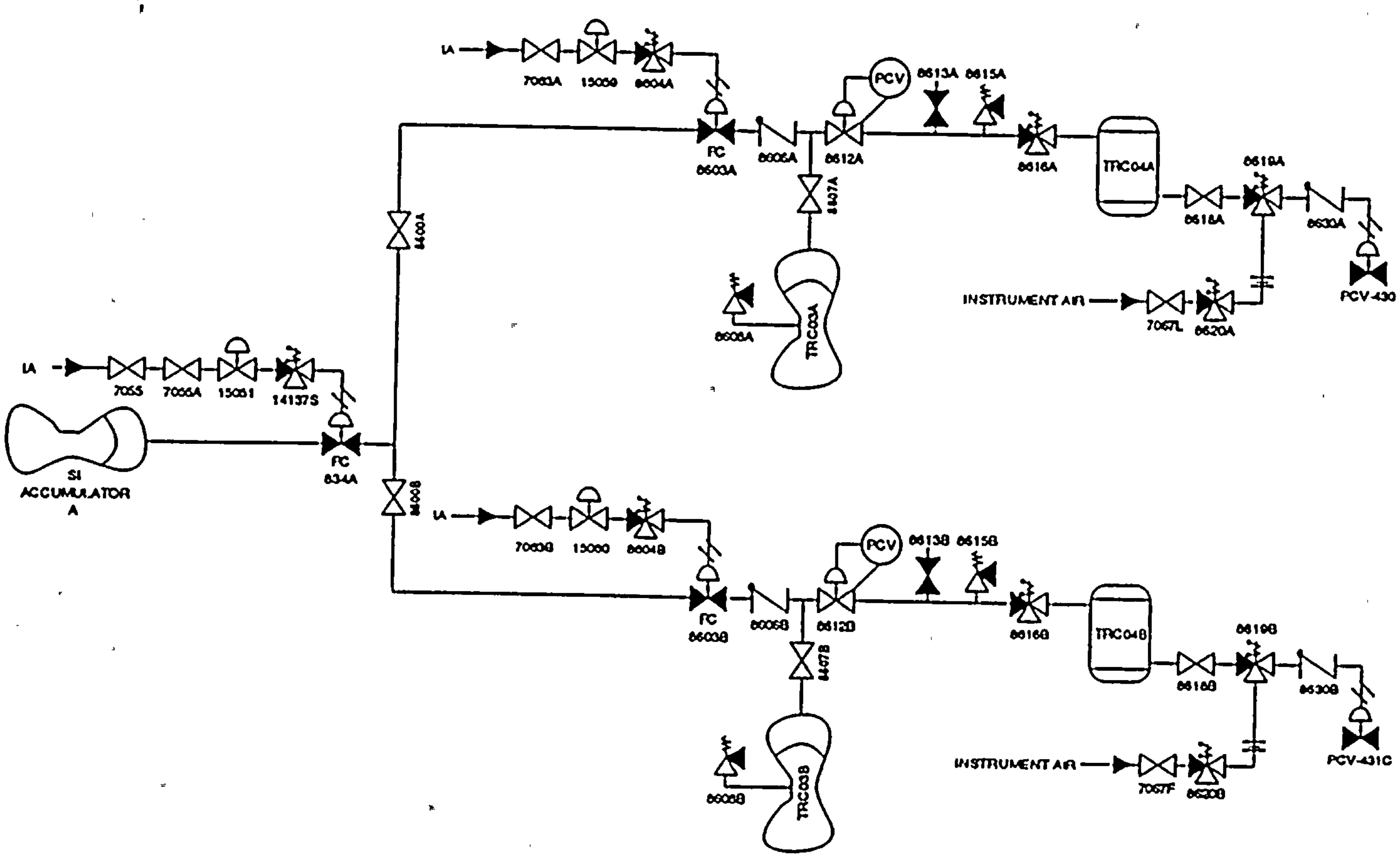


Figure 3.2.1-29
Overpressure Protection System Transmitters

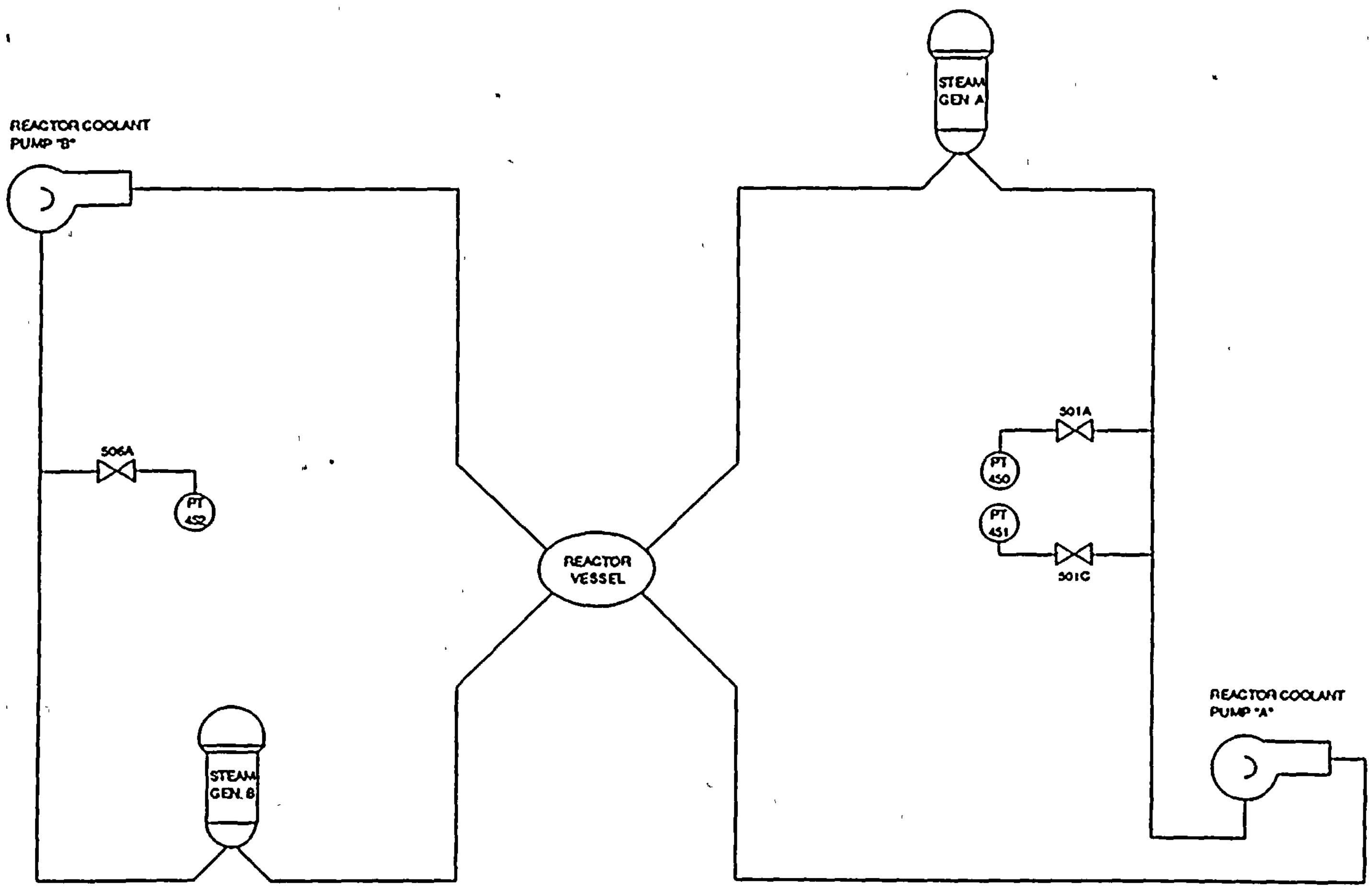


Figure 3.2.1-30
Residual Heat Removal System Simplified Flow Diagram

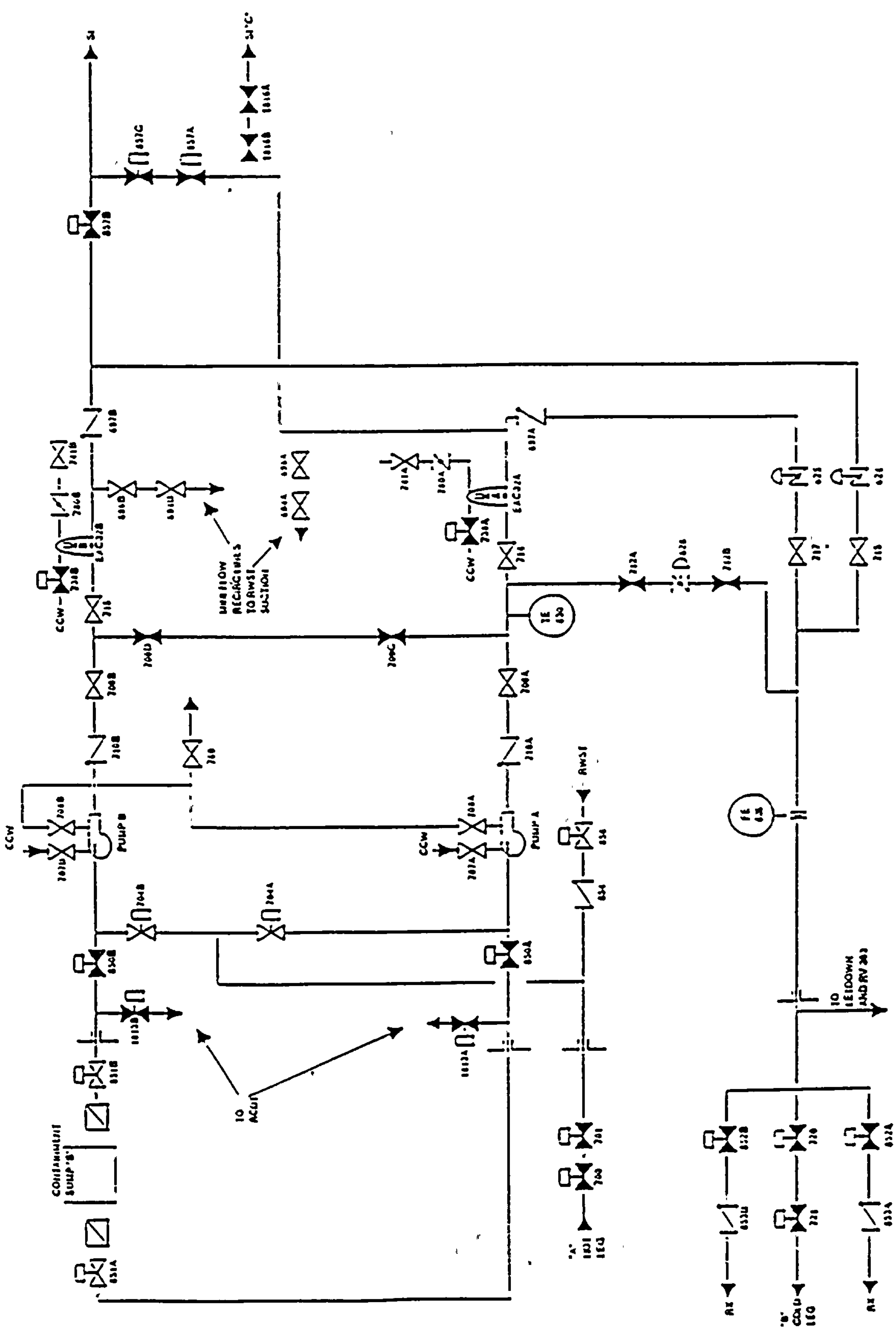


Figure 3.2.1-31
Safety Injection System Simplified Flow Diagram

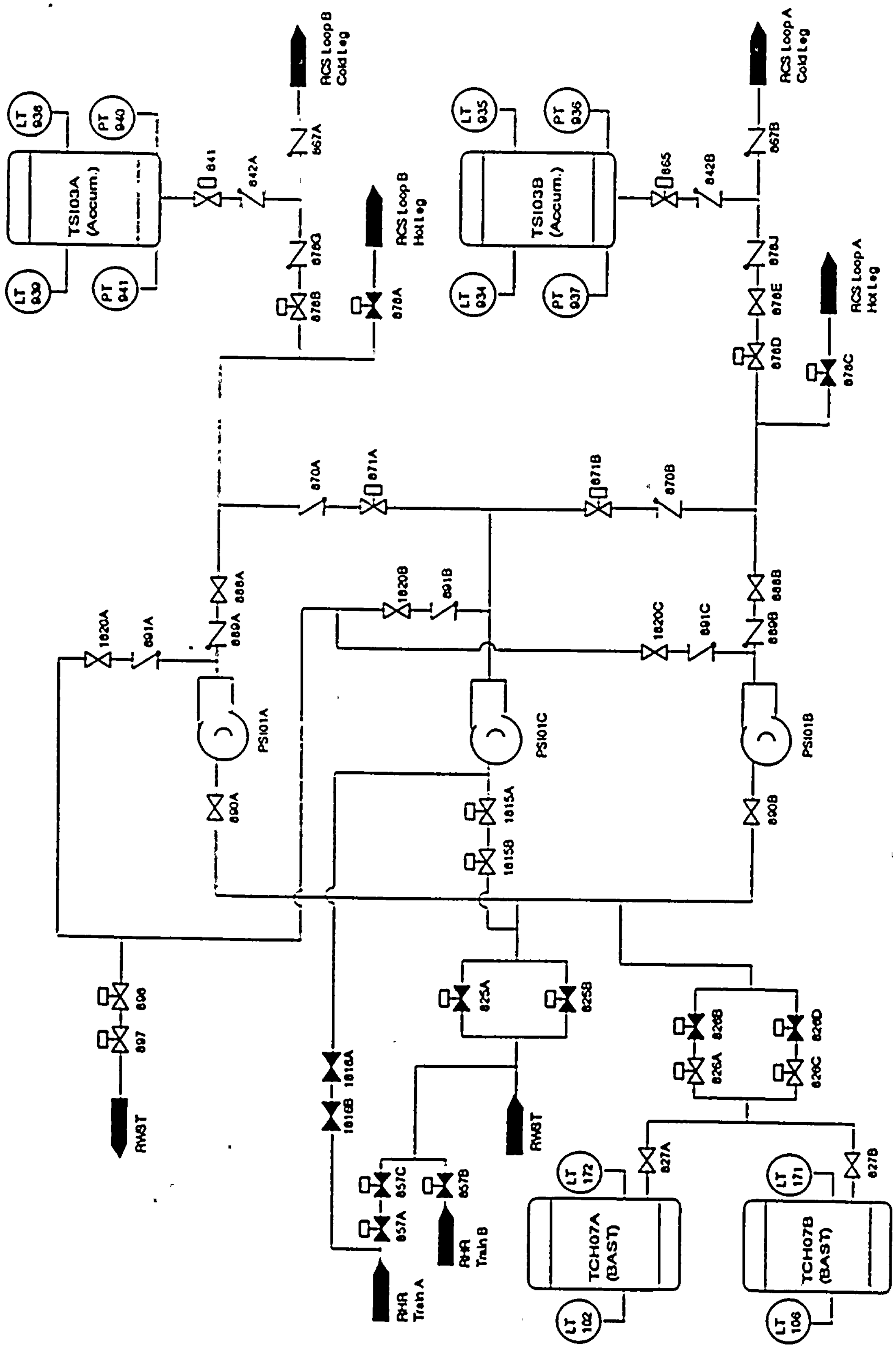
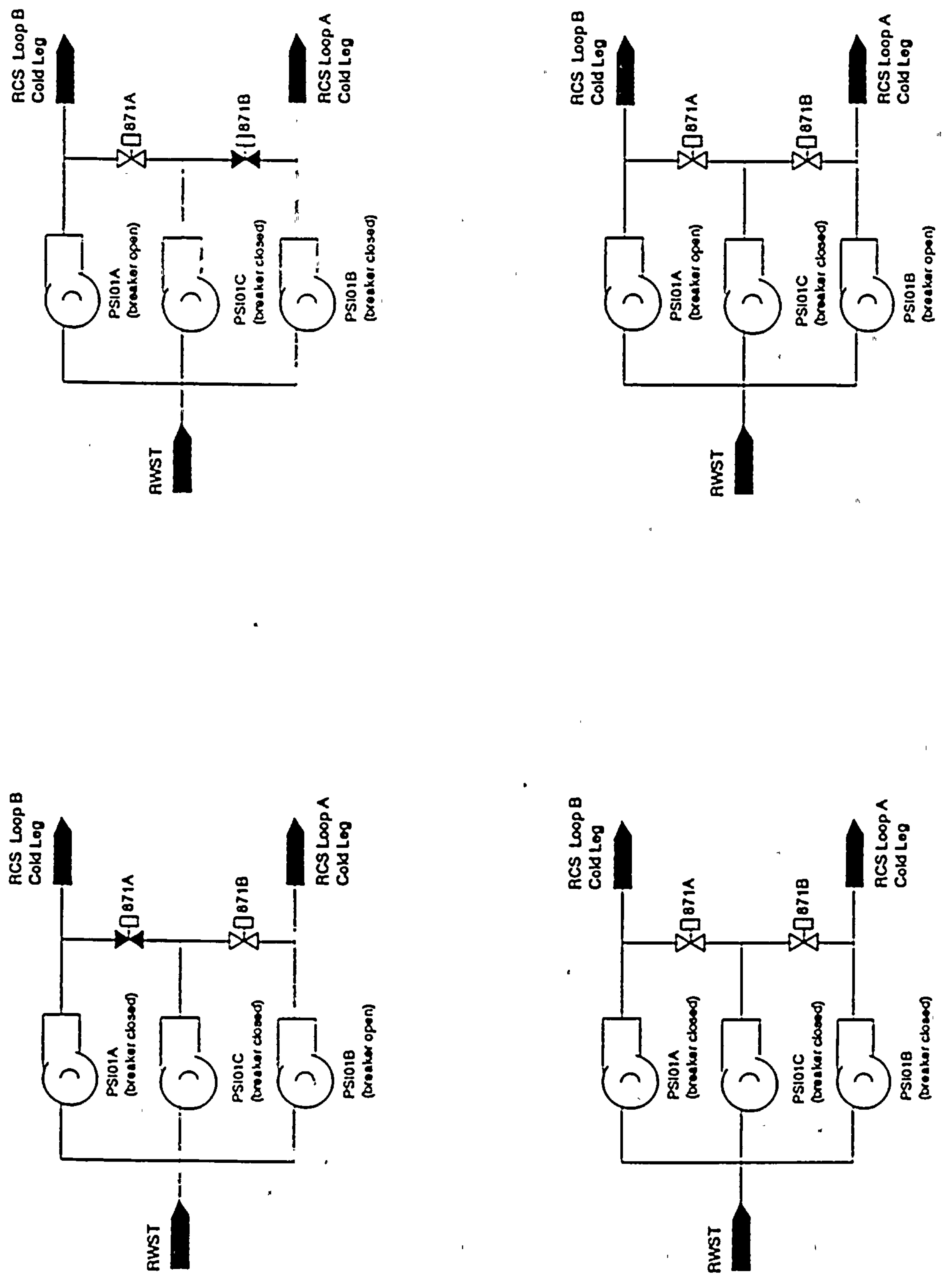


Figure 3.2.1-32
Possible Operational Configurations for Safety Injection Valves 871A and 871B



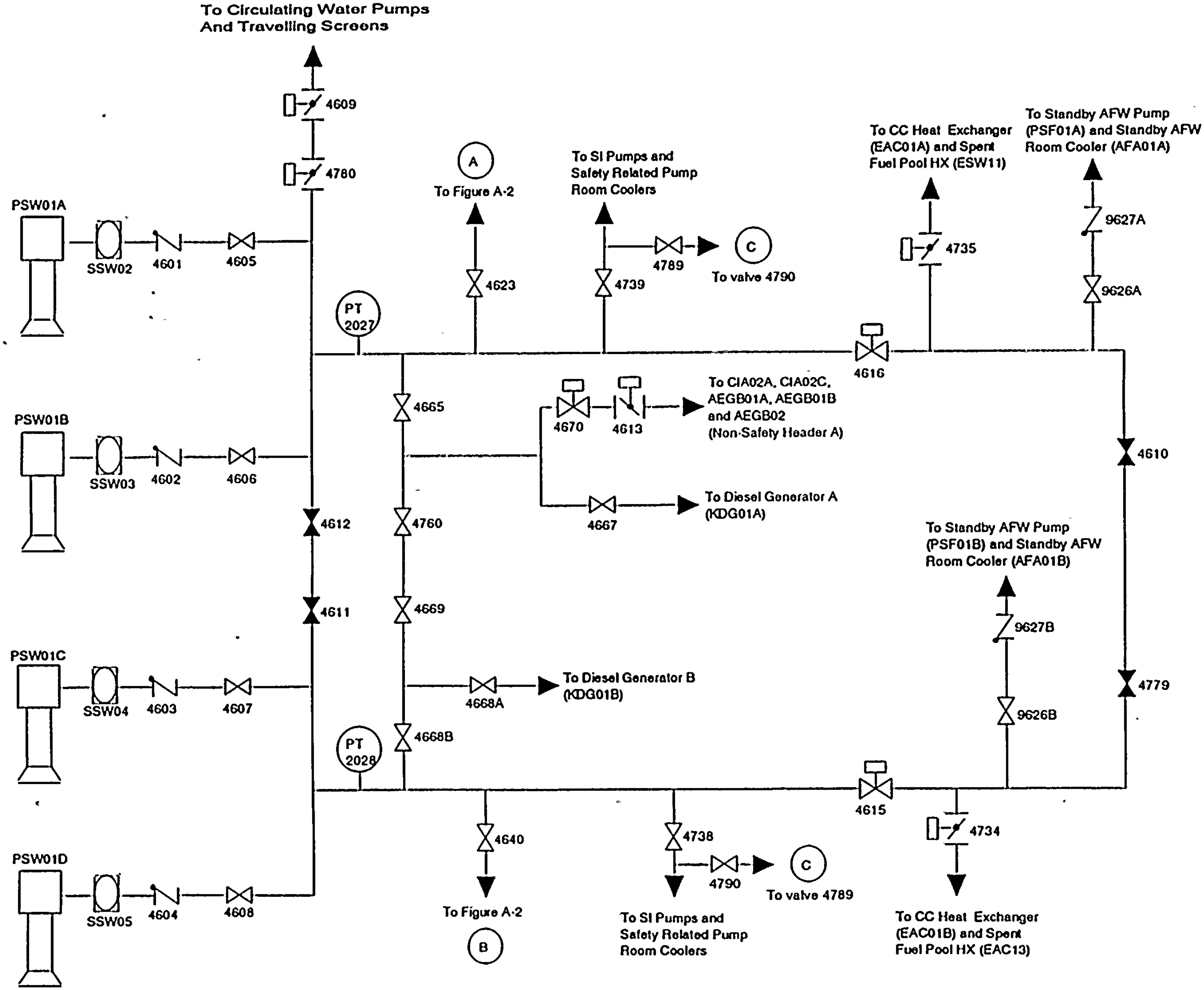


Figure 3.2.1-33
Service Water System Simplified Flow Diagram (1 of 2)

Figure 3.2.1-34
Service Water System Simplified Flow Diagram (2 of 2)

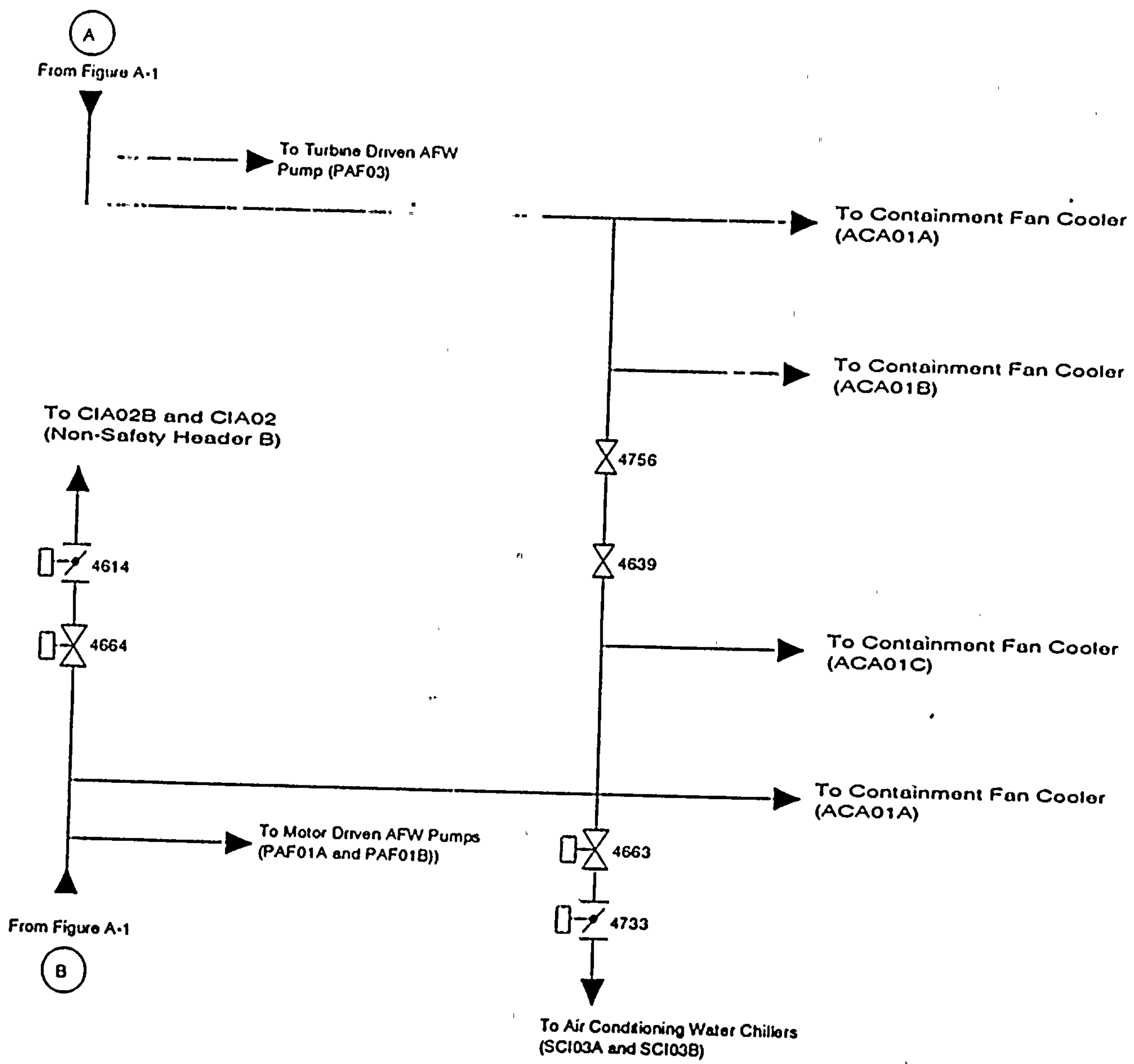


Figure 3.2.1-35
Steam Generator EMS01A Atmospheric Relief Valve 3411

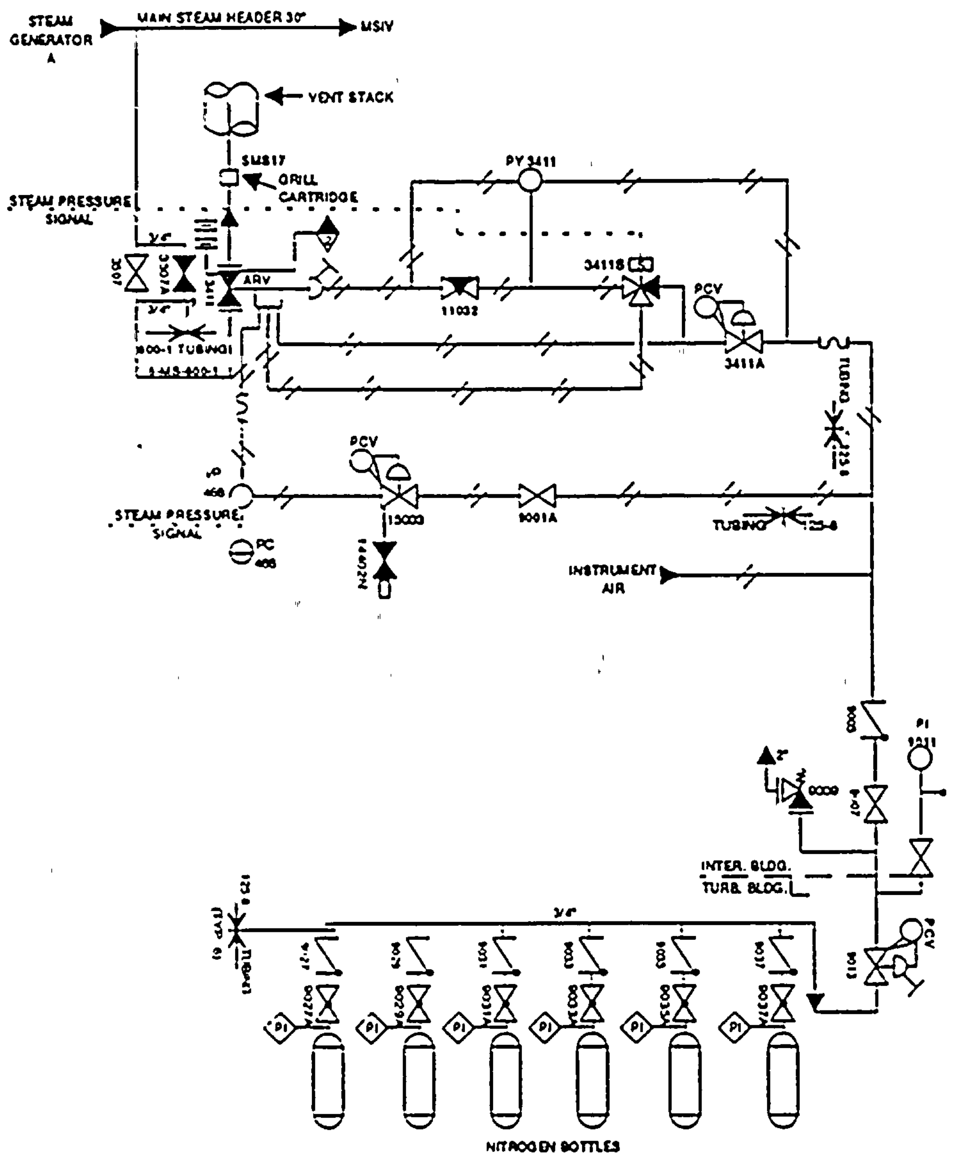
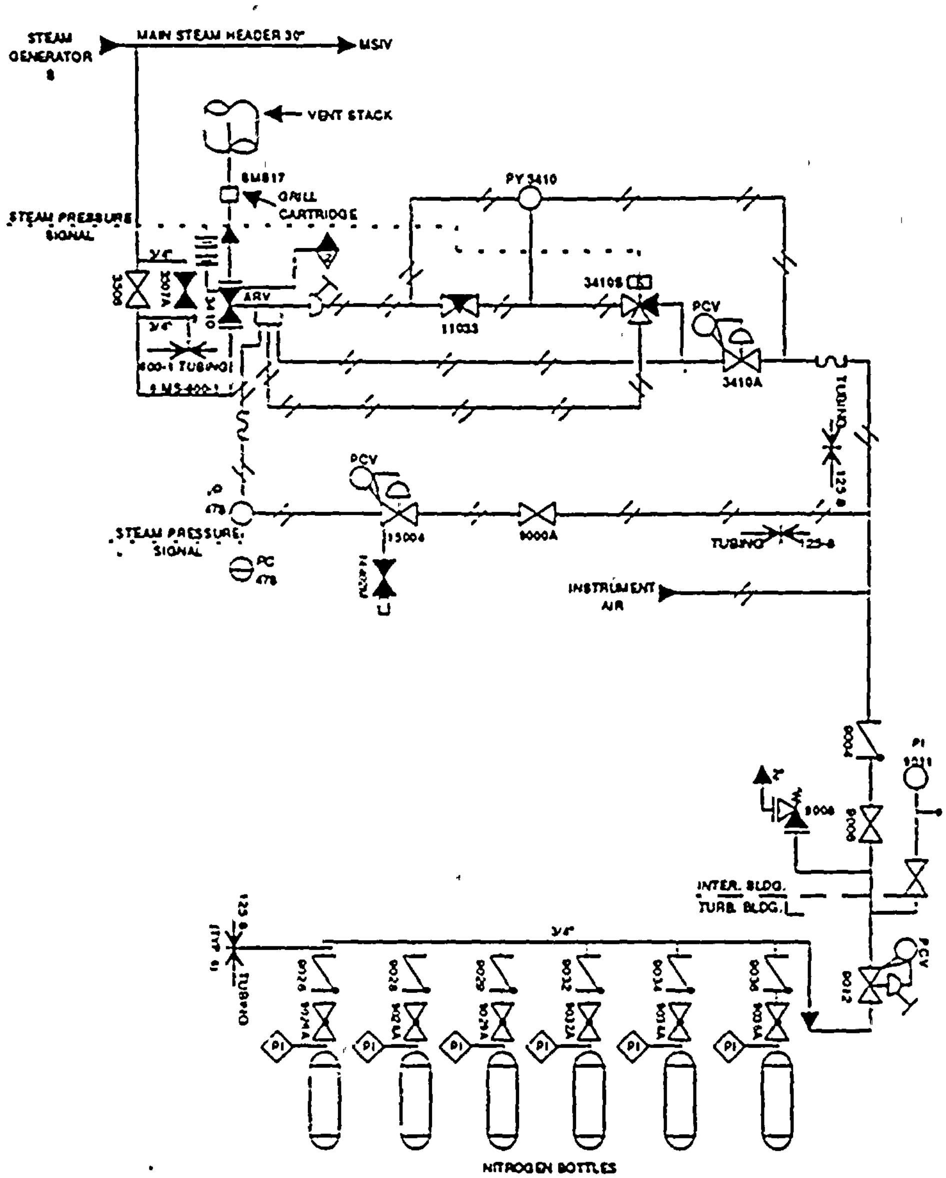


Figure 3.2.1-36
Steam Generator EMS01B Atmospheric Relief Valve 3410



3.2.2 Systems Analysis

The systems analysis segment of the Ginna PRA was accomplished in three major steps:

> **Information Retrieval** -- A detailed, quality assurance controlled work package was developed for each of the 14 major groups of plant systems described in Section 3.2.1. The first half of each of these work packages is roughly equivalent to the 14 subsections of Section 3.2.2. The Systems Analysis Task Leader reviewed each of these "Draft A" work packages at this stage.
>
> **Construction of Detailed Systems Model(s)** -- After review and approval of the "Draft A" work packages, the systems analysts constructed detailed fault trees per the success criteria passed on by the Accident Sequence Analysis Task Leader. The second half of the systems work package, which was constructed at this stage, contains sections on the assumptions behind the model; data assigned to the basic events; a discussion of common cause failure modes; directions on how to set any logic flags in the model(s); an evaluation of the potential for systems-based initiating events; and, insights gained on systems failure modes. The completed Revision 0 work packages were each reviewed and approved by the Systems Analysis Task Leader; the SAIC Principal Investigator; the SAIC Project Quality Assurance Manager; and, the RG&E Project Manager. As part of the RG&E Project Manager's review, the work packages were also reviewed by other members of the RG&E PRA team; by other appropriate RG&E engineers; and, by licensed operators from the Ginna Operations staff.
>
> **Model Integration** -- Support systems interfaces were extensively tested during the model integration phase. Required model changes were tracked and corrected using Temporary Changes to Work Packages. the Temporary Changes are, themselves, controlled documents under the project quality assurance plan.

3.2.3 Systems Dependencies

Dependencies for each of the systems were explicitly modeled in the Ginna PRA using the large linked fault tree approach. These dependencies are described in detail in Sections 3.2.1.n.3 (Electrical Dependencies); 3.2.1.n.4 (Cooling Water Dependencies); 3.2.1.n.5 (Instrument Air Dependencies); 3.2.1.n.6 (Actuation and Control Dependencies); and, 3.2.1.n.7 (Heating, Ventilation and Air Conditioning Dependencies).

A simplified, systems-level dependency diagram is shown in Figure 3.1.2-2.

A detailed, computerized Systems Analysis database has been constructed by the RG&E PRA team to track component-level dependencies. For each unique Ginna plant component represented in the logic model, the following dependencies and failure modes (where applicable) are tracked:

Generic component type;

Initial position / mode of the component assumed by the logic model;

Does the logic model require the component to change position / mode? (yes / no);

Failure mode on loss of air pressure;

Instrument air header component is supplied from;

Failure mode on loss of AC power;

Equipment Identification Number (EIN) of AC breaker / fuse, and the source of AC power to that device (up to two breakers / fuses / sources permitted);

Failure mode on loss of DC power;

EIN of DC fuse / switch, and the source of DC power to that device (up to two fuses / switches / sources permitted;

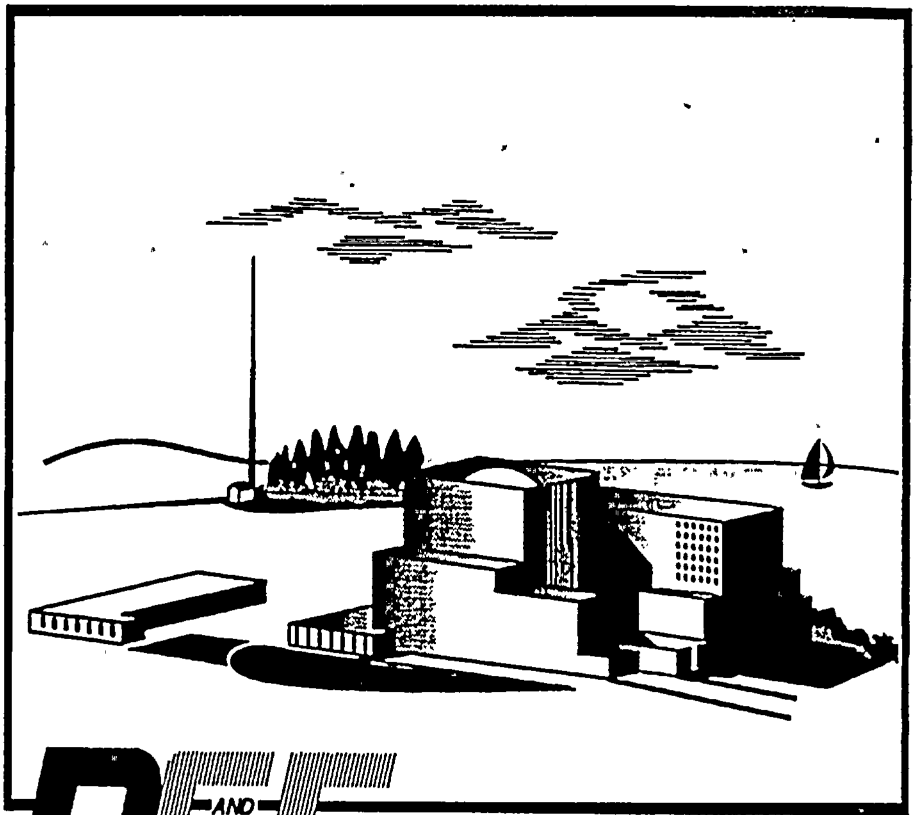
Failure mode on loss of equipment cooling water (service water of component cooling water);

Source of equipment cooling water;

Failure mode on loss of building / room cooling (HVAC); and,

- Source of building / room cooling.

During the course of verifying the fault tree electrical transfers, the RG&E PRA project team also constructed a computerized data base of power sources and electrical loads. By the end of the project, this specialized database contained over 5,000 entries.



Rochester Gas and Electric Corporation

R. E. Ginna Probabilistic Risk Assessment Project

Report to the United States Nuclear Regulatory Commission in response to Generic Letter 88-20
February 28, 1994

Volume 2 of 2

R. E. Ginna Probabilistic Risk Assessment Project
Report to the Nuclear Regulatory Commission in Response to
Generic Letter 88-20

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3.3.1 Generic Data

3.3.1.1 Introduction

The term generic data refers to component reliability parameter estimates based on either (1) the failure experience of nuclear utilities or other process industries, or (2) expert opinion. Generic data may be used in a PRA for several reasons:

1. Initial logic model check-out and validation may be performed at the same time plant-specific data is being collected and assessed; hence, the use of generic data saves time.

2. Plant operating experience may be limited; generic data must be used when credible plant-specific data does not exist.

3. It may not be possible to collect plant-specific data on certain components of interest (e.g., relays whose demand history is difficult to ascertain with much precision).

4. The PRA objectives may not justify the expense required to develop a plant-specific data set.

5. Generic data may form the basis for the prior distribution in a Bayesian updating process.

Experience has shown that more than half of all basic events in a PRA where plant data has been collected and reduced are quantified using generic data.

Since generic data plays important and various roles in PRAs, Science Applications International Corporation (SAIC) has developed a Generic Data Notebook for use in commercial nuclear power plant PRA projects. It is based on the collected experience and expertise of many SAIC PRA engineers. The SAIC Generic Data Notebook formed the basis for the Generic Data Work Package for the Ginna PRA project. Generic data sources have been reviewed against the component boundaries defined for the Ginna PRA [Ref. 3.3.1-1] to ensure consistancy. Additional generic data sources have been located to provide reliability parameter estimates for component types and failure modes specifically required for the Ginna PRA project [Ref. 3.3.1-2].

The remainder of this explanatory test addresses two areas. First, statistical terms and concepts relevant to the collection and use of generic data are explained. Second, the process used to develop the SAIC Generic Data Notebook is described.

3.3.1.2 Statistical Terms and Concepts

In order to understand and successfully apply a generic data set to a PRA, we must first become acquainted with some basic statistical terms and concepts. In general, the terms and concepts relevant to generic data may be found in any elementary statistics textbook [Ref. 3.3.1-3]; it is assumed that the reader understands random variables and their distribution functions. The intent of this section is to emphasize certain key concepts, thus "translating" abstract statistical terminology into the language of applied reliability data engineering.

3.3.1.3 Populations

A *population* is the total collection of objects of interest for a given problem. Examples of typical populations encountered in generic reliability data include:

1. Valves

2. Motor-operated valves

3. Valves installed in the Plant X decay heat removal system

We note that the second and third populations are subsets of the first population. Also, the second and third populations have some common objects, but neither is a subset of the other.

The concept of a population is the single most important feature in the collection and use of generic reliability data. Before applying generic data, we must try to match a generic data source's population to our particular problem. For example, consider the problem of selecting generic data for the third population defined above (Plant X decay heat removal system valves): we would feel more comfortable using data collected from the population of all U.S. commercial nuclear power plants rather than, say, data collected from foreign off-shore oil platforms. However, it is difficult to be "scientific" during the matching process since we do not know which attributes of a population control its reliability data. (Is it the basic equipment design, the materials used, or the maintenance policies applied to the component?)

The selection of generic data is further complicated by the fact that there may be several sets of generic data available, each based on a different population. Again, there is no clear-cut way to proceed in the matching process. An additional difficulty is that most generic data sources do not fully report their underlying populations. Thus, on a pragmatic level, the application of generic data to a PRA largely consists of trying to identify the populations used to build various generic data sources.

3.3.1.4 Uncertainty

The second most important statistical concept in the collection and use of generic reliability data is *uncertainty*. In virtually all PRAs published to date, equipment is assumed to fail at a constant rate. However, due to various reasons, the "true" value of a failure rate is often not known. This uncertainty in equipment failure rates leads to uncertainty in accident sequence frequencies.

PRA engineers often attempt to ascertain the effect that small deviations in equipment failure rates have on the overall PRA results. PRA uncertainty analysis is usually done by (1) assuming that each equipment failure rate is a random variable, and (2) calculating the distribution function of all accident sequences as a function of the equipment failure rate distribution functions. Note that this approach, while perhaps intuitive to an engineer, is treading on statistical "thin ice": Failure rates are either constant or random variables, but they cannot be both. Nevertheless, the practice is well-entrenched with no signs of revision.

In assigning an uncertainty distribution to an equipment failure rate, we must consider both data confidence and data tolerance. *Confidence bounds* are a measurement of imprecision in a population's failure rate due to sampling error. We can produce "tight" confidence bounds by counting failures over a long time period. *Tolerance* refers to variability among several populations due to varying attributes of each population. We try to reduce questions of tolerance by carefully matching the population in generic data sources to the one we are studying.

Unfortunately, most generic data sources do not properly present uncertainty information. Uncertainty in sources based on a single plant's experience is largely due to confidence concerns; uncertainty in sources based on either compilations of several plants' experience or expert opinion is largely due to tolerance concerns. Again the issue is one of matching of population attributes. If two populations are the same, then we can pool their experience to produce a generic failure rate estimate with narrow confidence bounds and no tolerance bounds. However, if two populations are different, then we must use more sophisticated methods to combine their experience. Usually we can determine the most appropriate method by reviewing discussions of how a generic data source was compiled; but, it is not possible (due to lack of information) to decompose and reassemble generic data according to these methods.

3.3.1.5 Generic Data Set Development

As previously mentioned, the major difficulty in developing a generic data set is identification of the populations used to construct various generic data sources. The following sections describe the process used to build the SAIC Generic Data Notebook. Emphasis is placed on explaining the techniques used to map existing generic data sources onto the needs of PRA. The technique used to aggregate multiple generic data sources for a given component type and failure mode is explained.

3.3.1.6 Scope Determination

All fault tree and top logic basic events defined in previous SAIC-conducted PRAs were tabulated and sorted to determine the scope of SAIC Generic Data Notebook. 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".)

3.3.1.7 Source Identification

A list of generic data sources was developed by (1) surveying the open literature and (2) reviewing previous PRAs and nuclear reliability studies. An effort was made to identify at least three sources for each component type and failure mode.

3.3.1.8 Source Classification

Each generic data source was classified in order to establish its relevance and usefulness. Three following attributes were identified for each source:

1. Origin

   Data sources with the most appropriate origin for commercial nuclear power plant PRA 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.

2. Scope

   Data sources with broad scopes (i.e., which are based on a large population of components) are more desirable than narrow scopes.

3. Quality

   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 an 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.

3.3.1.9 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:

1. Same component type and failure mode

   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.

2. Original information

   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.)

3. Availability

   The generic data source had to be widely available (i.e., not proprietary). This requirement ensured traceability and scrutibility.

4. Quality

   Mid-level and low quality sources were only used if high quality sources were not available.

5. Bayesian updated source

   Source 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).

6. Operating environment

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.).

7. Scope

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.

3.3.1.10 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 consists of three steps as described in the following sections.

Step 1: Fit Generic Data Sources

Each generic data source for a given component type and failure mode was fitted to a log-normal distribution as described by its median and logarithmic standard deviation. Any right-skewed distribution could be used [Ref. 3.3.1-4]; however, the log-normal distribution is easy to deal with computationally and is well suited to expressing uncertainty bounds (via error, or range factors). Properties of the log-normal distribution are given in Table 3.3.1-1.

Generic data sources provide statistical information in a variety of styles which form two board classes: (1) sources that provide distributional information, and (2) sources which provide failure counts and exposures. The methods used to form the log-normal uncertainty distribution depend upon the type of information provided.

Distributional Information. In this style, distributional information (e.g., a mean value, point estimate, upper and lower percentiles, etc.) is specified. Such information is difficult to assess since most generic data sources do not provide adequate information to interpret the supplied values. (For example, do the supplied values consider both data confidence and tolerance? Is the point value a distribution mean, median, or mode? What distributional type is used?) The following rules have been established regarding the use of generic data sources that provide distributional information:

1. Either a mean or median must be provided. Given both, the mean is preferred over the median.

2. The upper tail of the distribution must be established (in order of preference) by either the log-normal error factor or upper percentile.

As shown in Figure 3.3.1-1, a hierarchy for converting the supplied distributional information into a log-normal uncertainty distribution was developed from these rules. This hierarchy is applied by entering Figure 3.3.1-1 from the left-hand side (labeled "START"). A series of questions about the presence of certain information are posed; these questions are represented by branch points in Figure 3.3.1-1. A positive answer, which indicates that certain information exists, is represented by an "up" branch. Questions are asked until the right-hand side is reached (labeled "END STATE"). An end state labeled "NO" means that the provided information does not satisfy the established rules and must, therefore, be set aside. End states labeled with numerals represent cases where sufficient distributional information has been provided within the generic data source; in such cases, various formulas are used to determine the log-normal uncertainty fit. Table 3.3.1-2 provides an index of the possible endpoints and references to the appropriate formulas from Table 3.3.1-1 for calculating the log-normal median and logarithmic standard deviation.

Failure Count and Exposure. This style provides the total number of failures that have occurred over a specified time period or number of demands (or, alternatively, cycles or trial). There are three issues of concern in using this style of information:

a. It is not possible to ascertain whether or not the information is consistent with an assumption of constant failure rates and constant failure-on-demand probabilities as the time (or demands) between failures is not given.

b. Generic data sources typically do not state if the data has been statistically censored. If the last failure occurred exactly at the end of the exposure period, then the data is uncensored. If failures were counted until a preset total failure count was reached, then the data is Type I censored. If failures were counted for a preset time period, then the data is Type II censored. Knowledge of the censoring scheme used to collect the data is necessary to provide meaningful uncertainty estimates.

c. Only failure and exposure totals may be given even though the accompanying explanatory text of a generic data source may state that the population is heterogeneous. In such cases, the information appears to have a high information content (due to the large number of failures); however, there is no way to separate the data confidence from the data tolerance.

In the SAIC Generic Data Notebook, failure count and exposure information has been used to form classical confidence bounds based on the assumption of constant failure rates and constant failure-on-demand probabilities; the appropriate equations are:

$$\bar{\lambda} = \frac{f_T}{T} \tag{1}$$

$$\lambda_{.05} = \frac{x^2(2f_T, 0.05)}{2T} \tag{2}$$

$$\lambda_{.95} = \frac{x^2(2f_T + 2, 0.95)}{2T} \tag{3}$$

$$\bar{p} = \frac{f_D}{D} \tag{4}$$

$$p_{.05} = \frac{f_D F_{.05}(2f_D, 2D - 2f_D + 2)}{D - f_D + 1 + f_D F_{.05}(2f_D, 2D - 2f_D + 2)} \tag{5}$$

$$p_{.95} = \frac{(f_D + 1) F_{.95}(2f_D + 2, 2D - 2f_D)}{2D - 2f_D + (f_D + 1) F_{.95}(2f_D + 2, 2D - 2f_D)} \tag{6}$$

where:

=

failure rate mean value

$\lambda_{.05}$ = failure rate lower confidence bound

$\lambda_{.95}$ = failure rate upper confidence bound

$x^2(v,p)$ = pth percentile of a x^2 distribution with v degrees of freedom

f_T = number of time-related failures

T = time interval over which the f_T failures occurred

=

failure-on-demand probability mean value

$p_{.05}$ = failure-on-demand probability lower confidence bound

$p_{.95}$ = failure-on-demand probability upper confidence bound

$F_p(v_1,v_2)$ = pth percentile of an F distribution with v_1 and v_2 degrees of freedom

f_D = number of demand-related failures

D = number of demands over which the f_D failures occurred

These bounds have been subsequently converted into a log-normal uncertainty distribution in accordance with Figure 3.3.1-1 (either end states 2 or 3).

Step 2: Form Aggregate Distribution

The data sources were combined into a single estimate by forming the weighted sum of each input generic data source's distribution function:

$$Pr\{X \le x\} = \sum_{i=1}^{N} \omega_i Pr\{X_i \le x\} \quad (7)$$

where:

N = number of generic data sources

$Pr\{X \le x\}$ = distribution function of the aggregate reliability parameter

ω_i = weight of the ith generic data source

$Pr\{X_i \le x\}$ = distribution function of the ith generic data source

This aggregation method, developed by SAIC for EPRI during the Component Reliability Parameter Studies and based on the work of Stone [Ref. 3.3.1-5] and Winkler [Ref. 3.3.1-6], ensures that data tolerance is preserved. By "smearing" the uncertainty of all input generic data sources, an aggregated uncertainty bound is created which properly encompasses the entire range of uncertainty.

As previously discussed, each input generic data source is assumed to be log-normally distributed. The aggregate distribution has been formed by assigning equal weight to each input data source (i.e., $\omega_i = 1/N$).

It can be shown that, regardless of the input data source distributional type(s), the mean of the aggregate distribution is the weighted sum of the input means. Determination of the aggregate distribution percentiles typically requires a numerical solution. Using the previous assumptions (i.e., log-normally distributed input data sources and equal weights), the following equation applies:

$$\begin{aligned} p &= \sum_{i=1}^{N} \frac{1}{N}\, \Phi\left[\frac{\ln\left(\frac{x_p}{\hat{x}_i}\right)}{\sigma_i}\right] \\ &= \sum_{i=1}^{N} \frac{1}{N} \int_0^{x_p} \frac{1}{\sqrt{2\pi}\,\sigma_i t} \exp\left\{-\frac{\left[\ln\left(\frac{t}{\hat{x}_i}\right)\right]^2}{2\sigma_i^2}\right\} dt \end{aligned} \tag{8}$$

where:

$\hat{x}_i$ = median of the ith input data source

σ_i = logarithmic standard deviation of the ith input data source

Equation (8) has been solved (i.e., the value of x_p determined for a given value of p) for the 5th percentile ($p = 0.05$), the median ($p = 0.5$), and the 95th percentile ($p = 0.95$). These bounds have been subsequently converted into a log-normal distribution in accordance with Figure 3.3.1-1 (either end states 2 or 3).

Step 3: Fit Aggregate Distribution

To facilitate use of the aggregated distributions in traditional PRA uncertainty calculations, each was converted to a log-normal distribution in accordance with the hierarchy described by Figure 3.3.1-1. A computer program, titled "Computerized Analysis of Reliability Parameters -- CARP", was used to perform the aggregation process.

3.3.1.11 References

3.3.1-1 *Instruction for Determining Component Populations and Boundaries*, RG&E Probabilistic Risk Assessment Instruction PRA-002.

3.3.1-2 *Systems Analysis Procedure*, SAIC-139-91-020.

3.3.1-3 John Neter, William Wasserman, and G. A. Whitmore, *Applied Statistics*, third edition, Boston: Allyn and Bacon, Inc., 1988.

3.3.1-4 H. F. Martz, et. al., *A Comparison of Methods for Uncertainty Analysis of Nuclear Power Plant Safety System Fault Tree Models*, NURGE/CR-3263, April 1983.

3.3.1-5 M. Stone, "The Opinion Pool", *Annals of Mathematical Statistics*, Vol. 32, pp. 1339-1342, 1961.

3.3.1-6 R. L. Winkler, "The Consensus of Subjective Probability Distributions", *Management Science*, Vol. 15, pp. B61-B75, 1968.

Table 3.3.1-1
Summary of the Log-Normal Distribution

DENSITY FUNCTION

The probability density function (pdf) of a log-normally distributed random variable, X, is:

$$f_X(x) = \frac{1}{\sqrt{2\pi}\,\sigma x} \exp\left\{-\frac{\left[\ln\left(\frac{x}{\hat{x}}\right)\right]^2}{2\sigma^2}\right\} \tag{A-1}$$

where $\hat{x}$ is the median of X and σ is the logarithmic standard deviation of X.

DISTIRIBUTION FUNCTION

The cummulative distribution function (CDF) of a log-normally distributed random variable, X, is:

$$F_X(x) = \Pr\{X \leq x\}$$

$$= \int_0^x \frac{1}{\sqrt{2\pi}\,\sigma t} \exp\left\{-\frac{\left[\ln\left(\frac{t}{\hat{x}}\right)\right]^2}{2\sigma^2}\right\} dt \tag{A-2}$$

$$= \Phi\left[\frac{\ln\left(\frac{x}{\hat{x}}\right)}{\sigma}\right]$$

Tables of the standard normal CDF, $\Phi(...)$, are contained in most statistics books.

Table 3.3.1-1
Summary of the Log-Normal Distribution

RELATION TO NORMALLY DISTRIBUTED RANDOM VARIABLES

If the random variable Y is log-normally distributed, then the random variable $Y = \ln X$ is normally distributed. If Y is normally distributed with mean μ and standard deviation σ, then

$$\hat{x} = \text{median of } X = e^{\mu} \tag{A-3}$$

$$\bar{x} = \text{mean of } X = \exp\left(\mu + \frac{\sigma^2}{2}\right) = \hat{x}\ \exp\left(\frac{\sigma^2}{2}\right) \tag{A-4}$$

$$\text{Var}(X) = \text{variance of } X = e^{2\mu}\left(e^{2\sigma^2} - e^{\sigma^2}\right) = \hat{x}^2\left(e^{2\sigma^2} - e^{\sigma^2}\right) \tag{A-5}$$

ERROR FACTOR

As a measure of variation about a central tendency, error factor (or range factor) is used more often than variance:

$$ef = \frac{x_{.95}}{\hat{x}} \tag{A-6}$$

where $x_{.95}$ is the 95th percentile of X.

Also,

$$\begin{aligned} ef &= \frac{\hat{x}}{x_{.05}} \\ &= \sqrt{\frac{x_{.95}}{x_{.05}}} \end{aligned} \tag{A-7}$$

Table 3.3.1-1
Summary of the Log-Normal Distribution

where $x_{.05}$ is the 5th percentile of X.

It can be shown that

$$\sigma = \frac{\ln ef}{z_{.95}} \tag{A-8}$$

where $z_{.95}$ is the 95th percentile of the standard normal distribution (≈ 1.645).

The following development relates the quantities $\bar{x}$, $x_{.95}$, σ, and *ef*:

$$\begin{aligned}
\bar{x} &= \exp\left(\mu + \frac{\sigma^2}{2}\right) \\
&= \hat{x} \exp\left(\frac{\sigma^2}{2}\right) \\
&= \frac{x_{.95}}{ef} \exp\left(\frac{\sigma^2}{2}\right) \\
&= \frac{x_{.95}}{\exp(z_{.95}\sigma)} \exp\left(\frac{\sigma^2}{2}\right)
\end{aligned} \tag{A-9}$$

Or:

$$\frac{\sigma^2}{2} - z_{.95}\sigma + \ln\left(\frac{x_{.95}}{\bar{x}}\right) = 0$$

Table 3.3.1-1
Summary of the Log-Normal Distribution

Solving for σ:

$$\sigma = z_{.95} - \sqrt{z_{.95}^2 - 2\ln\left(\frac{x_{.95}}{\bar{x}}\right)} \qquad \text{(A-10)}$$

Note that for σ to be a real number:

$$\begin{aligned} z_{.95}^2 &\geq 2\ln\left(\frac{x_{.95}}{\bar{x}}\right) \\ x_{.95} &\leq \bar{x}\exp\left(\frac{z_{.95}^2}{2}\right) \\ &\leq 3.87\bar{x} \end{aligned} \qquad \text{(A-11)}$$

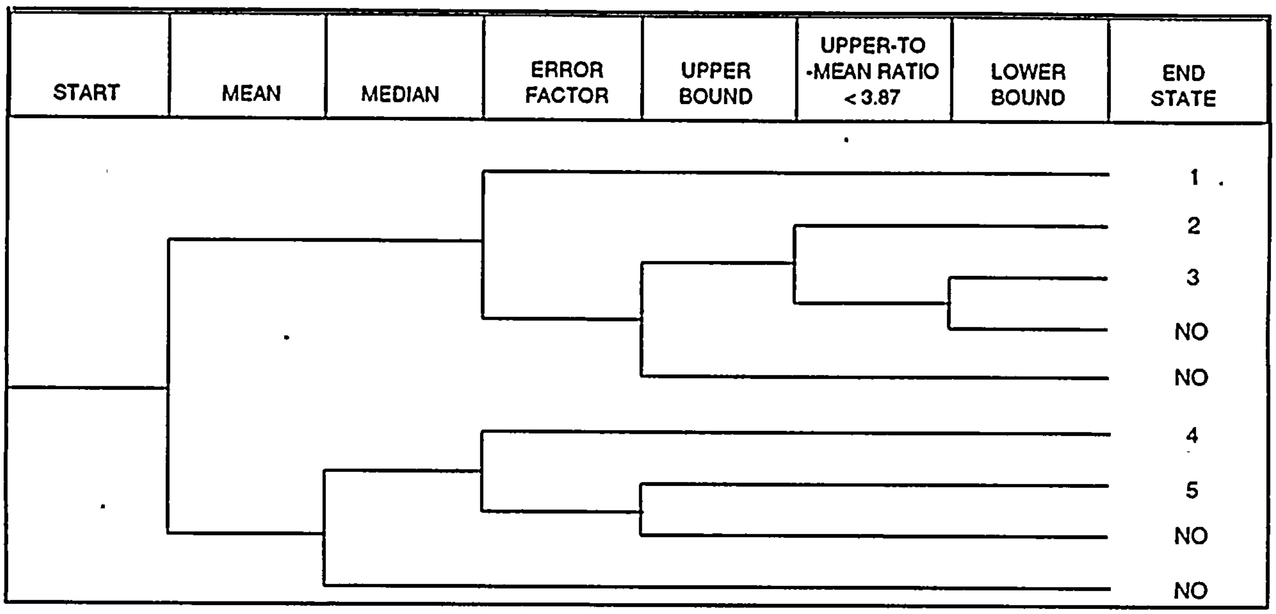
This result implies that for a given value of $\bar{x}$, $\sigma = z_{.95}$ (or ef $\approx$ 15) generates the maximum value of $x_{.95}$.

Table 3.3.1-2
Log-Normal Fit Hierarchy End States

End State	Known Information	Formulas from Table 3.3.1-1	
		Median	Logarithmic Standard Deviation
1	mean and error factor	A-4*	A-8
2	mean and upper bound, where the upper-bound-to-mean ratio is <3.87	A-4*	A-10
3	mean, upper and lower bounds	A-4*	A-7, A-8
4	median and error factor	given	A-8
5	median and upper bound	given	A-6, A-8

*Use after the logarithmic standard deviation is calculated.

Figure 3.3.1-1
Log-Normal Fit Hierarchy



3.3.2 Plant Specific Data and Data Analysis

3.3.2.1 Introduction

This section describes the estimation of component-level reliability parameters based on Ginna-specific experience for use in the R. E. Ginna PRA project. The primary purpose of this effort is to assess point values and corresponding uncertainties for the parameters necessary to quantify accident sequences. These parameters characterize the probabilities of the constituent events of accident sequences, and are estimated from plant historical records using statistical techniques. A secondary purpose of this data analysis effort is to provide insight into the operational and maintenance history of Ginna so that a more accurate representation of the plant's risk profile can be generated.

3.3.2.1.1 Analysis Scope

Plant-specific data was collected over the time period from January 1, 1980 to December 31, 1988 [Refs. 3.3.2-1 and 3.3.2-2]. The component population for which data was collected against and their boundaries are defined in separate documents [Refs. 3.3.2-3, Refs. 3.3.2-4]. In general, the scope of the data collected exceeds the needs of the integrated PRA plant logic model as defined on April 2, 1992 [Refs. 3.3.2-5] in that the data has been collected for components and/or failure modes which do not appear in the integrated model. This work package addresses only those plant-specific component-level reliability parameter estimates that are needed to support the integrated model. The additional data collected has not been analyzed; however, this "raw" data is provided in the work package for potential future applications.

3.3.2.1.2 Definitions

The following section provides definitions of the more unfamiliar terms associated with plant-specific data analysis. Common reliability and statistical terms (e.g., *failure rate*) are not addressed, and the use of a basic reference is suggested.

Component boundary: The set of equipment subcomponents and/or piece parts whose failure experience is included within the estimate of a specific reliability parameter. For example, the component boundary of a motor-driven pump includes the pump body, the supply AC circuit breaker, associated control circuitry including the supply DC fuse, the pump seals and seal cooling components, the lubrication system, the motor, the gear box, any status indication, and pump casing drains and vents.

Component population: The set of components selected for data collection and analysis. Component populations may be generally specified in terms of the specific component types and systems involved (e.g., motor-driven pumps in the service water system), or specifically defined by listing the EINs involved (e.g., PSW01A, PSW01B, PSW01C, and PSW01D).

Data window: The calendar time period over which the component failure history is collected.

EIN: The equipment identification number assigned by RG&E that uniquely identifies each component in the R. E. Ginna nuclear power plant.

Exposure: The period when a component is available to fail by a specified failure mode. Exposure may be measured in time units (for operating or standby failure rates) or in demand units (for failure-on-demand probabilities). For example, a motor-driven pump can only "fail to run" when the pump is operating; thus, the exposure for this failure mode is the total pump operating hours. Alternatively, the exposure for "motor-driven pump fails to start on demand" is the total number of start attempts during the data window.

Reliability parameter: A term referring to both failure rates and failure-on-demand probabilities.

3.3.2.2 General Technical Approach

The plant-specific data was analyzed in accordance with the *Data Analysis Task Procedure* [Ref. 3.3.2-6]. The following sections describe the implementation of this procedure in terms of the inputs to the analysis and the statistical estimation methods.

3.3.2.2.1 Analysis Inputs

As noted in Section 3.3.2.1.1, the plant-specific data constitutes the major input to this work package. The data collection activities were initiated prior to the development of the system fault tree models in conjunction with PRC Engineering (formerly ATESI) and the Reliability Centered Maintenance program at Ginna. The results of this effort is contained in a dBASE®-compatible computer file which provides failure counts and associated exposures for various failure modes on an EIN-basis (i.e., one record per EIN). The following sections provide background information on how the computer file was generated while Section 3.3.2.2.2 discusses how the file was used for the data analysis effort.

3.3.2.2.1.1 Plant Specific Data Collection Window

The time period from January 1, 1980 to December 31, 1988 was selected as the data collection window for the Ginna PRA since it was generally well documented and contained the most representative evidence of Ginna 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 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.

3.3.2.2.1.2 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 twenty (20) plant systems were therefore included in the data collection effort:

1. Reactor Coolant System
2. Engineered Safety Features Actuation System
3. Residual Heat Removal System
4. Emergency Diesel Generators
5. Chemical and Volume Control System
6. Safety Injection System
7. Main Feedwater System
8. Electrical Distribution - DC
9. Auxiliary Feedwater System
10. Electrical Distribution - AC
11. Main Steam System
12. Containment Isolation System
13. Service Water System
14. Containment Spray System
15. Standby Auxiliary Feedwater System
16. Condensate System
17. Circulating Water System
18. HVAC Systems
19. Component Cooling Water System
20. Instrument and Service Air Systems

Plant-specific data was also collected for the Steam Generator System; Turbine and Turbine-Generator, Fire Protection System, Reactor Protection System, and the Control Rod Drive System. Since these systems are out of the scope of the data analysis effort, they were only briefly reviewed to gain insights relating to the other twenty systems; however, the data is maintained by RG&E and available for future analysis. Data related to heat tracing was also collected. These events were removed from the Safety Injection and Chemical and Volume Control systems in order to create a separate category that would eliminate potential confusion over heat tracing boundaries.

Since the above twenty 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:

- Pumps
- Valves
- Breakers (for pumps, diesels, air compressors, large fans, and bus feeders)
- Dampers (air and motor-operated)
- Diesel generators
- Batteries
- Battery chargers
- VAC inverters
- Safety-related buses (including MCCs)
- Air compressors
- Air dryers
- Fans
- Heat exchangers
- Service Water strainers
- Heat tracing

The actual component population for which data was collected against and their boundaries are provided in Refs. 3.3.2-3 and 3.3.2-4, respectively. However, as discussed in Section 3.3.2.1.1, not all of the data collected was used by the data analysis task in support of the Ginna PRA effort.

3.3.2.2.1.3 Component Reliability Parameters Collected

After the component population and boundaries were determined, the following plant-specific information was collected:

1. Number of component failures (demand and time-related),
2. Number of component demands, and
3. Time which the component was in operation/standby.

The approach used to collect this information is described in more detail below [Ref. 3.3.2-7].

3.3.2.2.1.3.1 Plant-Specific Component Failures

Following a review of the available record types at Ginna, 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 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 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 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 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 between 1980 and 1988 were also reviewed to ensure that all failure and maintenance events were identified.

3.3.2.2.1.3.2 Calculation Of Component Demands

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.

3.3.2.2.1.3.2.1 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 Ginna 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 Ginna Results and Test personnel to ensure that the demands appeared appropriate since plant procedures may have been revised over the data time window.

3.3.2.2.1.3.2.2 Normal Operational Start Attempts

The number of normal start attempts was determined using the two methods described below.

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 (Section 3.3.3.2.1.3.2.1) 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.

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.

3.3.2.2.1.3.2.3 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:

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.

3.3.2.2.1.3.2.4 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.

3.3.2.2.1.3.2.5 Post-Maintenance Test Demands

The system screening tables discussed in Section 3.3.2.2.1.3.1 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.

3.3.2.2.1.3.2.6 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.

3.3.2.2.1.3.3 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 in Section 3.3.2.2.1.3.2.2. 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.

3.3.2.2.1.4 Ginna PRA Plant-Specific Failure Data Base

The plant-specific data compiled (i.e., number of component failures, demands and time in operation/standby) was entered into the Ginna PRA Plant-Specific Failure Data Base. The data as entered was also reviewed by an independent checker to ensure accuracy [Ref. 3.3.2-1].

3.3.2.2.2 Analysis Assumptions

The following assumptions have been made in developing the estimates of plant-specific reliability parameters:

1. All failure rates and failure-on-demand probabilities are constant over the data window. This assumption is commonly used in PRA data analysis work [Ref. 3.3.2-9, Section 5.3], 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).

2. The data provided by RG&E to SAIC was acceptable and accurate as delivered; no attempt was made by SAIC to independently verify the input data. However, it is noted that this information was collected under a separate QA program administered by ATESI.

3. Uncertainty estimates can be represented with a log-normal distribution. Martz [Ref. 3.3.2-10] 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.

3.3.2.2.3 Application Of Analysis Inputs

The plant-specific data directly met the majority of the data analysis task requirements; however, a program was necessary to more easily organize the data. This program was required since the initial data base provided data 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 [Ref. 3.3.2-8]). 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 PRA 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 3.3.2-1 illustrates this concept.

3.3.2.2.4 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. 3.3.2-9]:

$$\bar{\lambda} = \frac{n}{T}$$

$$\lambda_{0.05} = \frac{\chi^2(2f,\ 0.05)}{2T} \tag{4}$$

$$\lambda_{0.95} = \frac{\chi^2(2f+2,\ 0.95)}{2T}$$

where:

$$\begin{aligned} n &= \text{number of observed failures} \\ T &= \text{time period over which failures were observed} \\ \bar{\lambda} &= \text{mean failure rate} \\ \lambda_{0.05} &= 5\%\ \text{confidence bound on failure rate} \\ \lambda_{0.95} &= 95\%\ \text{confidence bound on failure rate} \\ \chi^2(\nu,\ p) &= p\text{th percentile of a chi-squared distribution} \\ &\quad\ \text{with } \nu \text{ degrees of freedom} \end{aligned} \tag{5}$$

For constant failure-on-demand probabilities, the following equations give the estimated mean value and 90% confidence bounds [Ref. 3.3.2-11]:

$$\bar{p} = \frac{n}{D}$$

$$p_{0.05} = \frac{n\, F_{0.05}(2n,\ 2D - 2n + 2)}{D - n + 1 + n\, F_{0.05}(2n,\ 2D - 2n + 2)} \qquad (6)$$

$$p_{0.95} = \frac{(n+1)\, F_{0.95}(2n+2,\ 2D - 2n)}{D - n + (n+1)\, F_{0.95}(2n+2,\ 2D - 2n)}$$

where:

$$\begin{aligned} n &= \text{number of observed failures} \\ D &= \text{number of demands} \\ \bar{p} &= \text{mean demand probability} \\ p_{0.05} &= \text{5\% confidence bound on demand probability} \qquad (7) \\ p_{0.95} &= \text{95\% confidence bound on demand probability} \\ F_p(\nu_1, \nu_2) &= p\text{th percentile of an F-distribution} \\ &\quad\ \text{with } \nu_1 \text{ and } \nu_2 \text{ degrees of freedom} \end{aligned}$$

The 90% confidence bounds may be mapped to a log-normal uncertainty bound by [Ref. 3.3.2-12, Appendix A]:

$$ef = \begin{cases} \sqrt{\dfrac{x_{0.95}}{\bar{x}}} & \text{for } x_{0.95} \geq 3.87\ \bar{x} \\ \exp\left[z_{0.95} \left(z_{0.95} - \sqrt{z_{0.95}^2 - 2 \ln\left(\dfrac{x_{0.95}}{\bar{x}}\right)} \right) \right] & \text{otherwise} \end{cases} \qquad (8)$$

where:

$$ef = \text{log-normal error factor}$$
$$z_{0.95} = \text{95th percentile of the standard normal distribution } (\approx 1.645) \qquad (9)$$

Equations (4) through (9) are implemented in the CARP computer program [Ref. 3.3.2-13].

3.3.2.2.5 Final Reliability Parameters

In general, reliability parameters based on Ginna-specific experience are recommended for final integrated logic model quantification. For certain component types and/or failure modes, few (or no) occurrences have been observed at Ginna. 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.

3.3.2.2.5.1 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:

$$\sigma = \frac{\ln ef}{z_{0.95}} \quad \text{logarithmic standard deviation}$$
$$Var = \bar{x}\,(e^{\sigma^2} - 1) \quad \text{variance} \qquad (10)$$

Then, for failure rates, the parameters of the prior gamma distribution in terms of the log-normal mean and variance are:

For failure-on-demand probabilities, the parameters of the prior beta distribution in terms of the log-normal mean and variance are:

$$\alpha = \frac{\bar{x}^2}{Var} \qquad \beta = \frac{\bar{x}}{Var} \tag{11}$$

$$\alpha = \frac{\bar{x}^2 (1 - \bar{x})}{Var} - \bar{x} \qquad \beta = \frac{\bar{x}(1-\bar{x})}{Var} - 1 + \bar{x} \tag{12}$$

3.3.2.2.5.2 Bayesian Update

For failure rates, the parameters of the posterior gamma distribution are:

$$\alpha' = \alpha + n \qquad \beta' = \beta + T \tag{13}$$

For failure-on-demand probabilities, the parameters of the posterior beta distribution are:

$$\alpha' = \alpha + n \qquad \beta' = \beta + D - n \tag{14}$$

3.3.2.2.4.3 · 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:

$$\bar{x}' = \frac{\alpha'}{\beta'} \qquad Var' = \frac{\alpha'}{\beta'^2} \tag{15}$$

For failure-on-demand probabilities, the mean and variance of the posterior beta distribution in terms of the beta distribution parameters are:

$$\bar{x}' = \frac{\alpha'}{\alpha' + \beta'} \qquad Var' = \frac{\alpha'\beta'}{(\alpha' + \beta' + 1)(\alpha' + \beta')^2} \tag{16}$$

The log-normal error factor in terms of the posterior mean and variance is:

$$ef' = \exp\left[z_{0.95}\sqrt{\ln\left(1 + \frac{Var'}{\bar{x}'^2}\right)}\right] \tag{17}$$

Equations (10) through (17) are also implemented in the CARP computer program.

3.3.2.3 Results

A summary report of all final reliability parameters (sorted by system, component type, and failure mode) is provided in Appendix E. This report 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. The final results have been entered into an updated CAFTA Type Code file, which is provided in Appendix F. The following sections discuss the calculated final results.

3.3.2.3.1 Plant-Specific Data Insights

There are 288 failure modes (organized by component type and system) included in the Ginna integrated PRA plant logic model. Plant-specific data is used in the determination of the failure rate or probability for more than 200 of these failure modes (70%). 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). Since Appendix E provides both the Ginna-specific and generic values prior to any Bayesian updating, a comparison of these two data points was performed. The results of this review are as follows:

1. Almost 25% of the calculated plant-specific values are within a factor of three (3) of the generic value,
2. 8% of the calculated plant-specific values are greater than a factor three (3) higher than generic data,
3. 8% of the calculated plant-specific values are greater than a factor three (3) lower than generic data, and
4. 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:

1. Containment Spray pumps (failure to run)

2. HVAC fans (failure to start)

3. Safety Injection pumps (failure to run)

4. AC electrical buses (all operating voltages except 120 VAC)

5. BAST level transmitters (fails high and fails to respond)

6. CVCS piping (plugs)

7. CVCS relief valves (transfer open)

8. Instrument Air dryer (failure to deliver flow)

9. Instrument Air receiver (local faults)

10. Instrument Air piping (rupture)

11. Main Steam Isolation Valves (failure to close)

12. Atmospheric Relief Valves (failure to open)

The observed plant-specific history for these components is described in detail below.

3.3.2.3.1.1 Containment Spray Pumps

There was only one failure of a Containment Spray 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.

3.3.2.3.1.2 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, Safety Injection Pump Cooler Fan 1C, and Standby Auxiliary Feedwater Cooler Fan 1B. 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.

3.3.2.3.1.3 Safety Injection Pumps

There was only one failure of a Safety Injection (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.

3.3.2.3.1.4 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.

3.3.2.3.1.5 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, RG&E has performed analyses to show that the safety function of the BAST is not required. This effort is expected to be completed during the 1994 refueling outage. 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.

3.3.2.3.1.6 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.

3.3.2.3.1.7 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.

3.3.2.3.1.8 Instrument Air Dryer

Ten failures of the Instrument Air (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.

3.3.2.3.1.9 Instrument Air 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.

3.3.2.3.1.10 Instrument Air 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.

3.3.2.3.1.11 Main Steam Isolation Valve

There were two failures of Main Steam Isolation Valve (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 ESAF 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.

3.3.2.3.1.12 Atmospheric Relief Valves

There was only one failure of an Atmospheric Relief Valve (AFV) 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.

3.3.2.3.2 IPE Requirements

The IPE submittal guidance [Ref. 3.3.2-14] requires the assessment of plant-specific data for major equipment affecting core-damage sequence results, including auxiliary feedwater and emergency core cooling pumps, batteries, feed pumps, electrical buses, breakers, and diesel generators. Each of these component types has been included within the scope of this work package, and Ginna-specific reliability parameters for them have been provided. Figures 3.3.2-1 through 3.3.2-6 compare the Ginna-specific experience to relevant generic data for motor-driven pumps, electrical buses, circuit breakers, and diesel generators since these are typically considered important components in a PRA model. Additional information can be found in the appendices.

3.3.2.3.3 Additional Integrated Model Requirements

Appendix G contains data estimates for basic events found in the integrated PRA model that are not provided in other PRA work packages [Ref. 3.3.2-5]. These are typically weather related or conditional probability events.

3.3.2.5 References

3.3.2-1 PRC, *Component Reliability Parameters Data Work Package for Rochester Gas & Electrical Corporation Ginna Nuclear Power Plant Probabilistic Risk Assessment*, Revision 0, June 14, 1991.

3.3.2-2 Letter from M. Flaherty, RG&E, to M. Stutzke, SAIC, Subject: *Correction to Data Base Containing Ginna-Specific Component Maintenance, Failure, and Exposure Values*, NSL-PRALT-92.008, February 18, 1992.

3.3.2-3 RG&E Design Analysis NSL-4976-DA024, *Probabilistic Risk Assessment Determination of Component Population for Data Task*, Revision 0, November 30, 1990.

3.3.2-4 RG&E Design Analysis NSL-4976-DA001, *Probabilistic Risk Assessment Determination of Component Boundaries*, Revision 1, November 30, 1990.

3.3.2-5 Letter from T. Daniels, RG&E, to M. Stutzke, SAIC, Subject: *Revision 0 of MASTER Fault Tree Model*, NSL-PRALT-92.034, April 2, 1992.

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3.3.2-8 RG&E Design Analysis NSL-4976-DA003, *Probabilistic Risk Assessment Determination of Reactor Critical Hours*, Revision 0, September 17, 1990.

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3.3.2-10 H.F. Martz, et. al., *A Comparison of Methods for Uncertainty Analysis of Nuclear Power Plant Safety System Fault Tree Models*, NUREG/CR-3263, April 1983.

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3.3.2-12 SAIC, *Generic Data Work Package*, Project Document 749-03-09, Revision 0, August 31, 1990.

3.3.2-13 SAIC, *CARP - Computerized Assessment of Reliability Parameters*, Version 1.1, March 1992.

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3.3.2-16 M.D. Flaherty, *Component Demands and Exposures, Documentation of Discussions With Gregg Joss of Ginna Results and Tests Group*, Dated June 3, 1991.

3.3.2-17 M.D. Flaherty, *Discussions With Gregg Joss Related To Component Exposures*, dated January 16, 1991.

3.3.2-18 R.E. Ginna Nuclear Power Plant, *Updated Final Safety Analysis Report*

Table 3.3.2-1
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 3.3.2-2
Other Required Data

AAAAWINTER	*Extreme Winter Temperatures (< 6°F).* This was conservatively estimated to be 0.1 since the minimum extreme temperature for Ginna is 2°F which is only exceeded less than 1% of the time [Ref. 3.3.2-18, Section 2.3.2.2].
CCBREAK001	*CCW Line To RCP A Breaks Due To Damage During A LOCA.* Since the CCW line is ~~outside~~ inside the missile barrier in containment and is therefore not protected, a value of 1.0 was assigned.
CCBREAK002	*CCW Line To RCP B Breaks Due To Damage During A LOCA.* Since the CCW line is ~~outside~~ inside the missile barrier in containment and is therefore not protected, a value of 1.0 was assigned.
HV_COLDOUT	*Outdoor Temperature Consistently Below Freezing.* It was conservatively estimated that the temperature was consistently below freezing 30% of the year. Consequently, a value of 0.3 was assigned.
RCMVD00515	*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).
RCMVD00516	*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).
SIPPJLOOPA	*Conditional Probability That LOCA Occurs In RCS Loop A.* This was conservatively set to 0.1.
SIPPJLOOPB	*Conditional Probability That LOCA Occurs In RCS Loop B.* This was conservatively set to 0.1.

Figure 3.3.2-1
Comparison of Motor-Driven Pump Failure Rates.

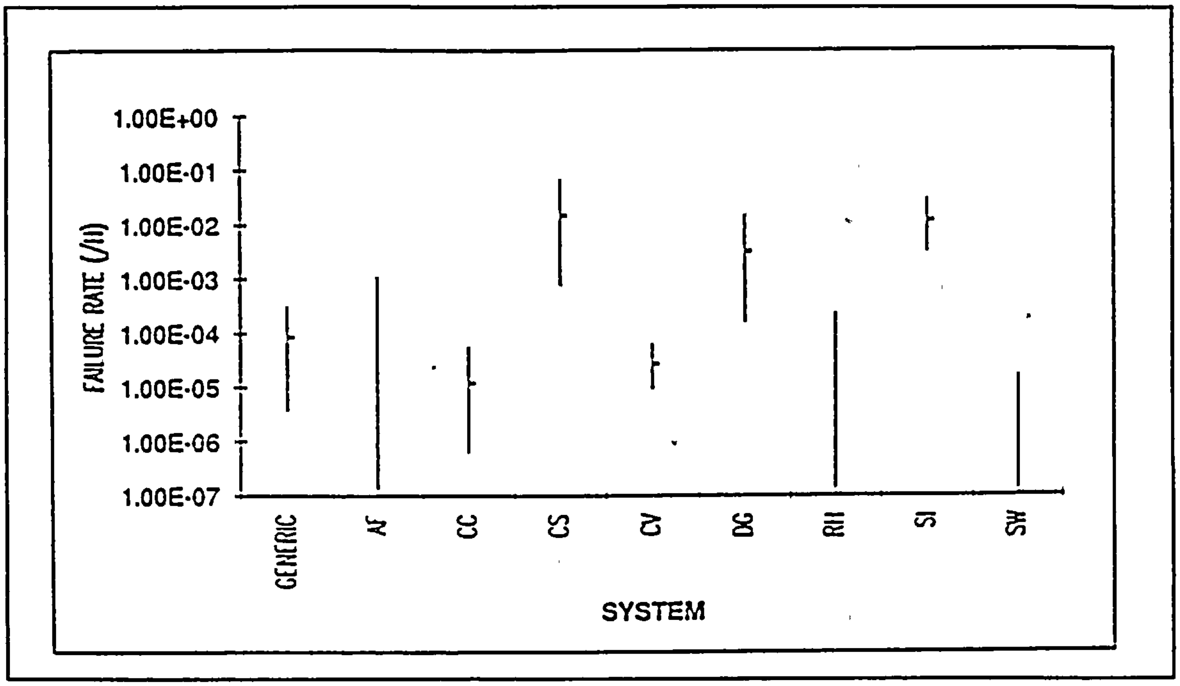


Figure 3.3.2-2
Comparison of Motor-Driven Pump Standby Failure Rates.

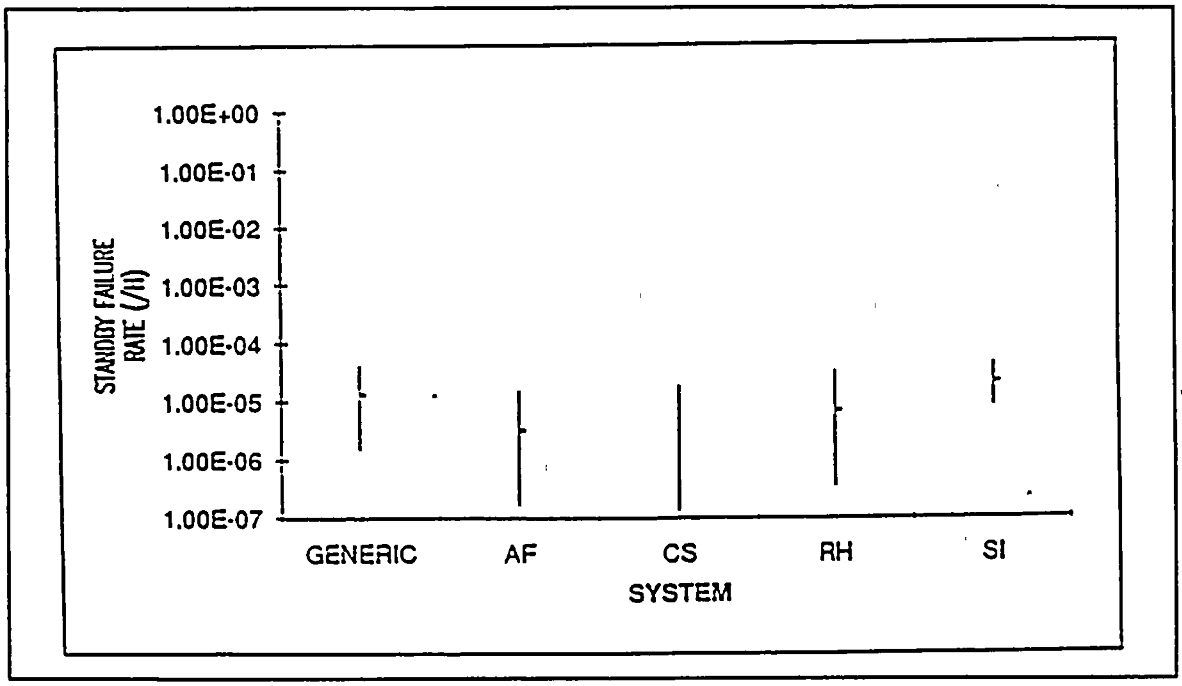


Figure 3.3.2-3
Comparison of Motor-Driven Pump Failure on Demand Probabilities.

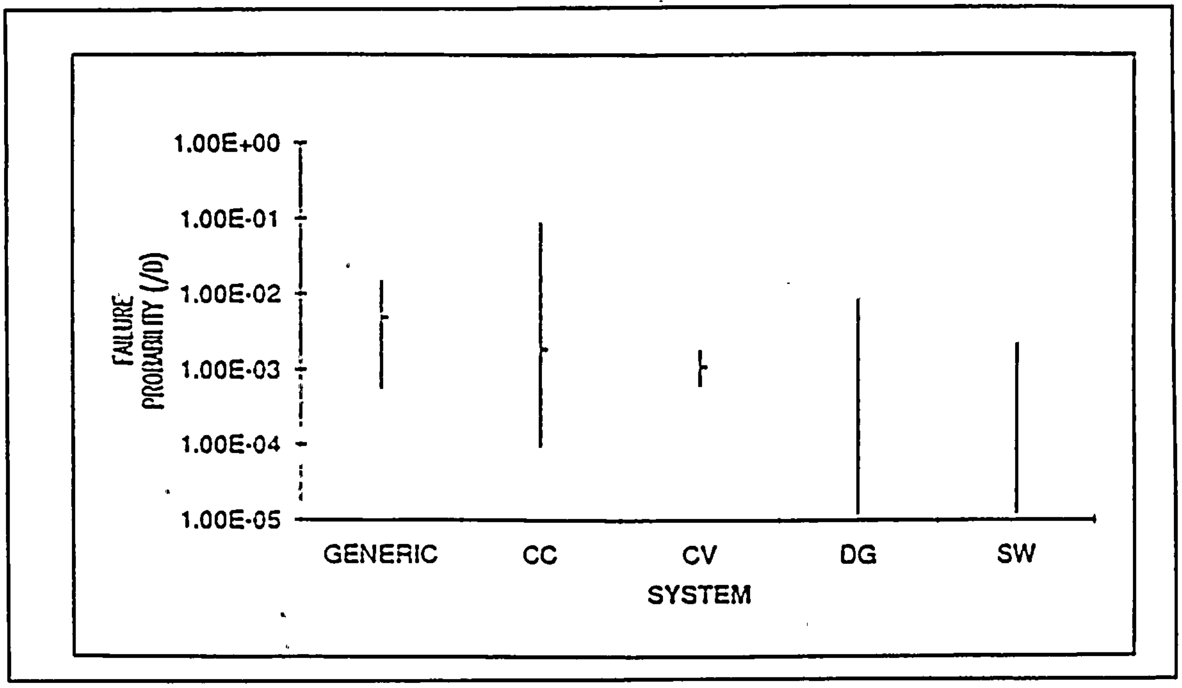


Figure 3.3.2-4
Comparison of Electrical Bus Failure Rates.

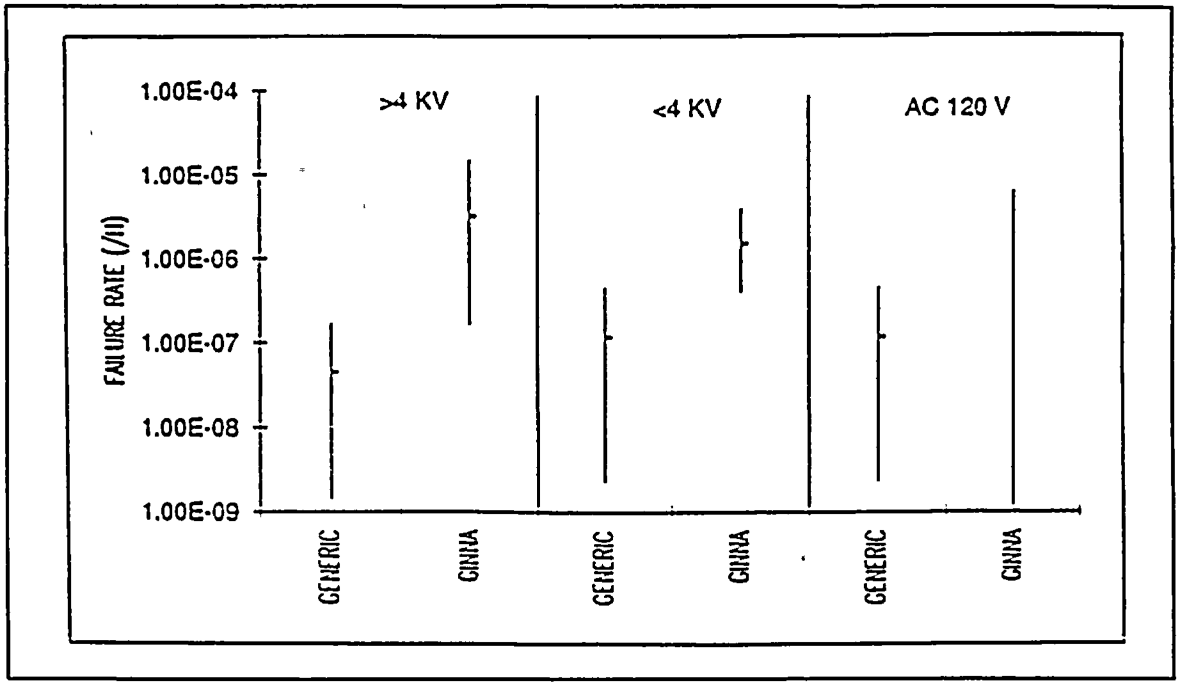


Figure 3.3.2-5
Comparison of Circuit Breaker Reliability Parameters

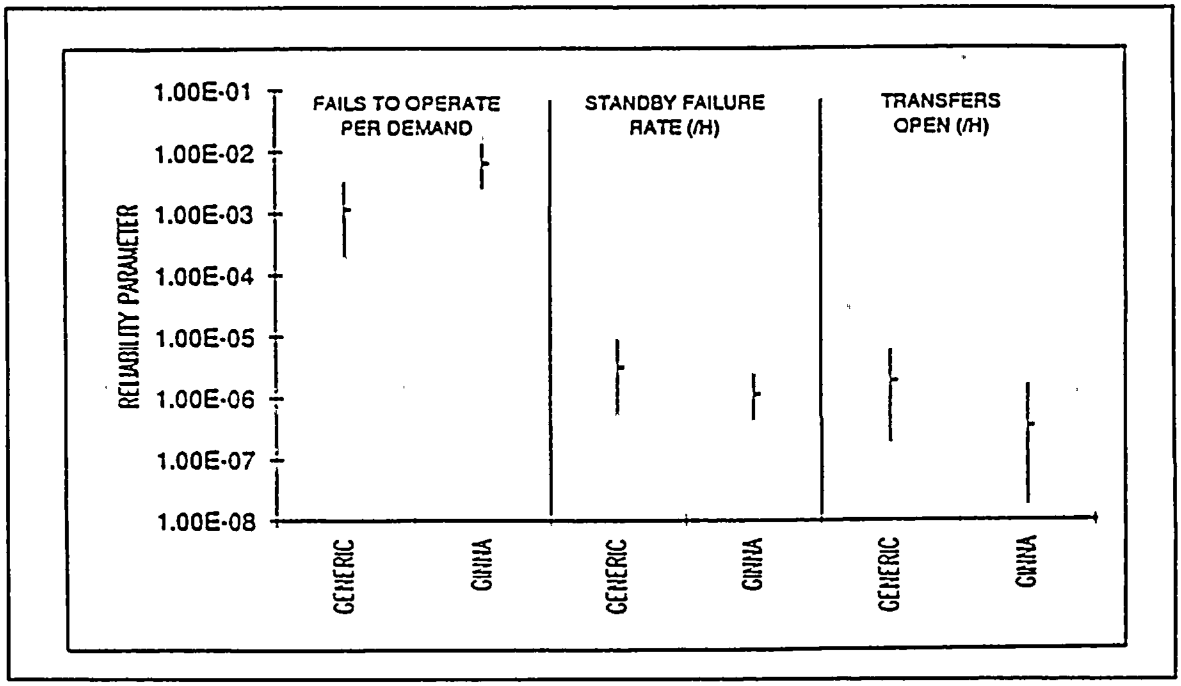
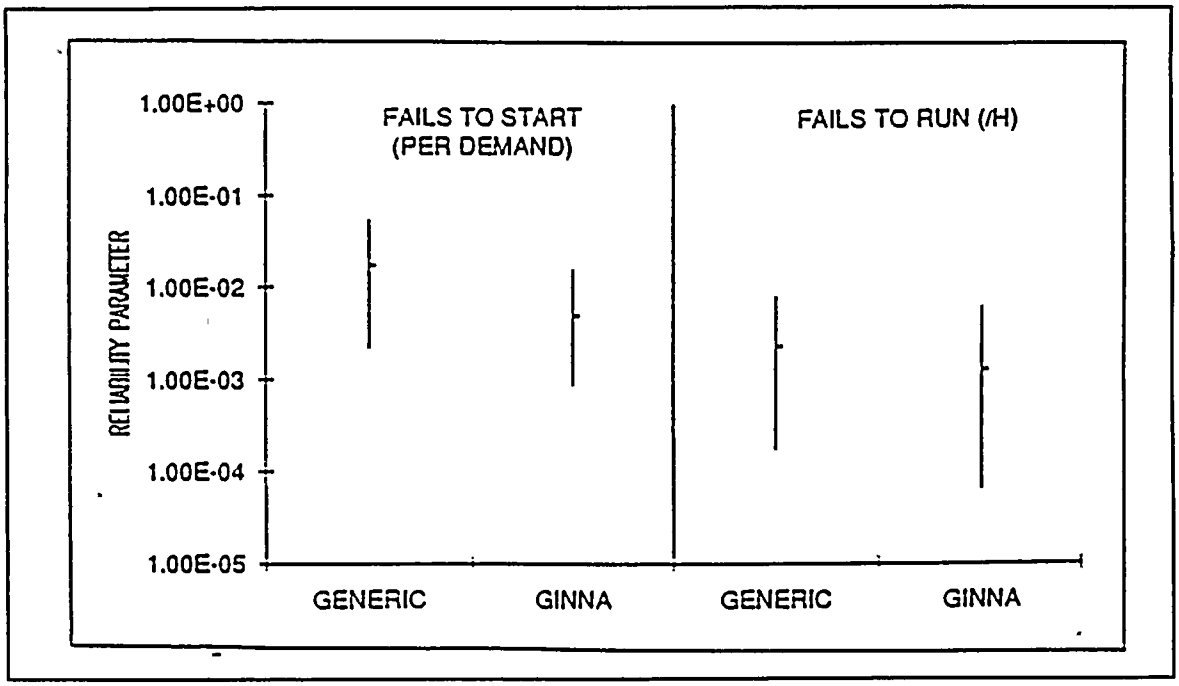


Figure 3.3.2-6
Comparison of Diesel Generator Reliability Parameters.



3.3.3 Human Reliability Analysis

3.3.3.1 Methodology

The general approach for the overall human reliability analysis performed for the Ginna PRA is depicted in Figure 3.3.3-1. The specific steps performed for the detailed HRA analysis are Steps #4-#8 of Figure 3.3.3-1. However, each step shown in Figure 3.3.3-1 is discussed briefly in this section. The implementation of Steps #1-#7 specific to the Ginna PRA detailed HRA analysis is discussed below while Step #8 is discussed in more detail in Section 3. Steps #1-3 were performed as preliminary or input steps to the detailed HRA analysis which is documented in this section.

3.3.3.1.1 Identification of Human Failure Events to Model in the PRA

Using the guidance given in the *Human Reliability Analysis Task Procedure* [Ref. 3.3.3-1], human failure events to be modeled in the Ginna PRA were identified. The resulting list of modeled HFEs is documented in Table 3.1.2-12 of Section 3.1.2.

3.3.3.1.2 Identification of Human Failure Events Which Require Detailed Analysis

Figure 3.3.3-1 shows Step #2 as a decision point for determining which HFEs are quantified with screening values and which are quantified using detailed HRA analysis techniques. In reality, all HFEs are initially quantified using the screening values. Human failure events requiring detailed analysis were identified following initial quantification as described in Section 3.4 below.

3.3.3.1.3 Human Failure Events Screening Values

All HFEs were initially quantified using the screening valves recommended in Table 10 of Reference 3.3.3-1. Table 3.1.2-12 shows the screening values used in initial quantification.

3.3.3.1.4 Human Failure Events Requiring Detailed Analysis

Human failure events requiring detailed analysis were identified from cut sets generated in initial quantification of the Ginna PRA with the assistance of the Accident Sequence Analysis Task Leader. With one exception, all HFEs which appeared in cut sets generated in initial quantification were selected to be analyzed in detail. (See Section 4.0 for explanation.)

3.3.3.1.5 Determination of Time Dependence

In this step, each HFE which required detailed analysis was analyzed for time-dependence. Procedures were reviewed in order to better understand the sequence of human actions required, and the plant parameters which act as cues for human actions, for the applicable accident scenarios. Estimates for the required timing of human actions were determined with the assistance of the Accident Sequence Analysis Task Leader. Examples of sources for timing information include systems analysis work packages and MAAP computer code runs. As a general rule, human actions that were required to be performed in one hour or less were considered time-dependent.

3.3.3.1.6 Selection of Model Type

Two methods of HFE quantification were used in the implementation of the *Human Reliability Analysis Task Procedure* [Ref. 3.3.3-1] for the Ginna PRA: 1) The SAIC time-reliability correlation (TRC) [Ref. 3.3.3-4]; and, 2) the Technique for Human Error Rate Prediction (THERP) [Ref. 3.3.3-5]. The general principles used for selecting between these two quantifications methods were:

1) The SAIC time-reliability correlation (TRC) was used to quantify the HFEs which were identified as being time-dependent; and ,

2) THERP was used to quantify HFEs which were identified as being time-independent.

However, allowance for exceptions to these general rules could be accommodated on a situation-specific basis when justified by arguments concerning human performance and human reliability influences.

Specific application of the SAIC TRC and THERP methods of quantification in the Ginna PRA are briefly described in the paragraphs below.

SAIC TRC: The nominal parameter inputs for the SAIC TRC model, given in Table 6 of Reference 3.3.3-1 and described in Chapter 10 of Reference 3.3.3-4, are used for quantification of time-dependent HFEs. The specific HFEs which required detailed analysis in the Ginna PRA are all associated with in-CR, proceduralized actions. Consequently, the probabilities given in Tables 10-8 and 10-9 of Reference 3.3.3-4 are applicable to the refinement of HFEs in the Ginna PRA. Tables 3.3.3-1 and 3.3.3-2, which are expansions of these two tables from Reference 3.3.3-4, were used in the quantification of time-dependent HFEs requiring detailed analysis. Quantification using Tables 3.3.3-1 and 3.3.3-2 was accomplished with information concerning 1) the time available for operator action and 2) whether or not burden (e.g., hesitancy due to conflict of goals or workload (see [Ref. 3.3.3-4])) could be a factor in human performance. Although Tables 3.3.3-1 and 3.3.3-2 provide probability values which are as low as a factor of 10^{-6}, a lower limit of 10^{-4} for acceptable probabilities has been assumed in this analysis.

THERP: The THERP analysis approach [Ref. 3.3.3-5] falls into the general category of decompositional approaches which use the human factors technique of task analysis to break tasks into subtasks and associated performance shaping factors (PSFs). The major drawback of decompositional methods is that, by reducing each task into reliability sub-units, the holistic characteristic of human performance, which is important to reliability, is lost. Consequently, detailed analysis of time-independent HFEs in the Ginna PRA has been limited to the application of "THERP-like" probability values in a more holistic sense.

For ease of traceability, the probabilities used for quantifying time-independent HFEs also are consistent with the summary of representative THERP probabilities given in Table 5-2 of Reference 3.3.3-4. More specifically, since all of the HFEs analyzed in detail for the Ginna PRA are associated with proceduralized actions and are conservatively assumed to be performed without independent checking, only two THERP values were applicable in the process of quantifying time-independent HFEs:

- 3E-3 - omission in procedure, without checkoff, ≤ 10 items
- 1E-2 - omission in procedure, without checkoff, ≥ 10 items

Consequently, quantification of time-independent HFEs in the Ginna PRA events was accomplished with information concerning: 1) The number of steps required to be performed and 2) whether or not there are any dependencies between modeled HFEs. Typically, the basic values given above were reduced by a factor of 3 in order to account for dependencies between events.

3.3.3.1.7 Identification of Parameters

The parameters required for the two HRA quantification methods used are noted in Table 4 of Reference 3.3.3-1. Since, as described above, all of the HFEs of analyzed in detail with the SAIC TRC for the Ginna PRA were in-CR room, proceduralized actions, the only additional factors required were burden and available time. Similarly, the HFEs quantified with THERP were all proceduralized, errors of omission with no independent checking assumed. Consequently, as described above, the principal factors (i.e., performance shaping factors) used in quantification involving THERP were the number of individual items to be performed and any dependencies between HFEs. However, procedural citations are included in the discussions of specific HFE quantifications to promote better understanding of the modeled event and the bases for its quantification.

3.3.3.1.8 Collection of Information

Three basic sources of information were used to determine the input parameters required of the chosen quantification methods. Procedural reviews supplied input information to both quantification methods. Secondly, interviews conducted with plant operators and shift supervisors and observation of crews utilizing the Ginna control room simulator provided a variety of information, such as a better understanding of the procedural pathway used for certain accident scenarios and the specific interpretation of certain procedural steps (i.e., transitioning to FR-H.1

[Ref. 3.3.3-6]). In addition, the same information sources noted in Section 3.1 were used to determine the available time required as input to the SAIC TRC model.

3.3.3.2 Quantification of Identified Human Failure Events

As indicated in Section 3.4, with one exception, all HFEs contained in cut sets which were generated in initial Ginna PRA quantification were analyzed in detailed. (The exception is event AFHFDSWX03. Further examination of this event during cut sets reviews indicated that this event would be more appropriately treated as a non-recovery event, in the *Recovery Analysis Work Package* [Ref. 3.3.3-2], since it is defined to address AFW water supplies in addition to that addressed by event AFHFDPCDO4, which is treated in the detailed HRA analysis.) The HFEs which have been analyzed in detail were identified in cut set reviews performed with the assistance of the Quantification and Recovery Analysis Task Leader. Table 3.3.3-3 shows all of the HFEs for which detailed HRA analysis was performed, their refined probabilities, and the quantification method used. As shown in this table, all of the HFEs which required detailed analysis were post-accident HFEs.

A brief discussion of each HFE analyzed in detail is provided below. In particular, the quantification method used and the factors which are judged to critically influence human reliability (and quantification of human failure event probability) are identified.

3.3.3.2.1 Transfer Condensate from Hotwell to CSTs: AFHFDCD04

Auxiliary Feedwater pumps PAF01A, PAF01B and PAF03 take suction from Condensate Storage Tanks TCD02A and TCD02B. When the AFW system is running (e.g., in response to a transient or LOCA), the CST supply will become depleted. It takes approximately 4 hours to drain the CSTs. The initial cue for refilling the CSTs is given in a CAUTION statement just prior to Step 31 in E-0 [Ref. 3.3.3-8]. This initial cue is reinforced in the FOLDOUT to E-1 [Ref. 3.3.3-9], which is periodically monitored by operators in accordance with the NOTE preceding Step 1 of this procedure.

Operators are directed to use ER-AFW.1 [Ref. 3.3.3-10] for refilling the CSTs. This procedure provides instructions for supplying the AFW pumps from several alternate water supplies. In order to provide alternate water supply from the hotwell specifically, Section 4.1 of ER-AFW.1 directs operators to perform nine (9) individual steps.

Quantification of this action takes into account the following human performance features:

1. The action is not time-constrained (i.e., time available from first cue is greater than 1 hour);

2. The action is proceduralized;

3. No explicit checkoffs are required within the procedure to provide independent checking; and,

4. Nine individual steps must be performed in order to successfully complete this action.

Since this action is not time-constrained, the quantification method used in THERP. The failure probability for a proceduralized action, without checkoff, and involving a short-list of tasks (i.e., less than 10) is quantified as:

AFHFDCD04 = 3E-3

3.3.3.2.2 Isolate Ruptured Steam Generator EMS01A: CTHFDISOLA

Operators are directed in E-3 [Ref. 3.3.3-11], Step 3 and Attachment RUPTURED S/G, to isolate flow from the ruptured steam generator in order to respond to a steam generator tube rupture (SGTR). The limiting factor for this HFE is the depletion of Refueling Water Storage Tank TSI01 prior to the establishment of RHR cooling. Since it takes a long time to deplete the RWST, this HFE is considered time-independent. Consequently, a THERP-like probability is assigned to this HFE.

This action involves both in-control room (in-CR) and ex-control room (ex-CR) activities (i.e., E-3, Steps 3c and 3f, respectively). Since field operators will be directed by in-CR operators, any diagnosis required for the performance of Step 3f would be coupled with in-CR activities. However, based upon discussions with R-shift operators, it is expected that in-CR operators will continue with subsequent steps of E-3 after providing instructions to field operators (i.e., these activities are independent in their implementation). Although, the in-CR and ex-CR activities involved with this overall action could have been modeled independently, they have conservatively been modeled as a single event. Since this action is proceduralized and involves less than 10 steps, the human failure event probability is quantified as:

CTHFDISOLA = 3E-3

3.3.3.2.3 Isolate Ruptured Steam Generator EMS01B: CTHFDISOLB

This HFE is identical to CTHFDISOLA, except that it applies to the isolation of ruptured Steam Generator EMS01B. The same discussion given above for CTHFDISOLA applies.

CTHFDISOLB = 3E-3

3.3.3.2.4 Restore Instrument Air to Containment After an Isolation Signal: IAHFDCNTBK

Following RCS cooldown in response to a SGTR, operators are directed (E-3, Step 16 [Ref. 3.3.3-11]) to ensure instrument air supply to containment, including restoration of service water flow to Instrument Air Compressors CIA02A, CIA02B and CIA02C. This action occurs in the midst of activities required for RCS depressurization and cooldown (see RCHFDCDDPR below) which are time-independent. (In addition, instrument air must be available in order for depressurization to be successful.) Consequently, this human failure event is also time-independent and is quantified with THERP for proceduralized actions involving less than 10 steps:

IAHFDCNTBK = 3E-3

3.3.3.2.5 Trip Reactor Coolant Pumps After a Loss of Component Cooling Water: RCHFD00RCP

Operators are directed by AP-RCP.1 [Ref. 3.3.3-12] to trip the RCP(s) if pump seal integrity cannot be ensured. According to WCAP-10541 [Ref. 3.3.3-13], RCP operation is permitted for 24 hours with the loss of either seal injection (i.e., CVCS) flow or cooling water (i.e., CCW) flow to the thermal barrier heat exchanger, but not the loss of both. However, this WCAP also states that it is expected that seal integrity will be maintained "...for many hours" without any seal cooling. Consequently, this action is considered time-independent and is quantified using THERP for procedurized actions involving fewer than 10 steps:

RCHFD00RCP = 3E-3

3.3.3.2.6 Initiate Bleed and Feed Cooling: RCHFD01BAF

The actions performed for bleed and feed are indicated in FR-H.1, Steps 11-13 [Ref. 3.3.3-6]. The path through the EOPs to FR-H.1 with respect to secondary cooling is via Red Path Criteria. The cue for performing bleed and feed (and transitioning to Steps 11-13) is defined when the steam generator level and pressurizer pressure criteria given in FR-H.1 (Step 2) are satisfied.

MAAP runs which were performed in support of the Ginna Level 1 PRA also can be used to provide proximate timing information. Specifically, the MAAP results generated for a loss of secondary cooling scenario in which bleed and feed actions were delayed by approximately 30 minutes (MAAP run FB13E, [Ref. 3.3.3-14]) were used to approximate the time available to perform the bleed and feed steps. These results showed substantial peaking of the hottest core node temperature (e.g., greater than 1550° F) but not to temperatures at which core damage would occur.

Based upon these MAAP results, the time available for performing bleed and feed actions is conservatively assumed to be approximately 30 minutes. Using the SAIC TRC for in-control room, rule-based actions without burden, the human failure event probability for a time available of 30 minutes is:

RCHFD01BAF = 2.35E-4

3.3.3.2.7 Cooldown to RHR After Safety Injection Fails - SSLOCA: RCHFDCD0SS

This event is used in small-small LOCA (SSLOCA) sequences in which SI fails. Under these conditions, core damage can still be averted if the RCS is rapidly depressurized to the RHR shutoff head and RHR is put into service. Procedures ES-0.2 [Ref. 3.3.3-15] and ES-03 [3.3.3-16] apply to this action but the procedure path into these procedures under the conditions of SSLOCA without SI is unclear.

The applicable MAAP run, SLOCA22 [Ref. 3.3.3-17], provides an available time of 60 minutes. Since the action is proceduralized, use of the SAIC TRC for rule-based actions is indicated. However, in order to address the additional requirements of the operators to make the appropriate procedural transition without clear guidance[1], the TRC with burden is recommended:

RCHFDCD0SS = 1.85E-3

3.3.3.2.8 Cooldown and Depressurize RCS Following SGTR: RCHFDCDDPR

Operators are directed to cooldown and depressurize the RCS in Steps 13a-d, 20 and 21 in E-3 [Ref. 3.3.3-11] in order to respond to a SGTR. The RCS depressurization and cooldown steps have been modeled as a single HFE since these activities are coupled. For instance, depressurization can be successful only if cooldown is successful. Dependence between cooldown and depressurization activities is reinforced by the caution before Step 18 which instructs operators that RCS cooldown must be completed before proceeding through Step 18. (There is no other pathway from Step 13 to Step 20 except through Steps 14-19.)

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[1] Note: Since the procedure set does not contain explicit guidance on the procedure transitions involved in this action, successful performance of this action would require a "work-around," or *circumvention*.

The major timing concern with respect to this action is the depletion of the RWST before cooldown can be accomplished. However, event if the affected steam generator is not isolated, RWST depletion will take a relatively long time. Consequently, this action is considered time-independent and THERP, for a proceduralized action involving less than 10 steps and without checkoff, is basis for the quantification of this human failure event. However, an additional factor of 3 reduction is recommended to credit the fact that isolation actions have been successfully performed when cooldown and depressurization steps are reached.

RCHFDCDDPR = 1E-3

3.3.3.2.9 Cooldown to RHR After SGTR Isolation Fails: RCHFDCDTR1

The applicable MAAP run, RUH2I [Ref. 3.3.3-18], for this event indicates an available time of 30 minutes. Like RCHFDCD0SS, this event involves rapid depressurization of the RCS to the RHR shutoff head but with non-specific procedural guidance concerning the required procedure transitions. Consequently, this event is also quantified using the SAIC TRC for rule-based actions, with burden:

RCHFDCDTR1 = 1.04E-2

3.3.3.2.10 Cooldown to RHR After SI Fails - SGTR: RCHFDCDTR2

The applicable MAAP run, RUH2C [Ref. 3.3.3-19], for this event indicates an available time of 45 minutes. Like RCHFDCD0SS, this event involves rapid depressurization of the RCS to the RHR shutoff head but with non-specific procedural guidance concerning the required procedure transitions. Consequently, this event is also quantified using the SAIC TRC for rule-based actions, with burden:

RCHFDCDTR2 = 3.94E-3

3.3.3.2.11 Close PORV Block Valve to Terminate LOCA: RCHFDPLOCA

Operators are instructed in both E-0 (Step 22a) [Ref. 3.3.3-8] and E-1 (Step 7b) [Ref. 3.3.3-9] to manually close any open PORVs, or to close their associated block valves. However, this action is defined as successful if an open PORV is closed anytime during the injection phase. (The dominant cut sets in which this action appears are all long-term sequences.) Consequently, this human failure event is considered time-independent and is quantified using a THERP-like number. Specifically, the failure probability used for a proceduralized action, without checkoff, and a short list of steps, such as that used for AFHFDCD04 and MSHFD0COOL, is reduced by a factor of 3 to credit for the replication between the E-0 and E-1 instructions:

RCHFDPLOCA = 1E-3

3.3.3.2.12 Establish and Maintain RHR Cooling Following SGTR: RHHFD0SGTR

This event models failures to successful establish and maintain shutdown cooldown with RHR following a rapid depressurization in a SGTR accident scenario. Previous depressurization actions have been successful, RHR hardware is available, and shutdown cooling entry conditions are met. Furthermore, actions taken for rapid depressurization are coupled with this action since preceding action are performed specifically for the purpose of getting into shutdown cooling (i.e., diagnosis is not required for this action; already occurred in prior to performance of rapid depressurization). Also, this action is not time-constrained. Consequently, this HFE is quantified using THERP for proceduralized actions involving less than 10 steps, but reduced by a factor of 3 to account for previous successful (and coupled) actions.

RHHFD0SGTR = 1E-3

3.3.3.2.13 Switchover to Recirculation Cooling: RRHFDRCR0A, RRHFDRCR0M, RRHFDRCR0S, RRHFDRCRSS

In a caution given before Step 1 of E-1 [Ref. 3.3.3-9], as well as in cautions and notes given in other EOPs, operators are directed to ES-1.3 [Ref. 3.3.3-20] in order to switch from the injection phase, in which water is supplied from the RWST, to recirculation, in which water is supplied from the containment sump, when the RWST is depleted. The specific cue for switchover to recirculation is RWST level of 28%. The time available for performing the steps given in ES-1.3 is the time from the switchover cue until the RWST is completely depleted (i.e., 0% level).

Based upon the discussion above, actions associated with recirculation switchovers should be quantified using the SAIC TRC for in-control room actions without burden. However, different available times (or times to depletion of the RWST) are expected for different LOCA sizes. Consequently, four different HFEs have been defined for each of the four, respective LOCA sizes.

3.3.3.2-14 Large LOCA Switchover to Recirculation Cooling: RRHFDRCR0A

In the Ginna UFSAR [Ref. 3.3.3-21, p. 6.3-28] there is a discussion of RWST level versus time for the maximum LOCA size possible with all ECCS and containment cooling pumps operating. The UFSAR states that, for this maximum LOCA size, the RWST level drops from 28% (i.e., the alarm which cues operator to switchover) to 15% (i.e., the low-low level alarm) in 8 minutes. Current emergency procedures direct that two RHR pumps, an SI pump and a containment spray pump be stopped when the 28% level alarm is received. These actions result in a reduced RWST depletion rate. With 44,525 gallons of inventory available between the two alarm points, and assuming a combined SI / CS flow of 2,600 GPM results in a duration of more than 17 minutes. This calculation allows no credit for RWST inventory between the 15% level and the injection suction point of 45,210 gallons.

Using 17 minutes as the available time with the SAIC TRC for rule-based, in-CR actions without burden, this HFE is quantified as:

RRHRDRCR0A = 4E-3

3.3.3.2.15 Medium LOCA Switchover to Recirculation Cooling: RRHFDRCR0M

For MLOCA, the rate of RWST depletion is dependent on break size, and not ECCS configuration. Consequently, MAAP runs were used to determine the available time for recirculation switchover for MLOCAs. The applicable MAAP run for MLOCAs is 9S51BC2E [Ref. 3.3.3-22]. Table 2 in the *Event Tree Work Package* [Ref. 3.3.3-3] summarizes MAAP run results, including the time to RWST depletion (i.e., 0% level). For MAAP run 9S51BC2E, RWST depletion occurs at 8.5 hours. Assuming a constant depletion rate, the cue (i.e., 28% level alarm) will occur at:

$$\begin{aligned} t &= 0.28 \times 8.5\ h \\ &= 2.38\ h \end{aligned}$$

Ordinarily, with such a long available time, this action would be considered time-independent. (From Table 3.3.3-1, TRC-generated values for such times are smaller than the lower acceptable limit defined in Section 3.6.) However, in order to be consistent with the quantification of the parallel action for LLOCA; this action is quantified with the lower acceptable limit of TRC values, i.e.,

RRHRDRCR0M = 1E-4

3.3.3.2.16 Small LOCA Switchover to Recirculation Cooling: RRHFDRCR0S

For SLOCAs, like MLOCAs, MAAP runs were used to determine the available time for recirculation switchover since the rate of RWST depletion is dependent on break size, and not ECCS configuration. The applicable MAAP run for SLOCAs is 9S1BCD2 [Ref. 3.3.3-23] which, according to Table 2 in the *Event Tree Work Package* [Ref. 3.3.3-3], has an RWST depletion time of 10.9 hours. Assuming a constant depletion rate, the cue (i.e., 28% level alarm) will occur at:

$$\begin{aligned} t &= 0.28 \times 10.9\ h \\ &= 3.05\ h \end{aligned}$$

Hence, the available time for recirculation switchover for SLOCAs is long, like that for MLOCAs. Consequently, the lower acceptable limit of TRC values is used to quantify this HFE also:

RRHRDRCR0S = 1E-4

3.3.3.2.17 Small -Small LOCA Switchover to Recirculation Cooling: RRHFDRCRSS

For SSLOCAs, like both MLOCAs and SLOCAS, MAAP runs can be used to determine the available time for recirculation switchover since the rate of RWST depletion is dependent on break size, and not ECCS configuration. The applicable MAAP run for SSLOCAs is 9S11BCDE-2 [Ref. 3.3.3-24] which, according to Table 2 in the *Event Tree Work Package* [Ref. 3.3.3-3], has an RWST depletion time of 13.5 hours. Assuming a constant depletion rate, the cue (i.e., 28% level alarm) will occur at:

$$\begin{aligned} t &= 0.28 \times 13.5\ h \\ &= 3.78\ h \end{aligned}$$

Hence, the available time for recirculation switchover for SSLOCAs is long, like that for both MLOCAs and SLOCAs. Consequently, the lower acceptable limit of TRC values is used to quantify this HFE also:

RRHRDRCRSS = 1E-4

3.3.3.3 Summary

Table 3.3.3-3 lists all of the HFEs which were quantified in detailed HRA analyses for the Ginna PRA. Table 3.3.3-4 lists all of the pre-accident HFEs modeled, their associated descriptions and screening values. Table 12 of Reference 3.3.3-3 lists all the post-accident HFEs and their associated screening values, including those which were not refined in the Detailed HRA Task.

3.3.4 References

3.3.3-1. Science Applications International Corporation, TQAP-2118-4.1, *Human Reliability Analysis Task Procedure*, Revision 1, August 6, 1993.

3.3.3-2. Science Applications International Corporation, 749-06-36, *Recovery Analysis Work Package*, Revision 0, January 14, 1994.

3.3.3-3. Science Applications International Corporation, 749-01-14, *Event Tree Work Package*, Revision 2, December 10, 1993.

3.3.3-4. E.M. Dougherty and J.R. Fragola, *Human Reliability Analysis: A Systems Engineering Approach With Nuclear Power Plant Applications*. NY: John Wiley & Sons, Inc., 1988.

3.3.3-5. A.D. Swain and H.E. Guttman, *Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Applications*, NUREG/CR-1278, USNRC, August 1983.

3.3.3-6. RG&E Procedure FR-H.1, *Response to Loss of Secondary Heat Sink*, Revision 9, September 4, 1990.

3.3.3-7. Science Applications International Corporation, 749-02-20.01, *Auxiliary Feedwater System Work Package*, Revision 0, September 15, 1992.

3.3.3-8. RG&E Procedure EOP E-0, *Reactor Trip or Safety Injection*, Revision 15, January 9, 1991.

3.3.3-9. RG&E Procedure EOP E-1, *Loss of Reactor or Secondary Coolant*, Revision 8, July 21, 1989.

3.3.3-10. RG&E Procedure ER-AFW.1, *Alternate Water Supply to the AFW Pumps*, Revision 7, February 29, 1989.

3.3.3-11. RG&E Procedure EOP E-3, *Steam Generator Tube Rupture*, Revision 10, April 9, 1990.

3.3.3-12. RG&E Procedure AP-RCP.1, *RCP Seal Malfunction*, Revision 6, November 17, 1989.

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3.3.3-15. RG&E Procedure EOP ES-0.2, *Natural Circulation Cooldown*, Revision 1, April 9, 1990.

3.3.3-16. RG&E Procedure EOP ES-0.3, *Natural Circulation Cooldown with Steam Void in Vessel*, Revision 1, April 30, 1990.

3.3.3-17. Rochester Gas & Electric, *Ginna PRA MAAP Run SLOCA22*, November 5, 1993.

3.3.3-18. Rochester Gas & Electric, *Ginna PRA MAAP Run RUH2I*, December 7, 1993.

3.3.3-19. Rochester Gas & Electric, *Ginna PRA MAAP Run RUH2C*, November 3, 1993.

3.3.3-20. RG&E Procedure EOP ES-1.3, *Transfer to Cold Leg Recirculation*, Revision 15, March 26, 1993.

3.3.3-21. Ginna Updated Final Safety Analysis Report (UFSAR), Revision 7, December 1991.

3.3.3-22. Rochester Gas & Electric, *Ginna PRA MAAP Run 9S51BC2E*, September 8, 1993.

3.3.3-23. Rochester Gas & Electric, *Ginna PRA MAAP Run 9S1BCD2*, July 10, 1993.

3.3.3-24. Rochester Gas & Electric, *Ginna PRA MAAP Run 9S11BCDE-2*, November 23, 1993.

Table 3.3.3-1 SAIC TRC: RULE-BASED WITHOUT HESITATION										
median response time (m) = 2 min; EF_R = 3.2; EF_U = 1.68										
time	0	1	2	3	4	5	6	7	8	9
0	1.00e+00	8.15e-01	5.00e-01	3.00e-01	1.85e-01	1.18e-01	7.80e-02	5.28e-02	3.67e-02	2.60e-02
10	1.88e-02	1.38e-02	1.03e-02	7.81e-03	5.98e-03	4.63e-03	3.62e-03	2.85e-03	2.27e-03	1.82e-03
20	1.47e-03	1.19e-03	9.77e-04	8.04e-04	6.65e-04	5.53e-04	4.62e-04	3.87e-04	3.26e-04	2.76e-04
30	2.35e-04	2.00e-04	1.71e-04	1.47e-04	1.26e-04	1.09e-04	9.45e-05	8.21e-05	7.15e-05	6.24e-05
40	5.46e-05	4.79e-05	4.21e-05	3.71e-05	3.27e-05	2.89e-05	2.56e-05	2.28e-05	2.02e-05	1.80e-05
50	1.61e-05	1.44e-05	1.29e-05	1.15e-05	1.04e-05	9.32e-06	8.40e-06	7.57e-06	6.84e-06	6.18e-06
60	5.59e-06	5.07e-06	4.60e-06	4.18e-06	3.80e-06	3.46e-06	3.15e-06	2.88e-06	2.63e-06	2.40e-06
70	2.20e-06	2.01e-06	1.84e-06	1.69e-06	1.55e-06	1.43e-06	1.31e-06	1.21e-06	1.11e-06	1.03e-06
80	9.47e-07	8.75e-07	8.08e-07	7.48e-07	6.92e-07	6.41e-07	5.94e-07	5.51e-07	5.11e-07	4.74e-07
90	4.41e-07	4.10e-07	3.81e-07	3.55e-07	3.30e-07	3.08e-07	2.87e-07	2.68e-07	2.50e-07	2.33e-07
100	2.18e-07	2.04e-07	1.91e-07	1.78e-07	1.67e-07	1.56e-07	1.47e-07	1.37e-07	1.29e-07	1.21e-07
110	1.14e-07	1.07e-07	1.00e-07	9.43e-08	8.87e-08	8.34e-08	7.85e-08	7.39e-08	6.96e-08	6.56e-08
120	6.19e-08	5.83e-08	5.50e-08	5.19e-08	4.90e-08	4.63e-08	4.38e-08	4.14e-08	3.91e-08	3.70e-08

Table 3.3.3-2
SAIC TRC: RULE-BASED WITH HESITATION

median response time (m) = 2 min; EF_R = 6.4; EF_U = 1.68

time	0	1	2	3	4	5	6	7	8	9
0	1.00e+00	7.23e-01	5.00e-01	3.65e-01	2.77e-01	2.17e-01	1.74e-01	1.42e-01	1.18e-01	9.96e-02
10	8.48e-02	7.28e-02	6.31e-02	5.51e-02	4.84e-02	4.27e-02	3.80e-02	3.39e-02	3.04e-02	2.73e-02
20	2.47e-02	2.24e-02	2.04e-02	1.86e-02	1.70e-02	1.56e-02	1.43e-02	1.32e-02	1.22e-02	1.12e-02
30	1.04e-02	9.66e-03	8.98e-03	8.37e-03	7.80e-03	7.29e-03	6.82e-03	6.38e-03	5.99e-03	5.62e-03
40	5.28e-03	4.97e-03	4.68e-03	4.42e-03	4.17e-03	3.94e-03	3.72e-03	3.53e-03	3.34e-03	3.17e-03
50	3.01e-03	2.85e-03	2.71e-03	2.58e-03	2.45e-03	2.34e-03	2.23e-03	2.12e-03	2.03e-03	1.94e-03
60	1.85e-03	1.77e-03	1.69e-03	1.62e-03	1.55e-03	1.48e-03	1.42e-03	1.36e-03	1.31e-03	1.26e-03
70	1.21e-03	1.16e-03	1.11e-03	1.07e-03	1.03e-03	9.90e-04	9.53e-04	9.18e-04	8.84e-04	8.52e-04
80	8.21e-04	7.92e-04	7.64e-04	7.37e-04	7.11e-04	6.87e-04	6.64e-04	6.41e-04	6.20e-04	5.99e-04
90	5.79e-04	5.60e-04	5.42e-04	5.25e-04	5.08e-04	4.92e-04	4.77e-04	4.62e-04	4.48e-04	4.34e-04
100	4.21e-04	4.08e-04	3.96e-04	3.84e-04	3.73e-04	3.62e-04	3.51e-04	3.41e-04	3.32e-04	3.22e-04
110	3.13e-04	3.04e-04	2.96e-04	2.88e-04	2.80e-04	2.72e-04	2.65e-04	2.58e-04	2.51e-04	2.44e-04
120	2.38e-04	2.31e-04	2.25e-04	2.20e-04	2.14e-04	2.08e-04	2.03e-04	1.98e-04	1.93e-04	1.88e-04

TABLE 3.3.3-3 REFINEMENT OF HUMAN FAILURE EVENTS: GINNA PRA			
HFE Event	*Refined Probability*	*Quantification Method*	*Definition*
AFHFDPCD04	3e-3	THERP	Operators fail to provide water to the CSTs from the Hotwell
CTHFDISOLA	3e-3	THERP	Operators fail to isolate S/G A after failure of tubes
CTHFDISOLB	3e-3	THERP	Operators fail to isolate S/G B after failure of tubes
IAHFDCNTBK	3e-3	THERP	Operators fail to restore IA to the containment (AOV 5392, SW to IA compressors)
RCHFD00RCP	3e-3	THERP	Operators fail to trip RCPs after loss of CCW support
RCHFD01BAF	2.35e-4	SAIC TRC	Operators fail to implement bleed and feed
RCHFDCD0SS	1.85e-3	SAIC TRC	Operator fails to cooldown to RHR after SI fails - SSLOCA
RCHFDCDDPR	1e-3	THERP	Operator fails to cooldown and depressurize RCS during SGTR given SI operation
RCHFDCDTR1	1.04e-2	SAIC TRC	Failure to cooldown to RHR after ruptured S/G isolation fails
RCHFDCDTR2	3.94e-3	SAIC TRC	Operator fails to cooldown to RHR after SI fails - SGTR
RCHFDPLOCA	1e-3	THERP	Operators fail to close PORV block valve (515/516) to terminate LOCA
RHHFD0SGTR	1e-3	THERP	Failure to establish and maintain RHR cooling following SGTR
RRHFDRCR0A	4e-3	SAIC TRC	Failure to Switch to Recirculation After LLOCA
RRHFDRCR0M	1e-4	SAIC TRC[2]	Failure to Switch to Recirculation After MLOCA
RRHFDRCR0S	1e-4	SAIC TRC[1]	Failure to Switch to Recirculation After SLOCA
RRHFDRCRSS	1e-4	SAIC TRC[1]	Failure to Switch to Recirculation After SSLOCA

[2] Based upon the "lowest acceptable limit" of values generated by the SAIC TRC quantification method.

Table 3.3.3-4
Pre-Accident Human Failure Events Modeled in the Ginna PRA

Name	Probability	Description
AFHFL0AFWA	3.00E-03	Failure to restore AFW Motor-Driven Pump Train 1A to service post test/maint
AFHFL0AFWB	3.00E-03	Failure to restore AFW Motor-Driven Pump Train 1B to service post test/maint
AFHFLSAFWA	3.00E-03	Failure to restore SAFW Pump Train 1C to service post test/maint
AFHFLSAFWB	3.00E-03	Failure to restore SAFW Pump Train 1D to service post test/maint
AFHFLTDAFW	3.00E-03	Failure to restore TDAFW pump train to service post test/maintenance
CCHFL0780A	3.00E-03	CCW THROTTLING VALVE 780A MISPOSITIONED
CCHFL0780B	3.00E-03	CCW THROTTLING VALVE 780B MISPOSITIONED
CSHFL0896A	3.00E-03	Motor Operated Valve 896A Is Left Unavailable After Testing Or Maintenance
CSHFL0896B	3.00E-03	Motor Operated Valve 896B Is Left Unavailable After Testing Or Maintenance
CSHFLTRANA	3.00E-03	Operators Fail To Restore CS Train A Equipment After Testing Or Maintenance
CSHFLTRANB	3.00E-03	Operators Fail To Restore CS Train B Equipment After Testing Or Maintenance
HVHFLSAFWA	3.00E-03	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION
HVHFLSAFWB	3.00E-03	LATENT HUMAN ERRORS IN SAFW-B COOLING INCL. SWITCH-B POSITION
HVHFL_SAFW	3.00E-03	OPERATOR FAILS TO DISCOVER ROOM HEATING FAILURE IN SAFW ROOM
MSHFLARV-A	3.00E-03	LATENT HUMAN ERROR DISABLES ARV 3411
MSHFLARV-B	3.00E-03	LATENT HUMAN ERROR DISABLES ARV 3410
RCHFL0431K	3.00E-03	CONTROLLER PC-431K MISCALIBRATED
RCHFLC429B	3.00E-03	ALARM PC-429B MISCALIBRATED
RCHFLC430B	3.00E-03	ALARM PC-430B MISCALIBRATED
RCHFLC431B	3.00E-03	ALARM PC-431B MISCALIBRATED
RCHFLC431F	3.00E-03	ALARM BISTABLE PC-431F MISCALIBRATED
RCHFLPC450	3.00E-03	ALARM PC-450 MISCALIBRATED
RCHFLPC451	3.00E-03	ALARM PC-451 MISCALIBRATED
RCHFLPC452	3.00E-03	ALARM PC-452 MISCALIBRATED
RCHFLPL451	3.00E-03	PRESSURE TRANSMITTER PT-451 MISCALIBRATED
RCHFLPT429	3.00E-03	PRESSURE TRANSMITTER PT-429 MISCALIBRATED
RCHFLPT430	3.00E-03	PRESSURE TRANSMITTER PT-430 MISCALIBRATED
RCHFLPT431	3.00E-03	PRESSURE TRANSMITTER PT-431 MISCALIBRATED
RCHFLPT449	3.00E-03	PRESSURE TRANSMITTER PT-449 MISCALIBRATED
RCHFLPT450	3.00E-03	PRESSURE TRANSMITTER PT-450 MISCALIBRATED
RCHFLPT452	3.00E-03	PRESSURE TRANSMITTER PT-452 MISCALIBRATED
RHHFLAC01A	3.00E-03	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)
RHHFLAC01B	3.00E-03	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)
RRHFL00856	3.00E-03	LATENT HUMAN FAILURE ON MOV 856
RRHFL0850A	3.00E-03	LATENT HUMAN FAILURE OF MOV 850A
RRHFL0850B	3.00E-03	LATENT HUMAN FAILURE OF MOV 850B
SIHFL0857B	3.00E-03	Latent Human Failure of MOV 857B
SIHFL0871A	3.00E-03	Laten Human Failure of MOV 871A
SIHFL0871B	3.00E-03	Latent Human Failure of MOV 871B
SIHFL857AC	3.00E-03	Latent Human Failure of MOV 857A OR 857C
SIHFLPSI1A	3.00E-03	Operators fail to restore PSI01A equipment after test or maintenance
SIHFLPSI1B	3.00E-03	Operators fail to restore PSI01B equipment after test or maintenance
SIHFLPSI1C	3.00E-03	Operators fail to restore PSI01C equipment after test or maintenance

3.3.4 Common Cause Failure Data

3.3.4.1 Introduction

This section describes the development of common cause failure data for use in the R.E. Ginna PRA project. Common cause failures are a subset of *dependent failures*, which are failures that defeat the redundancy or diversity that is employed to improve the availability of plant safety functions (e.g., coolant inventory control, etc.).

Common cause failures have been addressed in the Ginna PRA by incorporating appropriate common cause basic events in the integrated plant logic model. This section discusses how data was provided for quantifying all such events in the model documented in Ref. 3.3.4-1.

3.3.4.2 General Technical Approach

The beta factor method [Ref. 3.3.4-2] has been used to model common-cause failures in the Ginna PRA. 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 safety injection pumps fail to start on demand) due to all relevant common causes. It should be noted that:

1. Components within a common cause group have similar attributes and failure mechanisms, and are functionally redundant with respect to each other.

2. 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 PRAs of nuclear power plants. As noted in NUREG/CR-4780 [Ref. 3.3.4-3, p. 3-21]:

Although historical data collected from the operation of nuclear power plants indicates that common cause events do not always fail all redundant components, experience from using this simple model shows that, in many cases, it gives reasonable accurate (only slightly conservative) results for redundancy levels up to about three or four items.

Estimates for beta factors can be made from examination of plant-specific experience; generic estimates for major equipment types have also been published. The plant-specific data developed for the Ginna PRA has been examined for indications of common cause failures [Ref. 3.3.4-4], and sixteen events were identified. In assessing the usefulness of this information in the estimation of CCF beta factors for use in the Ginna PRA, several observations are relevant:

1. The data window for the Ginna PRA 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.

2. The plant specific data analysis scope does not address all components modeled in the PRA 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 a combination of generic data and plant-specific experience (incorporated through Bayesian updating) to determine the final CCF beta factors.

3.3.4.2.1 Generic CCF Data

Generic estimates for beta factors, obtained through a literature search, are listed in Table 3.3.4-1. For components and/or failure modes not expressly listed in Table 3.3.4-1, a beta factor of 0.1 is suggested. 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. 3.3.4-6, p. 6-12].

3.3.4.2.2 Bayesian Analysis

The steps involved in performing a Bayesian update are (1) development of prior distributions, (2) development of likelihood data, and (3) development of the posterior distribution. Moment matching was used to convert the log-normal distributions associated with the generic beta factor data into beta-distributed prior distributions:

$$\sigma = \frac{\ln(ef)}{1.645} = \frac{\ln(3)}{1.645} = 0.668 \tag{2}$$

where σ denotes the logarithmic standard deviation and *ef* denotes the log-normal error factor (equal to 3.0 as noted in Section 3.3.4.2.1). The variance, *V*, of a log-normal distribution is related to the mean, *M*, and σ by:

$$V = M^2(e^{\sigma^2} - 1) = M^2(e^{0.668^2} - 1) = 0.562\ M^2 \tag{3}$$

The beta distribution is a two-parameter distribution (α and β), with mean and variance:

$$\begin{aligned} M &= \frac{\alpha}{\alpha+\beta} \\ V &= \frac{\alpha\beta}{(\alpha+\beta+1)(\alpha+\beta)^2} \end{aligned} \tag{4}$$

Thus, the parameters α and β can be uniquely determined in terms of the mean and variance:

$$
\begin{aligned}
\alpha &= \frac{M^2(1-M)}{V} - M \\
&= \frac{(1-M)}{0.562} - M \\
\beta &= \frac{M(1-M)^2}{V} - 1 + M \\
&= \frac{(1-M)^2}{0.562M} - 1 + M
\end{aligned}
\tag{5}
$$

The Bayesian update is performed by changing the values of α and β:

$$
\begin{aligned}
\alpha' &= \alpha + f_{CCF} \\
\beta' &= \beta + f_I
\end{aligned}
\tag{6}
$$

where f_I denotes the number of independent failures of all components in the CCF group, and f_{CCF} denotes the number of common cause failures of the group. Note that α' and β' are the parameters of the beta-distributed posterior distribution. To provide distributions suitable for use in an uncertainty analysis, Equations (2) and (3) were used to convert the posterior distribution into a log-normal distribution, noting that the error factor is the ratio of the ninety-fifth percentile to the median:

Bayesian updated CCF beta factors were determined for all CCF events whose CCF group boundaries (EINs) were within the scope of the plant specific data analysis. Table 3.3.4-2 shows (1) the determination of the CCF group boundaries, identifies the associated CAFTA CCF beta factor event, and provides the statistical computational details. It should be noted that CCF events which have the same CCF group boundary have been grouped together in Table 3.3.4-2. (For example, SI pumps fail to run during injection, SICCMPSI1Y, and SI pumps fail to run during recirculation, SRCCMPSI1Y, have the same set of EINs in common: PSI01A, PSI01B, and PSI01C.)

It should be noted that one beta factor may be applied to more than one common cause failure event. (For example, AFAVPCCF$$ is used to quantify events AFCCPRECLA and AFCCPRECLB.) Such beta factors may have two or more estimates, depending on plant-specific failure history of the components comprising the associated common cause group. An aggregate beta factor was developed by forming a mixture distribution as described in Section 3.3.1.

$$M' = \frac{\alpha'}{\alpha'+\beta'}$$

$$V' = \frac{\alpha'\beta'}{(\alpha'+\beta'+1)(\alpha'+\beta')^2}$$

$$ef' = \exp\left[1.645\sqrt{\ln\left(1 + \frac{V'}{M^2}\right)}\right] = \exp\left[1.645\sqrt{\ln\left(1 + \frac{\beta'}{\alpha'(\alpha'+\beta'+1)}\right)}\right] \qquad (7)$$

3.3.4.3 Results

Final common cause beta factors for use in the Ginna PRA are listed in Table 3.3.4-3. The distribution of estimation methods (generic, Bayesian updating, or aggregation) are:

Method	Percentage	Description
generic	11 (7 of 65)	failure data not collected in plant-specific data analysis
Bayes (1)	35 (23 of 65)	no independent or common cause failures observed
Bayes (2)	31 (20 of 65)	some independent failures, but no common cause failures
Bayes (3)	11 (7 of 65)	some independent and common cause failures
Bayes (4)	2 (1 of 65)	no independent failures, but some common cause failures
aggregate	10 (7 of 65)	two or more beta factors estimates determined using Bayes (1) or Bayes (2) method

Thus, while some components have experienced common cause failure during the data window, there is no indication that the rate of common cause failure is of general concern at Ginna.

3.3.4.4 References

3.3.4-1 Letter from T. Daniels, RG&E, to M. Stutzke, SAIC, Subject: Revision 0 of MASTER Fault Tree Model, NSL-PRALT-92-034, April 2, 1992.

3.3.4-2 K. N. Fleming, "A Reliability Model for Common Cause Failure in Redundant Safety Systems," *Proceedings of the Sixth Annual Pittsburgh Conference on Modeling and Simulation*, General Atomics Report GA-A13284, April 23-25, 1975.

3.3.4-3 A. Mosleh, et. al., *Procedures for Treating Common Cause Failures in Safety and Reliability Studies*, NUREG/CR-4780, January 1988.

3.3.4-4 RG&E and PRC, *Common Cause Failure Data Analysis Work Package*, Rev. 0, June 14, 1991.

3.3.4-5 Plant-Specific Data Work Package, Project Document No. 749-03-22.1, Rev. 0, April 15, 1992.

3.3.4-6 D. M. Ericson, et. al., *Analysis of Core Damage Frequency: Internal Events Methodology, NUREG/CR-4550*, Vol. 1, Rev. 1, January 1990.

3.3.4-7 J. A. Steverson and C. L. Atwood, *Common Cause Fault Rates for Valves*, NUREG/CR-2770, February 1983.

3.3.4-8 T. R. Meachum and C. L. Atwood, *Common Cause Fault Rates for Instrumentation and Control Assemblies*, NUREG/CR-3289, May 1983.

3.3.4-9 C. L. Atwood, *Common Cause Fault Rates for Pumps*, NUREG/CR-2098, February 1983.

Table 3.3.4-1
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

Table 3.3.4-1 COMMON-CAUSE BETA FACTORS		
Description	*Value*	*Reference*
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
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 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_i	f_{ccf}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
ACCCDGXTIE	AC_CB_D	TOTAL	5	1	ACCBDCCF$$	0.1	1.5	13.1	2.50	18.1	1.21e-01	2.42e+00
		52/EG1A1	0									
		52/EG1A2	2									
		52/EG1B1	1									
		52/EG1B2	2									
AFCCDMOVNA	AF_MV_D	TOTAL	0	0	AFMVDCCF$$	0.1	1.50	13.51	1.50	13.51	1.00e-01	3.00e+00
		4007	0									
		4008	0									
AFCCDMOVNB	AF_MV_D	TOTAL	0	0	AFMVDCCF$$	0.1	1.50	13.51	1.50	13.51	1.00e-01	3.00e+00
		9701A	0									
		9701B	0									
AFCCFMDAFW	AF_MP_F	TOTAL	0	0	AFMPFCCF$$	0.03	1.70	54.82	1.70	54.82	3.00e-02	3.00e+00
		PFW02A	0									
		PFW02B	0									
AFCCFSAFWA	AF_MP_F	TOTAL	0	0	AFMPFCCF$$	0.03	1.70	54.82	1.70	54.82	3.00e-02	3.00e+00
		PFW03A	0									
		PFW03B	0									
AFCCPCROSS	AF_MV_P	TOTAL	0	0	AFMVPCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		4000A	0									
		4000B	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_t	f_{ccf}	*Beta Factor Event*	*M*	α	β	α'	β'	*M'*	*EF'*
AFCCPCSTCV	AF_CV_P	TOTAL	0	0	AFCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		4014	0									
		4016	0									
		4017	0									
AFCCPDISCA	AF_CV_P	TOTAL	0	0	AFCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		4009	0									
		4010	0									
		3998	0									
AFCCPDISCB	AF_CV_P	TOTAL	0	0	AFCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		9700A	0									
		9700B	0									
AFCCPRECLA	AF_AV_P	TOTAL	1	0	AFAVPCCF$$	0.191	1.25	5.29	1.25	6.29	1.66e-01	3.07e+00
		4304	0									
		4310	1									
AFCCPRECLB	AF_AV_P	TOTAL	0	0	AFAVPCCF$$	0.191	1.25	5.29	1.25	5.29	1.91e-01	3.00e+00
		9710A	0									
		9710B	0									
AFCCPSAFWX	AF_MV_P	TOTAL	0	0	AFMVPCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		9703A	0									
		9703B	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	Type Code	EIN	f_i	f_{ccf}	Beta Factor Event	M	α	β	α′	β′	M′	EF′
AFCCPSGINA	AF_CV_P	TOTAL	0	0	AFCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		4000C	0									
		4000D	0									
		4003	0									
		4004	0									
AFCCPSGINB	AF_CV_P	TOTAL	0	0	AFCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		9705A	0									
		9705B	0									
AFCCSMDAFW	AF_MP_S	TOTAL	0	0	AFMPSCCF$$	0.03	1.70	54.82	1.70	54.82	3.00e-02	3.00e+00
		PFW02A	0									
		PFW02B	0									
AFCCSSAFWA	AF_MP_S	TOTAL	1	0	AFMPSCCF$$	0.03	1.70	54.82	1.70	55.82	2.96e-02	3.00e+00
		PFW03A	0									
		PFW03B	1									
CCCC738A/B	CC_MV_P	TOTAL	2	0	CCMVPCCF$$	0.08	1.56	17.90	1.56	19.90	7.25e-02	3.02e+00
		738A	0									
		738B	2									
CCCCPUMP/R	CC_MP_F	TOTAL	1	0	CCMPFCCF$$	0.03	1.70	54.82	1.70	55.82	2.95e-02	3.00e+00
		PAC02A	0									
		PAC02B	1									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_i	f_{CCF}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
CCCCPUMP/S	CC_MP_A	TOTAL	1	0	CCMPACCF$$	0.03	1.70	54.82	1.70	55.82	2.95e-02	3.00e+00
		PAC02A	0									
		PAC02B	1									
CSCCM0836X	CS_AV_P	TOTAL	2	0	CSAVPCCF$$	0.191	1.25	5.29	1.25	7.29	1.46e-01	3.12e+00
		836A	1									
		836B	1									
CSCCM0847X	CS_CV_P	TOTAL	0	0	CSCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		847A	0									
		847B	0									
CSCCM0860X	CS_MV_P	TOTAL	3	0	CSMVPCCF$$	0.08	1.56	17.90	1.56	20.90	6.93e-02	3.02e+00
		860A	0									
		860B	0									
		860C	2									
		860D	1									
CSCCM0862X	CS_CV_P	TOTAL	0	0	CSCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		862A	0									
		862B	0									
CRCCM0896X	CS_MV_X	TOTAL	2	0	CRMVXCCF$$	0.08	1.56	17.90	1.56	19.90	7.25e-02	3.02e+00
		896A	2									
		896B	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_i	f_{ccf}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
CSCCMPSI2X	CS_MP_S	TOTAL	0	0	CSMPSCCF$$	0.05	1.64	31.16	1.64	31.16	5.00e-02	3.00e+00
		PSI02A	0									
		PSI02B	0									
CSCCMPSI2Y	CS_MP_F	TOTAL	1	0	CSMPFCCF$$	0.05	1.64	31.16	1.64	32.16	4.85e-02	3.00e+00
		PSI02A	0									
		PSI02B	1									
CTCCMINIEX	HV_MC_C	TOTAL	0	0	HVMCCCCF$$	0.1	1.50	13.51	1.50	13.51	1.00e-01	3.00e+00
		7970	0									
		7971	0									
CTCCMINISU	HV_MC_C	TOTAL	0	0	HVMCCCCF$$	0.1	1.50	13.51	1.50	13.51	1.00e-01	3.00e+00
		7478	0									
		7445	0									
CVCCMLTDBA	CV_LT_D	TOTAL	4	0	CVLTDCCF$$	0.1	1.50	13.51	1.50	17.51	7.90e-02	3.05e+00
		LT102	1									
		LT106	2									
		LT171	0									
		LT172	1									
CVCCMLTHBA	CV_LT_H	TOTAL	33	4	CVLTHCCF$$	0.1	1.50	13.51	5.50	42.51	1.15e-01	1.88e+00
		LT102	7									
		LT106	5									
		LT171	8									
		LT172	13									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_t	f_{ccr}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
CVCCMLTLBA	CV_LT_L	TOTAL	0	1	CVLTLCCFSS	0.1	1.50	13.51	2.50	13.51	1.56e-01	2.37e+00
		LT102	0									
		LT106	0									
		LT171	0									
		LT172	0									
CVCCMPAABC	CV_MP_A	TOTAL	4	0	CVMPACCFSS	0.252	1.08	3.20	1.08	7.20	1.30e-01	3.35e+00
		PCH01A	0									
		PCH01B	3									
		PCH01C	1									
CVCCMPFABC	CV_MP_F	TOTAL	4	0	CVMPFCCFSS	0.016	1.73	106.70	1.73	110.70	1.54e-02	3.00e+00
		PCH01A	0									
		PCH01B	0									
		PCH01C	4									
DGCC000RUN	DG_DG_F	TOTAL	1	0	DGDGFCCFSS	0.05	1.64	31.16	2.64	31.16	7.81e-02	2.43e+00
		KDG01A	0									
		KDG01B	1									
DGCC0START	DG_DG_A	TOTAL	2	1	DGDGACCFSS	0.05	1.64	31.16	2.64	33.16	7.37e-02	2.44e+00
		KDG01A	1									
		KDG01B	1									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	Type Code	EIN	f_I	f_{ccf}	Beta Factor Event	M	α	β	α′	β′	M′	EF′
MSCCARVAIR	MS_RV_P	TOTAL	1	0	MSRVPCCF$$	0.1	1.50	13.51	1.50	14.51	9.38e-02	3.01e+00
		3410	1									
		3411	0									
MSCCCARVSG	MS_RV_X	TOTAL	0	0	MSRVCCCF$$	0.07	1.58	21.05	1.58	21.05	7.00e-02	3.00e+00
		3410	0									
		3411	0									
MSCCCMSIVX	MS_AV_X	TOTAL	2	0	MSAVCCCF$$	0.191	1.25	5.29	1.25	7.29	1.46e-01	3.11e+00
		3516	2									
		3517	0									
MSCCPSGVCS	MS_CV_P	TOTAL	0	0	MSCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		3504B	0									
		3505B	0									
MSCCPSGMOV	MS_MV_P	TOTAL	1	0	MSMVPCCF$$	0.08	1.56	17.90	1.56	18.90	7.61e-02	3.01e+00
		3504A	0									
		3505A	1									
RCCC00430P	RC_RZ_P	TOTAL	0	0	RCRZPCCF$$	0.07	1.58	21.05	1.58	21.05	7.00e-02	3.00e+00
		PCV-430	0									
		PCV-431C	0									
RCCC431A/B	RC_AV_N	TOTAL	0	0	RCAVNCCF$$	0.191	1.25	5.29	1.25	5.29	1.91e-01	3.00e+00
		PCV-431A	0									
		PCV-431B	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_t	f_{ccf}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
RCCC515/6P	RC_MV_P	TOTAL	0	0	RCMVPCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		515	0									
		516	0									
RCCC515/6X	RC_MV_X	TOTAL	0	0	RCMVXCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		515	0									
		516	0									
RHCC697A/B RRCC697A/B	RH_CV_P	TOTAL	0	0	RHCVPCCF$$ RRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		697A	0									
		697B	0									
RHCC710A/B RRCC710A/B	RH_CV_P	TOTAL	0	0	RHCVPCCF$$ RRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		710A	0									
		710B	0									
RHCC851A/B	RH_MV_X	TOTAL	1	0	RHMVXCCF$$	0.08	1.56	17.90	1.56	18.90	7.61e-02	3.01e+00
		851A	0									
		851B	1									
RHCC852A/B RRCC852A/B	RH_MV_P	TOTAL	0	0	RHMVPCCF$$ RRMVPCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		852A	0									
		852B	0									
RHCC853A/B RRCC853A/B	RH_CV_P	TOTAL	0	0	RHCVPCCF$$ RRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		853A	0									
		853B	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	Type Code	EIN	f_i	f_{ccf}	Beta Factor Event	M	α	β	α'	β'	M'	EF'
RHCCPUMPAB RRCCPUMPAB	RH_MP_S	TOTAL	1	1	RHMPSCCF$$ RRMPSCCF$$	0.11	1.47	11.92	2.47	12.92	1.61e-01	2.38e+00
		PAC01A	0									
		PAC01B	1									
RHCCPUMPBA RRCCPUMPBA	RH_MP_F	TOTAL	0	0	RHMPFCCF$$ RRMPFCCF$$	0.11	1.47	11.92	1.47	11.92	1.10e-01	3.00e+00
		PAC01A	0									
		PAC01B	0									
RRCC850A/B	RH_MV_P	TOTAL	1	0	RRMVPCCF$$	0.08	1.56	17.90	1.56	18.90	7.61e-02	3.01e+00
		850A	1									
		850B	0									
RRCCM0857M	RH_MV_P	TOTAL	1	0	RRMVPCCF$$	0.08	1.56	17.90	1.56	18.90	7.61e-02	3.01e+00
		857A	0									
		857B	0									
		857C	1									
SICCM0825X	SI_MV_P	TOTAL	0	0	SIMVPCCF$$	0.08	1.56	17.90	1.56	17.90	8.00e-02	3.00e+00
		825A	0									
		825B	0									
SICCM0826X	SI_MV_P	TOTAL	3	0	SIMVPCCF$$	0.08	1.56	17.90	1.56	20.90	6.93e-02	3.02e+00
		826A	1									
		826B	1									
		826C	0									
		826D	1									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_t	f_{CCF}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
SICCM0826Y	SI_MV_X	TOTAL	1	0	SIMVXCCF$$	0.08	1.56	17.90	1.56	18.90	7.61e-02	3.01e+00
		826A	0									
		826B	0									
		826C	1									
		826D	0									
SICCM0867X SRCCM0867X	SI_CV_P	TOTAL	0	0	SICVPCCF$$ SRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		867A	0									
		867B	0									
SICCM0878X SRCCM0878X	SI_CV_P	TOTAL	0	0	SICVPCCF$$ SRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		878G	0									
		878J	0									
SICCM0889X SRCCM0889X	SI_CV_P	TOTAL	0	0	SICVPCCF$$ SRCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		870A	0									
		870B	0									
		889A	0									
		889B	0									
SICCM0891X	SI_CV_P	TOTAL	0	0	SICVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		891A	0									
		891B	0									
		891C	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	Type Code	EIN	f_I	f_{ccf}	Beta Factor Event	M	α	β	α′	β′	M′	EF′
SICCMPSIIX SRCCMPSIIX	SI_MP_S	TOTAL	1	2	SIMPSCCF$$ SRMPSCCF$$	0.17	1.31	6.38	3.31	7.38	3.10e-01	1.99e+00
		PSI01A	0									
		PSI01B	0									
		PSI01C	1									
SICCMPSIIY SRCCMPSIIY	SI_MP_F	TOTAL	1	0	SIMPFCCF$$ SRMPFCCF$$	0.17	1.31	6.38	1.31	7.38	1.50e-01	3.05e+00
		PSI01A	0									
		PSI01B	0									
		PSI01C	1									
SWCCBFMOVC	SW_MV_C	TOTAL	7	0	SWMVCCCF$$	0.08	1.56	17.90	1.56	24.90	5.88e-02	3.05e+00
		4780	0									
		4609	0									
		4613	0									
		4614	6									
		4733	0									
		4734	0									
		4735	1									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	Type Code	EIN	f_i	f_{ccf}	Beta Factor Event	M	α	β	α'	β'	M'	EF'
SWCCBFMOVN	SW_MV_N	TOTAL	3	0	SWMVNCCF$$	0.08	1.56	17.90	1.56	20.90	6.93e-02	3.02e+00
		4780	0									
		4609	0									
		4613	1									
		4614	1									
		4733	0									
		4734	0									
		4735	1									
SWCCCHECKN	SW_CV_N	TOTAL	0	0	SWCVNCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		4601	0									
		4602	0									
		4603	0									
		4604	0									
SWCCGTMOVC	SW_MV_C	TOTAL	4	0	SWMVCCCF$$	0.08	1.56	17.90	1.56	21.90	6.64e-02	3.03e+00
		4670	0									
		4664	2									
		4663	1									
		4615	1									
		4616	0									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_i	f_{ccf}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
SWCCGTMOVN	SW_MV_N	TOTAL	2	0	SWMVNCCF$$	0.08	1.56	17.90	1.56	19.90	7.25e-02	3.02e+00
		4670	0									
		4664	2									
		4663	0									
		4615	0									
		4616	0									
SWCCPPMPSV	SW_SV_P	TOTAL	5	0	SWSVPCCF$$	0.1	1.50	13.51	1.50	18.51	7.50e-02	3.06e+00
		4324	4									
		4325	0									
		4326	1									
SWCCPSWCVS	SW_CV_P	TOTAL	0	0	SWCVPCCF$$	0.06	1.61	25.25	1.61	25.25	6.00e-02	3.00e+00
		9627A	0									
		9627B	0									
SWCCPSWMVA	SW_MV_P	TOTAL	4	0	SWMVPCCF$$	0.08	1.56	17.90	1.56	21.90	6.64e-02	3.03e+00
		4013	1									
		4027	1									
		4028	2									
SWCCPSWMVB	AF_MV_P	TOTAL	2	0	AFMVPCCF$$ SWMVPCCF$$	0.08	1.56	17.90	1.56	19.90	7.25e-02	3.02e+00
		9629A	1									
		9629B	1									

Table 3.3.4-2
BAYESIAN UPDATED BETA FACTORS

CCF Event(s)	*Type Code*	*EIN*	f_t	f_{ccf}	*Beta Factor Event*	*M*	α	β	α′	β′	*M′*	*EF′*
SWCCPUMPSR	SW_MP_F	TOTAL	0	0	SWMPFCCF$$	0.03	1.70	54.82	1.70	54.82	3.00e-02	3.00e+00
		PSW01A	0									
		PSW01B	0									
		PSW01C	0									
		PSW01D	0									
SWCCPUMPSS	SW_MP_A	TOTAL	0	0	SWMPACCF$$	0.03	1.70	54.82	1.70	54.82	3.00e-02	3.00e+00
		PSW01A	0									
		PSW01B	0									
		PSW01C	0									
		PSW01D	0									

Table 3.3.4-3
FINAL COMMON CAUSE BETA FACTORS

Beta Factor Event	*Description*	*Mean Beta Factor*	*Error Factor*	*Parent Event(s)*	*Basis*
ACCBDCCF$S	Beta factor for D/G breakers fail to close	1.21e-01	2.42e+00	ACCCDGXTIE	Bayes (3)
ACRTDCCF$S	Beta factor for AC Power related Agastat timing relays	1.00e-01	3.00e+00	ACCC0UVAGA	generic
AFAVPCCF$S	Beta factor for AFW air operated valve fails to open	1.79E-01	3.05+00	AFCCPRECLA AFCCPRECLB	aggregate
AFCVPCCF$S	Beta factor for AFW check valve fails to open	6.00e-02	3.00e+00	AFCCPCSTCV AFCCPDISCA AFCCPDISCB AFCCPSGINA AFCCPSGINB	Bayes (1)
AFMPFCCF$S	Beta factor for AFW motor-driven pump fails to run	3.00E-02	3.00e+00	AFCCFMDAFW AFCCFSAFWA	Bayes (1)
AFMPSCCF$S	Beta factor for AFW motor-driven pump fails to start	2.98e-02	3.00e+00	AFCCSMDAFW AFCCSSAFWA	aggregate
AFMVDCCF$S	Beta factor for AFW motor operated valve fails to throttle flow	1.00e-01	3.00e+00	AFCCDMOVNA AFCCDMOVNB	Bayes (1)
AFMVPCCF$S	Beta factor for AFW motor operated valve fails to open	8.00e-02	3.00e+00	AFCCPCROSS AFCCPSAFWX	Bayes (1)
CCMPACCF$S	Beta factor for CCW pump fails to start	2.95e-02	3.00e+00	CCCCPUMP/S	Bayes (2)
CCMPFCCF$S	Beta factor for CCW pump fails to run	2.95e-02	3.00e+00	CCCCPUMP/R	Bayes (2)
CCMVPCCF$S	Beta factor for motor-operated valve fails to open	7.25e-02	3.02e+00	CCCC738A/B	Bayes (2)
CRMVXCCF$S	Beta factor for CS MOV fails to close	7.25e-02	3.02+00	CRCCM0860X CRCCM0896X	Bayes (2)
CSAVPCCF$S	Beta factor for CS AOV fails to open	1.46e-01	3.12e+00	CSCCM0836X	Bayes (2)
CSCVPCCF$S	Beta factor for CS check valve fails to open	6.00e-02	3.00e+00	CSCCM0847X CSCCM0862X	Bayes (2)
CSLTDCCF$S	Beta factor for RWST level transmitter fails to respond	1.00e-01	3.00e+00	CSCCMLDRWT	generic
CSLTLCCF$S	Beta factor for RWST level transmitter fails low	1.00e-01	3.00e+00	CSCCMLTLRW	generic
CSMPFCCF$S	Beta factor for CS pump fails to run	4.85e-02	3.00e+00	CSCCMPSI2Y	Bayes (2)
CSMPSCCF$S	Beta factor for CS pump fails to start	5.00e-02	3.00e+00	CSCCMPSI2X	Bayes (1)
CSMVPCCF$S	Beta factor for CS MOV fails to open	6.93e-02	3.02e+00	CSCCM0860X	Bayes (2)
CSVBPCCF$S	Beta factor for NaOH tank vacuum breakers fail to open	1.00e-01	3.00e+00	CSCCMVBADD	generic
CVLTDCCF$S	Beta factor for BAST level transmitters fail to respond	7.90e-02	3.05e+00	CVCCMLTDBA	Bayes (2)
CVLTHCCF$S	Beta factor for BAST level transmitter fails low	1.15e-01	1.88e+00	CVCCMLTHBA	Bayes (3)
CVLTLCCF$S	Beta factor for BAST level transmitter fails low	1.56e-01	2.37e+00	CVCCMLTLBA	Bayes (4)

Table 3.3.4-3 FINAL COMMON CAUSE BETA FACTORS					
Beta Factor Event	*Description*	*Mean Beta Factor*	*Error Factor*	*Parent Event(s)*	*Basis*
CVMPACCF$$	Beta factor for CVCS pumps fail to run	1.54E-02	3.00e+00	CVCCMPAABC	Bayes (2)
CVMPFCCF$$	Beta factor for CVCS motor pumps fail to start	1.30e-01	3.55e+00	CVCCMPFABC	Bayes (2)
DGDGACCF$$	Beta factor for diesel generator fails to start	7.37e-02	2.44e+00	DGCC0START	Bayes (3)
DGDGFCCF$$	Beta factor for diesel generator fails to run	7.81e-02	2.43e+00	DGCC000RUN	Bayes (2)
ESRTDCCF$$	Beta factor for Agastat time delay relay fails to energize	1.00e-01	3.00e+00	ESCCMS1AGA ESCCSI0AGA	generic
HVMCCCCF$$	Beta factor for air-operated damper fails to close	1.00e-01	3.00e+00	CTCCMINIEX CTCCMINISU	Bayes (1)
MSAVCCCF$$	Beta factor for MSIV fails to close	1.46e-01	3.11e+00	MSCCCMSIVX	Bayes (2)
MSAVPCCF$$	Beta factor for ARV fails to open (air operation)	9.38e-02	3.01e+00	MSCCARVAIR	Bayes (2)
MSCVPCCF$$	Beta factor for Main Steam check valve fails to open	6.00e-02	3.00e+00	MSCCPSGVCS	Bayes (1)
MSMVPCCF$$	Beta factor for Main Steam MOV fails to open	7.61e-02	3.01e+00	MSCCPSGMOV	Bayes (2)
MSRVCCCF$$	Beta factor for ARV fails to close	7.00e-02	3.00e+00	MSCCCARVSG	Bayes (1)
MSXVPCCF$$	Beta factor for ARV fails to open (manual operation)	1.00e-01	3.00e+00	MSCCARVMAN	generic
RCAVNCCF$$	Beta factor for RCS AOV fails to open	6.00e-02	3.00e+00	RCCC431A/B	Bayes (1)
RCMVPCCF$$	Beta factor for RCS MOV fails to open	8.00e-02	3.00e+00	RCCC515/6P	Bayes (1)
RCMVXCCF$$	Beta factor for RCS MOV fails to close	8.00e-02	3.00e+00	RCCC515/6X	Bayes (1)
RCRZPCCF$$	Beta factor for PORV fails to open	7.00e-02	3.00e+00	RCCC00430P	Bayes (1)
RHCVPCCF$$	Beta factor for RHR check valve fails to open [injection]	6.00e-02	3.00e+00	RHCC697A/B RHCC710A/B RHCC853A/B	Bayes (1)
RHMPFCCF$$	Beta factor for RHR pump fails to run [injection]	1.10e-01	3.00e+00	RHCCPUMPBA	Bayes (1)
RHMPSCCF$$	Beta factor for RHR pump fails to start [injection]	1.61e-01	2.38e+00	RHCCPUMPAB	Bayes (3)
RHMVPCCF$$	Beta factor for RHR MOV fails to open [injection]	8.00e-02	3.00e+00	RHCC852A/B	Bayes (1)
RHMVXCCF$$	Beta factor for RHR MOV fail to close [injection]	7.61e-02	3.01e+00	RHCC851A/B	Bayes (2)
RRCVPCCF$$	Beta factor for RHR check valve fails to open [recirc]	6.00e-02	3.00e+00	RRCC697A/B RRCC710A/B RRCC853A/B	Bayes (1)
RRMPFCCF$$	Beta factor for RHR pump fails to run [recirc]	1.10e-01	3.00e+00	RRCCPUMPBA	Bayes (1)

Table 3.3.4-3
FINAL COMMON CAUSE BETA FACTORS

Beta Factor Event	*Description*	*Mean Beta Factor*	*Error Factor*	*Parent Event(s)*	*Basis*
RRMPSCCF$S	Beta factor for RHR pump fails to start [recirc]	1.61e-01	2.38e+00	RRCCPUMPAB	Bayes (3)
RRMVPCCF$S	Beta factor for RHR MOV fails to open [recirc]	7.74e-02	3.01+00	RRCC852A/B RRCC850A/B RRCCM0857M	aggregate
SICVPCCF$S	Beta factor for SI check valve fails to open	6.00e-02	3.00e+00	SICCM0889X SICCM0867X SICCM0878X SICCM0891X	Bayes (1)
SIMPFCCF$S	Beta factor for SI pump fails to run	1.50e-01	3.05e+00	SICCMPSI1Y	Bayes (2)
SIMPSCCF$S	Beta factor for SI pump fails to start	3.10e-01	1.99e+00	SICCMPSI1X	Bayes (3)
SIMVPCCF$S	Beta factor for SI MOV fails to open	7.47-02	3.03+00	SICCM0825X SICCM0826X	aggregate
SIMVXCCF$S	Beta factor for SI MOV fails to close	7.61e-02	3.01e+00	SICCM0826Y	Bayes (2)
SRCVPCCF$S	Beta factor for SI check valve fails to open	6.00e-02	3.00e+00	SRCCM0867X SRCCM0878X SRCCM0889X	Bayes (1)
SRMPFCCF$S	Beta factor for SI pump fails to run	1.50e-01	3.05e+00	SRCCMPSI1Y	Bayes (2)
SRMPSCCF$S	Beta factor for SI pump fails to start	1.50e-01	3.05e+00	SRCCMPSI1X	Bayes (3)
SWCVNCCF$S	Beta factor for SW check valve fails to open	6.00e-02	3.00e+00	SWCCCHECKN	Bayes (1)
SWCVPCCF$S	Beta factor for SW check valve fails to open	6.00e-02	3.00e+00	SWCCPSWCVS	Bayes (1)
SWEJFCCF$S	Beta factor for SW expansion joint failures	1.00e-01	3.00e+00	SWCCEXPANJ	generic
SWMPACCF$S	Beta factor for SW pumps fail to start	3.00e-02	3.00e+00	SWCCPUMPSS	Bayes (1)
SWMPFCCF$S	Beta factor for SW pumps fail to run	3.00e-02	3.00e+00	SWCCPUMPSR	Bayes (1)
SWMVCCCF$S	Beta factor for SW MOVs fail to close	6.26e-02	3.05e+00	SWCCBFMOVC SWCCGTMOVC	aggregate
SWMVNCCF$S	Beta factor for SW MOVs fail to open	7.09e-02	3.03+00	SWCCBFMOVN SWCCGTMOVN	aggregate
SWMVPCCF$S	Beta factor for SW MOVs fail to open	6.95e-02	3.04+00	SWCCPSWMVA SWCCPSWMVB	aggregate
SWSVPCCF$S	Beta factor for SW SOVs fail to open	7.50e-02	3.06e+00	SWCCPPMPSV	Bayes (2)

3.3.5 Test and Maintenance Unavailability Data

3.3.5.1 Introduction

This work package describes the estimation of test/maintenance (T/M) event probabilities based on Ginna-specific experience for use in the R. E. Ginna PRA project. The primary purpose of this effort is to assess point values and corresponding uncertainties for the T/M events contained in the various system-level fault tree models used to generate accident sequence cut sets. T/M events are added to fault trees 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, T/M events are very plant-specific. Consequently, a secondary purpose of this data analysis effort is to provide a more accurate representation of the Ginna risk profile.

3.3.5.1.1 Analysis Scope

Plant-specific data was collected by RG&E over the time period from January 1, 1980 to December 31, 1988 [Refs. 3.3.5-1 and 3.3.5-2]. The component population for which data was collected against and their boundaries are defined in separate documents [Refs. 3.3.5-3 and 3.3.5-4]. In general, the scope of the data collected by RG&E exceeds the needs of the integrated PRA plant logic model as defined on April 2, 1992 [Ref. 3.3.5-5] in that data has been collected for components and/or events which do not appear in the integrated model. This work package addresses only those plant-specific T/M event probability estimates that are needed to support the integrated model. The additional data collected by RG&E has not been analyzed; however, this "raw" data is provided in the work package for potential future applications.

3.3.5.1.2 Definitions

The following section provides definitions of the more unfamiliar terms associated with plant-specific T/M event data analysis. Common reliability and statistical terms (e.g., *failure rate*) are not addressed, and the use of a basic reference is suggested.

Data window: The calendar time period over which the component testing and maintenance history is collected.

EIN: The equipment identification number assigned by RG&E that uniquely identifies each component in the R. E. Ginna nuclear power plant.

Maintenance unavailability: The probability that equipment is unable to perform its safety-related functions while the plant is on-line due to maintenance activities. In this context, the term *maintenance* refers to either planned, periodic activities intended to preserve equipment (e.g., cleaning, inspection, etc.) or unplanned, corrective repairs required to restore equipment to service after failure (e.g., pump bearing replacement, etc.).

Testing unavailability: The probability that equipment is unable to perform its safety-related functions while the plant is on-line due to testing activities. In general, all tests (e.g., periodic, surveillance, inservice inspection, etc.) which place equipment out-of-service is addressed in the assessment of testing unavailability. Equipment which has automatic test override capability or is not declared inoperable by Operations is not included when estimating testing unavailability.

T/M event: A basic event added to a system fault tree model to account for equipment unavailability during plant on-line operation due to either testing or maintenance. T/M events are typically defined at a subsystem or equipment train level.

T/M event boundary: The set of EINs whose unavailability due to testing and/or maintenance causes the occurrence of the T/M event. For example, a T/M event may be specified for one equipment train that contains a motor-operated pump. In this case, the T/M event boundary is the list of EINs which comprise the equipment train (e.g., pump, suction valves, discharge valves, check valves, circuit breaker, etc.).

3.3.5.2 General Technical Approach

The plant-specific T/M event data supplied by RG&E has been analyzed in accordance with the *Data Analysis Task Procedure* [Ref. 3.3.5-6]. The following sections describe the implementation of this procedure in terms of the inputs to the analysis and the statistical estimation methods.

3.3.5.2.1 Analysis Inputs

As noted in Section 3.3.5.1.1, the plant-specific data provided by RG&E constitutes the major input to this work package. The data collection activities were initiated by RG&E prior to the development of the system fault tree models in conjunction with PRC Engineering (formerly ATESI) and the Reliability Centered Maintenance Program at Ginna. The results of this combined effort (referred to as RG&E hereafter) is contained in a dBASE®-compatible computer file which provides both failure/exposure information and maintenance out-of-service time on an

EIN-basis (i.e., one record per EIN). This data has been analyzed in the *Plant-Specific Data Work Package* [Ref. 3.3.5-7], which includes among its output, summarized maintenance unavailability data (total out-of-service hours and total on-line hours) for component types within each system. Testing unavailabilities were provided in a separate document on a procedure (or train) basis [Ref. 3.3.5-8]. The following sections provide a brief summary on how the Ginna-specific maintenance and testing information was compiled by RG&E while the remaining sections discuss how the information was used in support of the system fault tree models. The *Plant-Specific Data Work Package* [Ref. 3.3.5-7] provides additional information related to the data collection window, component population, and component boundaries.

3.3.5.2.1.1 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 PRA 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 *Plant-Specific Data Work Package* [Ref. 3.3.5-7]. 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, Ginna 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 twenty systems included in the data analysis is small. Since Ginna operates on a 12 month refueling cycle, most PM activities are 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.

3.3.5.2.1.2 Testing Unavailability Data

The only type of testing related unavailability data that was collected by RG&E was 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 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 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.

3.3.5.2.1.3 . Ginna PRA Plant-Specific Failure Data Base

The final values for the number of maintenance events and their total duration were entered into the Ginna PRA Plant-Specific Failure Data Base. The data as entered was reviewed by an independent checker to ensure accuracy as described in [Ref. 3.3.5-1]. Testing unavailabilities are also documented in [Ref. 3.3.5-1].

3.3.5.2.2 Analysis Assumptions

The following assumptions have been made in developing the estimates of plant-specific T/M event probabilities:

1. The data provided by RG&E is acceptable and accurate as delivered; no attempt has been made to independently verify the input data. However, it is noted that this information was collected under a separate QA program acceptable to RG&E.

2. Uncertainty estimates can be represented with a log-normal distribution. Martz [Ref. 3.3.5-9] 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.

3.3.5.2.3 Application Of Analysis Inputs - Maintenance Unavailability

The plant-specific maintenance data as provided by RG&E directly met the majority of the data analysis task requirements; however, a program was necessary to more easily organize the data. This program was required since the RG&E supplied data base provided data on a component level while the fault tree T/M events typically include multiple components. Therefore, a dBASE® program, RGEDATA.PRG, was developed to determine the total on-line hours and the out-of-service hours due to maintenance on a system and component type basis. The total on-line time is assumed to be equal to the number of reactor critical hours during the data window (64,054.35 [Ref. 3.3.5-10]), multiplied by the size of the associated component population.

The following equation was used to calculate average component-level maintenance unavailabilities in RGEDATA.PRG:

$$\bar{a}_M = \frac{T_R}{T_{OL}} \tag{1}$$

where:

$$\begin{aligned} T_R &= \text{total repair (out-of-service) hours during plant on-line operation for a specified component type within a given system} \\ T_{OL} &= \text{total on-line hours during the data window for the specified component type and system} \end{aligned} \tag{2}$$

It should be noted that Equation (1) applies regardless of the probability distributions that describe times-to-failures or out-of-service durations [Ref. 3.3.5-11]. Table 3.3.5-1 shows the application of Equation (1) to the summarized maintenance unavailability data collected by RG&E.

3.3.5.2.4 Application Of Analysis Inputs - Testing Unavailability

The following equation has been used to calculate average equipment-train-level testing unavailabilities:

$$\bar{a}_T = f_T \cdot \tau_T \tag{3}$$

where:

$$\begin{aligned} f_T &= \text{test frequency / reactor year} \\ \tau_T &= \text{test duration} \end{aligned} \tag{4}$$

As discussed previously, only periodic tests (PTs) are consistently performed when the plant is on-line; special tests (STs) and refueling shutdown surveillances (RSSPs) are typically only performed when the plant is shutdown. The various PT procedures, system-level fault tree work packages, and other information [Ref. 3.3.5-12] have been reviewed to determine which plant systems included within the integrated logic model could be affected by the performance of PTs. This information is summarized in Table 3.3.5-2.

3.3.5.2.5 Test / Maintenance Event Probability Estimation

The probability of a T/M event can be conservatively bounded by summing the contributions from component-level maintenance unavailabilities and equipment-train-level testing unavailabilities:

$$\bar{a}_{T/M\ event} = \sum_i \bar{a}_M^{(i)} + \sum_j \bar{a}_T^{(j)} \tag{5}$$

In order to apply Equation (5), it is necessary to define the T/M event boundaries in terms of the separate EINs whose unavailabilities (either maintenance-related or test-related) cause the occurrence of the T/M event. T/M event boundaries have been 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 Table 3.3.5-3.

3.3.5.3 Results

Estimates of T/M event mean probabilities are given in Table 3.3.5-3, which also shows the T/M event boundary definitions. All estimates are lower than the T/M event screening probability of 1.00E-02 used in model construction and initial quantification, and are generally consistent with data given in NUREG/CR-4550 [Ref. 3.3.5-14]. 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 are provided at the end of the table.

1. Maintenance events for components which are required to close was ignored since the valve would be either close or otherwise isolated during its out-of-service period.

2. 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.

3.3.5.3.1 Uncertainty Assessment

The average T/M event probabilities are uncertain due to several factors:

1. Statistical confidence

   Equation (1) provides 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.

2. 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.

3. Input estimation errors

   The values used to calculate testing unavailability, Equation (3), 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.

Numerical information required to support a detailed quantitative assessment of uncertainties has not been provided; moreover, there is not a unified approach within the PRA community for conducting such an assessment. (The philosophical issues raised above cannot be directly addressed through the application of probability theory or statistics; rather, they provide the basis for making assumptions that govern subsequent numerical investigations.) 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 [Ref. 3.3.5-14, Table 8.2-4].

3.3.5.4 References

3.3.5-1 PRC and RG&E, *Component Reliability Parameters Data Analysis Work Package*, Revision 0, June 14, 1991.

3.3.5-2 RG&E, *Correction to Data Base Containing Ginna-Specific Component Maintenance, Failure, and Exposure Values*, letter from M. D. Flaherty to M. A. Stutzke, NSL-PRALT-92.008, February 18, 1992.

3.3.5-3 RG&E *Probabilistic Risk Assessment Determination of Component Population for Data Task*, RG&E Design Analysis NSL-4976-DA024, Revision 0, November 30, 1990.

3.3.5-4 RG&E, *Probabilistic Risk Assessment Determination of Component Boundaries*, RG&E Design Analysis NSL-4976-DA001, Revision 1, November 30, 1990.

3.3.5-5 RG&E, *Revision 0 of MASTER Fault Tree Model*, letter from T. A. Daniels to M. A. Stutzke, NSL-PRALT-92.034, April 2, 1992.

3.3.5-6 SAIC, *Data Analysis Procedure for Rochester Gas & Electric Corporation Ginna Nuclear Power Plant Probabilistic Risk Assessment Project*, SAIC-139-91-030, Revision 0, August 3, 1990.

3.3.5-7 SAIC, *Plant-Specific Data Work Package*, Project Document 749-03-22.1, Revision 1, June 26, 1992.

3.3.5-8 PRC and RG&E, *Maintenance/Testing Unavailabilities Work Package*, Revision 0, june 14, 1991.

3.3.5-9 H. F. Martz, et. al., *A Comparison of Methods for Uncertainty Analysis of Nuclear Power Plant Safety System Fault Tree Models*, NUREG/CR-3263, April 1983.

3.3.5-10 RG&E, *Probabilistic Risk Assessment Determination of Reactor Critical Hours*, RG&E Design Analysis NSL-4976-DA003, Revision 0, September 17, 1990.

3.3.5-11 Sheldon M. Ross, *Introduction To Probability Models*, New York: Academic Press, 1980.

3.3.5-12 RG&E, *Impact of Periodic Tests (PTs) on Systems Modeled by RG&E and New Initiating Events for Feed/Steam Line Breaks*, letter from M. D. Flaherty to M. A. Stutzke, March 11, 1992.

3.3.5-13 SAIC, *Electric Power System Analysis Work Package*, Doc. No. 749-02-20.06, Revision 0, June 20, 1992.

3.3.5-14 D. M. Ericson, et. al., *Analysis of Core Damage Frequency: Internal Events Methodology,* NUREG/CR-4450, Volume 1, Revision 1, January 1990.

Table 3.3.5-1 - Summarized Maintenance Unavailability Data				
CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
AF AV	auxiliary feedwater air-operated valve	9.21e-05	59	640543.50
AF CV	auxiliary feedwater check valve	3.11e-04	399	1281087.00
AF MP	auxiliary feedwater motor-driven pump	1.55e-03	398	256217.40
AF MV	auxiliary feedwater motor-operated valve	1.80e-03	1616	896760.90
AF TP	auxiliary feedwater turbine-driven pump	2.61e-03	167	64054.35
AF XV	auxiliary feedwater manual valve	3.67e-04	1081	2946500.10
CC CV	component cooling water check valve	1.04e-05	6	576489.15
CC MP	component cooling water motor-driven pump	2.03e-04	39	192163.05
CC MV	component cooling water motor-operated valve	3.90e-05	25	640543.50
CC XV	component cooling water manual valve	0.00	0	3651097.95
CS AV	containment spray air-operated valve	1.41e-04	18	128108.70
CS CV	containment spray check valve	0.00	0	384326.10
CS MP	containment spray motor-driven pump	2.34e-03	300	128108.70

Table 3.3.5-1 - Summarized Maintenance Unavailability Data				
CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
CS MV	containment spray motor-operated valve	2.14e-04	137	640543.50
CS TK	containment spray tank	0.00	0	128108.70
CS XV	containment spray manual valve	2.23e-06	3	1345141.35
CV MP	chemical and volume control motor-driven pump	7.63e-03	3423	448380.45
CV RV	chemical and volume control relief valve	4.68e-04	210	448380.45
CV XV	chemical and volume control manual valve	1.42e-06	7	4932184.95
DG DG	diesel generator	1.42e-03	182	128108.70
HV AF	heating, ventilation, and air conditioning air filter	9.68e-04	124	128108.70
HV MC	heating, ventilation, and air conditioning air-operated damper	2.83e-04	943	3330826.20
HV MF	heating, ventilation, and air conditioning motor-driven fan	7.14e-04	2058	2882445.75
IA AM	instrument air air compressor	4.26e-03	1364	320271.75
IA AR	instrument air air receiver	9.37e-05	24	256217.40
IA CV	instrument air 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

Table 3.3.5-1 - Summarized Maintenance Unavailability Data				
CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
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	residual heat removal air-operated valve	2.08e-04	40	192163.05
RH CV	residual heat removal check valve	0.00	0	576489.15
RH HX	residual heat removal heat exchanger	1.01e-04	13	128108.70
RH MP	residual. heat removal motor-driven pump	2.09e-03	268	128108.70
RH MV	residual heat removal motor-operated valve	1.28e-04	148	1152978.30
RH XV	residual heat removal manual valve	0.00	0	1152978.30
SI CV	safety injection check valve	1.13e-05	13	1152978.30
SI MP	safety injection motor-driven pump	2.35e-03	451	192163.05
SI MV	safety injection motor-operated valve	2.31e-04	252	1088923.95
SI XV	safety injection manual valve	0.00	0	832706.55
SW AV	service water air-operated valve	1.99e-05	14	704597.85
SW CV	service water check valve	2.21e-03	850	384326.10

Table 3.3.5-1 - Summarized Maintenance Unavailability Data				
CAFTA Type Code	*Description*	*Mean*	*Total Repair/OOS Hours*	*Total On-Line Hours*
SW MP	service water motor-driven pump	2.48e-02	6355	256217.40
SW MV	service water motor-operated valve	4.97e-04	478	960815.25
SW SV	service water solenoid valve	1.32e-04	127	960815.25
SW XV	service water manual valve	1.17e-05	84	7174087.20

Table 3.3.5-2 - Survey of Periodic Tests Causing Equipment Unavailability					
System	*PT*	*Remarks*	*Test Frequency*	*Test Duration (Source)*	$\bar{a}_T$
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

Table 3.3.5-2 - Survey of Periodic Tests Causing Equipment Unavailability					
System	*PT*	*Remarks*	*Test Frequency*	*Test Duration (Source)*	$\bar{a}_T$
MF Main Feedwater	N/A	There are no PTs which affect this system as modeled.	N/A	N/A	N/A
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 3.3.5-3
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 3.3.5-3
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 3.3.5-3 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 3.3.5-3
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 3.3.5-3 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 3.3.5-3 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		

Table 3.3.5-3 T/M Event Boundaries and Probabilities						
T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
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		
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		

Table 3.3.5-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
		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 3.3.5-3
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 3.3.5-3
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		

Table 3.3.5-3
T/M Event Boundaries and Probabilities

T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
		SW XV	9631A	1.17e-05		
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	2.21e-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 3.3.5-3
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	2.21e-03		
		SW SV	5272	1.32e-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 3.3.5-3
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 3.3.5-3
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 3.3.5-3
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	

Table 3.3.5-3 T/M Event Boundaries and Probabilities						
T/M Event	Description	CAFTA Type Code	EIN	Component Mean	T/M Event Mean	Notes
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	
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.

Table 3.3.5-3
T / M Event Boundaries and Probabilities

Notes (continued)

(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.

3.3.6 Initiator Frequencies

3.3.6.1 Introduction

This section describes the estimation of initiator frequencies for use in the Ginna PRA. 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 (i.e., precursors to ATWS sequences). 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.

Section 3.3.6.2 describes the estimation of each initiator's frequency; related initiators (e.g., LOCAs) have been grouped together for discussion purposes. A list of all initiator frequencies is provided in Section 3.3.6.3; this list constitutes the interface between the data analysis task and the remainder of the PRA with respect to initiator frequency data. Section 3.3.6.4 cites relevant references.

3.3.6.2 General Technical Approach

Estimation of initiator frequencies began with a review of reactor trip history over the data analysis window (January 1, 1980 through December 31, 1988 [Ref. 3.3.6-1]; 7.31 critical years [Ref. 3.3.6-2]) as recorded in the *RCS Transient Validation Report* [Ref. 3.3.6-3], various plant operational records [Refs. 3.3.6-4 and 3.3.6-5], and Licensee Event Reports (LERs). Table 3.3.6-1 lists the individual reactor trips by occurrence date and time, and shows their classification according to the EPRI PWR transient categories [Ref. 3.3.6-6] and the PRA project initiators [Ref. 3.3.6-7, Table 14]. In addition, each event has been matched to associated LERs and Ginna Station Event Reports (A-25.1 forms).

The results provided in Table 3.3.6-1 show that the all reactor trips 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 PRA. In addition, five of the fifteen events (33%) that were classified as TIRXTRIP were attributed to either maintenance or calibration errors, or spurious reactor trip signals (e.g., AMSAC actuation). These events are distributed evenly throughout the data analysis window.

A total of ten reactor trips (38%) were not classified for the purposes of the Ginna PRA 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

[illegible]

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. 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 for the Ginna PRA was a combination of generic and plant-specific experience (incorporated using Bayesian analysis). Table 3.3.6-13 provides a listing of all initiating events included in the Ginna PRA and each initiator's frequency. The determination of these frequencies is described in the following sections.

3.3.6.2.1 TIRXTRIP - Reactor Trip

The frequency of initiator TIRXTRIP has been estimated using Bayesian methods. The prior distribution is based on industry-wide data collected by INEL [Ref. 3.3.6-8], which is an update of earlier work performed by EPRI. Table 3.3.6-10 of the *Initiating Events Work Package* [Ref. 3.3.6-7] lists the types of transients which are included within the boundary of initiator TIRXTRIP; Table 3.3.6-2 relists this information and includes 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:

$$\text{mean} = \frac{\alpha}{\beta} \qquad \text{variance} = \frac{\alpha}{\beta^2} \tag{1}$$

Table 3.3.6-2 shows the estimated parameter values, which have been calculated using Equation (1). Assuming that reactor trip events (n events in T years) follow a Poisson process, then the Bayesian posterior distribution is also a gamma distribution [Ref. 3.3.6-9] with parameters:

$$\alpha' = \alpha + n \qquad \beta' = \beta + T \tag{2}$$

Thus, $\alpha' = 3.16 + 15 = 18.16$ and $\beta' = 0.41 + 7.31 = 7.72$. Using Equation (1), the posterior mean and variance are, respectively, 2.35 and 0.30.

3.3.6.2.2 TIGRLOSP, TISWLOSP, ACLOPRTALL - Loss of Offsite Power

The offsite power scheme for Ginna 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 12A, and (2) Circuit 751 (fed from Station 204) which feeds Station Auxiliary Transformer 12B. The emergency electrical buses (12A and 12B) can be fed from either Station Auxiliary Transformer; the usual alignment is to supply Bus 12A from Station Auxiliary Transformer 12A and Bus 12B from Station Auxiliary Transformer 12B. Failure of either offsite power source results in a loss of one emergency bus side until the respective emergency diesel generator starts; note that a reactor trip will not occur if either offsite power source is lost (loss of Circuit 767 on 4/14/81 resulted in a turbine runback). Based on this discussion, two initiators have been defined to address losses of offsite power (LOSP) for Ginna:

1. TIGRLOSP, which 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:

   a. Transmission network up to, but not including, the breaker connecting RG&E Station 204 to Station Auxiliary Transformer 12A.

   <u>and</u>

   b. Transmission network up to, but not including, Station 13A (the Ginna switchyard).

   It is assumed that loss of the transmission network leads to reactor trip since the Ginna steam dump capacity is only 50% of rated steam flow (i.e., turbine runback is insufficient to prevent reactor trip). This initiator results in an immediate demand for both diesel generators.

2. TISWLOSP, which is defined as a loss of all alternating current electrical power in the Ginna switchyard exclusive of those failures addressed by TIGRLOSP. This event includes failures in the Ginna switchyard which cause an electrical load rejection and failure of Circuit 767 (including Transformer 6). This initiator results in an immediate demand for Diesel Generator 1B.

One additional event related to loss of offsite power is of concern: ACLOPRTALL, which is

[illegible]

[illegible]

defined as a loss of all offsite power following reactor trip. This event is analogous to TIGRLOSP, but may happen following the occurrence of any initiating event. Based on the discussion in WASH-1400 [Ref. 3.3.6-10, Appendix II, p. II-90], a turbine/generator trip may challenge the transient stability of the transmission grid due to the sudden loss of generation. While it is recognized that the Ginna switchyard (feeding Circuit 767) and Station 204 (feeding Circuit 751) are electrically independent from a design viewpoint, it is conservatively assumed that transmission grid instability caused by loss of the Ginna generating capacity will fail both offsite power sources (i.e., partial losses of offsite power following trip are not separately considered).

During the data window, Ginna has not experienced a loss of offsite power as defined by either initiating event, including both on-line and shutdown periods; thus, a Bayesian process has been used to combine U.S. nuclear plant LOSP frequency data with the Ginna experience.

Generic data for development of the prior LOSP initiator frequency distributions was taken from an EPRI database [Ref. 3.3.6-11]. A multi-stage screening process was used to select events from the EPRI database. First, events that occurred outside the data window (1/1/80 to 12/31/88) were excluded. Second, events which did not result in a reactor trip or which occurred during cold shutdown because of special maintenance activities were excluded (all EPRI Category II and IV events). Third, events which resulted in a reactor trip (and, thus, loss of power from the unit auxiliary transformer) but did not involve a loss of power from the startup transformers were excluded. (Most Category III events involved use of diesel generators to provide required electrical power, even if alternative offsite power was available; such events were excluded. Category III events were retained if alternative offsite power was not available.) Fourth, events caused by natural phenomena that is extremely unlikely at the Ginna Site (e.g., hurricanes) were excluded.

Table 3.3.6-3 lists the EPRI database events relevant to Ginna. Each event has been classified as "grid" if it is applicable to initiator TIGRLOSP, and "plant" if it is applicable to initiator TISWLOSP. Considerable engineering judgement was used in LOSP event classification and, thus, the results are uncertain. The major difficulty lies in deciding if a particular event would have failed all offsite power sources had it occurred at Ginna. Events due to single hardware failures (e.g., logic cards, etc.) or human errors were generally classified as "plant"; weather-related events were generally classified as "grid".

The events in the generic LOSP database (Table 3.3.6-1) were assessed using the INEL/EPRI methodology. This approach was taken to ensure consistency with the generic data for other initiators taken from the INEL study. In this approach, only complete calendar years of experience are used; partial years (due to plant commencing commercial operation during the data window) have been excluded. The mean frequency (and its standard deviation) are based on the cumulative experience of the database:

$$\text{CUM MEAN} = \frac{\Sigma\ E_i}{N}$$

$$\text{CUM STD DEV} = \sqrt{\frac{\Sigma\ (E_i\ -\ \text{CUM MEAN})^2}{N-1}} \tag{3}$$

where E_i denotes the number of LOSP events that occurred at a particular site during a particular year. The summations are taken over all plants and all complete years in the data window. Tables 3.3.6-4 and 3.3.6-5 show the inputs and calculated results.

Performing the Bayesian updating for TISWLOSP:

$$\begin{aligned} \alpha' &= 0.024 + 0 = 0.024 \\ \beta' &= 0.894 + 9 = 9.894 \\ \text{mean}' &= \frac{\alpha'}{\beta'} = 2.43\text{E}{-03} \\ \text{var}' &= \frac{\alpha'}{\beta^2} = 2.45\text{E}{-04} \end{aligned} \tag{4}$$

Similarly for TIGRLOSP:

$$\begin{aligned} \alpha' &= 0.0105 + 0 = 0.0105 \\ \beta' &= 0.7845 + 9 = 9.7845 \\ \text{mean}' &= \frac{\alpha'}{\beta'} = 1.07\text{E}{-03} \\ \text{var}' &= \frac{\alpha'}{\beta^2} = 1.10\text{E}{-04} \end{aligned} \tag{5}$$

Note that the Ginna experience is based on no occurrences in nine calendar years.

The EPRI database cannot be used to estimate the probability that offsite power is lost following a reactor trip (event ACLOPRTALL) since it does not record such events. WASH-1400 [Ref. 3.3.6-10] estimates the probability at 1.0E-03. Since this datum does not reflect recent nuclear power plant experience, a log-normal error factor of 15.0 has been assigned for the uncertainty distribution.

The probability of restoring offsite power is based solely on the generic LOSP database since it is not possible to perform a Bayesian update due to lack of Ginna-specific experience. Based on analysis by Iman and Hora [Ref. 3.3.6-12], a Weibull distribution was fit to the offsite power restoration time data in Table 3.3.6-3. Specifically:

$$\Pr\{\text{ not restored by } t\ \} = e^{-(\lambda t)^{\beta}} \tag{6}$$

Application of the maximum likelihood method to a random sample (t_1, t_2,..., t_n) of Weibull-distributed restoration times yields:

$$\lambda = \left[\frac{1}{n}\,\Sigma\, t_i^{\beta}\right]^{-\frac{1}{\beta}}$$

$$\frac{\Sigma\, t_i^{\beta}\ \ln t_i}{\Sigma\, t_i^{\beta}} - \frac{1}{\beta} - \frac{1}{n}\,\Sigma\,\ln t_i = 0 \tag{7}$$

Figure 3.3.6-1 shows the probability that offsite power is not restored as a function of time for switchyard and grid LOSP events, along with the numerically determined values of λ and β.

3.3.6.2.3 TIFWLOSS - Loss of Main Feedwater

The frequency of initiator TIFWLOSS was estimated in the same manner as initiator TIRXTRIP. Table 3.3.6-6 lists the information relevant to development of the prior distribution. The Bayesian posterior mean and variance are, respectively, 1.24E-2 and 1.56E-3.

[illegible]

A digital feedwater control system (ADFCS) was installed at Ginna 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. There were no loss of main 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. However, it is noted that nuclear industry experience indicates that digital control systems are effective in reducing the MFW-related trip frequency. This is significant since NUREG/CR-5622 [Ref. 3.3.6-13] reports that 61% of MFW-related trips are due to problems with feedwater control.

3.3.6.2.4 TIFWEXCS - Excessive Main Feedwater Flow

The frequency initiator TIFWEXCS was estimated in the same manner as initiator TIFWLOSS. Table 3.3.6-7 lists the information relevant to development of the prior distribution. The Bayesian posterior mean and variance are, respectively, 1.98E-2 and 2.59E-3.

Once again, the addition of the ADFCS is not expected to significantly reduce the frequency of excessive main feedwater-related trips since there were none in the observed data window. Consequently, the estimated frequency for TIFWEXCS was not adjusted.

3.3.6.2.5 TIIALOSS - Loss of Instrument Air

NUREG/CR-5472 [Ref. 3.3.6-14] presents the results of an NRC-sponsored review of instrument air systems at nuclear power plants, and recommends using a generic initiating frequency of 9.2E-2/y in any PRA-type analysis. While an uncertainty analysis is not provided, the study notes that 20 years of critical operation without an IA-caused trip is not conclusive evidence that a plant is performing better than 9.2E-2/y. Consequently, a Bayesian update using Ginna experience was not performed even though no IA-initiated reactor trips were observed during the data window. It is noted that NUREG/CR-5472 recommends that credit should be given for recovery of IA in sequences where it is important if this initiator frequency is used. A log-normal error factor of 15.0 is suggested as an appropriate uncertainty distribution.

3.3.6.2.6 Steamline and Feedline Breaks

Estimation of high energy line break[1] frequencies was based upon a review of similar events defined in previous PRAs and safety studies. Table 3.3.6-8 identifies the sources that were reviewed, along with the frequency data that was obtained during the review.

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. Also, the data presented in NUREG/CR-5622 does not specify how many events were actual piping ruptures; assuming that only one event involved a catastrophic rupture, then a reasonable estimate for the overall frequency of feedwater line breaks is about 3.00E-03/y. This value is consistent with the information presented in NUREG/CR-4407 as discussed above. Table 3.3.6-8 suggests that feedwater line breaks occur more often than do steamline breaks. (One possible explanation is that feedwater piping is subject to water hammer effects.) Accordingly, an overall frequency of 5.00E-04/y is a reasonable estimate for the frequency of steamline breaks.

The specific location of a high-energy line break impacts plant safety system response in several ways:

1. Steamline breaks located in the segments of pipe between the steam generators and the MSIVs fail the turbine-driven AFW pump steam supply due to NPSH concerns regardless of whether the break is isolated or not.

2. Feedline breaks located in the segments of pipe downstream of the common discharge from the high pressure feedwater heaters totally fail feedwater flow (MFW, AFW, and SAFW) to one steam generator.

3. 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).

4. 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.

---

[1]The term high energy line break refers to either steamline or feedwater piping ruptures.

5. In general, high-energy line breaks result in SI actuation due to low pressurizer pressure and low steamline pressure; breaks located inside containment also actuate 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, all AFW pumps will start on low steam generator level.)

6. High-energy line breaks inside containment result in CS actuation (see item 4 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 have been defined:

TISLBACT	Steamline Break in Line for S/G A Inside Containment
TISLBBCT	Steamline Break in Line for S/G B Inside Containment
TISLB0TB	Steamline Break in Turbine Building
TISLBAIB	Steamline Break in Line for S/G A Inside Intermediate Building
TISLBBIB	Steamline Break in Line for S/G B Inside Intermediate Building
TI0SLBSD	Steamline Break Through Steam Dump
TISLBSVA	Inadvertent Safety Valve Operation for S/G A
TISLBSVB	Inadvertent Safety Valve Operation for S/G B
TIFLBACT	Feedline Break in Line For S/G A Inside Containment
TIFLBBCT	Feedline Break in Line for S/G B Inside Containment
TI0FLBTB	Feedline Break in Turbine Building
TIFLBAIB	Feedline Break in Line for S/G A Inside Intermediate Building
TIFLBBIB	Feedline Break in Line for S/G B Inside Intermediate Building

Each initiator's frequency has been estimated by (1) partitioning the total steamline break and feedline break frequencies previously presented 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 3.3.6-2 shows the appropriate location of steam and feedwater piping in the reactor, intermediate, and turbine buildings. Based on a review of the relevant general arrangement drawing [Ref. 3.3.6-15], the following relationships were estimated:

1. The length of steamline piping inside containment is the same for both steam headers ($S_{A\text{-}RB} = S_{B\text{-}RB}$).

2. The length of steam header A piping inside containment is the same as the length inside the intermediate building ($S_{A\text{-}RB} = S_{A\text{-}IB}$).

3. 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 ($S_{B\text{-}F} + S_{B\text{-}IB} - 3S_{B\text{-}RB}$).

4. The length of steam header B piping located outdoors is the same as the length inside the intermediate building ($S_{B\text{-}F} = S_{B\text{-}IB}$).

5. Approximately 90% of all steam piping is located within the turbine building.

6. The above relations also apply to feedwater piping.

If f_{MS} denotes the total steamline break frequency, then:

$$\begin{aligned}(1-0.9)\ f_{MS} &= f_{TI00PRSLBA} + f_{TI0PRSLBOA} + f_{TI00PRSLBB} \\ &= f_{B\text{-}F} + f_{TI0PRSLBOB} \\ &= 6\ f_{TI00PRSLBA}\end{aligned} \qquad (8)$$

where $f_{B\text{-}F}$ is the frequency of pipe breaks in the segment of steam header B that is located outside (behind the facade). However, rather than create a separate initiator for pipebreaks located within the facade, this piping was conservatively assumed to be located in the Intermediate Building. Thus:

$$
\begin{aligned}
f_{TI00PRSLBA} = f_{TI00PRSLBB} = f_{TI0PRSLBOA} &= \frac{0.1}{6} \; f_{MS} \\
&= \frac{0.1}{6} \cdot 5.00E\text{-}04/y \\
&= 8.33E\text{-}06/y \\
f_{TI0PRSLBOB} &= 3 \cdot f_{TI00PRSLBA} \\
&= 3 \cdot 8.33E\text{-}06/y \\
&= 2.50E\text{-}05/y \\
f_{TI00PRSLBO} &= 0.9 \; f_{MS} \\
&= 0.9 \cdot 5.00E\text{-}04/y \\
&= 4.50E\text{-}04/y
\end{aligned}
\tag{9}
$$

Initiators TISLBSVA and TISLBSVB address inadvertent steam generator safety valve lift, and are estimated in the same manner as initiator TIRXTRIP. Table 3.3.6-9 lists the information relevant to development of the prior distribution. The Bayesian posterior mean and variance respectively, 1.51E-03 and 1.91E-04. Assuming inadvertent safety valve lift is equally likely in either steam heater, then

$$
\begin{aligned}
f_{TIPRSLBSVA} = f_{TIPRSLBSVB} &= \frac{1}{2} \cdot 1.51E\text{-}03/y \\
&= 7.55E\text{-}04/y
\end{aligned}
\tag{10}
$$

Initiator TI0SLBSD 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. 3.3.6-9, p. 239] 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:

1. The ratio of the 95th percentile to the 5th percentile is 100.0.

2. 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:

$$\begin{aligned} \alpha &= 0.84 \\ \beta &= 132.29 \\ \text{5th percentile} &= 2.02E{-04} \\ \text{95th percentile} &= 2.02E{-02} \\ \text{mean} &= 6.35E{-03} \\ \text{variance} &= 4.80E{-05} \end{aligned} \tag{11}$$

Performing the Bayesian update using Equations (2) and (1), the posterior mean and variance are, respectively, 6.02E-03 and 4.31E-05.

For feedline breaks, relations among the relative frequencies exist similar to those for steamline breaks:

$$\begin{aligned} f_{T10MFWLBAI} = f_{T10MFWLBBI} = f_{T10MFWLBAO} &= \frac{0.1}{6} \cdot f_{FW} \\ &= \frac{0.1}{6} \cdot 3.00E{-03}/y \\ &= 5.00E{-05}/y \\ f_{T10MFWLBBO} &= 3 \cdot f_{T10MFWLBAI} \\ &= 3 \cdot 5.00E{-05}/y \\ &= 1.50E{-04}/y \\ f_{T100MFWLBO} &= 0.9\ f_{FW} \\ &= 0.9 \cdot 3.00E{-03}/y \\ &= 2.70E{-03}/y \end{aligned} \tag{12}$$

A log-normal uncertainty distribution (error factor = 15.0) is suggested for all high-energy line break initiators.

3.3.6.2.7 Loss of Coolant Accidents

The Electric Power Research Institute (EPRI) has recently formulated a new methodology [Ref. 3.3.6-34] 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 3.3.6-10 shows the parameter values determined in the EPRI report (all values are shown in Table 4.4-2 of Ref. 3.3.6-34, except for the pipe segment counts which are shown in Table 307 of Ref. 3.3.6-34). Substituting in the above equations for these values yields:

Z_l = (2.9E-10 / h) * (1.4) * (7 / 15) * (109)

= 2.1E-08 / h = 1.8E-04 / y

[illegible] [illegible]

Z_m = (2.9E-10 / h) * [(0.6) * (9 / 10) * (195) + (1.4) * (1 / 3) * (109)]

= (4.5E-08 / h = 4.0E-04 / y

Z_s = (2.9E-10 / h) * [(1.2) * (339) + (0.6) * (1 / 10) * (195) + (1.4) * (1 / 5) * (109)]

= 1.3E-07 / h = 1.1E-03 / y

The LOCA sizes used in the Ginna PRA generally match the EPRI data ranges; uncertainty in establishing the Ginna 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 PRA. Thus:

$$f\,(LLOCA) = 1.8\text{E-04 / y}$$

$$f\,(MLOCA) = 4.0\text{E-04 / y}$$

$$f\,(SLOCA) + f\,(SSLOCA) \doteq 1.1\text{E-03 / y}$$

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. Accordingly, it was decided to use simple split fractions of 1/3 for small LOCAs and 2/3 for small-small LOCAs. Therefore,

f (SLOCA) = (1 /3) * (1.1E-03 / y) = 3.7E-04 / y

f (SSLOCA) = (2 /3) * (1.1E-03 / y) = 7.3E-04 / y

The data in Table 3.3.6-10 does not apply to reactor vessel rupture (LIRVRUPT). The NUREG-1150 studies of Surry [Ref. 3.3.6-16] and Sequoyah [Ref. 3.3.6-17] estimated that the core-damage frequency due to reactor vessel ruptures was on the order of 10^{-8}/y. 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. 3.3.5-18].

Reactor vessel failure may occur due to brittle fracture during severe overcooling transients. Three conditions must exist in order to cause brittle fracture:

1. The reactor vessel materials must be at low temperature and be susceptible to brittle fracture.

2. A flaw (crack or notch) must be present, and

3. A tensile stress of sufficient magnitude must exist.

Conditions 1 and 3 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 depressurization since SI flow will exceed the LOCA break flow and the rate of coolant shrinkage during steamline break events. Condition 2 is always possible since reactor vessel inspection techniques cannot detect flaws below about 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, 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 10^{-8}/y for an RT_{PTS} value of 270 °F. 10CFR50.61 establishes the following screening criteria for the RT_{PTS} of reactor beltline materials:

1. 270 °F for plates, forgings, and axial weld materials

2. 300 °F for circumferential weld materials

Plant-specific evaluations for Ginna [Ref. 3.3.6-19] indicate the RT_{PTS} values will remain below these criteria throughout the expected operating lifetime of the unit. 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 10^{-8}/y.

Table 3.3.6-11 lists the final Ginna LOCA frequencies. A log-normal distribution (ef = 15.0) is recommended as an appropriate uncertainty distribution.

3.3.6.2.8 LIOSGTRn - Steam Generator Tube Rupture

Adams and Sattison [Ref. 3.3.6-20] report a total of five (5) single steam generator tube rupture 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 on 1/25/82 in the "B" steam generator; this event and thirteen reactor years

were removed from consideration during development of the Bayesian prior distribution to prevent "double counting". Specifically, the generic mean was assumed to be 8E-3/y for the entire plant, and 4E-3/y for a single steam generator. Using the Martz and Waller method to develop a gamma prior distribution (see Section 2.6), the following values were determined:

$$\begin{aligned} \alpha &= 0.84 \\ \beta &= 210 \\ \text{5th percentile} &= 1.27E{-}04 \\ \text{95th percentile} &= 1.27E{-}02 \\ \text{mean} &= 4.00E{-}03 \\ \text{variance} &= 1.90E{-}05 \end{aligned} \qquad (13)$$

Performing the Bayesian update using Equations (2) and (1), the posterior mean and variance are, respectively, 3.77E-03 and 1.69E-05 for the "A" steam generator. For the "B" steam generator, the posterior mean and variance are, respectively, 8.25E-03 and 3.70E-05.

3.3.6.2.9 TIOOSWA, TI000SWB - Loss of Service Water

Initiators TI000SWA and TI000SWB refer to a total loss of service water from safety-related 20" headers A or B, respectively. Ginna has experienced two precursor events to a total loss of service water 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. 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 service water since adequate flow will pass under the ice dam for some time.

Lam and Rosenthal [Ref. 3.3.6-21] report the frequency of complete loss of service water to be 1.8E-02/reactor year. Using the Marty and Waller method to develop a gamma prior distribution (see Section 2.6), the following values were determined:

$$
\begin{aligned}
\alpha &= 0.84 \\
\beta &= 46.7 \\
\text{5th percentile} &= 5.72E{-}04 \\
\text{95th percentile} &= 2.72E{-}02 \\
\text{mean} &= 1.80E{-}02
\end{aligned}
\tag{14}
$$

Performing the Bayesian update using Equations (2) and (11), the posterior mean and variance are, respectively, 1.52E-02 and 2.88E-04.

3.3.6.2.10 TI000CCW - Loss of Component Cooling Water

The frequency of initiator TI000CCW was estimated in the same manner as initiator TIRXTRIP. Table 3.3.6-12 lists information relevant to development of the prior distribution. The Bayesian posterior mean and variance are, respectively, 2.20E-03 and 2.68E-04.

3.3.6.2.11 TI0ACBUSnn - Loss of 480V Buses

Plant-specific experience for 480V bus failures is discussed and assessed using a Bayesian update in the Plant Specific Data Work Package [Ref. 3.3.6-22]. Accordingly, the frequency of initiator TI0ACBUSnn has been estimated by converting the hourly failure rate into an annual frequency as follows:

$$
\begin{aligned}
\text{frequency} &= \text{failure rate} \times \text{fraction of time spent in Mode 1} \times 8760\ h/y \\
&= 7.84E{-}07 \times \frac{7.31}{9} \times 8760 \\
&= 5.58E{-}03
\end{aligned}
\tag{15}
$$

It is noted that none of the observed failures in the plant-specific data resulted in a reactor trip.

3.3.6.2.12 TI000DCn - Loss of DC Buses

Plant-specific experience for DC bus failures is discussed and assessed using a Bayesian update in the Plant Specific Data Work Package [Ref. 3.3.6-33]. Accordingly, the frequency of initiator TI000DCn has been estimated by converting the hourly failure rate into an annual frequency as follows:

$$\begin{aligned} \text{frequency} &= \text{failure rate} \times \text{fraction of time spent in Mode 1} \times 8760\ h/y \\ &= 2.41E{-}08 \times \frac{7.31}{9} \times 8760 \qquad (16) \\ &= 1.71E{-}04 \end{aligned}$$

It is noted that none of the observed failures in the plant-specific data resulted in a reactor trip.

3.3.6.3 Results

Table 3.3.6-13 summarizes the Ginna PRA initiator frequencies, and also provides uncertainty distribution information.

3.3.6.4 References

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Table 3.3.6-1 R. E. GINNA REACTOR TRIP HISTORY (1/1/80 - 12/31/88)							
Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*[a]	*PRA 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	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	1, 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	1, 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	1, A-25.1	
18 JAN 83	0246	5	Automatic reactor trip during startup due to low level in S/G B.	21	n/a	1, A-25.1	2
18 JUN 83	?	25	Automatic reactor trip caused by failed Intermediate Range instrumentation during startup.	39	TIRXTRIP	1	
20 JUN 83	0013	20	Automatic reactor trip during startup due to low feedwater flow to S/G A.	21	n/a	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	1, 83-027-00	2
30 MAY 84	2221	83	Automatic reactor trip following failure of generator excitor.	34	TIRXTRIP	1, 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	1, A-25.1, 85-006-00	

Table 3.3.6-1 R. E. GINNA REACTOR TRIP HISTORY (1/1/80 - 12/31/88)							
Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*(a)	*PRA 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	1, 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	1, 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	1, 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	1, 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	1, 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	1, 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	1, 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	1, A-25.1, 86-004-00	3
30 JUL 86	1855	25	Automatic reactor trip due to faulty relays in the Intermediate Range blocking circuitry.	39	TIRXTRIP	1, A-25.1, 86-005-00	

Table 3.3.6-1 R. E. GINNA REACTOR TRIP HISTORY (1/1/80 - 12/31/88)							
Date	*Time*	*Initial Power Level*	*Description*	*EPRI PWR Category*[a]	*PRA 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	1, 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	1, 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	2, 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	1, 2, 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	1, 2, 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	2, A-25.1	

Table 3.3.6-1
R. E. GINNA REACTOR TRIP HISTORY (1/1/80 - 12/31/88)

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 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 PRA 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 PRA 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 PRA initiator category was assigned to this steam line break since it was small and did not result in an automatic reactor trip.

Table 3.3.6-2 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	0.01	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
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
24	Loss of condensate pumps (all loops)	0.01	0.10	0.0100
25	Loss of condenser vacuum	0.14	0.43	0.1849
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 3.3.6-2
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
37	Loss of power to necessary plant systems	0.11	0.40	0.1600
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	7.70		18.6256
		α	3.16	
		β	0.41	

Table 3.3.6-3
U.S. NUCLEAR PLANT LOSP EVENTS RELEVANT TO GINNA
(1/1/80 TO 12/31/88)

PLANT	DATE	DURATION (H:M)	TYPE	CAUSE
Calvert Cliffs 1 & 2	07/23/87	01:58	plant	one transmission line contacted a tree; defective logic card lead to loss of other transmission line
Diablo Canyon 2	07/17/88	00:38	plant	short to ground in 12 kV connection to RCP propagated to loss of both startup transformers
Dresden 2	08/16/85	00:05	plant	failure to automatically isolate fault in main transformer
Farley 2	10/08/83	02:45	plant	failure in 230 kV switchyard breaker
Fort St. Vrain	05/17/83	01:45	grid	snow and wind
Fort St. Vrain	04/03/86	unknown	plant	storm (did not fail all offsite power sources)
Indian Pt. 2	06/03/80	01:45	plant	lightning bolt failed a shield wire, which fell across all incoming transmission lines (not credible as a "grid" event for Ginna layout)
McGuire 1	08/21/84	00:20	plant	human error during testing and maintenance of switchyard computer and control circuitry
Palisades	07/14/87	07:26	plant	human error during maintenance activities lead to inadvertent actuation of fire protection system
Palo Verde 1	10/03/85	00:24	grid	multiplexer malfunction
Pilgrim	11/19/86	unknown	grid	storm
Pilgrim	03/31/87	unknown	grid	rainstorm
Pilgrim	11/12/87	11:00	grid	snow and ice
Prairie Island 1 & 2	07/15/80	01:02	grid	electrical storm
River Bend	01/01/86	00:46	plant	malfunction of a switchyard protective system
San Onofre 1	11/22/80	00:01	plant	incorrect alignment during switching
San Onofre 1	11/21/85	00:04	plant	short in 4.16 kV ESF bus lead to loss of one auxiliary transformer and manual reactor trip
Turkey Point 3 & 4	02/12/84	00:15	plant	spurious actuation of differential relay
Turkey Point 3	02/16/84	00:15	plant	inadvertent jarring of a relay on a cubical door

Table 3.3.6-3
U.S. NUCLEAR PLANT LOSP EVENTS RELEVANT TO GINNA
(1/1/80 TO 12/31/88)

PLANT	DATE	DURATION (H:M)	TYPE	CAUSE
Turkey Point 3 & 4	05/17/85	2:05	grid	offsite fire under transmission lines
WNP 2	01/31/85	unknown	plant	auxiliary relay vibration caused reactor trip without turbine generator trip

Table 3.3.6-4
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TISWLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
ANO	May-74	0	0	0	0	0	0	0	0	0
Arnold	Feb-74	0	0	0	0	0	0	0	0	0
Beaver Valley	Jan-76	0	0	0	0	0	0	0	0	0
Big Rock Point	Jan-76	0	0	0	0	0	0	0	0	0
Braidwood	Oct-86								0	0
Browns Ferry	Jun-73	0	0	0	0	0	0	0	0	0
Brunswick	Dec-74	0	0	0	0	0	0	0	0	0
Byron	Oct-84						0	0	0	0
Callaway	Jun-84						0	0	0	0
Calvert Cliffs	Jul-74	0	0	0	0	0	0	0	1	0
Catawba	Jul-84						0	0	0	0
Clinton	Sep-86								0	0
Connecticut Yankee	Jan-68	0	0	0	0	0	0	0	0	0
Cook	Oct-74	0	0	0	0	0	0	0	0	0
Cooper	Jan-74	0	0	0	0	0	0	0	0	0
Crystal River	Dec-76	0	0	0	0	0	0	0	0	0
Davis-Besse	Apr-77	0	0	0	0	0	0	0	0	0
Diablo Canyon	Apr-84						0	0	0	1
Dresden	Oct-59	0	0	0	0	0	1	0	0	0
Farley	Jun-77	0	0	0	1	0	0	0	0	0
Fermi	Mar-85							0	0	0
FitzPatrick	Oct-74	0	0	0	0	0	0	0	0	0
Ft. Calhoun	Dec-73	0	0	0	0	0	0	0	0	0
Ft. St. Vrain	Dec-73	0	0	0	0	0	0	1	0	0
Ginna	Sep-69	0	0	0	0	0	0	0	0	0
Grand Gulf	Jun-82				0	0	0	0	0	0
Harris	Oct-86								0	0
Hatch	Aug-74	0	0	0	0	0	0	0	0	0
Hope Creek	Apr-86								0	0
Indian Point 2	Oct-71	1	0	0	0	0	0	0	0	0
Indian Point 3	Oct-71	0	0	0	0	0	0	0	0	0
Kewaunee	Dec-73	0	0	0	0	0	0	0	0	0
La Salle	Apr-82				0	0	0	0	0	0
Limerick	Oct-84						0	0	0	0

Table 3.3.6-4
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TISWLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
Maine Yankee	Sep-72	0	0	0	0	0	0	0	0	0
McGuire	Jan-81			0	0	1	0	0	0	0
Millstone	Oct-70	0	0	0	0	0	0	0	0	0
Monticello	Jan-71	0	0	0	0	0	0	0	0	0
Nine Mile Point	Sep-69	0	0	0	0	0	0	0	0	0
North Anna	Nov-77	0	0	0	0	0	0	0	0	0
Oconee	Feb-73	0	0	0	0	0	0	0	0	0
Oyster Creek	Apr-69	0	0	0	0	0	0	0	0	0
Palisades	Mar-71	0	0	0	0	0	0	0	1	0
Palo Verde	Dec-84						0	0	0	0
Peach Bottom	Aug-73	0	0	0	0	0	0	0	0	0
Perry	Mar-86								0	0
Pilgrim	Jun-72	0	0	0	0	0	0	0	0	0
Point Beach	Oct-70	0	0	0	0	0	0	0	0	0
Prairie Island	Aug-73	0	0	0	0	0	0	0	0	0
Quad Cities	Oct-71	0	0	0	0	0	0	0	0	0
Rancho Seco	Aug-74	0	0	0	0	0	0	0	0	0
River Bend	Aug-85							1	0	0
Robinson	Jul-70	0	0	0	0	0	0	0	0	0
Salem	Aug-76	0	0	0	0	0	0	0	0	0
San Onofre	Mar-67	1	0	0	0	0	1	0	0	0
Seabrook	Oct-86								0	0
Sequoyah	Oct-80		0	0	0	0	0	0	0	0
Shoreham	Dec-84						0	0	0	0
South Texas	Aug-87									0
St. Lucie	Mar-76	0	0	0	0	0	0	0	0	0
Summer	Aug-82				0	0	0	0	0	0
Surry	May-72	0	0	0	0	0	0	0	0	0
Susquehanna	Jul-82				0	0	0	0	0	0
Three Mile Island	May-74	0	0	0	0	0	0	0	0	0
Trojan	Nov-75	0	0	0	0	0	0	0	0	0
Turkey Point	Jul-72	0	0	0	0	2	0	0	0	0
Vermont Yankee	Mar-72	0	0	0	0	0	0	0	0	0
Vogtle	Jan-87									0
Waterford	Dec-84						0	0	0	0

Table 3.3.6-4
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TISWLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
WNP	Dec-83					0	1	0	0	0
Wolf Creek	Mar-85							0	0	0
Yankee Rowe	Jun-61	0	0	0	0	0	0	0	0	0
Zion	Apr-73	0	0	0	0	0	0	0	0	0
TOTAL EVENTS		2	0	0	1	3	3	2	2	1
PLANT YEARS		47	48	49	53	54	62	65	71	73
MEAN		0.0426	0	0	0.0189	0.0556	0.0484	0.0308	0.0282	0.0137
STD DEV		0.204	0	0	0.1374	0.302	0.2163	0.174	0.1666	0.117
CUM MEAN		0.0426	0.0211	0.0139	0.0152	0.0239	0.0288	0.0291	0.029	0.027
CUM STD DEV		0.204	0.1443	0.1174	0.1228	0.1773	0.1885	0.1834	0.1807	0.173

alpha 0.024

beta 0.894

[illegible]

[illegible]

Table 3.3.6-5
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TIGRLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
ANO	May-74	0	0	0	0	0	0	0	0	0
Arnold	Feb-74	0	0	0	0	0	0	0	0	0
Beaver Valley	Jan-76	0	0	0	0	0	0	0	0	0
Big Rock Point	Jan-76	0	0	0	0	0	0	0	0	0
Braidwood	Oct-86								0	0
Browns Ferry	Jun-73	0	0	0	0	0	0	0	0	0
Brunswick	Dec-74	0	0	0	0	0	0	0	0	0
Byron	Oct-84						0	0	0	0
Callaway	Jun-84						0	0	0	0
Calvert Cliffs	Jul-74	0	0	0	0	0	0	0	0	0
Catawba	Jul-84						0	0	0	0
Clinton	Sep-86								0	0
Connecticut Yankee	Jan-68	0	0	0	0	0	0	0	0	0
Cook	Oct-74	0	0	0	0	0	0	0	0	0
Cooper	Jan-74	0	0	0	0	0	0	0	0	0
Crystal River	Dec-76	0	0	0	0	0	0	0	0	0
Davis-Besse	Apr-77	0	0	0	0	0	0	0	0	0
Diablo Canyon	Apr-84						0	0	0	0
Dresden	Oct-59	0	0	0	0	0	0	0	0	0
Farley	Jun-77	0	0	0	0	0	0	0	0	0
Fermi	Mar-85							0	0	0
FitzPatrick	Oct-74	0	0	0	0	0	0	0	0	0
Ft. Calhoun	Dec-73	0	0	0	0	0	0	0	0	0
Ft. St. Vrain	Dec-73	0	0	0	1	0	0	0	0	0
Ginna	Sep-69	0	0	0	0	0	0	0	0	0
Grand Gulf	Jun-82				0	0	0	0	0	0
Harris	Oct-86								0	0
Hatch	Aug-74	0	0	0	0	0	0	0	0	0
Hope Creek	Apr-86								0	0
Indian Point 2	Oct-71	0	0	0	0	0	0	0	0	0
Indian Point 3	Oct-71	0	0	0	0	0	0	0	0	0
Kewaunee	Dec-73	0	0	0	0	0	0	0	0	0
La Salle	Apr-82				0	0	0	0	0	0
Limerick	Oct-84						0	0	0	0

Table 3.3.6-5
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TIGRLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
Maine Yankee	Sep-72	0	0	0	0	0	0	0	0	0
McGuire	Jan-81			0	0	0	0	0	0	0
Millstone	Oct-70	0	0	0	0	0	0	0	0	0
Monticello	Jan-71	0	0	0	0	0	0	0	0	0
Nine Mile Point	Sep-69	0	0	0	0	0	0	0	0	0
North Anna	Nov-77	0	0	0	0	0	0	0	0	0
Oconee	Feb-73	0	0	0	0	0	0	0	0	0
Oyster Creek	Apr-69	0	0	0	0	0	0	0	0	0
Palisades	Mar-71	0	0	0	0	0	0	0	0	0
Palo Verde	Dec-84						1	0	0	0
Peach Bottom	Aug-73	0	0	0	0	0	0	0	0	0
Perry	Mar-86								0	0
Pilgrim	Jun-72	0	0	0	0	0	0	1	2	0
Point Beach	Oct-70	0	0	0	0	0	0	0	0	0
Prairie Island	Aug-73	1	0	0	0	0	0	0	0	0
Quad Cities	Oct-71	0	0	0	0	0	0	0	0	0
Rancho Seco	Aug-74	0	0	0	0	0	0	0	0	0
River Bend	Aug-85							0	0	0
Robinson	Jul-70	0	0	0	0	0	0	0	0	0
Salem	Aug-76	0	0	0	0	0	0	0	0	0
San Onofre	Mar-67	0	0	0	0	0	0	0	0	0
Seabrook	Oct-86								0	0
Sequoyah	Oct-80		0	0	0	0	0	0	0	0
Shoreham	Dec-84						0	0	0	0
South Texas	Aug-87									0
St. Lucie	Mar-76	0	0	0	0	0	0	0	0	0
Summer	Aug-82				0	0	0	0	0	0
Surry	May-72	0	0	0	0	0	0	0	0	0
Susquehanna	Jul-82				0	0	0	0	0	0
Three Mile Island	May-74	0	0	0	0	0	0	0	0	0
Trojan	Nov-75	0	0	0	0	0	0	0	0	0
Turkey Point	Jul-72	0	0	0	0	0	1	0	0	0
Vermont Yankee	Mar-72	0	0	0	0	0	0	0	0	0
Vogtle	Jan-87									0
Waterford	Dec-84						0	0	0	0

Table 3.3.6-5
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TIGRLOSP

PLANT	DATE	1980	1981	1982	1983	1984	1985	1986	1987	1988
WNP	Dec-83					0	0	0	0	0
Wolf Creek	Mar-85							0	0	0
Yankee Rowe	Jun-61	0	0	0	0	0	0	0	0	0
Zion	Apr-73	0	0	0	0	0	0	0	0	0
TOTAL EVENTS		1	0	0	1	0	2	1	2	0
PLANT YEARS		47	48	49	53	54	62	65	71	73
MEAN		0.0213	0	0	0.0189	0	0.0323	0.0154	0.0282	0
STD DEV		0.1459	0	0	0.1374	0	0.1781	0.124	0.2374	0
CUM MEAN		0.0213	0.0105	0.0069	0.008	0.0128	0.013	0.0132	0.0156	0.013
CUM STD DEV		0.21459	0.1026	0.0883	0.1005	0.0891	0.1125	0.1144	0.1409	0.131

alpha 0.0105

beta 0.7845

Table 3.3.6-6
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
	TOTAL	0.16		0.26
		α	0.098	
		β	0.62	

Table 3.3.6-7
DEVELOPMENT OF PRIOR DISTRIBUTION FOR TIFWEXCS - EXCESSIVE MAIN FEEDWATER FLOW

EPRI PWR Category	*Description*	*Average Frequency (/y)*	*Standard Deviation*	*Variance*
19	Increase in feedwater flow (1 loop)	0.44	1.17	1.37
20	Increase in feedwater flow (all loops)	0.02	0.18	0.03
	TOTAL	0.46		1.40
		α	0.151	
		β	0.329	

Table 3.3.6-8 HIGH ENERGY LINE BREAK FREQUENCIES USED IN PREVIOUS PRAs		
Source	*Description*	*Frequency (/y)*
NUREG/CR-4407 [Ref. 3.3.6-23]	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 [Ref. 3.3.6-13]	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
NUREG/CR-4550 analysis of Zion [Ref. 3.3.6-24]	steamline break	1.90E-03

Table 3.3.6-9 DEVELOPMENT OF PRIOR DISTRIBUTION FOR INADVERTENT STEAM GENERATOR SAFETY VALVE 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	

[illegible]

[illegible]

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[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

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[illegible]

Table 3.3.6-10
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 3.3.6-11 LOCA FREQUENCIES		
Initiator	Break Size	Mean Yearly Frequency
LISSLOCA	0" - 1"	7.30E-04
LISBLOCA	1" - 1.5"	3.70E-04
LIMBLOCA	1.5" - 5.5"	4.00E-04
LILBLOCA	> 5.5"	1.80E-04
LIRVRUPT	reactor vessel rupture	< 1.00E-08

Table 3.3.6-12
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 3.3.6-13
Final Ginna PRA Initiator Frequencies

Description	*Designator*	*Frequency*
Reactor Trip	TIRXTRIP	2.35
Loss Of Off-Site Power - grid	TIGRLOSP	2.43E-03
Loss Of Off-Site Power - Switchyard	TISWLOSP	1.07E-03
Loss of Main Feedwater	TIFWLOSS	1.24E-02
Feedwater Line Break In Line For SG A Inside Containment	TIFLBACT	5.00E-05
Feedwater Line Break In Line For SG B Inside Containment	TIFLBBCT	5.00E-05
Feedwater Line Break In Turbine Building	TI0FLBTB	2.70E-03
Feedwater Line Break In Line For SG A Inside Intermediate Building	TIFLBAIB	5.00E-05
Feedwater Line Break In Line For SG B Inside Intermediate Building	TIFLBBIB	1.50E-04
Excessive Feedwater	TIFWEXCS	1.98E-02
Steam Line Break In Line For SG A Inside Containment	TISLBACT	8.33E-06
Steam Line Break In Line For SG B Inside Containment	TISLBBCT	8.33E-06
Steam Line Break In Turbine Building	TISLB0TB	4.50E-04
Steam Line Break In Line For SG A Inside Intermediate Building	TISLBAIB	8.33E-06
Steam Line Break In Line For SG B Inside Intermediate Building	TISLBBIB	2.50E-05
Steam Line Break Through The Steam Dump System	TI0SLBSD	6.02E-03
Inadvertent Safety Valve Operation On SG A	TISLBSVA	7.55E-04
Inadvertent Safety Valve Operation (Or Exterior SLB) On SG B	TISLBSVB	7.55E-04
Loss of Instrument Air	TIIALOSS	9.20E-02
Reactor Vessel Rupture	LIRVRUPT	1.00E-08
Large LOCA	LILBLOCA	1.80E-04
Medium LOCA	LIMBLOCA	4.00E-04
Small LOCA	LISBLOCA	3.70E-04
Small-Small LOCA	LISSLOCA	7.30E-04
Steam Generator Tube Rupture In SG A	LI0SGTRA	3.77E-03
Steam Generator Tube Rupture In SG B	LI0SGTRB	8.25E-03
Loss Of Service Water Safety-Related Header A	TI000SWA	1.78E-03
Loss Of Service Water Safety-Related Header B	TI000SWB	1.78E-03
Loss Of Component Cooling Water	TI000CCW	2.20E-03
Loss Of Main DC Distribution Panel A (DCPDPCB03A)	TI000DCA	1.71E-04
Loss Of Main DC Distribution Panel B (DCPDPCB03B)	TI000DCB	1.71E-04

Figure 3.3.6-1
Off-Site Power Restoration Probability

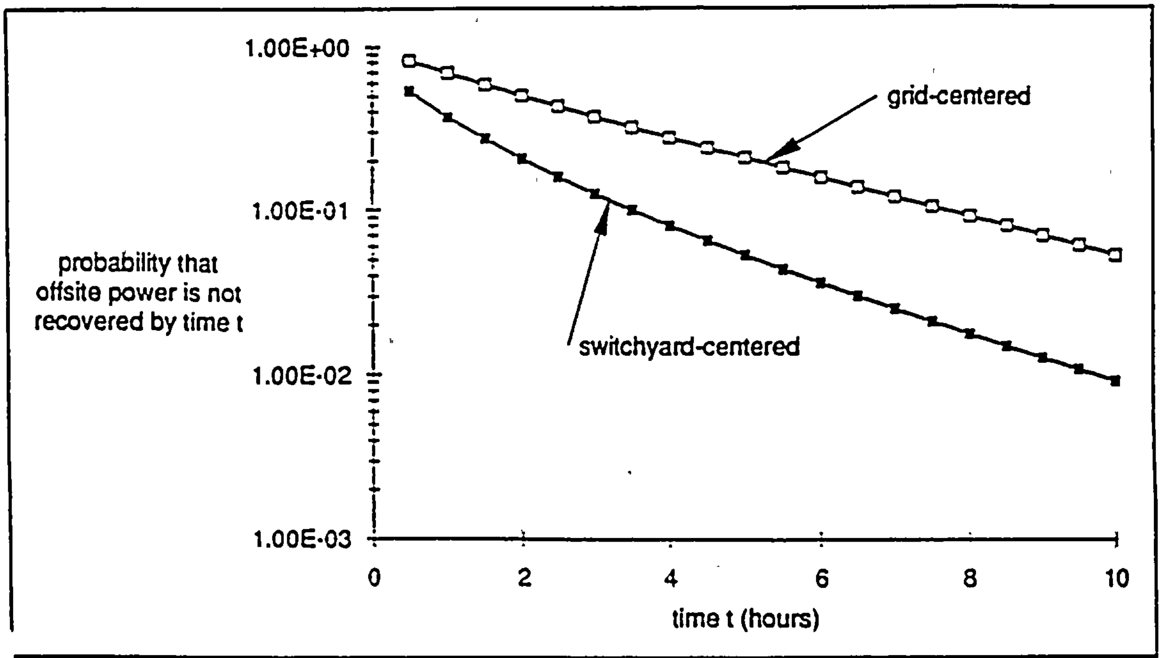
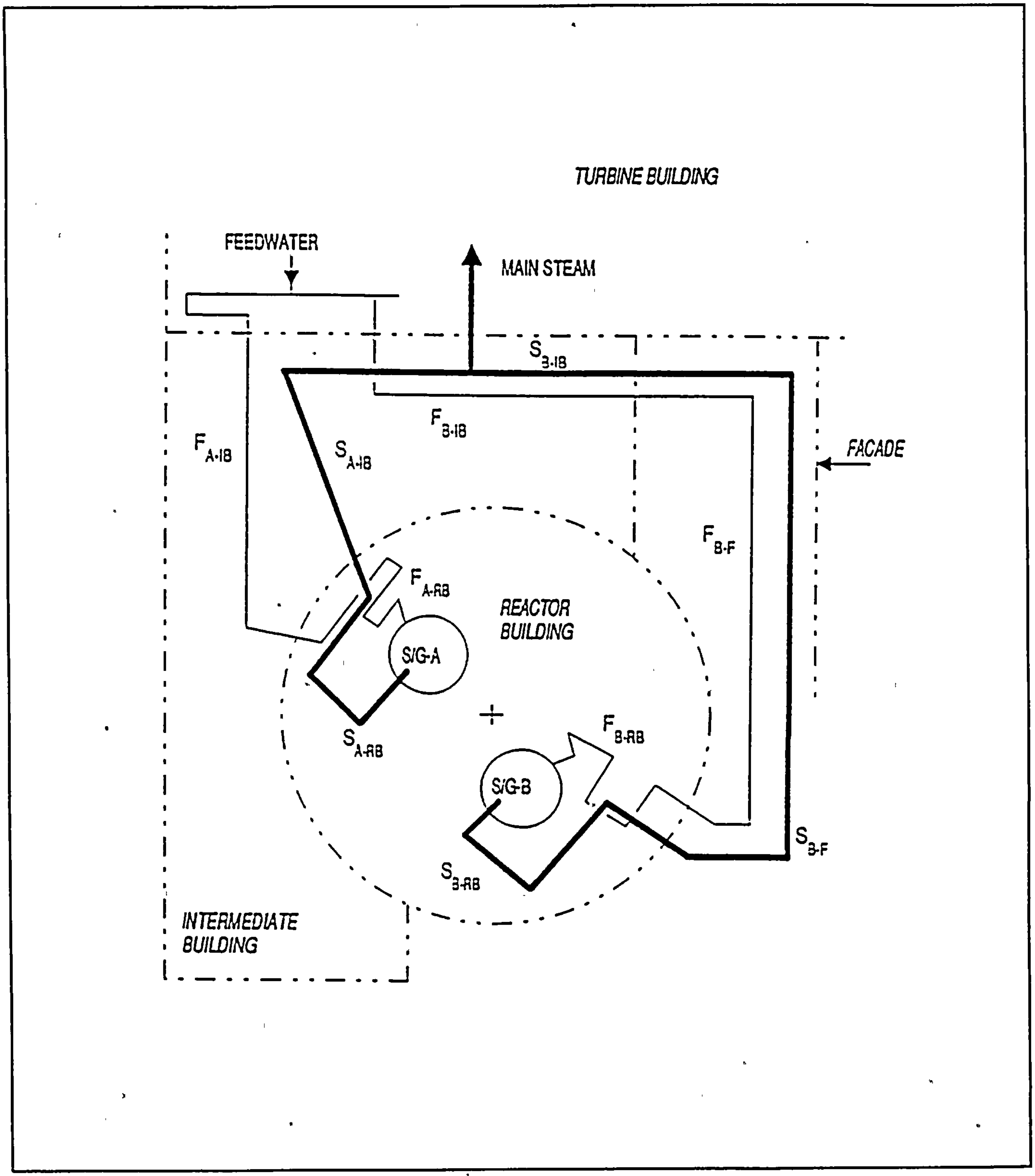


Figure 3.3.6-2
High-Energy Line Piping Arrangement



3.3.7 Quantification of Sequence Frequencies

3.3.7.1 Quantification Inputs

The first step in the quantification process is the collection of three basic types of logic models and their associated data sets:

1. Accident sequence models;

2. Top logic models; and

3. Systems fault tree models.

The computerized models used as inputs to this task are listed in Table 3.3.7-1.

3.3.7.2 Model Integration

The individual logic models and databases shown in Table 3.3.7-1 were combined into an integrated plant model. This model is made up of four computer files:

1. The CAFTA fault tree file GINNA.CAF;

2. The CAFTA basic event database file GINNA.BE;

3. The CAFTA type code database file GINNA.TC; and

4. The CAFTA gate definition database file GINNA.GT.

A fifth file, the CAFTA module definition file GINNA.CUT, was created from this assembled integrated model by using the CAFTA fault tree editor's EVALUATE / MODULES ONLY option.

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The individual computer files shown in Table 3.3.7-1 that are used to build the master integrated plant model are subject to quality assurance control. These models, and not the integrated model, are maintained as the living Ginna plant model. Thus, all changes, modifications and/or corrections made under the relevant quality assurance procedures are incorporated directly into the individual computer model files. The integrated plant model is created on-line immediately before each quantification session through the use of the batch file MAKE_INT.BAT and the CAFTA macro files INTBE.MAC, INTGT.MAC, INTCAF.MAC, INTMOD.MAC, and INTLOAD.MAC. The flow chart in Figure 3.3.7-1 describes this integration process.

3.3.7.3 Model Solution

After creating the integrated Ginna PRA model, minimal cut sets were determined for each core damage accident sequence. The generation of sequence cut sets was a three-step process:

1. Logic flags were set to configure the integrated model for the initial plant systems operating alignment and for the specific sequence being solved;

2. The CAFTA work station was used to generate sequence-specific cut sets; and

3. Generated cut sets were identified and removed to eliminate mutually exclusive events and to satisfy sequence logic involving success paths as dictated by the event trees.

The following sections describe the logic flag settings used; provide the rationale for setting the solution truncation limit; describe the process used to identify and eliminate mutually exclusive events; describe the process used to eliminate cut sets which do not satisfy the sequence logic; and discuss the automated CAFTA computer solution process used to implement the overall quantification scheme.

3.3.7.3.1 Logic Flags

Various logic flags (so-called house events) have been incorporated into the Ginna PRA logic models. A logic flag is not a true basic event, as it does not have an associated probability; rather, a logic flag is set to either TRUE or FALSE (in the Boolean sense) depending on the desired outcome. Ginna PRA logic flags are of two types:

1. **Configuration logic flags.** These flags are used to set allowable 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. Use of this type of flag will allow the Ginna PRA models to be used for future studies of system train alignments; and

2. **Sequence logic flags.** These flags are used to properly configure the integrated model for each accident sequence solution.

Configuration logic flags are used to set the assumed initial operating configuration of multiple-train systems. A good example of the use of configuration logic flags may be found in the Ginna PRA Service Water System model [Ref. 3.3.7-14]. The Ginna Service Water System is equipped with four service water pumps. A typical operating configuration was assumed for the start of this analysis; that is, service water pumps PSW01A and PSW01D were assumed to be operating, and service water pumps PSW01B and PSW01C were assumed to be in standby. This assumption is carried out by setting configuration logic flags AAAASWP1AR (Service Water Pump PSW01A Is In Operation), AAASWP1DR (Service Water Pump PSW01D Is In Operation), AAAASWP1BS (Service Water Pump PSW01B Is Selected In Standby), and AAASWP1CS (Service Water Pump PSW01C Is Selected In Standby) to TRUE and configuration logic flags AAAASWP1AS (Service Water Pump PSW01A Is Selected In Standby), AAASWP1DS (Service Water Pump PSW01D Is Selected In Standby), AAAASWP1BR (Service Water Pump PSW01B Is In Operation), and AAASWP1CR (Service Water Pump PSW01C Is In Operation) to FALSE.

A complete list of configuration logic flags and their as-quantified settings is given in Table 3.3.7-4.

[illegible]

Sequence logic flags are used to properly configure the integrated plant model for the specific sequence being solved. As is typical of logic models when employing the small event tree / large fault tree modeling methodology, the Ginna PRA logic models have been constructed to answer a variety of possible top event success criteria. For example, the top event success criteria for the Service Water System is different for sequences where RCS cooling shifts from injection to recirculation from the containment sump. The sequence logic flag AAAARECIRC is used in the model to indicate whether the sequence being solved requires recirculation (AAAARECIRC set to TRUE) or not (AAARECIRC set to FALSE).

There are three other sequence logic flags in addition to AAAARECIRC that are used throughout the Ginna PRA logic models as appropriate:

> AAAAA0ATWS (*ATWS Has Occurred*) is used to configure the fault tree logic before solving anticipated transient without SCRAM (ATWS) sequences;
>
> AAAAAFISSG (*Operators Isolate S/G affected By Tube Rupture [I1 Success]*) is set to TRUE for all non-SGTR sequences or when event tree top event I1 succeeds; and
>
> 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).

A complete list of sequence logic flags and their sequence-by-sequence settings is given in Table 3.3.7-5.

3.3.7.3.2 Truncation Limit Selection

All Ginna PRA accident sequences were solved using a truncation value of 5.0E-08/year: that is, only cut sets with frequencies greater than this truncation value were generated. In a large and complex logic model such as the integrated plant model created for the Ginna PRA, it is not practical to generate all cut sets associated with each sequence; such a process would require prohibitively long computer solution times. Selection of the truncation value evolved from a considerable period of experimentation. The objective of this experimentation was to generate all cut sets that significantly contribute to the over-all core damage frequency. For Ginna, where the total core damage frequency from internal initiating events is about 1.0E-04/year, the truncation value of 5.0E-08/year will identify any cut sets that contribute 0.05% of the total frequency.

[illegible]

3.3.7.3.3 Treatment of Mutually Exclusive Events

Solution of the integrated logic model for any selected sequence will generate cut sets that contain mutually exclusive events. The term mutually exclusive events refers to sets of multiple initiating events (such as a cut set containing initiating events for both loss of off-site power (grid) and loss of off-site power (switchyard) and double maintenance events (such as a cut set containing events for having both trains of component cooling water in maintenance at the same time). The likelihood of mutually exclusive events is considered to be significantly small. It would be a gross overprediction to multiply the frequencies of multiple initiators or multiple maintenance events.

The CAFTA cut set file MUTEXC.CUT was generated from the listings of mutually exclusive events in each of the systems work packages [Refs. 3.3.7-3 through 3.3.7-16] and a compilation of multiple initiating events.

During the solution process, it is also 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, I2 and UH2. In other words, sequence RB1L1 cannot occur if any one of the three other events (I1, I2 or UH2) have failed. The correct Boolean algebra statement of sequence RB1L1, therefore, is:

R * /I1 * /I2 * /UH2 * B1 * L1

Note that the success paths, I1, I2 and UH2, were accounted for through the use of Boolean complimentation. While CAFTA is capable of generating cut sets from fault trees containing complimented events, this process requires prohibitively long computer solution times. Instead, the concept of cut set deletion has been used, where:

RB1L1 = R * B1 * L1 - (I1 + I2 + UH2)

Cut set deletion for our example is accomplished by first generating cut sets for sequence RB1L1 and event tree top events I1, I2 and UH2. Thus, any cut set appearing in sequence RB1L1 that also appears in any of the three success events (I1, I2 or UH2) would be deleted.

3.3.7.3.4 Automated CAFTA Solution Process

Cut set generation for the Ginna PRA was automated through the use of Microsoft Disk Operating System (MS-DOS) batch files and macro files on Science Application International Corporation's CAFTA work station [Ref. 3.3.7-21]. Batch files contain commands written using Microsoft Disk Operation System (DOS) batch language. Macro files are ASCII text files that contain an encoded series of keystrokes for execution within the components of the CAFTA work station. The following software versions have been used to generate results:

Code	Version
CAF386.EXE	2.2c
CUT386.EXE	2.2c
CSED386.EXE	2.2c
BTRIEVE.EXE	4.11b
COMB386.EXE	2.2d
MS-DOS	5.0

Two types of batch and macro files were used in the Ginna PRA quantification process. Quantification batch and macro files are the basic components of the quantification process that are called repeatedly. Quantification driver files are used to call the quantification batch and macro files to build sequence logic models and find minimal cut sets. Quantification batch and macro files are shown in Table 3.3.7-6. Quantification driver programs are shown in Table 3.3.7-7.

As discussed in Section 3.3.7.3.3, the concept of cut set deletion has been used to account for the various events which may succeed in any given sequence. The success path cut sets are generated by the quantification batch files as shown in Table 3.3.7-6. To expedite the solution, certain success path files generated to support quantification of the transient sequences have been reused in the SLOCA, MLOCA, LLOCA, and SGTR sequence solution process. Thus, the order in which sequences are solved is important (transients first, then all others).

3.3.7.4 Initial Quantification Results

Minimal cut sets were generated for all core damage sequences. These cut sets were then processed through the Recovery Analysis task (See Section 3.3.7.5).

3.3.7.5 .Recovery Analysis

This section documents the recovery analysis performed for the R. E. Ginna PRA project. Recovery analysis efforts included:

1. Examination of the accident sequence minimal cut sets generated by the Quantification Task, thus confirming the solution method and ensuring that each core-damage cut set is consistent with the plant design, technical specifications, and operating procedures,

2. Identification of the possible means by which core damage may be averted through the use of alternative equipment or operator actions,

3. Quantification of the likelihood that recovery scenarios are unsuccessful, and

4. Integration of recovery scenarios into the plant risk model on a minimal cut set basis, thereby allowing the calculation of a realistic core-damage frequency.

3.3.7.5.1 Minimal Cut Set Examination

Each minimal cut sets generated during the accident sequence quantification task [Ref. 3.3.7-23] has been reviewed for consistency with the plant design, technical specifications, and operating procedures. This review helps confirm the validity of the integrated logic model and its solution method. During the review, various deficiencies with the integrated model were noted (e.g., incomplete system fault tree models, conflicts among the various system-level models, failure to correctly implement the success criteria in the integrated model, overly conservative modeling assumptions, etc.); the integrated model has been changed (documented in accordance with PQAP-2118-6.2 [Ref. 3.3.7-24]) and requantified as necessary. Thus, the final list of recovered minimal cut sets (which provide the basis for estimated the core-damage frequency) represent the culmination of PRA project.

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[illegible]

[illegible]
[illegible]

3.3.7.5.2 Identification of Nonrecovery Events

During the minimal cut set review, minimal cut sets with relatively high frequencies were carefully examined to ensure that such cut sets represented credible, yet realistic, core-damage scenarios. The as-quantified cut sets are based upon the use of conservative screening data for post-trip human failure events; further, 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 cut sets 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 the Ginna plant.

In general, two approaches have been used:

1. If the cut set 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. Table 3.3.7-9 provides a cross-reference of post-trip human failure events to the various core-damage sequences. Note that the refinement of post-trip human failure events is documented in Section 3.3.3.4 [Ref. 3.3.7-25].

2. If the use of alternative equipment would avert core damage, then a nonrecovery event was appended to the cut set to reflect the likelihood that such usage was unsuccessful. It is important to note that specific nonrecovery events have been applied to the cut sets as appropriate, rather than applying a global nonrecovery event to all of the cut sets in a given core-damage sequence. A specific nonrecovery events may be applied to several cut sets within a sequence or to cut sets contained in a mixture of sequences; the key to doing so is to note that a specific nonrecovery event applies to a specific context (e.g., similar equipment failures, leading to similar operator cues and response). Table 3.3.7-10 provides a cross-reference of nonrecovery events to the various core-damage sequences.

In summary, recovery actions have been addressed through application of the following guidelines:

1. Nonrecovery events have not been added to as-quantified cut sets containing post-trip human failure events; rather, the post-trip human failure events have been refined.

2. Nonrecovery events have been added to as-quantified cut sets where appropriate, subject to the following caveats:

   a. The postulated recovery action must be implemented through existing plant procedures; no credit is taken for novel or "heroic" operator actions.

   b. Only one nonrecovery event is applied to a cut set, except as noted below.

   c. The restoration of offsite power is assumed to be independent of all other recovery actions; it is permitted to append two nonrecovery events to a cut set as long as one, and only one, pertains to offsite power restoration.

   d. Common-cause failures are assumed to be nonrecoverable.

   e. Repair of failed equipment is not considered.

3.3.7.5.3 Quantification of Nonrecovery Events

Nonrecovery 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 further discussed in Section 3.3.7.5.1. Other nonrecovery events consist of a hardware-related contribution (Section 3.3.7.5.2) and a human reliability contribution (Section 3.3.7.5.3), which are summed together to estimate the overall nonrecovery event probability.

3.3.7.5.3.1 Off-Site Power Restoration

Accident sequence cut sets involving a loss of offsite power (LOSP) may possible be recovered by timely restoration of offsite power. In general, restoration of offsite power is only applicable to sequences either initiated by the LOSP (e.g., initiators TIGRLOSP and TISWLOSP) or to cut sets containing a post-trip LOSP (event ACLORPTALL).

In general, the probability of restoring offsite power at a nuclear power plant is time-dependent. The data analysis task has separately provided such time-dependent probabilities [Ref. 3.3.7-26] based on the available generic data for US nuclear power plants. For grid-centered LOSP events, the following equation applies:

$$Pr\{OSP\ not\ restored\ by\ time\ t\} = \exp\left[-(0.327\,t)^{0.907}\right]$$

For switchyard-centered LOSP events, the following equation applies:

$$Pr\{OSP\ not\ restored\ by\ time\ t\} = \exp\left[-(0.986\,t)^{0.673}\right]$$

The only LOSP-related nonrecovery event is NROGRID10H, which describes the failure to restore offsite power following a grid-centered LOSP event within 10 hours. This event has been applied to cut sets containing the initiator TIGRLOSP and failure of emergency power diesel generator B (EDG1B). These cut sets lead to a complete failure of AFW due to loss of HVAC in the Intermediate Building. RG&E has recently reassessed the survivability of the AFW pumps following an extended loss of HVAC [Ref. 3.3.7-27]; results suggest about a 24 hour coping period for the turbine-driven AFW pump. To account for uncertainties in this analysis, a value of 10 hours has been used to quantify the nonrecovery event. Thus:

$$\begin{aligned} Pr\{NROGRID10H\} &= \exp\left[-(0.327 \cdot 10)^{0.907}\right] \\ &= 5.4E{-}02 \end{aligned}$$

3.3.7.5.3.2 Hardware-Related Contribution

As previously noted, nonrecovery events not related to the restoration of offsite power consist of a hardware contribution and human reliability contribution. The hardware contribution considers failure of the alternative equipment used to implement the recovery action (e.g., failure of the standby CCW pump to start and run, etc.). In principle, hardware contributions could be addressed by developing a fault tree model and joining its resulting cut sets with the appropriate as-quantified cut sets. Often, however, the hardware contribution is negligible, depending on the probability of the hardware contribution failure, the frequency of the cut set to which it is applied, and the sequence truncation limit:

$$Pr\{hardware\} < \frac{truncation\ limit}{as\text{-}quantified\ cut\ set\ frequency} \rightarrow \text{neglect hardware contribution}$$

The nonrecovery event worksheets provide an approximate hardware contribution failure probability for use in the above relation. Note that the largest as-quantified cut set frequency (for the cut set containing the nonrecovery event) should be used when applying this relation. Table 3.3.7-11 illustrates the application of this relation on a sequence basis, and shows that the hardware contributions of all nonrecovery events is negligible.

3.3.7.5.3.3 Human-Failure-Event-Related Contribution

A multi-factor method has been developed to quantify the human reliability contribution of nonrecovery events. Such an approach describes each human failure event (HFE) solely in terms of its performance shaping factors (PSFs) or influences. Quantification is accomplished using a linear formulation that leads to an index, which is assumed to be proportional to the HFE occurrence probability. Examples of multi-factored approaches include:

- D. Embrey (SLIM) [Ref. 3.3.7-28],
- J. Williams (HEART) [Ref. 3.3.7-29],
- L. Phillips (STAHR) [Ref. 3.3.7-30],
- D. Bley (FLIM) [Ref. 3.3.7-31], and
- G. Hannaman [Ref. 3.3.7-32].

During the recovery analysis, various plant-specific or situation-specific information was collected for each nonrecovery event. This information includes the important influences on the human reliability of each nonrecovery HFE. Collection efforts for the influence information focused upon the factors which were reasonably independent of one another, and were capable of differentiating between different nonrecovery events with respect to their reliability. In addition, the influence information recorded on each nonrecovery event worksheet can be correlated, either directly or indirectly, with most of the commonly cited influences on human performance (e.g., training, procedures, man/machine interface, environment, stress, etc.). This information is collected under the following categories:

Procedure. Any and all procedures are identified that would be used or on which the recovery action would be based.

Location. The recovery action is indicated to take place either solely in the control room, solely ex-control room, or in some combination of in- and ex-control room activities.

Available time. The time from the leading cues(s) for the action (e.g., the plant emergency procedure entry conditions) to the last reasonable time at which the recovery can be initiated and assumed successful is estimated.

Human engineering. An influences that would inhibit or complicate recovery activities (e.g., task complexity, requirements for task aids, poor labeling, difficult access, inadequate lighting, and adverse environmental conditions such as temperature, humidity, and radiation) are identified.

Training. The familiarity that the primary "actors" (e.g., control room operator, shift supervisor, outside operator or technician) have with the specific recovery action is represented by this influence. For example, some actions are routinely performed as part of normal operations and, therefore, are well practiced.

During the collection of information to support the recovery analysis, it was noted that all postulated recovery actions were well-supported by the Ginna operating procedures. Thus, while procedural support is an important influence on human reliability, it is not useful in differentiating among the various nonrecovery event probabilities for the Ginna PRA.

As previously noted, the human performance influences on each event are converted to an index in the multi-factored approach. Table 3.3.7-12 lists the range of each influence's index. It should be noted that increasing the index for a particular influence implies worsening conditions for successful action. The overall index used to determine HFE probabilities, I, is calculated as a sum of the indices for each influence. Note that the minimum value of I is 0, and that the maximum value of I is 8. The mean estimate of HFE occurrence probability, P, is:

$$P = 10^{\left(\frac{3I}{8}\right)-4}$$

The conversion of the overall index into an HFE occurrence probability corresponds to the following calibration:

$$\max(P) = 0.1$$

$$\min(P) = 0.0001$$

The minimum bound on P corresponds with the lower credible limit used in the refined post-trip human failure event analysis [Ref. 3.3.7-25, 34]. The upper bound corresponds to the "allowed" value cited in the IPE process [Ref. 3.3.7-33].

The nonrecovery event worksheets show the index assigned for each influence, the overall index, and the HFE occurrence probability calculation.

3.3.7.5.4 Computer Codes

This section documents the various computer software and associated files used during the recovery analysis, as required by PQAP-2118-3.1, Section 5.2.3 [Ref. 3.3.7-34].

3.3.7.5.4.1 Computer Code Usage

The Cutset Editor (CSED386.EXE, Version 2.2c) in the CAFTA PRA workstation has been used to append nonrecovery events to various core-damage sequence cut sets determined in the Quantification Task. The Reliability Database Editor (CAF386.EXE, Version 2.2c) has been used to create the final database of PRA basic events.

3.3.7.5.5 Results

Table 3.3.7-13 presents the final core-damage frequency estimates for each sequence modeled in the R. E. Ginna PRA project. The columns labeled "Refined HFD" and "NR" indicate if the as-quantified sequence contains a post-trip human failure event whose probability was refined or if a nonrecovery event was added to one or more cut sets. The total core-damage frequency due to internal events is estimated as 7.43E-05/y, with contributions from the general sequence types as follows:

Sequence Type	Frequency	Percent
steam generator tube rupture	2.69E-05	36.2
PORV LOCAs	2.16E-05	29.1
small-small LOCAs	9.64E-06	13.0
medium LOCAs	5.75E-06	7.7
small LOCAs	4.96E-06	6.7
large LOCAs	3.09E-06	4.2
transients	2.22E-06	3.0
ATWS	1.65E-07	0.2
RCP seal LOCAs	< 5.00E-08	0

3.3.7.6 References

3.3.7-1 Science Applications International Corporation, Task Quality Assurance Plan TQAP-2118-5.1, *Quantification Task Procedure*, Revision 1, July 30, 1993.

3.3.7-2 Science Applications International Corporation, 749-01-14, *Event Trees Work Package*, Revision 2, December 10, 1993.

3.3.7-3 Science Applications International Corporation, 749-02-20.1, *Auxiliary Feedwater Systems Work Package*, Revision 0, September 15, 1992 (including Temporary Changes To Work Packages AFW-1, AFW-2, AFW-3, AFW-4, AFW-5, AFW-6, AFW-7, AFW-8, and AFW-9).

3.3.7-4 Science Applications International Corporation, 749-02-20.2, *Chemical & Volume Control Systems Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages CVCS-1, CVCS-2, CVCS-3, CVCS-4, CVCS-5, CVCS-6, CVCS-7, CVCS-8, CVCS-9, CVCS-10, and CVCS-11).

3.3.7-5 Science Applications International Corporation, 749-02-20.3, *Component Cooling Water System Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages CCW-1, CCW-2, CCW-3, CCW-4, CCW-5, and CCW-6).

3.3.7-6 Science Applications International Corporation, 749-02-20.4, *Containment Isolation Systems Work Package*, Revision 1, November 1, 1993.

3.3.7-7 Science Applications International Corporation, 749-02-20.5, *Containment Spray System Work Package*, Revision 0, June 15, 1992 (including Temporary Changes To Work Packages CS-1, CS-2, CS-3, CS-4, CS-5, and CS-6).

3.3.7-8 Science Applications International Corporation, 749-02-20.6, *Electric Power Systems Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages EP-1, EP-2, EP-3, EP-4, EP-5, EP-6, EP-7, and EP-8).

3.3.7-9 Science Applications International Corporation, 749-02-20.7, *Engineered Safety Features Actuation System Work Package*, Revision 0, October 2, 1992 (including Temporary Changes To Work Packages ESFAS-1, ESFAS-2, ESFAS-3, ESFAS-4, ESFAS-5, ESFAS-6, and ESFAS-7).

3.3.7-10 Science Applications International Corporation, 749-02-20.8, *Heating, Ventilation & Air Conditioning Systems Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages HVAC-1, HVAC-2, HVAC-3, HVAC-4, HVAC-5, HVAC-6, and HVAC-7).

3.3.7-11 Science Applications International Corporation, 749-02-20.9, *Residual Heat Removal System Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages RHR-1, RHR-2, RHR-3, RHR-4, RHR-5, RHR-6, RHR-7, RHR-8, RHR-9, RHR-10, RHR-11, RHR-12, RHR-13, RHR-14, and RHR-15).

3.3.7-12 Science Applications International Corporation, 749-02-20.10, *Primary Pressure Control Systems Work Package*, Revision 0, October 2, 1992 (including Temporary Changes To Work Packages PPC-1, PPC-2, PPC-3, PPC-4, PPC-5, PPC-6, PPC-7, PPC-8, PPC-9, PPC-10, PPC-11, and PPC-12).

3.3.7-13 Science Applications International Corporation, 749-02-20.11, *Safety Injection System Work Package*, Revision 0, June 1, 1992 (including Temporary Changes To Work Packages SI-1, SI-2, SI-3, SI-4, SI-5, SI-6, SI-7, SI-8, SI-9, SI-10, SI-11, SI-12, SI-13, SI-14, SI-15, and SI-16).

3.3.7-14 Science Applications International Corporation, 749-02-20.12, *Service Water System Work Package*, Revision 0, October 1, 1992 (including Temporary Changes To Work Packages SW-1, SW-2, SW-3, SW-4, SW-5, and SW-6).

3.3.7-15 Science Applications International Corporation, 749-02-20.13, *Instrument Air Systems Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages IA-1, IA-2, IA-3, IA-4, and IA-5).

3.3.7-16 Science Applications International Corporation, 749-02-20.14, *Turbine Generator Plant Systems Work Package*, Revision 0, October 9, 1992 (including Temporary Changes To Work Packages TGP-1, TGP-2, TGP-3, TGP-4, and TGP-5).

3.3.7-17 Science Applications International Corporation, 749-03-22.1, *Plant Specific Data Work Package*, Revision 0, June 26, 1992 (including Temporary Changes To Work Package PSD-1).

3.3.7-18 Science Applications International Corporation, 749-03-22.2, *Test & Maintenance Unavailability Data Work Package*, Revision 0, July 6, 1992.

3.3.7-19 Science Applications International Corporation, 749-03-22.3, *Common Cause Failure Data Work Package*, Revision 0, September 4, 1992.

3.3.7-20 Science Applications International Corporation, 749-03-26, *Initiator Frequencies Work Package*, Revision 0, October 12, 1992 (including Temporary Change To Work Packages IF-1, IF-2, and IF-3).

3.3.7-21 Science Applications International Corporation, *Computer Aided Fault Tree Analysis (CAFTA) Users Manual*, Version 2.2c.

3.3.7-22 Science Applications International Corporation, *Generic Data Work Package*, Revision 1, July 24, 1992 (including Temporary Changes To Work Packages GD-1, GD-2, and GD-3).

3.3.7-23 Science Applications International Corporation, *Quantification Work Package*, Project Document 749-05-40, Rev. 0, December 17, 1993.

3.3.7-24 Science Applications International Corporation, *Temporary Changes to Work Packages*, PQAP-2118-6.2, Rev. 0, April 2, 1993.

3.3.7-25 Science Applications International Corporation, *Human Failure Events Analyzed in Detail*, Project Document 749-04-32, Rev. 0, December 28, 1993.

3.3.7-26 Science Applications International Corporation, *Initiator Frequencies Work Package*, Project Document 749-03-26, Rev. 0, October 1992. Includes Temporary Change Form IF-1, IF-2, and IF-3.

3.3.7-27 Rochester Gas & Electric Corporation, *AFW Room Heatup Calculation*, DA-NS-93-143, Rev. 0, February 1, 1994.

3.3.7-28 D. E. Embrey, *The Use of Performance Shaping Factors and Quantified Expert Judgement in the Evaluation of Human Reliability: An Initial Assessment*, NUREG/CR-2986, 1983.

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3.3.7-29 J. C. Williams, "A Data-Based Method for Assessing and Reducing Human Error to Improve Operational Performance," *Conference Record for 1988 IEEE Fourth Conference on Human Factors and Power Plants*, 88CH2576-7, June 5-7, 1988, pp. 436-450.

3.3.7-30 L. D. Phillips, P. Humphreys, D. E. Embrey, and D. L. Shelby, Appendix C of *A Pressurized Thermal Shock Evaluation of the Calvert Cliffs Unit 1 Nuclear Power Plant*, NUREG/CR-4183, September 1985.

3.3.7-31 S. H. Chien, A. A. Dykes, J. W. Stegar, and D. C. Bley, "Quantification of Human Error Rates Using a SLIM-Based Approach," *Conference Record for 1988 IEEE Fourth Conference on Human Factors and Power Plants*, 88CH2576-7, June 5-9, 1988, pp. 297-302.

3.3.7-32 G. W. Hannaman and D. H. Worledge, "Some Developments in Human Reliability Analysis Approaches and Tools," *Reliability Engineering and System Safety*, Vol. 22, 1988.

3.3.7-33 United States Nuclear Regulatory Commission, *Individual Plant Examination: Submittal Guidance*, NUREG-1335, August 1989, p. C-20.

3.3.7-34 Science Applications International Corporation, *Review of Work Packages and Technical Reports*, PQAP-2118-3.1, Rev. 1, June 9, 1993.

Table 3.3.7-1
R. E. Ginna PRA Project Quantification Inputs

Description	*Reference*	*Associated Computer Files*	*Notes*
Accident Sequence Logic	3.3.7-2	SEQ.CAF	Developed from the core damage sequences in the event trees.
Event Tree Top Logic	Ref. 3.3.7-2	TOPLOG.CAF	
Systems Logic Models	Ref. 3.3.7-3 Ref. 3.3.7-4 Ref. 3.3.7-5 Ref. 3.3.7-6 Ref. 3.3.7-7 Ref. 3.3.7-8 Ref. 3.3.7-9 Ref. 3.3.7-10 Ref. 3.3.7-11 Ref. 3.3.7-12 Ref. 3.3.7-13 Ref. 3.3.7-14 Ref. 3.3.7-15 Ref. 3.3.7-16	AFW.CAF CVCS.CAF CCW.CAF CT.CAF CS.CAF AC.CAF, DC.CAF, DG.CAF, UV.CAF, ACINST.CAF ESFAS.CAF HVAC.CAF RHR.CAF PPC.CAF SI.CAF, ACCUM.CAF SW.CAF IA.CAF TGP.CAF	The *.CAF files contain fault tree gate equations. Each file also has an associated basic event (*.BE), gate definition (*.GT), type code (*.TC), and module definition (*.CUT) file.
Mutually Exclusive Events	Systems Work Packages [Refs. 3.3.7-3 - 3.3.7-16 above]	MUTEXC.CUT	All mutually exclusive events identified in the Systems Analysis Work Packages, with the addition of all double initiators.
Component-Level Reliability Parameters	Ref. 3.3.7-17 Ref. 3.3.7-22	SEQ.TC	File is loaded by INTBE.MAC.
Test & Maintenance Unavailability Data	Ref. 3.3.7-18	Embedded in individual systems .BE files.	
Common Cause Failure Data	Ref. 3.3.7-19	Embedded in individual systems .BE files.	
Initiator Frequencies	Ref. 3.3.7-20	SEQ.BE	
Pre-Trip Human Failure Events		Embedded in individual systems .BE files.	
Post-Trip Human Failure Events		Embedded in individual systems .BE files.	

Tabl[illegible]3.7-2
Integrated C[illegible]TA BE File

Basic Event	C Factor	Units	Description
AAAA00ATWS	1		ATWS HAS OCCURRED <LOGIC FLAG>
AAAAAFISSG	1		Operators isolate S/G affected by tube rupture (I1 success)
AAAACCHX_A	1		CCW Heat Exchanger EAC01A Is In Service
AAAACCPMPA	1		<FLAG> CCW PUMP A IS ALIGNED TO RUN
AAAACT0101	1		SI Pumps B and C Failed; No Level 1 Cutsets of SI and SR Injection Failures
AAAACT0105	1		CS Failed; No Level 1 Cutsets of CS203, CSCVP0862A, CSCCM0862X, CSXVK0868A
AAAACT0107	1		DELTERM gates DC331, DC043, DC193, IA270
AAAACT0108	1		CVCS Failed; DELTERM CVMMMV0313, DCMMMCB01A, DCBDFMCB0A, DCMMCB04AV
AAAACT0109	1		CS Failed; No Level 1 Cutsets of CS103, CSCVP0862B, CSCCM0862X, CSXVK0868B
AAAACT0111	1		Valid for Sequences *XH and *XL Only
AAAACT0112	1		DELTERM gates IA150, DC350, DC035, and DC185
AAAACT0113	1		SI Pumps A and C Failed; No Level 1 Cutsets of SI and SR Injection Failures
AAAACT0132	1		DELTERM gates DC135, DC035, DC185, IA141, IA280
AAAACT0202	1		AOV 202 in Service (2/3 Orifice Valves Typically in Service)
AAAACT0403	1		Level 1 Cutsets Cannot Contain Failures of TDAFW, MDAFW, and SAFW Inject Lines
AAAACT0404	1		Level 1 Cutsets Cannot Contain Failures of TDAFW, MDAFW, and SAFW Inject Lines
AAAACT200A	1		AOV 200A in Service (2/3 Orifice Valves Typically in Service)
AAAACT200B	1		AOV 200B in Service (2/3 Orifice Valves Typically in Service)
AAAACT206B	1		DELTERM gates IA120, DC575, DC096, DC296
AAAACT310A	1		DELTERM gates IA141, DC556, DC085, DC285
AAAACT401A	1		Level 1 Cutsets Cannot Contain Gate MS511
AAAACT401B	1		Level 1 Cutsets Cannot Contain Gates AF436, AFMMSGASTM, MSCCPSGCVS
AAAACT402A	1		Level 1 Cutsets Cannot Contain Gate MS551
AAAACT402B	1		Level 1 Cutsets Cannot Contain Gates AF426, AFMMSGBSTM, MSCCPSGCVS
AAAACTMINI	1.63E-02		Conditional Probability That Mini-Purge System in Use
AAAACTPIPE	1.00		Conditional Probability that Piping Inside Missile Barrier is Ruptured
AAAACTPRES	1		Containment Pressure Greater Than 75 psig
AAAACTX108	1		Level 1 Cutsets Cannot Contain CVMMMV0313, DCMMMCB01A, DCBDFMCB0A, DCMMCB04AV
AAAACTX111	1		DELTERM gates DC085, DC285, DC551, and IA270
AAAAES0BAF	1		ECCS MANUALLY STARTED TO SUPPORT BLEED-AND-FEED OPERATION
AAAAHVCT_A	1		TRAIN A RUNNING (LOGIC FLAG)
AAAAHVCT_B	1		TRAIN-B RUNNING (LOGIC FLAG)
AAAAHVCT_C	1		TRAIN-C RUNNING (LOGIC FLAG)
AAAAHVCT_D	1		TRAIN-D RUNNING (LOGIC FLAG)
AAAAIAC02A	1		IA COMPRESSOR CIA02A RUNNING
AAAAIAC02B	1		IA COMPRESSOR CIA02B RUNNING
AAAAIAC02C	.0000001		IA COMPRESSOR CIA02C RUNNING
AAAAMCCG18	1		480 VAC MOTOR CONTROL CENTER MCCG IS BEING POWERED FROM 480 VAC BUS 18
AAAAPUMP0A	1		CHARGING PUMP A RUNNING
AAAAPUMP0B	1		CHARGING PUMP B RUNNING
AAAAPUMP0C	1		CHARGIN PUMP C RUNNING
AAAARECIRC	1		Sequences That Require Recirculation

Table [illegible]-2
Integrated C[illegible]A BE File

Basic Event	C	Factor	Units	Description
AAAASWP1AR		1		Service Water Pump PSW01A Is In Operation
AAAASWP1AS		1		Service Water Pump PSW01A Is Selected In Standby
AAAASWP1BR		1		Service Water Pump PSW01B Is In Operation
AAAASWP1BS		1		Service Water Pump PSW01B Is Selected In Standby
AAAASWP1CR		1		Service Water Pump PSW01C Is In Operation
AAAASWP1CS		1		Service Water Pump PSW01C Is Selected In Standby
AAAASWP1DR		1		Service Water Pump PSW01D Is In Operation
AAAASWP1DS		1		Service Water Pump PSW01D Is Selected In Standby
AC030				No power on Bus 14
AC035		1.0E-03		LOSS OF NORMAL POWER ON BUS 14
AC040				No Power on Bus 11A
AC060		1E-3		POWER ON BUS 13 NOT AVAILABLE
AC070		1E-3		POWER ON BUS 15 NOT AVAILABLE
AC130				No power on Bus 16
AC135		1.0E-03		LOSS OF NORMAL POWER ON BUS 16
AC140				No Power on Bus 11B
AC202				No Power To Bus 18 From Normal Power Source
AC203				No Power To Bus 18 From Bus 12A
AC302				No Power To Bus 17 From Normal Power Source
AC401		1E-3		NO POWER TO BUS 14 FROM BUS 12A
AC405				No Power From Bus 14 Normal Power Source
AC501		1E-3		NO POWER TO BUS 16 FROM BUS 12B
AC505				No Power On Bus 16 From Normal Power Source
AC601		1E-3		NO POWER ON MCC 1A
AC603		1E-3		NO POWER ON MCC 1B
AC607		1E-3		NO POWER ON MCC 1F
AC611				No Power On Motor Control Center MCCD
AC612				No Power On Motor Control Center MCCD (Circular Logic Clip)
AC613				Loss Of 480 VAC Power On Motor Control Center J
AC614				Components To Motor Control Center MCCJ Fail (Circular Logic Clip)
AC615		1E-3		NO POWER ON MCC 1M
AC617				No Power On Motor Control Center MCCC
AC618				No Power On Motor Control Center MCCC (Circular Logic Clip)
AC619				No Power On Motor Control Center MCCH
AC620				Components To Motor Control Center MCCH Fail (Circular Logic Clip)
AC621		1E-3		NO POWER ON MCC 1K
AC623				No power on MCC 1L
AC800		1.00E-03		Loss of 120 VAC Power on Panel ACPDPTB07
AC850		1.00E-03		Loss of 120 VAC Power on Panel ACPDPTB02
ACB1F0011A	1	24	H	Local Fault On 4160 VAC Bus 11A
ACB1F0011B	1	24	H	Local Fault On 4160 VAC Bus 11B
ACB1F0S12A	1	24	H	Local Fault On 4160 VAC Bus 12A

Basic Event	C	Factor	Units	Description
ACB1F0S12B	1	24	H	Local Fault On 4160 VAC Bus 12B
ACB2FBUS13	1	24	H	Local Fault On 480 VAC Bus 13
ACB2FBUS14	1	24	H	Local Fault On 480 VAC Bus 14
ACB2FBUS15	1	24	H	Local Fault On 480 VAC Bus 15
ACB2FBUS16	1	24	H	Local Faults On 480 VAC Bus 16
ACB2FBUS17	1	24	H	Local Fault on 480 VAC Bus 17
ACB2FBUS18	1	24	H	Local Fault on 480 VAC Bus 18
ACB2FMCC1A	1	24	H	Local Fault On 480 VAC Motor Control Center MCCA
ACB2FMCC1B	1	24	H	Local Fault On 480 VAC Motor Control Center MCCB
ACB2FMCC1C	1	24	H	Local Fault On 480 VAC Motor Control Center MCCC
ACB2FMCC1D	1	24	H	Local Fault On 480 VAC Motor Control Center MCCD
ACB2FMCC1E	1	24	H	Local Faults On 480 VAC Motor Control Center MCCE
ACB2FMCC1F	1	24	H	Local Faults On 480 VAC Motor Control Center MCCF
ACB2FMCC1G	1	24	H	Local Fault On 480 VAC Motor Control Center MCCG
ACB2FMCC1H	1	24	H	Local Fault On 480 VAC Motor Control Center MCCH
ACB2FMCC1J	1	24	H	Local Fault On 480 VAC Motor Control Center MCCJ
ACB2FMCC1K	1	24	H	Local Fault On 480 VAC Motor Control Center MCCK
ACB2FMCC1L	1	24	H	Local Fault On 480 VAC Motor Control Center MCCL
ACB2FMCC1M	1	24	H	Local Fault On 480 VAC Motor Control Center MCCM
ACB4FBUS1A	1	24	H	Bus Faults On 120 VAC Instrument Bus A (IBPDPCBAR)
ACB4FBUS1B	1	24	H	120 VAC Instrument Bus B (IBPDPCBBW) Bus Faults
ACB4FBUS1C	1	24	H	120 VAC Instrument Bus 1C (IBPDPCBCB) Bus Faults
ACB4FBUS1D	1	24	H	120 VAC Instrument Bus D (IBPDPCBDY) Bus Faults
ACB4FDISTA	1	24	H	120 VAC Distribution Panel A (IBPDPCBA) Panel Faults
ACB4FDISTB	1	24	H	120 VAC Distribution Panel B (IBPDPCBB) Panel Faults
ACB4FDISTC	1	24	H	120 VAC Distribution Panel C (IBPDPCBC) Panel Faults
ACB4FDISTD	1	24	H	120 VAC Distribution Panel D (IBPDPCBD) Panel Faults
ACB4FDISTE	1	24	H	120 VAC Distribution Panel E (IBPDPCBE) Panel Faults
ACB4FPCB03	1	24	H	Local Fault On 120 VAC Power Distribution Panel ACPDPCB03
ACB4FPCB06	1	24	H	Local Fault On 120 VAC Power Distribution Panel ACPDPCB06
ACB4FPTB02	1	24	H	Local Fault On 120 VAC Power Distribution Panel ACPDPTB02
ACB4FPTB07	1	24	H	Local Fault On 120 VAC Power Distribution Panel ACPDPTB07
ACCBD012AX		1.00E+00		
ACCBD012AY		1.00E+00		
ACCBD012BX		1.00E+00		
ACCBD012BY		1.00E+00		
ACCBD1309B	1	0	N	AC BREAKER BUS13/09B FAILS TO OPERATE
ACCBD1418B	1	1	N	AC BREAKER BUS14/18B FAILS TO OPERATE
ACCBD1418C	1	1	N	AC BREAKER BUS14/18C FAILS TO OPERATE
ACCBD1419A	1	0	N	AC BREAKER BUS14/19A FAILS TO OPERATE
ACCBD1420A	1	0	N	AC BREAKER BUS14/20A FAILS TO OPERATE
ACCBD1420C	1	0	N	AC BREAKER BUS14/20C FAILS TO OPERATE

[illegible]

Tabl .7-2
Integrated C A BE File

Basic Event	C	Factor	Units	Description
ACCBD1421C	1	0	N	AC BREAKER BUS14/21C FAILS TO OPERATE
ACCBD1422A	1	0	N	AC BREAKER BUS14/22A FAILS TO OPERATE
ACCBD1423A	1	0	N	AC BREAKER BUS14/23A FAILS TO OPERATE
ACCBD1423B	1	0	N	AC BREAKER BUS14/23B FAILS TO OPERATE
ACCBD1423C	1	0	N	AC BREAKER BUS14/23C FAILS TO OPERATE
ACCBD1424B	1	0	N	AC BREAKER BUS14/24B FAILS TO OPERATE
ACCBD1502B	1	0	N	AC BREAKER BUS15/02B FAILS TO OPERATE
ACCBD1504B	1	0	N	AC BREAKER BUS15/04B FAILS TO OPERATE
ACCBD1611B	1	1	N	AC BREAKER BUS16/11B FAILS TO OPERATE
ACCBD1611C	1	1	N	AC BREAKER BUS16/11C FAILS TO OPERATE
ACCBD1612A	1	0	N	AC BREAKER BUS16/12A FAILS TO OPERATE
ACCBD1613A	1	0	N	AC BREAKER BUS16/13A FAILS TO OPERATE
ACCBD1613C	1	0	N	AC BREAKER BUS16/13C FAILS TO OPERATE
ACCBD1614C	1	0	N	AC BREAKER BUS16/14C FAILS TO OPERATE
ACCBD1615A	1	0	N	AC BREAKER BUS16/15A FAILS TO OPERATE
ACCBD1615B	1	0	N	AC BREAKER BUS 16/15B FAILS TO OPERATE
ACCBD1615C	1	0	N	AC BREAKER BUS 16/15C FAILS TO OPERATE
ACCBD1616B	1	0	N	AC BREAKER BUS16/16B FAILS TO OPERATE
ACCBD1617C	1	0	N	AC BREAKER BUS16/17C FAILS TO OPERATE
ACCBD1725B	1	1	N	AC BREAKER BUS17/25B FAILS TO OPERATE
ACCBD1725C	1	1	N	AC BREAKER BUS17/25C FAILS TO OPERATE
ACCBD1727C	1	0	N	480 VAC Circuit Breaker In Bus 17 Unit 27C (52/SWP1B) Fails To Operate
ACCBD1727D	1	0	N	480 VAC Circuit Breaker In Bus 17 Unit 27D (52/SWP1C) Fails To Operate
ACCBD1829C	1	0	N	480 VAC Circuit Breaker In Bus 18 Unit 29C (52/SWP1A) Fails To Operate
ACCBD1829D	1	0	N	480 VAC Circuit Breaker In Bus 18 Unit 29D (52/SWP1D) Fails To Operate
ACCBD1831B	1	1	N	AC BREAKER BUS18/31B FAILS TO OPERATE
ACCBD1831C	1	1	N	AC BREAKER BUS18/31C FAILS TO OPERATE
ACCBD2BTAA	1	1	N	4160 VAC Bus 11A / Bus 12A Tie Breaker 52/BTA-A (BUS11A/11) Fails To Operate
ACCBD2BTBB	1	1	N	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate
ACCBD422AR	1	0	N	AC BREAKER BUS14/22A FAILS TO OPERATE (RECIRCULATION)
ACCBD5211A	1	1	N	4160 VAC Circuit Breaker 52/11A (BUS11A/10) Fails To Operate On Demand
ACCBD5211B	1	1	N	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand
ACCBD615AR	1	0	N	AC BREAKER BUS16/15A FAILS TO OPERATE (RECIRCULATION)
ACCBDB/02M	1	0	N	AC BREAKER MCCB/02M FAILS TO OPERATE
ACCBDB02MM	1	0	N	AC BREAKER MCCB/02MM FAILS TO OPERATE
ACCBDC/01F	1	0	N	AC BREAKER MCCC/01F FAILS TO OPERATE
ACCBDC/13B	1	0	N	AC BREAKER MCCC/13B FAILS TO OPERATE
ACCBDC/16F	1	0	N	AC BREAKER MCCC/16F FAILS TO OPERATE
ACCBDD/01B	1	0	N	AC BREAKER MCCD/01B FAILS TO OPERATE
ACCBDD/02F	1	0	N	AC BREAKER MCCD/02F FAILS TO OPERATE
ACCBDD/11M	1	0	N	AC BREAKER MCCD/11M FAILS TO OPERATE
ACCBDD/15F	1	0	N	AC BREAKER MCCD/15F FAILS TO OPERATE

Table [illegible]7-2
Integrated C[illegible]. BE File

Basic Event	C	Factor	Units	Description
ACCBDH/01K	1	1	N	AC BREAKER MCCH/01K FAILS TO OPERATE
ACCBDH/02B	1	1	N	AC BREAKER MCCH/02B FAILS TO OPERATE
ACCBDH/02D	1	1	N	AC BREAKER MCCH/02D FAILS TO OPERATE
ACCBDJ/01K	1	1	N	AC BREAKER MCCJ/01K FAILS TO OPERATE
ACCBDJ/02B	1	1	N	AC BREAKER MCCJ/02B FAILS TO OPERATE
ACCBDJ/02D	1	1	N	AC BREAKER MCCJ/02D FAILS TO OPERATE
ACCBDK/01B	1	0	N	AC BREAKER MCCK/01B FAILS TO OPERATE
ACCBDK/01F	1	0	N	AC BREAKER MCCK/01F FAILS TO OPERATE
ACCBDL/02M	1	0	N	AC BREAKER MCCL/02M FAILS TO OPERATE
ACCBDM/02M	1	0	N	AC BREAKER MCCM/02M FAILS TO OPERATE
ACCBN1419C	1	1	N	AC BREAKER BUS14/19C FAILS TO OPEN
ACCBN1420A	1	1	N	AC BREAKER BUS14/20A FAILS TO OPEN
ACCBN1420C	1	1	N	AC BREAKER BUS14/20C FAILS TO OPEN
ACCBN1421A	1	1	N	AC BREAKER BUS14/21A FAILS TO OPEN
ACCBN1421C	1	1	N	AC BREAKER BUS14/21C FAILS TO OPEN
ACCBN1422A	1	1	N	AC BREAKER BUS14/22A FAILS TO OPEN
ACCBN1422B	1	1	N	AC BREAKER BUS14/22B FAILS TO OPEN
ACCBN1423A	1	1	N	AC BREAKER BUS14/23A FAILS TO OPEN
ACCBN1423B	1	1	N	AC BREAKER BUS14/23B FAILS TO OPEN
ACCBN1423C	1	1	N	AC BREAKER BUS14/23C FAILS TO OPEN
ACCBN1612A	1	1	N	AC BREAKER BUS16/12A FAILS TO OPEN
ACCBN1613C	1	1	N	AC BREAKER BUS16/13C FAILS TO OPEN
ACCBN1614A	1	1	N	AC BREAKER BUS16/14A FAILS TO OPEN
ACCBN1614C	1	1	N	AC BREAKER BUS16/14C FAILS TO OPEN
ACCBN1615A	1	1	N	AC BREAKER BUS16/15A FAILS TO OPEN
ACCBN1615B	1	1	N	AC BREAKER BUS16/15B FAILS TO OPEN
ACCBN1615C	1	1	N	AC BREAKER BUS16/15C FAILS TO OPEN
ACCBN1616A	1	1	N	AC BREAKER BUS16/16A FAILS TO OPEN
ACCBN1616B	1	1	N	AC BREAKER BUS16/16B FAILS TO OPEN
ACCBN1617A	1	1	N	AC BREAKER BUS16/17A FAILS TO OPEN
ACCBN1726C	1	1	N	AC BREAKER BUS17/26C FAILS TO OPEN
ACCBN1727A	1	1	N	AC BREAKER BUS17/27A FAILS TO OPEN
ACCBN1727B	1	1	N	AC BREAKER BUS17/27B FAILS TO OPEN
ACCBN1727C	1	1	N	AC BREAKER BUS17/27C FAILS TO OPEN
ACCBN1727D	1	1	N	AC BREAKER BUS17/27D FAILS TO OPEN
ACCBN1829A	1	1	N	AC BREAKER BUS18/29A FAILS TO OPEN
ACCBN1829B	1	1	N	AC BREAKER BUS18/29B FAILS TO OPEN
ACCBN1829C	1	1	N	AC BREAKER BUS18/29C FAILS TO OPEN
ACCBN1829D	1	1	N	AC BREAKER BUS18/29D FAILS TO OPEN
ACCBN1830C	1	1	N	AC BREAKER BUS18/30C FAILS TO OPEN
ACCBNMCD5K	1	1	N	AC BREAKER MCCD/5K FAILS TO OPEN
ACCBR00013	1	24	H	480 VAC AC Circuit Breaker 52/13 (BUS13/10B) Transfers Open

Basic Event	C	Factor	Units	Description
ACCBR00014	1	24	H	480 VAC Bus 14 Feeder Breaker 52/14 (BUS14/18B) Transfers Open
ACCBR00015	1	24	H	480 VAC Bus 15 Feeder Circuit Breaker 52/15 (BUS15/01B) Transfers Open
ACCBR00016	1	24	H	480 VAC Circuit Breaker 52/16 (BUS16/11B) Transfers Open
ACCBR00017	1	24	H	480 VAC Circuit Breaker 52/17 (BUS17/25B) Transfers Open
ACCBR00018	1	24	H	480 VAC AC Circuit Breaker 52/18 (BUS18/31B) Transfers Open
ACCBR001B3	1	720	H	AC BREAKER 52/EG1B3 TRANSFERS OPEN
ACCBR00C6F	1	0	M	480 VAC Circuit Breaker In MCC C Unit 6F (42/4616) Transfers Open
ACCBR00D6F	1	0	M	480 VAC Circuit Breaker In MCC D Unit 6F (42/4734) Transfers Open
ACCBR00H2J	1	0	M	480 VAC Circuit Breaker In MCC H Unit 2J (42/4670) Transfers Open
ACCBR00H2M	1	0	M	480 VAC Circuit Breaker In MCC H Unit 2M (42/4609) Transfers Open
ACCBR00J2M	1	0	M	480 VAC Circuit Breaker In MCC J Unit 2M (42/4780) Transfers Open
ACCBR012AX		1.00E+00		
ACCBR012AY	1	24	H	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open
ACCBR012BX	1	24	H	4160 VAC Circuit Breaker 52/12BX (Normal Supply To Bus 12B) Transfers Open
ACCBR012BY		1.00E+00		
ACCBR013SS	1	24	H	4160 VAC Circuit Breaker 52/13SS (BUS11A/01) Transfers Open
ACCBR014SS	1	24	H	4160 VAC PXABSS014 Feeder Circuit Breaker 52/14SS (BUS12A/15) Transfers Open
ACCBR015SS	1	24	H	4160 VAC PXTBSS015 Feeder Circuit Breaker 52/15SS (BUS11B/30) Transfers Open
ACCBR016SS	1	24	H	4160 VAC Circuit Breaker 52/16SS (BUS12B/17) Transfers Open
ACCBR017SS	1	24	H	4160 VAC AC Circuit Breaker 52/17SS (BUS12B/18) Transfers Open
ACCBR018SS	1	24	H	4160 VAC Circuit Breaker 52/18SS (BUS12A/14) Transfers Open
ACCBR02/06	1	0	H	AC BREAKER ACPDPTB02/06 TRANSFERS OPEN
ACCBR04007	1	0	H	AC BREAKER MCCC/06M TRANSFERS OPEN
ACCBR04008	1	0	H	AC BREAKER MCCD/06M TRANSFERS OPEN
ACCBR04013	1	0	H	AC BREAKER MCCD/12M TRANSFERS OPEN
ACCBR04027	1	0	H	AC BREAKER MCCC/12C TRANSFERS OPEN
ACCBR04028	1	0	H	AC BREAKER MCCD/12J TRANSFERS OPEN
ACCBR07/01	1	0	H	AC BREAKER ACPDPTB07/01 TRANSFERS OPEN
ACCBR0C11M	1	0	M	480 VAC Circuit Breaker In MCC C Unit 11M (42/4663) Transfers Open
ACCBR0C13J	1	0	H	480 VAC Circuit Breaker in MCCC Unit 13 J Transfers Open
ACCBR0C14J	1	0	M	480 VAC Circuit Breaker In MCC C Unit 14J (42/4615) Transfers Open
ACCBR0C14M	1	0	M	480 VAC Circuit Breaker In MCC C Unit 14 M (42/4614) Transfers Open
ACCBR0D05M	1	24	H	480 VAC Circuit Breaker MCCD/05M Transfers Open
ACCBR0D11J	1	0	M	480 VAC Circuit Breaker In MCC D Unit 11J (42/4613) Transfers Open
ACCBR0D13C	1	0	M	480 VAC Circuit Breaker In MCC D Unit 13C (42/4735) Transfers Open
ACCBR0D13F	1	0	M	480 VAC Circuit Breaker In MCC D Unit 13F (42/4664) Transfers Open
ACCBR0D14J	1	0	M	480 VAC Circuit Breaker In MCC D Unit 14J (42/4733) Transfers Open
ACCBR11A/9	1	0	H	AC BREAKER BUS11A/9 TRANSFERS OPEN
ACCBR11B23	1	0	H	AC BREAKER BUS11B/23 TRANSFERS OPEN
ACCBR1309A	1	0	H	AC BREAKER BUS13/09A TRANSFERS OPEN
ACCBR1309B	1	0	H	AC BREAKER BUS13/09B TRANSFERS OPEN
ACCBR1418C	1	24	H	AC BREAKER BUS14/18C TRANSFERS OPEN

Basic Event	C	Factor	Units	Description
ACCBR1420A	1	0	H	AC BREAKER BUS14/20A TRANSFERS OPEN
ACCBR1420B	1	0	H	480 VAC Circuit Breaker BUS14/20B (25/CSP1A) Transfers Open
ACCBR1420C	1	0	H	AC BREAKER BUS14/20C TRANSFERS OPEN
ACCBR1421C	1	0	H	AC BREAKER BUS14/21C TRANSFERS OPEN
ACCBR1422A	1	0	H	AC BREAKER BUS14/22A TRANSFERS OPEN
ACCBR1423A	1	0	H	AC BREAKER BUS14/23A TRANSFERS OPEN
ACCBR1423B	1	0	H	AC BREAKER BUS14/23B TRANSFERS OPEN
ACCBR1423C	1	0	H	AC BREAKER BUS14/23C TRANSFERS OPEN
ACCBR1424B	1	0	H	AC BREAKER BUS14/24B TRANSFERS OPEN
ACCBR1502B	1	0	H	AC BREAKER BUS15/02B TRANSFERS OPEN
ACCBR1503B	1	24	H	480 VAC Circuit Breaker BUS15/03B (52/LTB) Transfers Open
ACCBR1504B	1	0	H	AC BREAKER BUS15/04B TRANSFERS OPEN
ACCBR1611C	1	24	H	AC BREAKER BUS16/11C TRANSFERS OPEN
ACCBR1612A	1	0	H	AC BREAKER BUS16/12A TRANSFERS OPEN
ACCBR1613B	1	0	H	480 VAC Circuit Breaker BUS16/13B (52/CSP1B) Transfers Open
ACCBR1613C	1	0	H	AC BREAKER BUS16/13C TRANSFERS OPEN
ACCBR1614C	1	0	H	AC BREAKER BUS16/14C TRANSFERS OPEN
ACCBR1615A	1	0	H	AC BREAKER BUS16/15A TRANSFERS OPEN
ACCBR1615B	1	0	H	AC BREAKER BUS 16/15B TRANSFERS OPEN
ACCBR1615C	1	0	H	AC BREAKER BUS 16/15C TRANSFERS OPEN
ACCBR1616B	1	0	H	AC BREAKER BUS16/16B TRANSFERS OPEN
ACCBR1617C	1	0	H	AC BREAKER BUS16/17C TRANSFERS OPEN
ACCBR1725C	1	24	H	AC BREAKER BUS17/25C TRANSFERS OPEN
ACCBR1726C	1	24	H	480 VAC MCCG Feeder Circuit Breaker 52/MCC1G2 (BUS17/26C) Transfers Open
ACCBR1727C	1	0	M	480 VAC Circuit Breaker In Bus 17 Unit 27C (52/SWP1B) Transfers Open
ACCBR1727D	1	0	M	480 VAC Circuit Breaker In Bus 17 Unit 29D (52/SWP1C) Transfers Open
ACCBR1829C	1	0	D	480 VAC Circuit Breaker In Bus 18 Unit 29C (52/SWP1A) Transfers Open
ACCBR1829D	1	0	D	480 VAC Circuit Breaker In Bus 18 Unit 29D (52/SWP1D) Transfers Open
ACCBR1830C	1	24	H	480 VAC MCCG Feeder Circuit Breaker 52/MCC1G1 (BUS18/30C) Transfers Open
ACCBR1831C	1	24	H	AC BREAKER BUS18/31C TRANSFERS OPEN
ACCBR1ACB2	1	24	H	Inverter INVTA Output Breaker INVTCVTA/02 Transfers Open
ACCBR1ACB4	1	24	H	Transformer CVTA Feed Breaker INVTCVTA/04 Transfers Open
ACCBR1CCB4	1	24	H	Constant Voltage Transformer CVTB Input Breaker INVTCVTB/04 Transfers Open
ACCBR2BTAA	1	24	H	4160 VAC Bus 12A / Bus 11A Tie Circuit Breaker 52/BTA-A (BUS11A/11) Trans. Open
ACCBR2BTBB	1	24	H	4160 VAC Bus 12B / Bus 11B Tie Circuit Breaker 52/BTB-B (BUS12B/20) Trans. Open
ACCBR400A1	1	4	H	AC Breaker IBPDPCBA/01 Transfers Open
ACCBR400B1	1	4	H	AC Breaker ICPDPCBB/01 Transfers Open
ACCBR400C1	1	4	H	AC Breaker IBPDPCBC/01 Transfers Open
ACCBR422AR	1	0	H	AC BREAKER BUS14/22A TRANSFERS OPEN (RECIRCULATION)
ACCBR615AR	1	0	H	AC BREAKER BUS16/15A TRANSFERS OPEN (RECIRCULATION)
ACCBR75112	1	24	H	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails
ACCBR76702	1	24	H	34.5 kVAC Oil Circuit Breaker 52/76702 (RG&E Circuit 767 From Sta. 13A) Fails

Table [illegible]2
Integrated C[illegible]BE File

Basic Event	C	Factor	Units	Description
ACCBRB0206	1	0	H	120 VAC Circuit Breaker ACPDPTB02/06 Transfers Open
ACCBRB02MM	1	0	H	AC BREAKER MCCB/02MM TRANSFERS OPEN
ACCBRB05MM	1	24	H	480 VAC Circuit Breaker MCCB/05MM Transfers Open
ACCBRB0701	1	0	H	120 VAC Circuit Breaker ACPDPTB07/01 Transfers Open
ACCBRBUS1A	1	24	H	Instrument Bus A (IBPDPCBAR) Normal Supply Breaker IBPDPCBAR/M1 Transfers Open
ACCBRBUS1B	1	24	H	Instrument Bus B (IBPDPCBBW) Normal Supply Breaker IBPDPCBBW/M1 Transfers Open
ACCBRBUS1C	1	24	H	Instrument Bus C (IBPDPCBCB) Normal Supply Breaker IBPDPCBCB/M1 Transfers Open
ACCBRBUS1D	1	24	H	Instrument Bus D (IBPDPCBDY) Normal Supply Breaker IBPDPCBDY/M1 Transfers Open
ACCBRC/01F	1	0	H	AC BREAKER MCCC/01F TRANSFERS OPEN
ACCBRC/06C	2	2075	H	AC BREAKER MCCC/06C TRANSFERS OPEN
ACCBRC/06J	1	0	H	AC BREAKER MCCC/06J TRANSFERS OPEN
ACCBRC/07J	1	0	H	AC BREAKER MCCC/07J TRANSFERS OPEN
ACCBRC/07M	1	0	H	AC BREAKER MCCC/07M TRANSFERS OPEN
ACCBRC/09M	1	0	H	AC BREAKER MCCC/09M TRANSFERS OPEN
ACCBRC/10J	1	0	H	AC BREAKER MCCC/10J TRANSFERS OPEN
ACCBRC/12J	1	0	H	AC BREAKER MCCC/12J TRANSFERS OPEN
ACCBRC/13B	1	0	H	AC BREAKER MCCC/13B TRANSFERS OPEN
ACCBRC/15J	1	0	H	AC BREAKER MCCC/15J TRANSFERS OPEN
ACCBRC/16F	1	0	H	AC BREAKER MCCC/16F TRANSFERS OPEN
ACCBRC010C	2	0	H	AC BREAKER MCC C UNIT 10C TRANSFERS OPEN
ACCBRC2518	1	8	H	AC BREAKER IBPDSPCBAR/03 (CIRCUIT C2518) TRANSFERS OPEN
ACCBRC2536	1	24	H	Instrument Bus A Breaker IBPDPCBAR/21 To MQ400A Transfers Open
ACCBRC2537	1	24	H	Instrument Bus A (IBPDPCBAR) Breaker IBPDCPCBAR/22 Transfers Open
ACCBRC2541	1	8	H	AC BREAKER IBPDPCBBW/03 (CIRCUIT C2541) TRANSFERS OPEN
ACCBRC2559	1	24	H	Instrument Bus B (IBPDPCBBW) Breaker IBPDPCBBW/21 To MQ400B Transfers Open
ACCBRC2565	1	8	H	AC BREAKER IBPDPCBCB/03 (CIRCUIT C2565) TRANSFERS OPEN
ACCBRC2566	1	8	H	AC BREAKER IBPDPCBCB/04 (CIRCUIT C2566) TRANSFERS OPEN
ACCBRC2583	1	24	H	Instrument Bus C Breaker IBPDPCBCB/21 To MQ400C Transfers Open
ACCBRC2607	1	24	H	Instrument Bus D (IBPDPCBDY) Breaker IBPDPCBDY/21 To MQ400D Transfers Open
ACCBRC2612	1	8	H	AC BREAKER IBPDPCBA/01 (CIRCUIT C2612) TRANSFERS OPEN
ACCBRC2613	1	8	H	AC BREAKER IBPDPCBA/02 (CIRCUIT C2613) TRANSFERS OPEN
ACCBRC2630	1	8	H	AC BREAKER IBPDPCBB/01 (CIRCUIT C2630) TRANSFERS OPEN
ACCBRC2631	1	8	H	AC BREAKER IBPDPCBB/02 (CIRCUIT C2631) TRANSFERS OPEN
ACCBRC2648		8	H	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN
ACCBRC2649	1	8	H	AC BREAKER IBPDPCBC/02 (CIRCUIT C2649) TRANSFERS OPEN
ACCBRC2651	1	8	H	AC BREAKER IBPDPCBC/04 (CIRCUIT C2651) TRANSFERS OPEN
ACCBRC2662	1	8	H	AC BREAKER IBPDPCBD/02 (CIRCUIT C2662) TRANSFERS OPEN
ACCBRCB302	1	24	H	120 VAC Circuit Breaker ACPDPCB03/02 Transfers Open
ACCBRCB602	1	24	H	120 VAC Circuit Breaker ACPDPCB06/02 Transfers Open
ACCBRCBAR1	1	24	H	AC Instrument Bus A Breaker 1 (IBPDPCBAR/01) Transfers Open
ACCBRCBB/1	1	0	H	AC BREAKER MCCB/1 TRANSFERS OPEN
ACCBRCBC05	1	0	H	120 VAC Instrument Bus C Circuit Breaker IBPDPCBC/05 Transfers Open

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Basic Event	C	Factor	Units	Description
ACCBRCBCB1	1	24	H	AC Instrument Bus B Breaker 1 (IBPDPCBCB/01) Transfers Open
ACCBRCBE01	1	0	H	120 VAC Instrument Bus A Circuit Breaker IBPDPCBE/01 Transfers Open
ACCBRCC08J	1	0	H	480 VAC Circuit Breaker MCCC/08J (42/860A) Transfers Open
ACCBRCC08M	1	0	H	480 VAC Circuit Breaker MCCC/08M (42/896A) Transfers Open
ACCBRCC11F	1	0	H	480 VAC Circuit Breaker MCCC/11F (42/860C) Transfers Open
ACCBRCD08J	1	0	H	480 VAC Circuit Breaker MCCD/08J (42/860B) Transfers Open
ACCBRCD08M	1	0	H	480 VAC Circuit Breaker MCCD/08M (42/896B) Transfers Open
ACCBRCD11F	1	0	H	480 VAC Circuit Breaker MCCD/11F (42/860D) Transfers Open
ACCBRD/01B	1	0	H	AC BREAKER MCCD/01B TRANSFERS OPEN
ACCBRD/02F	1	0	H	AC BREAKER MCCD/02F TRANSFERS OPEN
ACCBRD/03F	1	0	H	AC BREAKER MCCD/03F TRANSFERS OPEN
ACCBRD/06C	2	2075	H	AC BREAKER MCCD/06C TRANSFERS OPEN
ACCBRD/06J	1	0	H	AC BREAKER MCCD/06J TRANSFERS OPEN
ACCBRD/07J	1	0	H	AC BREAKER MCCD/07J TRANSFERS OPEN
ACCBRD/07M	1	0	H	AC BREAKER MCCD/07M TRANSFERS OPEN
ACCBRD/09M	1	0	H	AC BREAKER MCCD/09M TRANSFERS OPEN
ACCBRD/10J	1	0	H	AC BREAKER MCCD/10J TRANSFERS OPEN
ACCBRD/12F	1	0	H	AC BREAKER MCCD/12F TRANSFERS OPEN
ACCBRD/15F	1	0	H	AC BREAKER MCCCD15F TRANSFERS OPEN
ACCBRD16FF	1	0	H	AC BREAKER MCCD/16FF TRANSFERS OPEN
ACCBRF/04B	1	0	H	AC BREAKER MCCF/04B TRANSFERS OPEN
ACCBRF/04D	1	0	H	AC BREAKER MCCF/04D TRANSFERS OPEN
ACCBRH/01K	1	24	H	AC BREAKER MCC/01K TRANSFERS OPEN
ACCBRH/02B	1	24	H	AC BREAKER MCCH/02B TRANSFERS OPEN
ACCBRH/02D	1	24	H	AC BREAKER MCCH/02D TRANSFERS OPEN
ACCBRJ/01K	1	24	H	AC BREAKER MCCJ/01K TRANSFERS OPEN
ACCBRJ/02B	1	24	H	AC BREAKER MCCJ/02B TRANSFERS OPEN
ACCBRJ/02D	1	24	H	AC BREAKER MCCJ/02D TRANSFERS OPEN
ACCBRK/01B	1	0	H	AC BREAKER MCCK/01B TRANSFERS OPEN
ACCBRK/01F	1	0	H	AC BREAKER MCCK/01F TRANSFERS OPEN
ACCBRK01DD	1	24	H	480 VAC Circuit Breaker MCCK/01DD Transfers Open
ACCBRL/01B	1	0	H	AC BREAKER MCCL/01B TRANSFERS OPEN
ACCBRL/02M	1	0	H	AC BREAKER MCCL/02M TRANSFERS OPEN
ACCBRM/02M	1	0	H	AC BREAKER MCCM/02M TRANSFERS OPEN
ACCBRMC04H	1	24	H	480 VAC Motor Control Center C Breaker MCCC/04H Transfers Open
ACCBRMC05D	1	24	H	AC Breaker MCCC/5D Transfers Open (To Battery Charger A1)
ACCBRMC07K	1	24	H	480 VAC Motor Control Center B Breaker MCCB/07K Transfers Open
ACCBRMC16D	1	24	H	480 VAC Motor Control Center C Breaker MCCC/16D Transfers Open
ACCBRMC4HH	1	24	H	AC Breaker MCCC/4HH Transfers Open (To Battery Charger A)
ACCBRMCC1A	1	24	H	480 VAC MCCA Feeder Circuit Breaker 52/MCCA (BUS13/08B) Transfers Open
ACCBRMCC1B	1	24	H	480 VAC MCCB Feeder Circuit Breaker 52/MCCB (BUS15/04A) Transfers Open
ACCBRMCC1C	1	24	H	480 VAC MCCC Feeder Circuit Breaker 52/MCCC (BUS14/22C) Transfers Open

Basic Event	C	Factor	Units	Description
ACCBRMCC1D	1	24	H	480 VAC MCCD Feeder Circuit Breaker 52/MCCD (BUS16/16C) Transfers Open)
ACCBRMCC1E	1	24	H	480 VAC MCCE Feeder Circuit Breaker 52/MCCE (BUS15/05B) Transfers Open
ACCBRMCC1F	1	24	H	480 VAC MCCF Feeder Circuit Breaker 52/MCCF (BUS15/2C) Transfers Open
ACCBRMCC1H	1	24	H	480 VAC MCCH Feeder Circuit Breaker 52/MCCH (MCCC/05MM) Transfers Open
ACCBRMCC1J	1	24	H	480 VAC MCCJ Feeder Circuit Breaker 52/MCCJ (MCCD/05KK) Transfers Open
ACCBRMCC1K	1	24	H	480 VAC MCCK Feeder Circuit Breaker 52/MCCK (MCCC/05M) Transfers Open
ACCBRMCC1L	1	24	H	480 VAC MCCL Feeder Circuit Breaker 52/MCCL (MCCC/11J) Transfers Open
ACCBRMCC1M	1	24	H	480 VAC MCCM Feeder Circuit Breaker 52/MCCM (MCCD/15D) Transfers Open
ACCBRMCC4D	1	24	H	408 VAC Motor Control Center D Breaker MCCD/04D Transfers Open
ACCBRMD16F	1	24	H	AC Breaker MCCD/16F Transfers Open (To Battery Charger B1)
ACCBRMD4MM	1	24	H	AC Breaker MCCD/4MM Transfers Open (To Battery Charger B)
ACCBRPOL10	1	0	H	AC BREAKER MCCC/02H TRANSFERS OPEN
ACCC0UVAGA		7.650E-06		Common Cause Failure Of AC Power Agastat Time Delay Relays To Energize
ACCFR024BN	1	0	H	FUSE FUBUS14/24B-N FAILS OPEN
ACCFR024BP	1	0	H	FUSE FUSBUS14/24B-P FAILS OPEN
ACCFRB/02M	1	0	H	FUSE FUMCCB/02M FAILS OPEN
ACIVF0400A	1	24	H	Failure Of Twinco Voltage Regulator MQ400A
ACIVF0400B	1	24	H	Twinco Voltage Regulator MQ400B Fails
ACIVF0400C	1	24	H	Failure Of Twinco Voltage Regulator MQ400C
ACIVF0400D	1	24	H	Failure Of Twinco Voltage Regulator MQ400D
ACIVF0400E	1	24	H	Failure Of Twinco Voltage Regulator MQ400E
ACIVFBUS1A	1	24	H	Failure Of Instrument Bus A (IBPDPCBAR) Static Switch SCICBAR
ACIVFBUS1C	1	24	H	Instrument Bus C (IBPDPCBCB) Static Switch SCICBCB Fails
ACLOPRTALL		1.00E-03		Loss of All Off-Site Power Following Reactor Trip
ACMMACPNLB		2.042E-04		120 VAC Distribution Panel B (IBPDPCBB) Faults
ACMMACPNLC		2.042E-04		120 VAC Distribution Panel C (IBPDPCBC) Faults
ACMMACPNLE		2.042E-04		120 VAC Distribution Panel E (IBPDPCBE) Faults
ACMMBUS013		1.029E-04		Bus Faults On 480 VAC Bus 13
ACMMBUS01A		2.042E-04		120 VAC Instrument Bus A (IBPDPCBAR) Bus Faults
ACMMBUS01B		8.005E-05		120 VAC Instrument Bus B (IBPDPCBBW) Bus Faults
ACMMBUS01C		2.042E-04		120 VAC Instrument Bus C (IBPDPCBCB) Bus Faults
ACMMBUS01D		8.005E-05		120 VAC Instrument Bus D (IBPDPCBDY) Bus Faults
ACMMDIST0A		2.042E-04		120 VAC Distribution Panel (IBPDPCBA) Faults
ACMMDIST0D		2.042E-04		120 VDC Distribution Panel D (IBPDPCBD) Faults
ACMMINV01A		5.190E-04		Instrument Bus A (IBPDPCBAR) Inverter INVTA Circuit Faults
ACMMINV01C		5.783E-04		Instrument Bus C (IBPDPCBCB) Inverter INVTB Circuit Faults
ACMMMCC01A		5.074E-05		480 VAC Motor Control Center MCCA Faults
ACMMMCC01B		5.074E-05		
ACMMMCC01C		5.074E-05		480 VAC Motor Control Center MCCC Faults
ACMMMCC01D		5.074E-05		480 VAC Motor Control Center MCCD Faults
ACMMMCC01E		5.074E-05		480 VAC Motor Control Center MCCE Faults
ACMMMCC01F		5.074E-05		480 VAC Motor Control Center MCCF Faults

Table 3.3.7-2
Integrated CAFTA BE File

Basic Event	C Factor	Units	Description
ACMMMCC01H	5.074E-05		480 VAC Motor Control Center MCCH Faults
ACMMMCC01J	5.074E-05		480 VAC Motor Control Center MCCJ Faults
ACMMMCC01K	5.074E-05		480 VAC Motor Control Center MCCK Faults
ACMMMCC01L	5.074E-05		480 VAC Motor Control Center MCCL Faults
ACMMMCC01M	5.074E-05		480 VAC Motor Control Center MCCM Faults
ACMMSST014	8.405E-05		
ACMMSST015	8.405E-05		4160 VAC / 480 VAC Transformer PXTBSS015 Faults
ACMMSST016	8.405E-05		Transformer PXABSS016 Faults
ACMMSST017	8.405E-05		Transformer PXSHSS017 Faults
ACMMSST018	8.405E-05		Transformer PXSHSS018 Faults
ACMMSTAT0A	7.836E-05		Instrument Bus A (IBPDPCBAR) Constant Voltage Transformer CVTA Faults
ACMMSTAT0C	7.836E-05		Instrument Bus C (IBPDPCBCB) Constant Voltage Transformer CVTB Faults
ACREBBX114 1	1		Bus 14 Breaker Auxiliary Relay 18BX1/14 Fails To Deenergize On Demand
ACREBBX116 1	1		Bus 16 Breaker Auxiliary Relay 11BX1/16 Fails To Deenergize On Demand
ACREBBX214 1	1		Bus 14 Breaker Auxiliary Relay 18BX2/14 Fails To Deenergize On Demand
ACREBBX216 1	1		Bus 16 Breaker Auxiliary Relay 11BX2/16 Fails To Deenergige On Demand
ACREE0052Z 1	1	N	RELAY 52Z FAILS TO ENERGIZE ON DEMAND
ACREE1T12A 1	1	N	Synchro Verifier Relay 25A/11T-12A Fails To Energize On Demand
ACREE1T12B 1	1	N	Synchro Verifier Relay 25B/11T-12B Fails To Energize On Demand
ACREE63/X3 1	1	N	RELAY 63/X3 FAILS TO ENERGIZE ON DEMAND
ACREE63/X4 1	1	N	RELAY 63/X4 FAILS TO ENERGIZE ON DEMAND
ACREE63/X5 1	1	N	RELAY 63/X5 FAILS TO ENERGIZE ON DEMAND
ACREE6BU1G 1	1	N	Turbine / Generator Backup Lockout Relay 86BU/1G Fails To Energige On Demand
ACREE86P1G 1	1	N	Turbine / Generator Primary Lockout Relay 86P/1G Fails To Energize On Demand
ACREE86X1G 1	1	N	Turbine / Generator Auxiliary Lockout Relay 86X/1G Fails To Energize On Demand
ACREE94P1G 1	1	N	Turbine / Generator Primary Lockout Relay 94P/1G Fails To Energize On Demand
ACREEXT12A 1	1	N	Synchro Verifier Auxiliary Relay 25AX/11T-12A Fails To Energize On Demand
ACREEXT12B 1	1	N	Synchro Verifier Auxiliary Relay 25BX/11T-12B Fails To Energize On Demand
ACREK6B12A 1	24	H	4160 VAC Bus 12A Backup Differential Lockout Relay 86B/12A Spuriously Energizes
ACREK6B12B 1	24	H	4160 VAC Bus 12B Backup Differential Lockout Relay 86B/12B Spuriously Energizes
ACREK8611A 1	24	H	4160 VAC Bus 11A Differential Lockout Relay 86/11A Spuriously Energizes
ACREK8611B 1	24	H	4160 VAC Bus 11B Differential Lockout Relay 86/11B Spuriously Energizes
ACREK8612A 1	24	H	4160 VAC Bus 12A Differential Lockout Relay Spuriously Energizes
ACREK8612B 1	24	H	4160 VAC Bus 12B Differential Lockout Relay 86/12B Spuriously Energizes
ACREKBX114 1	24	H	Bus 14 Breaker Auxiliary Relay 18BX1/14 Spuriously Energizes
ACREKBX116 1	24	H	Bus 16 Breaker Auxiliary Relay 11BX1/16 Spuriously Energizes
ACREKBX214 1	24	H	Bus 14 Breaker Auxiliary Relay 18BX2/14 Spuriously Energizes
ACRTD00BLA 1	1		Agastat Time Delay Relay 2/BLA Fails To Energize After KDG01A Starts
ACRTD00BLB 1	1		Agastat Time Delay Relay 2/BLB Fails To Energize After KDG01B Starts
ACRTD00CCF 1	1		Agastat Time Delay Relay Fails To Energize On Demand
ACRTD62AST 1	1	N	Turbine Auto Stop Timer Relay 62AST Fails On Demand
ACRTDCCF$$	.1		Beta Factor For Common Cause Failure Event ACCCOUVAGA

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Basic Event	C	Factor	Units	Description
ACSCZB1G13				
ACSCZB9X13				
ACSZCA12AX	1	1	N	4160 VAC Circuit Breaker 52/12AX Auxiliary Switch 52a/12AX Fails To Close
ACSZCB1G13	1	1	N	Circuit Breaker Auxiliary Switch 52b/1G13A72 Fails To Close
ACSZCB9X13	1	1	N	Circuit Breaker Auxiliay Switch 52b/9X13A72 Fails to Close
ACSZCS12BX	1	1	N	4160 VAC Circuit Breaker 52/12BX Cell (S) Switch 52S/12BX Fails To Close
ACT1FSST13	1	24	H	Fault On 480 VAC Bus 13 4160 / 480 VAC Transformer PXTBSS013
ACT1FSST14	1	24	H	Fault On 4160 VAC / 480 VAC Bus 14 Transformer PXABSS014
ACT1FSST15	1	24	H	Fault On 4160 VAC / 480 VAC Bus 15 Transformer PXTBSS015
ACT1FSST16	1	24	H	480 VAC Bus 16 Transformer PXABSS016 Transfers Open
ACT1FSST17	1	24	H	Fault On 480 VAC Bus 17 4160 / 480 VAC Transformer PXSHSS017
ACT1FSST18	1	24	H	Fault On 480 VAC Bus 18 4160 / 480 VAC Transformer PXSHSS018
ACT1FST12A	1	24	H	Fault On Station Auxiliary Transformer PXYD012A
ACT1FST12B	1	24	H	Fault On Station Auxiliary Transformer PXYD012B
ACT1FTRAN6	1	24	H	Failure Of Station 13A 115 kVAC / 34.5 kVAC Transformer #6 (RG&E Circuit 767)
ACT6FBUS1A	1	24	H	Failure Of Constant Voltage Transformer CVTA
ACT6FBUS1C	1	24	H	Failure Of Constant Voltage Transformer CVTB
ACT6FCB005	1	24	H	480 VAC / 120 VAC Transformer PXCB005 Fails
ACT6FCB01E	1	24	H	480 VAC / 120 VAC Transformer PXCB001E Fails
ACT6FCVT1B	1	24	H	Instrument Bus D (IBPDPCBDY) Constant Voltage Transformer CVTA2 Fails
ACT6FCVTA2	1	24	H	Instrument Bus B (IBPDPCBBW) Constant Voltage Transformer CVTA1 Fails
AF100				No Flow To Either S/G From Any AFW Train
AF400				Turbine-Driven AFW Pump Train Fails To Provide Flow To S/Gs
AF493				Air-Operated Valve 4297 Fails To Close To Isolate S/G A (TDAFW Pump)
AF497				Air-Operated Valve 4298 Fails To Close To Isolate S/G A (TDAFW Pump)
AF500				Motor-Driven AFW Pump Train A Fails To Provide Flow To S/Gs
AF586				Failure To Close MOV 4007 To Isolate S/G A When Required
AF600				Motor-Driven AFW Pump Train B Fails To Provide Flow To S/Gs
AF686				Failure To Close MOV 4008 To Isolate S/G B When Required
AF800				Less Than Full AFW Flow To Either S/G
AF900				Failure Of Standby Auxiliary Feedwater To Both Steam Generators
AFAVK04291	1	384	H	Air operated valve 4291 transfers closed
AFAVK04297	1	384	H	Air operated valve 4297 transfers closed
AFAVK04298	1	384	H	Air operated valve 4298 transfers closed
AFAVP04304	1	1116	H	Air operated valve 4304 fails to open
AFAVP04310	1	1116	H	Air operated valve 4310 fails to open
AFAVP9710A	1	1116	H	Air operated valve 9710A fails to open
AFAVP9710B	1	1116	H	Air operated valve 9710B fails to open
AFAVPCCF$$		1.79E-01		Beta factor for AFW air operated valve fails to open
AFAVX04297	1	5580	H	Air operated valve 4297 fails to close
AFAVX04298	1	5580	H	Air operated valve 4298 fails to close
AFCCDMOVNA		8.640E-05		Common cause failure of MOVs 4007 and 4008 to throttle flow

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Table [illegible]7-2
Integrated C[illegible] BE File

Basic Event	C	Factor	Units	Description
AFCCDMOVNB		8.640E-05		Common cause failure of MOVs 9701A and 9701B to throttle flow
AFCCFMDAFW		2.743E-05		Common cause failure of AFW Pumps 1A and 1B to run
AFCCFSAFWA		2.743E-05		Common cause failure of SAFW Pumps 1C and 1D to run
AFCCPCROSS		2.611E-04		Common cause failure of MOVs 4000A and 4000B to open
AFCCPCSTCV		6.612E-06		Common cause failure of check valves 4014, 4016, and 4017 to open
AFCCPDISCA		6.612E-06		Common cause failure of check valves 4009, 4010, and 3998 to open
AFCCPDISCB		6.612E-06		Common cause failure of check valves 9700A and 9700B to open
AFCCPRECLA		5.094E-04		Common cause failure of AOVs 4304 and 4310 to open
AFCCPRECLB		5.094E-04		Common cause failure of AOVs 9710A and 9710B to open
AFCCPSAFWX		2.611E-04		Common cause failure of MOVs 9703A and 9703B to open
AFCCPSGINA		6.612E-06		Common cause failure of check valves 4000C, 4000D, 4003, and 4004 to open
AFCCPSGINB		6.612E-06		Common cause failure of check valves 9705A and 9705B to open
AFCCPSLUIC		1.137E-06		Common cause failure of check valves 9574A and 9588A to open
AFCCSMDAFW		3.662E-05		Common cause failure of AFW Pumps 1A and 1B to start
AFCCSSAFWA		3.662E-05		Common cause failure of SAFW Pumps 1C and 1D to start
AFCVC4000C	1	1		Check Valve 4000C Fails to Close
AFCVC4000D	1	1		Check Valve 4000D Fails to Close
AFCVC9705A	1	1		Check Valve 9705A Fails to Close
AFCVC9705B	1	1		Check Valve 9705B Fails to Close
AFCVP03998	1	384	H	Check valve 3998 fails to open
AFCVP04003	1	384	H	Check valve 4003 fails to open
AFCVP04004	1	384	H	Check valve 4004 fails to open
AFCVP04009	1	384	H	Check valve 4009 fails to open
AFCVP04010	1	384	H	Check valve 4010 fails to open
AFCVP04014	1	384	H	Check valve 4014 fails to open
AFCVP04016	1	384	H	Check valve 4016 fails to open
AFCVP04017	1	384	H	Check valve 4017 fails to open
AFCVP04023	1	384	H	Check valve 4023 fails to open
AFCVP04045	1	4404	H	Check valve 4045 fails to open
AFCVP04049	1	66	H	Check valve 4049 fails to open
AFCVP4000C	1	384	H	Check valve 4000C fails to open
AFCVP4000D	1	384	H	Check valve 4000D fails to open
AFCVP9574A	1	66	H	Check valve 9574A fails to open
AFCVP9588A	1	66	H	Check valve 9588A fails to open
AFCVP9700A	1	384	H	Check valve 9700A fails to open
AFCVP9700B	1	384	H	Check valve 9700B fails to open
AFCVP9705A	1	384	H	Check valve 9705A fails to open
AFCVP9705B	1	384	H	Check valve 9705B fails to open
AFCVPCCF$$		6.00E-02		Beta factor for AFW check valve fails to open
AFFTD04084	1	1116	H	Flow transmitter FT-4084 fails to respond
AFFTD04085	1	1116	H	Flow transmitter FT-4085 fails to respond
AFFTH02001	1	384	H	Flow transmitter FT-2001 fails high

Basic Event	C	Factor	Units	Description
AFFTH02002	1	384	H	Flow transmitter FT-2002 fails high
AFFTH04084	1	384	H	Flow transmitter FT-4084 fails high
AFFTH04085	1	384	H	Flow transmitter FT-4085 fails high
AFHFD04297		0.1		Operators fail to close air operated valve 4297 to isolate S/G A
AFHFD04298		0.1		Operators fail to close air operated valve 4298 to isolate S/G B
AFHFD1ATRP		1.00		Operators fail to reopen MOV 4007 after Pump 1A trips
AFHFD1BTRP		1.00		Operators fail to reopen MOV 4008 after Pump 1B trips
AFHFDAFWAB		1.00		Operators fail to open cross-tie valves between AFW motor-driven trains
AFHFDC4007		0.1		Operators fail to close 4007 to isolate S/G A
AFHFDC4008		0.1		Operators fail to close 4008 to isolate S/G B
AFHFDPCD04		1.00		Operators fail to provide water to the CSTs from the Hotwell
AFHFDSAFWX		1.00E-04		Operators fail to start SAFW Pump 1C and 1D
AFHFDSWX03		1.00		Operators fail to perform suction transfer from CST to SW
AFHFDXSAFW		1.00		Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G
AFHFL0AFWA		3.00E-03		Failure to restore AFW Motor-Driven Pump Train 1A to service post test/maint
AFHFL0AFWB		3.00E-03		Failure to restore AFW Motor-Driven Pump Train 1B to service post test/maint
AFHFLSAFWA		3.00E-03		Failure to restore SAFW Pump Train 1C to service post test/maint
AFHFLSAFWB		3.00E-03		Failure to restore SAFW Pump Train 1D to service post test/maint
AFHFLTDAFW		3.00E-03		Failure to restore TDAFW pump train to service post test/maintenance
AFHXFEAF01	1	1116	H	AFW Turbine-Driven Pump Lube Oil Cooler EAF01 cooling cap fails
AFHXFEAF2A	1	1116	H	AFW Motor-Driven Pump 1A Lube Oil Cooler EAF02A cooling cap fails
AFHXFEAF2B	1	1116	H	AFW Motor-Driven Pump 1A Lube Oil Cooler EAF02B cooling cap fails
AFLTD2022A	1	384	H	Condensate Storage Tank A level transmitter LT-2022A fails to respond
AFLTD2022B	1	384	H	Condensate Storage Tank B level transmitter LT-2022B fails to respond
AFMM04028		0.000E+00		4028 Circuit Breaker or Control Fuses Fail
AFMM0TDAFW		1.283E-02		Failure of TDAFW pump train components
AFMMAFWABX		2.388E-04		Failure of valves for AFW Train A to Train B cross-connect
AFMMCB4007		0.000E+00		4007 Circuit Breaker or Control Fuses Fail
AFMMCB4008		0.000E+00		4008 Circuit Breaker or Control Fuses Fail
AFMMCB4013		0.000E+00		4013 Circuit Breaker or Control Fuses Fail
AFMMCB4027		0.000E+00		4027 Circuit Breaker or Control Fuses Fail
AFMMCBMDPA		0.000E+00		PAF01A Circuit Breaker or Control Fuses Fail
AFMMCBMDPB		0.000E+00		PAF01B Circuit Breaker or Control Fuses Fail
AFMMCBSBPC		0.000E+00		PSF01A Circuit Breaker or Control Fuses Fail
AFMMCBSBPD		0.000E+00		PSF01B Circuit Breaker or Control Fuses Fail
AFMMHOTWEL		4.938E-03		Failure of components needed to transfer condensate
AFMMMDFP1A		6.842E-03		Failure of AFW Motor-Driven AFW Pump Train A
AFMMMDFP1B		6.842E-03		Failure of AFW Motor-Driven AFW Pump Train B
AFMMNOOCST		2.983E-04		Outside Condensate Storage Tank not available
AFMMSAFWPC		2.324E-02		Failure of SAFW Pump 1C train
AFMMSAFWPD		2.324E-02		Failure of SAFW Pump 1D Train
AFMMSGAINJ		1.798E-03		Failure of AFW injection line to S/G A

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Basic Event	C	Factor	Units	Description
AFMMSGASAF		5.467E-04		Failure of SAFW injection line to S/G A
AFMMSGASTM		2.655E-03		Failure of S/G A Main Steam components to TDAFW pump
AFMMSGBINJ		1.798E-03		Failure of AFW injection line to S/G B
AFMMSGBSAF		9.010E-04		Failure of SAFW injection line to S/G B
AFMMSGBSTM		2.655E-03		Failure of S/G B Main Steam components to TDAFW pump
AFMMSGTURA		6.212E-04		Failure of TDAFW injection line to S/G A
AFMMSGTURB		6.212E-04		Failure of TDAFW injection line to S/G B
AFMMSLUICA		1.708E-04		Failure of valves associated with Sluice Pump A
AFMMSLUICB		1.708E-04		Failure of components associated with Sluice Pump B
AFMMSWPMPA		2.196E-02		Failure of Service Components for AFW Motor-Driven Pump B
AFMMSWPMPB		2.196E-02		Failure of Service Water components for AFW Motor-Driven Pump B
AFMMSWTDAF		4.815E-03		Failure of main Service Water line to TDAFW pump
AFMMSWTURB		2.196E-02		Failure of Service Water components to TDAFW pump
AFMMSWXXXA		4.679E-03		Failure of main Service Water line to AFW Motor-Driven Pump 1A
AFMMSWXXXB		4.679E-03		Failure of main Service Water line to AFW Motor-Driven Pump 1B
AFMMXXCSTS		5.422E-04		Failure of Condensate Storage Tanks
AFMPFCCF$$		3.00E-02		Beta factor for AFW motor-driven pump fails to run
AFMPFPAF1A	1	24	H	AFW Motor-Driven Pump 1A fails to run
AFMPFPAF1B	1	24	H	AFW Motor-Driven Pump 1B fails to run
AFMPFPCD04	1	24	H	Condensate Transfer Pump PCD04 fails to run
AFMPFPSF1A	1	24	H	SAFW Motor-Driven Pump 1C fails to run
AFMPFPSF1B	1	24	H	SAFW Motor-Driven Pump 1D fails to run
AFMPSCCF$$		2.98E-02		Beta factor for AFW motor-driven pump fails to start
AFMPSPAF1A	1	384	H	AFW Motor-Driven Pump 1A fails to start
AFMPSPAF1B	1	384	H	AFW Motor-Driven Pump 1B fails to start
AFMPSPCD04	1	66	H	Condensate Transfer Pump PCD04 fails to start
AFMPSPSF1A	1	384	H	SAFW Motor-Driven Pump 1C fails to start
AFMPSPSF1B	1	384	H	SAFW Motor-Driven Pump 1D fails to start
AFMVD04007	1	384	H	Motor operated valve 4007 fails to throttle flow
AFMVD04008	1	384	H	Motor operated valve 4008 fails to throttle flow
AFMVD9701A	1	384	H	Motor operated valve 9701A fails to throttle flow
AFMVD9701B	1	384	H	Motor operated valve 9701B fails to throttle flow
AFMVDCCF$$		1.00E-01		Beta factor for AFW motor operated valve fails to throttle flow
AFMVK03996	1	384	H	Motor operated valve 3996 transfers closed
AFMVK09746	1	384	H	Motor operated valve 9746 transfers closed
AFMVK9704A	1	384	H	Motor operated valve 9704A transfers closed
AFMVK9704B	1	384	H	Motor operated valve 9704B transfers closed
AFMVP04007	1	384	H	Motor operated valve 4007 fails to open
AFMVP04008	1	384	H	Motor operated valve 4008 fails to open
AFMVP4000A	1	384	H	Motor operated valve 4000A fails to open
AFMVP4000B	1	384	H	Motor operated valve 4000B fails to open
AFMVP9703A	1	384	H	Motor operated valve 9703A fails to open

Table 3.3.7-2
Integrated CAFTA BE File

Basic Event	C	Factor	Units	Description
AFMVP9703B	1	384	H	Motor operated valve 9703B fails to open
AFMVPCCF$$		8.00E-02		Beta factor for AFW motor operated valve fails to open
AFMVX04007	1	384	H	Motor operated valve 4007 fails to close
AFMVX04008	1	384	H	Motor operated valve 4008 fails to close
AFMVX09746	1	1116	H	Motor operated valve 9746 fails to close
AFMVX9704A	1	1116	H	Motor operated valve 9704A fails to close
AFMVX9704B	1	1116	H	Motor operated valve 9704B fails to close
AFPCD02033	1	1116	H	Pressure controller PC-2033 fails to respond
AFPCD02034	1	1116	H	Pressure controller PC-2034 fails to respond
AFPPJFAILX	1	24	H	Failure of AFW pump suction line (pipe rupture)
AFTKBTCD2A	1	66	H	Bladder for CST A ruptures
AFTKBTCD2B	1	66	H	Bladder for CST B ruptures
AFTKJTCD03	1	24	H	Outside Condensate Storage Tank TCD03 ruptures
AFTKJTCD2A	1	12	H	Condensate Storage Tank A (TCD02A) ruptures
AFTKJTCD2B	1	12	H	Condensate Storage Tank B (TCD02B) ruptures
AFTM004048		1.10E-03		Manual valve 4048 out of service for testing/maintenance
AFTM0AFWAB		4.33E-03		AFW cross-connect line out-of-service for maintenance
AFTM0AFWIA		2.48E-03		AFW injection line to S/G A out-of-service for maintenance
AFTM0AFWIB		2.48E-03		AFW injection line to S/G B out-of-service for maintenance
AFTM0AFWPA		3.19E-03		AFW Pump Train 1A out-of-service for maintenance
AFTM0AFWPB		3.19E-03		AFW Pump Train 1B out-of-service for maintenance
AFTM0TDAFW		9.04E-03		TDAFW Pump Train out-of-service for maintenance
AFTMCONDPP		2.91E-03		Condensate Transfer Pump out-of-service for test/maintenance
AFTMOUTCON		1.10E-03		Outside Condensate Storage Tank valves out-of-service for test/maintenance
AFTMSAFWAB		4.33E-03		SAFW cross-connect line out-of-service for maintenance
AFTMSAFWIA		2.85E-03		SAFW injection line to S/G A out-of-service for maintenance
AFTMSAFWIB		4.65E-03		SAFW injection line to S/G B out-of-service for maintenance
AFTMSAFWPC		5.55E-03		SAFW Pump Train 1C out-of-service for maintenance
AFTMSAFWPD		5.55E-03		SAFW Pump Train 1D out-of-service for maintenance
AFTMTDAFWA		1.50E-03		TDAFW Pump Train injection line to S/G A out-of-service for maintenance
AFTMTDAFWB		1.50E-03		TDAFW Pump Train injection line to S/G B out-of-service for maintenance
AFTPFTDAFW	1	24	H	Turbine-driven AFW pump fails to run
AFTPSTDAFW	1	384	H	Turbine-driven AFW pump fails to start
AFXVK03999	1	384	H	Manual valve 3999 transfers closed
AFXVK04000	1	384	H	Manual valve 4000 transfers closed
AFXVK04001	1	384	H	Manual valve 4001 transfers closed
AFXVK04002	1	384	H	Manual valve 4002 transfers closed
AFXVK04005	1	384	H	Manual valve 4005 transfers closed
AFXVK04006	1	384	H	Manual valve 4006 transfers closed
AFXVK04011	1	384	H	Manual valve 4011 transfers closed
AFXVK04012	1	384	H	Manual valve 4012 transfers closed
AFXVK04015	1	384	H	Manual valve 4015 transfers closed

Basic Event	C	Factor	Units	Description
AFXVK04018	1	384	H	Manual valve 4018 transfers closed
AFXVK04019	1	384	H	Manual valve 4019 transfers closed
AFXVK04048	1	66	H	Manual valve 4048 transfers closed
AFXVK04070	1	384	H	Manual valve 4070 transfers closed
AFXVK04071	1	384	H	Manual valve 4071 transfers closed
AFXVK04081	1	1116	H	Manual valve 4081 transfers closed
AFXVK04082	1	1116	H	Manual valve 4082 transfers closed
AFXVK04356	1	1116	H	Manual valve 4356 transfers closed
AFXVK04357	1	1116	H	Manual valve 4357 transfers closed
AFXVK4070A	1	66	H	Manual valve 4070A transfers closed
AFXVK4071A	1	66	H	Manual valve 4071A transfers closed
AFXVK9501B	1	66	H	Manual valve 9501B transfers closed
AFXVK9509C	1	384	H	Manual valve 9509C transfers closed
AFXVK9570A	1	66	H	Manual valve 9570A transfers closed
AFXVK9573A	1	66	H	Manual valve 9573A transfers closed
AFXVK9702A	1	384	H	Manual valve 9702A transfers closed
AFXVK9702B	1	384	H	Manual valve 9702B transfers closed
AFXVK9702C	1	1116	H	Manual valve 9702C transfers closed
AFXVK9702D	1	87624	H	Manual valve 9702D transfers closed
AFXVK9706A	1	384	H	Manual valve 9706A transfers closed
AFXVK9706B	1	384	H	Manual valve 9706B transfers closed
AFXVP04046	1	4404	H	Manual valve 4046 fails to open
AFXVP9509E	1	384	H	Manual valve 9509E fails to open
AFXVP9584G	1	384	H	Manual valve 9584G fails to open
AFXVP9586G	1	384	H	Manual valve 9586G fails to open
AFXVX04047	1	4404	H	Manual valve 4047 fails to close
AFXVX9509C	1	4404	H	Manual valve 9509C fails to close
AFXVX9509D	1	384	H	Manual valve 9509D fails to close
AFXVX9509F	1	384	H	Manual valve 9509F fails to close
CC000				Failure of the CCW to loads
CC010				CCW Not Available To RCP A Pump Seal
CC020				CCW Not Available To RCP B Pump Seal
CC212				CCW Heat Exchanger EAC01A Is Not In Service
CCAVK0754A	1	24		AIR-OPERATED VALVE 754A TRANSFER CLOSED
CCAVK0754B	1	24		AIR-OPERATED VALVE 754B TRANSFER CLOSED
CCBREAK001		0		CCW LINE TO RCP A BREAKS DUE TO DAMAGE DURING A LOCA
CCBREAK002		0		CCW LINE TO RCP B BREAKS DUE TO DAMAGE DURING A LOCA
CCCC738A/B		3.452E-04		MOVS 738A/B FAIL TO OPEN <common cause event>
CCCCPUMP/R		8.354E-06		COMMON CAUSE FAILURE OF CCW PUMPS TO RUN
CCCCPUMP/S		5.458E-05		COMMON CAUSE FAILURE TO START OF CCW PUMPS
CCCVK00816	1	24		CHECK VALVE 816 TRANSFERS CLOSED
CCCVK0723A	1	24		CHECK VALVE 723A TRANSFER CLOSED

Table [illegible]2
Integrated C[illegible] BE File

Basic Event	C	Factor	Units	Description
CCCVK0723B	1	24		CHECK VALVE 723B TRANSFERS CLOSED
CCCVK0750A	1	24		CHECK VALVE 750A TRANSFERS CLOSED
CCCVK0750B	1	24		CHECK VALVE 750B TRANSFERS CLOSED
CCCVK0753A	1	24		CHECK VALVE 753A TRANSFERS CLOSED
CCHFDSTART		.1		OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI
CCHFD_HX_A		1E-3		OPERATOR FAILS TO CORRECTLY PUT CCW HEAT EXCHANGER EAC01A INTO SERVICE
CCHFD_HX_B		1E-3		OPERATOR FAILS TO CORRECTLY PUT CCW HEAT EXCHANGER EAC01B INTO SERVICE
CCHFD_RCPA		1E-3		OPERATOR FAILS TO ISOLATE CCW TO RCP A
CCHFD_RCPB		1E-3		OPERATOR FAILS TO ISOLATE CCW TO RCP B
CCHFL0780A		3.00E-03		CCW THROTTLING VALVE 780A MISPOSITIONED
CCHFL0780B		3.00E-03		CCW THROTTLING VALVE 780B MISPOSITIONED
CCHXF_HX_A	1	24		HEAT EXCHANGER EAC01A COOLING CAP. FAILS
CCHXF_HX_B	1	24		HEAT EXCHANGER EAC01B COOLING CAP. FAILS
CCHXJ_HX_A	1	24		EEAT EXCHANGER EAC01A TUBE RUPTURE
CCHXJ_HX_B	1	24		HEAT EXCHANGER EAC01B TUBE RUPTURE
CCHXP_HX_A	1	24		HEAT EXCHANGER EAC01A PLUGS
CCHXP_HX_B	1	24		HEAT EXCHANGER EAC01B PLUGS
CCMM00738A		4.762E-03		MOV 738A FAILS TO OPEN
CCMM00738B		4.762E-03		MOV 738B FAILS TO OPEN
CCMMEAC01A		2.292E-05		HEAT EXCHANGER TRAIN A FAILS TO COOL
CCMMEAC01B		2.292E-05		HEAT EXCHANGER TRAIN B FAILS TO COOL
CCMMPS-617		1.100E-03		PS 617 FAILS TO SEND START SIGNAL TO STANDBY PUMP
CCMMPUMPAA		0.000E+00		Failures of Circuit Breaker or DC Fuses Prevent Start of PAC01A
CCMMPUMPBA		0.000E+00		Failures of Circuit Breaker or DC Fuses Prevent Start of PAC01B
CCMMPUMP_A		3.134E-04		CCW_PA PUMP TRAIN FAILS TO RUN
CCMMPUMP_B		3.134E-04		CCW PUMP TRAIN B FAILS TO RUN
CCMMRCPAIS		1.480E-02		CCW To RCP A Not Isolated
CCMMRCPBIS		1.480E-02		CCW To RCP B Not Isolated
CCMMRHRHXA		5.540E-03		CCW FLOW THROUGH RHR HX EAC02A FAILS
CCMMRHRHXB		5.540E-03		CCW FLOW THROUGH RHR HX EAC02B FAILS
CCMMRRPMPA		1.007E-04		Manual valves for RHR Pump A transfer closed
CCMMRRPMPB		1.007E-04		Manual valves for RHR Pump B transfer closed
CCMM_COOLA		2.952E-06		SERVICE WATER FAILS TO PROVIDE COOLING TO EAC01A
CCMM_COOLB		2.952E-06		SERVICE WATER FAILS TO PROVIDE COOLING TO EAC01B
CCMM_RCP-A		1.681E-04		CCW TO RCP-A EQUIPMENT FAILURES
CCMM_RCP-B		1.443E-04		CCW TO RCP-B EQUIPMENT FAILURES
CCMPACCF$$		2.95E-02		CCF PROBABILITY FACTOR FOR PUMP FAILURE TO START
CCMPAPUMPA	1	1		MOTOR-DRIVEN CCW PUMP PAC02A FAILS TO START
CCMPAPUMPB	1	1		MOTOR-DRIVEN CCW PUMP PAC02B FAILS TO START
CCMPFCCF$$		2.95E-02		CCF PROBABILITY FACTOR FOR PUMP FAILURE TO RUN
CCMPFPUMPA	1	24		MOTOR-DRIVEN PUMP PACO2A FAILS TO RUN
CCMPFPUMPB	1	24		MOTOR-DRIVEN PUMP PACO2B FAILS TO RUN

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Basic Event	C	Factor	Units	Description
CCMVC0749A	1	1		MOTOR-OPERATED VALVE 749A FAILS TO CLOSE
CCMVC0749B	1	1		MOTOR-OPERATED VALVE 749B FAILS TO CLOSE
CCMVC0759A	1	1		MOTOR-OPERATED VALVE 759A FAILS TO CLOSE
CCMVC0759B	1	1		MOTOR-OPERATED VALVE 759B FAILS TO CLOSE
CCMVK00817	1	24		MOTOR-OP VALVE 817 TRANSFERS CLOSED
CCMVK0749A	1	24		MOTOR-OP VALVE 749A TRANSFERS CLOSED
CCMVK0749B	1	24		MOTOR-OP VALVE 749B TRANSFERS CLOSED
CCMVK0759A	1	24		MOTOR-OP VALVE 759A TRANSFERS CLOSED
CCMVK0759B	1	24		MOTOR-OP VALVE 759B TRANSFERS CLOSED
CCMVP0738A	1	372	H	MOTOR-OPERATED VALVE 738A FAILS TO OPEN
CCMVP0738B	1	372	H	MOTOR-OPERATED VALVE 738B FAILS TO OPEN
CCMVPCCF$$		7.25E-02		MOTOR-OPERATED VALVE CCF$$ FAILS TO OPEN
CCPSDPS617	1	24		PRESSURE SWITCH PS-617 FAILS TO RESPOND
CCPSHPS617	1	24		PRESSURE SWITCH PS-617 FAILS HIGH
CCTKJSURGE	1	24		CCW SURGE TANK RUPTURE
CCTM_PUMPA		2.13E-04		CCW PUMP A IN MAINTENANCE
CCTM_PUMPB		2.13E-04		CCW PUMP B IN TEST OR MAINTENANCE
CCXVK00728	1	24		MANUAL VALVE 728 TRANSFERS CLOSED
CCXVK00769	1	377	H	MANUAL VALVE 769 TRANSFERS CLOSED
CCXVK0707A	1	377	H	MANUAL VALVE 707A TRANSFERS CLOSED
CCXVK0707B	1	377	H	MANUAL VALVE 707B TRANSFERS CLOSED
CCXVK0708A	1	377	H	MANUAL VALVE 708A TRANSFERS CLOSED
CCXVK0708B	1	377	H	MANUAL VALVE 708B TRANSFERS CLOSED
CCXVK0722A	1	24		MANUAL VALVE 722A TRANSFERS CLOSED
CCXVK0722B	1	24		MANUAL VALVE 722B TRANSFERS CLOSED
CCXVK0724A	1	24		MANUAL VALVE 724A TRANSFERS CLOSED
CCXVK0724B	1	24		MANUAL VALVE 724B TRANSFERS CLOSED
CCXVK0733A	1	24		MANUAL VALVE 733A TRANSFERS CLOSED
CCXVK0733B	1	24		MANUAL VALVE 733B TRANSFERS CLOSED
CCXVK0734A	1	24		MANUAL VALVE 734A TRANSFERS CLOSED
CCXVK0734B	1	24		MANUAL VALVE 734B TRANSFERS CLOSED
CCXVK0741A	1	4392	H	MANUAL VALVE 741A TRANSFERS CLOSED
CCXVK0741B	1	4392	H	MANUAL VALVE 741B TRANSFERS CLOSED
CCXVK0751A	1	24		MANUAL VALVE 751A TRANSFERS CLOSED
CCXVK0751B	1	24		MANUAL VALVE 751B TRANSFERS CLOSED
CCXVK0752A	1	24		MANUAL VALVE 752A TRANSFERS CLOSED
CCXVK0752B	1	24		MANUAL VALVE 752B TRANSFERS CLOSED
CCXVK0753B	1	24		MANUAL VALVE 753B TRANSFERS CLOSED
CCXVK0756A	1	24		MANUAL VALVE 756A TRANSFERS CLOSED
CCXVK0756B	1	24		MANUAL VALVE 756B TRANSFERS CLOSED
CCXVK0757A	1	24		MANUAL VALVE 757A TRANSFERS CLOSED
CCXVK0757B	1	24		MANUAL VALVE 757B TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
CCXVK0761B	1	24		MANUAL VALVE 761B TRANSFERS CLOSED
CCXVK0761F	1	24		MANUAL VALVE 761F TRANSFERS CLOSED
CCXVK0762A	1	24		MANUAL VALVE 762A TRANSFERS CLOSED
CCXVK0762B	1	24		MANUAL VALVE 762B TRANSFERS CLOSED
CCXVK0764C	1	24	H	Manual valve 764C transfers closed
CCXVK0764D	1	12	H	Manual Valve 764D Transfers Closed
CCXVK0777A	1	12	H	Manual Valve 777A Transfers Closed
CCXVK0777B	1	12	H	Manual Valve 777B Transfers Closed
CCXVK0777C	1	12	H	Manual Valve 777C Transfers Closed
CCXVK0777D	1	12	H	Manual Valve 777D Transfers Closed
CCXVK0777E	1	26	H	Manual valve 777E transfers closed
CCXVK0777F	1	26	H	Manual valve 777F transfers closed
CCXVK0777G	1	26	H	Manual valve 777G transfers closed
CCXVK0777H	1	26	H	Manual valve 777H transfers closed
CCXVK0777J	1	26	H	Manual valve 777J transfers closed
CCXVK0777K	1	26	H	Manual valve 777K transfers closed
CCXVK0777L	2	87624	H	Manual valve 777L transfers closed
CCXVK0777M	1	26	H	Manual valve 777M transfers closed
CCXVK0777N	2	87624	H	Manual valve 777N transfers closed
CCXVK0777P	1	26	H	Manual valve 777P transfers closed
CCXVK0777R	1	26	H	Manual valve 777R transfers closed
CCXVK0777S	2	87624	H	Manual valve 777S transfers closed
CCXVK0780A	1	4392	H	MANUAL VALVE 780A TRANSFERS CLOSED
CCXVK0780B	1	4392	H	MANUAL VALVE 780B TRANSFERS CLOSED
CCXVN04620	1	1		MANUAL VALVE 4620 FAILS TO OPEN
CCXVN0734A	1	1		MANUAL VALVE 734A FAILS TO OPEN
CCXVN0734B	1	1		MANUAL VALVE 734B FAILS TO OPEN
CCXVNO4619	1	1		MANUAL VALVE 4619 FAILS TO OPEN
CR400				Failure to Provide Flow From Containment Sprays During Recirculation
CR401				MOVs 896A and 896B fail to close
CRCCM0860P		9.231E-06		Common Cause Failure Of CS MOVs To Open (Recirc)
CRCCM0860X		4.959E-05		Common Cause Failure Of CS MOVs To Close (Recirc)
CRCCM0862P		2.570E-07		Common Cause Failure To Open Of Check Valves 862A And 862B (Recirc)
CRCCM0896X		9.202E-04		Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)
CRCCMPSI2F		8.672E-03		Common Cause Failure Of Containment Spray Pumps To Run (Recirc)
CRCCMPSI2S		1.680E-06		Common Cause Failure Of Containment Spray Pumps To Start (Recirc)
CRCVP0862A	1	12	H	Check Valve 862A Fails To Open On Demand (Recirculation)
CRCVP0862B	1	12	H	Check Valve 862B Fails To Open On Demand (Recirculation)
CRCVPCCF$$		6.00E-02		Beta Factor For Common Cause Failur Of CS Check Valves To Open (Recirculation)
CRMMWPSI2A		8.772E-06		Failure Of Containment Spray Pump PSI02A Cooling Components
CRMMWPSI2B		8.772E-06		Failure Of Containment Spray Pump PSI02B Cooling Components (Recirc)
CRMPFCCF$$		4.85E-02		Beta Factor For Common Cause Failure Of Containment Spray Pumps To Run (Recirc)

Table [illegible]7-2
Integrated C[illegible]A BE File

Basic Event	C	Factor	Units	Description
CRMPFSI02A	1	12	H	Containment Spray Pump PSI02A Fails To Run (Recirculation)
CRMPFSI02B	1	12	H	Containment Spray Pump PSI02B Fails To Run (Recirculation)
CRMPSCCF$$		5.0E-02		Beta Factor For Common Cause Failure Of Containment Spray Pumps To Start (Recr)
CRMPSSI02A	1	12	H	Containment Spray Pump PSI02A Fails To Start On Demand (Recirculation)
CRMPSSI02B	1	12	H	Containment Spray Pump PSI02B Fails To Start (Recirculation)
CRMVP0860A	1	12	H	Motor Operated Valve 860A Fails To Open On Demand (Recirculation)
CRMVP0860B	1	12	H	Motor Operated Valve 860B Fails To Open On Demand (Recirculation)
CRMVP0860C	1	12	H	Motor Operated Valve 860C Fails To Open On Demand (Recirculation)
CRMVP0860D	1	12	H	Motor Operated Valve 860D Fails To Open On Demand (Recirculation)
CRMVPCCF$$		6.93E-02		Beta Factor For Containment Spray MOVs Common Cause Failure To Open (Recirc)
CRMVX00897	1	372	H	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE
CRMVX00898	1	372	H	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE
CRMVX0860A	1	12	H	Motor Operated Valve 860A Fails To Close On Demand (Recirculation)
CRMVX0860B	1	12	H	Motor Operated Valve 860B Fails To Close On Demand (Recirculation)
CRMVX0860C	1	12	H	Motor Operated Valve 860C Fails To Close On Demand (Recirculation)
CRMVX0860D	1	12	H	Motor Operated Valve 860D Fails To Close On Demand (Recirculation)
CRMVX0896A	1	4392	H	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)
CRMVX0896B	1	4392	H	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)
CRMVXCCF$$		7.25E-02		MOTOR-OPERATED VALVE FAILS TO CLOSE COMMON CAUSE BETA FACTOR
CRMVZ0896A	1	4392	H	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)
CRMVZ0896B	1	4392	H	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)
CRPPPAC11A	1	12	H	Failure Of Pump PSI02A Heat Exchanger EAC11A (Recirculation)
CRPPPAC11B	1	12	H	Failure Of Pump PSI02B Heat Exchanger EAC11B (Recirculation)
CRXVK0858A	1	12	H	Manual Valve 858A Transfers Closed (Recirculation)
CRXVK0858B	1	12	H	Manual Valve 858B Transfers Closed (Recirculation)
CRXVK0868A	1	12	H	Manual Valve 868A Transfers Closed (Recirculation)
CRXVK0868B	1	12	H	Manual Valve 868B Transfers Closed (Recirculation)
CRXVR0875A	1	12	H	Manual Valve 875A Transfers Open (Recirculation)
CRXVR0875B	1	12	H	Manual Valve 875B Transfers Open (Recirculation)
CRXVR0876A	1	12	H	Manual Valve 876A Transfers Open (Recirculation)
CRXVR0876B	1	12	H	Manual Valve 876B Transfers Open (Recirculation)
CS110				No flow available at TSI01 (RWST) discharge header
CS300				Failure to Provide Flow From Containment Spray During Injection
CS410		1.0E-03		FAILURE OF THE RWST DURING INJECTION
CS411		1.00E-03		RWST level transmitters fail to respond (no cue to switch to recirc)
CSCCM0860X		2.862E-04		Common Cause Failure To Open Of Containment Spray MOVs (Injection)
CSCCM0862X		7.968E-06		Common Cause Failure To Open Of CS Check Valves 862A And 862B (Injection)
CSCCMLDRWT		9.399E-04		Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters
CSCCMLHRWT		2.424E-06		Common Cause Failure (High) Of TSI01 (RWST) Level Transmitters
CSCCMLLRWT		2.472E-06		Common Cause Failure (Low) Of TSI01 (RWST) Level Transmitters
CSCCMLTLRW		2.472E-06		Common Cause Failure (Low) Of TSI01 (RWST) Level Transmitters
CSCCMPSI2X		5.208E-05		Common Cause Failure To Start Of Containment Spray Pumps (Injection)

Basic Event	C	Factor	Units	Description
CSCCMPSI2Y		8.672E-03		Common Cause Failure To Run Of Containment Spray Pumps (Injection)
CSCVC0862A	1	1		Check Valve 862A Fails to Close
CSCVC0862B	1	1		Check Valve 862B Fails to Close
CSCVP0862A	1	372	H	Check Valve 862A Fails To Open On Demand (Injection)
CSCVP0862B	1	372	H	Check Valve 862B Fails To Open On Demand (Injection)
CSCVPCCF$$		6.00E-02		Beta Factor For Common Cause Failure Of A CS Check Valve To Open (Injection)
CSHFDRECIR		1.00E-01		Operators Fail to Switch to Containment Spray Recirculation Mode
CSHFL0896A		3.00E-03		Motor Operated Valve 896A Is Left Unavailable After Testing Or Maintenance
CSHFL0896B		3.00E-03		Motor Operated Valve 896B Is Left Unavailable After Testing Or Maintenance
CSHFLTRANA		3.00E-03		Operators Fail To Restore CS Train A Equipment After Testing Or Maintenance
CSHFLTRANB		3.00E-03		Operators Fail To Restore CS Train B Equipment After Testing Or Maintenance
CSLTDCCF$$		1.00E-01		Beta Factor For RWST Level Transmitters Common Cause Failure To Respond
CSLTDLT920	1	4392	H	RWST Level Transmitter LT-920 Fails To Respond
CSLTDLT921	1	4392	H	RWST Levle Transmitter LT-921 Fails To Respond
CSLTHCCF$$		1.00E-01		Beta Factor For RWST Level Transmitter Common Cause Failure (High)
CSLTHLT920	1	12	H	RWST Level Transmitter LT-920 Fails High
CSLTHLT921	1	12	H	Level Transmitter LT-921 Fails High
CSLTLCCF$$		1.00E-01		Beta Factor For RWST Level Transmitters Common Cause Failure (Low)
CSLTLLT920	1	12	H	RWST Level Transmitter LT-920 Fails Low
CSLTLLT921	1	12	H	RWST Level Transmitter LT-921 Fails Low
CSMM00RWST		2.570E-04		Insufficient Flow Available From TSI01 (RWST)
CSMM896A/B		6.601E-04		MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)
CSMPFCCF$$		4.85E-02		Beta Factor For Common Cause Failure Of A CS Pump To Run (Injection)
CSMPFSI02A	1	12	H	Containment Spray Pump PSI02A Fails To Run (Injection)
CSMPFSI02B	1	12	H	Containment Spray Pump PSI02B Fails To Run (Injection)
CSMPSCCF$$		5.00E-02		Beta Factor For Common Cause Failure Of A CS Pump To Start (Injection)
CSMPSSI02A	1	372	H	Containment Spray Pump PSI02A Fails To Start On Demand (Injection)
CSMPSSI02B	1	372	H	Containment Spray Pump PSI02B Fails To Start On Demand (Injection)
CSMVC0860A	1	1		MOV 860A Fails to Close
CSMVC0860B	1	1		MOV 860B Fails to Close
CSMVC0860C	1	1		MOV 860C Fails to Close
CSMVC0860D	1	1		MOV 860D Fails to Close
CSMVK00897	1	372	H	MOV 897 transfers closed
CSMVK00898	1	372	H	MOV 898 transfers closed
CSMVK0896A	1	252	H	Motor Operated Valve 896A Transfers Closed (Injection)
CSMVK0896B	1	252	H	Motor Operated Valve 896B Transfers Closed (Injection)
CSMVP0860A	1	372	H	Motor Operated Valve 860A Fails To Open On Demand (Injection)
CSMVP0860B	1	372	H	Motor Operated Valve 860B Fails To Open On Demand (Injection)
CSMVP0860C	1	372	H	Motor Operated Valve 860C Fails To Open On Demand (Injection)
CSMVP0860D	1	372	H	Motor Operated Valve 860D Fails To Open On Demand (Injection)
CSMVPCCF$$		6.93E-02		Beta Factor For Common Cause Failure Of A CS MOV To Open (Injection)
CSPPJTSI01	1	12	H	TSI01 (RWST) Outlet Piping For SI / CS Ruptures

Basic Event	C	Factor	Units	Description
CSTKJTSI01	1	12	H	Refueling Water Storage Tank (RWST) TSI01 Ruptures
CSTMTRAINA		3.89E-03		Containment Spray Train A Is Unavailable Due To Test Or Maintenance
CSTMTRAINB		3.89E-03		Containment Spray Train B Is Unavailable Due To Test Or Maintenance
CSXVK0858A	1	372	H	Manual Valve 858A Transfers Closed (Injection)
CSXVK0858B	1	372	H	Manual Valve 858B Transfers Closed (Injection)
CSXVK0868A	1	372	H	Manual Valve 868A Transfers Closed (Injection)
CSXVK0868B	1	372	H	Manual Valve 868B Transfers Closed (Injection)
CSXVR0875A	1	1092	H	Manual Valve 875A Transfers Open (Injection)
CSXVR0875B	1	1092	H	Manual Valve 875B Transfers Open (Injection)
CSXVR0876A	1	1092	H	Manual Valve 876A Transfers Open (Injection)
CSXVR0876B	1	1092	H	Manual Valve 876B Transfers Open (Injection)
CT172				NO CLOSE SIGNAL TO AOVs 371 AND 200B
CT312				Failure of Main Steam Safety Valves to Reclose
CT313				Failure of TDAFW Steam Admission Line from S/G A
CT315				Failure of MSIV 3517 to Close
CT326				Failure of Miscellaneous Manual Valves for Penetration 401 to Close
CT330				Failure of Containment Penetration 206b (S/G A Blowdown Sample Line)
CT335				Failure of Containment Penetration 321 (S/G A Blowdown Line)
CT342				Failure of Main Steam Safety Valves to Reclose
CT343				Failure of TDAFW Steam Admission Line From S/G B
CT345				Failure of MSIV 3516 to Close
CT356				Failure of Miscellaneous Manual Valves for Penetration 402 to Close
CT360				Failure of Containment Penetration 207b (S/G B Blowdown Sample Line)
CT365				Failure of COntainment Penetration 322 (S/G B Blowdown Line)
CTAVX01721	1	1119	H	AOV 1721 Fails to Close
CTAVX01723	1	1119	H	AOV 1723 Fails to Close
CTAVX01728	1	1119	H	AOV 1728 Fails to Close
CTAVX05735	1	1119	H	AOV 5735 Fails to Close
CTAVX05736	1	1119	H	AOV 5736 Fails to Close
CTAVX05737	1	1119	H	AOV 5737 Fails to Close
CTAVX05738	1	1119	H	AOV 5738 Fails to Close
CTAVX1003A	1	1119	H	AOV 1003A Fails to Close
CTAVX1003B	1	1119	H	AOV 1003B Fails to Close
CTAVXCCF$$		0.191		Beta Factor for Containment Isolation AOV Fails to CLose
CTCCCPURGE		4.145E-04		Common Cause Failure of Mini-Purge AOVs to Close
CTCCCSGBLO		1.776E-03		Common Cause Failure of Steam Generator Blowdown AOVs to Close
CTCCCSUMPA		1.776E-03		Common Cause Failure of AOVs 1723 and 1728 to Close
CTCCCXRCDT		1.776E-03		Common Cause Failure of AOVs 1721, 1003A, and 1003B to Close
CTHFDCSMOV		1.0		Operators Fail to Close MOVs 860A/B/C/D After Isolating Containment Spray
CTHFDISOLA		1.00E-01		Operators Fail to Isolate S/G A
CTHFDISOLB		1.00E-01		Operators Fail to Isolate S/G B
CTHRLX1003		0.1		Ops Places Local Control Switch on Boron Recycle & Waste Disp Pnl in Bypass Pos

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Basic Event	C	Factor	Units	Description
CTXVR01722	1	4404	H	Manual Valve 1722 Transfers Open
CV400		1.00E-03		NO FLOW FROM CHARGING TO AUXILIARY SPRAY
CV500				No Boron Injection From CVCS
CV998				Loss Of Seal Injection Or Return To RCP A
CV999				Loss Of Seal Injection Or Return To RCP B
CVAVC0112C	1	1		AIR-OPERATED VALVE 112C FAILS TO CLOSE
CVAVK00142	1	24	H	AIR-OPERATED VALVE 142 TRANSFERS CLOSED
CVAVK00294	1	24	H	AIR-OPERATED VALVE 294 TRANSFER CLOSED
CVAVK0110B	1	36	H	AIR-OPERATED VALVE 110B TRANSFERS CLOSED
CVAVK0270A	1	24	H	AIR-OPERATED VALVE 270A TRANSFERS CLOSED
CVAVK0270B	1	24	H	AIR-OPERATED VALVE 270B TRANSFERS CLOSED
CVAVP00111	1	108	H	Air-operated valve 111 fails to open
CVAVP00296	2	8760	H	AIR-OPERATED VALVE 296 FAILS TO OPEN
CVAVP0112B	1	2214	H	AIR-OPERATED VALVE 112B FAILS TO OPEN (STANDBY)
CVAVX00202	1	2214	H	AOV 202 Fails to Close
CVAVX00371	1	2214	H	AOV 371 FAILS TO CLOSE
CVAVX0200A	1	2214	H	AOV 200A Fails to Close
CVAVX0200B	1	2214	H	AOV 200B Fails to Close
CVAVXCCF$$		0.191		Beta Factor for CVCS AOVs Fail to Close
CVCCLTDOWN		1.099E-02		Common Cause Failure of AOVs 200A, 200B, and 202 to Close
CVCCMPAABC		1.663E-05		CHARGING PUMPS FAIL TO START <common cause event>
CVCCMPFABC		8.486E-05		CHARGING PUMPS FAIL TO RUN <common cause event>
CVCVK00295	1	24	H	CHECK VALVE 295 TRANSFERS CLOSED
CVCVK0302C	1	24	H	CHECK VALVE 302C TRANSFERS CLOSED
CVCVK0302D	1	24	H	CHECK VALVE 302D TRANSFERS CLOSED
CVCVK0304A	1	24	H	CHECK VALVE 304A TRANSFERS CLOSED
CVCVK0304B	1	24	H	CHECK VALVE 304B TRANSFERS CLOSED
CVCVK0322A	1	24	H	CHECK VALVE 322A TRANSFERS CLOSED
CVCVK0322B	1	24	H	CHECK VALVE 322B TRANSFERS CLOSED
CVCVK0370B	1	24	H	CHECK VALVE 370B TRANSFERS CLOSED
CVCVK09314	1	24	H	CHECK VALVE 9314 TRANSFERS CLOSED
CVCVN00266	1	1		CHECK VALVE 266 FAILS TO OPEN
CVCVN00333	1	1		CHECK VALVE 333 FAILS TO OPEN
CVCVN00339	1	1		CHECK VALVE 339 FAILS TO OPEN
CVCVN00351	1	1		CHECK VALVE 351 FAILS TO OPEN
CVCVN00364	1	1		Check valve 364 fails to open
CVCVN01241	1	1		Check valve 1241 fails to open
CVCVN01258	1	1		Check valve 1258 fails to open
CVCVP00297	2	8760	H	CHECK VALVE 297 FAILS TO OPEN
CVCVP00357	1	2214	H	check valve 357 fails to open
CVCVP00393	1	43800	H	CHECK VALVE 393 FAILS TO OPEN
CVCVP09313	2	8760	H	CHECK VALVE 9313 FAILS TO OPEN

Basic Event	C	Factor	Units	Description
CVCVP09315	1	43800	H	CHECK VALVE 9315 FAILS TO OPEN
CVHFDBORAT		5.00E-03		Operators Fail To Implement Emergency Boration
CVHFDPMPST		0.1		Operators Fail To Manually Load Charging Pump Following Loss Of Offsite Power
CVHTFHTRAC	1	24	H	BORIC ACID HEAT TRACE FAILURE
CVHXPECH04	1	24	H	HEAT EXCHANGER ECH04 PLUGS
CVHXPECH2A	1	24	H	REGEN HEAT EXCHANGER ECH02A PLUGGED
CVHXPECH2B	1	24	H	REGEN HEAT EXCHANGER ECH02B PLUGGED
CVHXPECH2C	1	24	H	REGEN HEAT EXCHANGER ECH02C PLUGGED
CVLTD00112	1	1		LEVEL TRANSMITTER LT-112 FAILS TO RESPOND
CVLTD00139	1	1		LEVEL TRANSMITTER LT-139 FAILS TO RESPOND
CVMM00110B		8.179E-03		AOV 110B TRANSFERS CLOSED
CVMM00112B		2.806E-02		112B FAILS TO OPEN ON DEMAND
CVMM00112C		2.498E-02		112C FAILS TO CLOSE ON DEMAND (GAS ENTRAINMENT FROM THE VCT)
CVMM00350N		3.760E-03		MOV 350 FAILS TO OPEN
CVMMACIDFL		6.756E-03		INSUFFICIENT FLOW FROM BORIC ACID FILTER (FCH02)
CVMMALTCHG		5.412E-02		ALTERNATE CHARGING PATH NOT ALIGNED
CVMMBAPMPA		1.811E-03		BORIC ACID PUMP PCH03A FAILS TO START AND RUN
CVMMBAPMPB		1.799E-03		BORIC ACID PUMP PCH03B FAILS TO START AND RUN
CVMMNORINJ		8.634E-03		FAILURE OF NORMAL INJECTION FLOWPATH
CVMMPCH1AA		1.080E-03		CHARGING PUMP PCH01A FAILS TO START
CVMMPCH1AF		1.635E-03		CHARGING PUMP PCH01A FAILS TO RUN
CVMMPCH1BA		1.080E-03		CHARGING PUMP PCH01B FAILS TO START
CVMMPCH1BF		1.635E-03		CHARGING PUMP PCH01B FAILS TO RUN
CVMMPCH1CA		1.080E-03		CHARGING PUMP PCH01C FAILS TO START
CVMMPCH1CF		1.635E-03		CHARGING PUMP PCH01C FAILS TO RUN
CVMMPDTOIV		1.227E-04		PATH FROM PULSATION DAMPENER TO ISOLATION VALVES BLOCKED
CVMMRCPAFP		4.880E-05		NO FLOW THROUGH SEAL INJECTION FILTER A
CVMMRCPALP		5.345E-05		SEAL LEAKOFF PATH FROM RCP A OBSTRUCTED
CVMMRCPBFP		4.880E-05		NO FLOW PATH TO RCP B SEAL FROM SEAL INJECTION FILTER
CVMMRCPBLP		5.345E-05		SEAL LEAKOFF PATH FROM RCP B OBSTRUCTED
CVMMRCPIFP		1.503E-03		NO FLOW THROUGH SEAL INJECTION FILTER A (SERVES BOTH TRAINS)
CVMMRCPRET		1.767E-03		NO FLOW THROUGH NORMAL SEAL WATER RETURN PATH
CVMMRXMAKE		1.799E-03		FAILURE OF REACTOR MAKEUP WATER TO THE BLENDER
CVMMRXPMPA		1.790E-03		REACTOR MAKEUP WATER PUMP A (PCH08A) FAILS TO START AND RUN
CVMMRXPMPB		1.781E-03		REACTOR MAKEUP WATER PUMP B (PCH08B) FAILS TO START AND RUN
CVMMRXTANK		4.613E-04		FAILURE OF REACTOR MAKEUP WATER TANK (TCH15)
CVMPACCF$$		1.54E-02		BETA FACTOR FOR CVCS PUMPS FAIL TO RUN
CVMPAPCH1A	1	1		CHARGING MOTOR-DRIVEN PUMP PCH01A FAILS TO START
CVMPAPCH1B	1	1		CHARGING MOTOR-DRIVEN PUMP PCH01B FAILS TO START
CVMPAPCH1C	1	1		CHARGING MOTOR-DRIVEN PUMP PCH01C FAILS TO START
CVMPAPCH3A	1	1		BORIC ACID MOTOR-DRIVEN PUMP PCH03A FAILS TO START
CVMPAPCH3B	1	1		BORIC ACID MOTOR-DRIVEN PUMP PCH03B FAILS TO START

Basic Event	C	Factor	Units	Description
CVMPAPCH8A	1	1		Motor-driven pump PCH08A (RMU Pump A) fails to start
CVMPAPCH8B	1	1		Motor-driven pump PCH08B (RMU Pump B) fails to start
CVMPFCCF$$		1.30E-01		BETA FACTOR FOR CVCS MOTOR PUMP FAILURE TO RUN
CVMPFPCH1A	1	24	H	MOTOR-DRIVEN PUMP PCH01A FAILS TO RUN
CVMPFPCH1B	1	24	H	MOTOR-DRIVEN PUMP PCH01B FAILS TO RUN
CVMPFPCH1C	1	24	H	MOTOR-DRIVEN PUMP PCH01C FAILS TO RUN
CVMPFPCH3A	1	24	H	MOTOR-DRIVEN PUMP PCH03A FAILS TO RUN
CVMPFPCH3B	1	24	H	MOTOR-DRIVEN PUMP PCH03B FAILS TO RUN
CVMPFPCH8A	1	24	H	Motor-driven pump PCH08A (RMU Pump A) fails to run
CVMPFPCH8B	1	24	H	Motor-driven pump PCH08B (RMU Pump B) fails to run
CVMVK00313	1	24	H	MOTOR-OPERATED VALVE 313 TRANSFERS CLOSED
CVMVN00350	1	1		MOTOR-OPERATED VALVE 350 FAILS TO OPEN
CVMVX00313	1	1119	H	MOV 313 Fails to Close
CVPPJ0RWST	1	12	H	CVCS Piping Ruptures At Refueling Water Storage Tank TSI01
CVPPJCVCOM	1	24	H	Common CVCS Piping Rupture
CVPPJCVRCS	1	24	H	PIPING FAILURE AT CVCS CONNECTIONS TO RCS
CVPPPBASYS	1	24	H	BORIC ACID SUPPLY SYSTEM FLOW PATH OBSTRUCTED
CVPPPECH03	1	24	H	FILTER FCH03 PLUGGED
CVPPPFCH02	1	108	H	BORIC ACID FILTER FCH02 PLUGS
CVPPPFCH08	1	24	H	FILTER FCH08 PLUGGED
CVRVN00314	1	1		SEAL RETURN HEADER RELIEF VALVE 314 FAILS TO OPEN
CVRVP0392A	1	43800	H	aov/rv392a fails to relieve to rcs
CVRVR00283	1	36	H	RELEIF VALVE 283 SPURIOUS OPEN
CVRVR00284	1	36	H	RELIEF VALVE 284 SPURIOUS OPEN
CVRVR00285	1	36	H	RELIEF VALVE 285 OPENS SPURIOUSLY
CVTKJTCH15	1	108	H	RMU Water Storage Tank TCH15 ruptures
CVTMCHPMPA		8.57E-03		TEST OR MAINTENANCE RENDERS PUMP A UNAVAILABLE
CVTMCHPMPB		8.10E-03		PUMP B UNAVAILABLE DUE TO TEST OR MAINTENANCE
CVTMCHPMPC		8.10E-03		TEST OR MAINTENANCE RENDERS PUMP C UNAVAILABLE
CVXVK00265	1	24	H	MANUAL VALVE 265 TRANSFERS CLOSED
CVXVK00267	1	24	H	MANUAL VALVE 267 TRANSFERS CLOSED
CVXVK00268	1	24	H	MANUAL VALVE 268 TRANSFERS CLOSED - ISOLATES SUCTION
CVXVK00269	1	24	H	MANUAL VALVE 269 TRANSFERS CLOSED
CVXVK00286	1	24	H	MANUAL VALVE 286 TRANSFERS CLOSED
CVXVK00287	1	24	H	MANUAL VALVE 287 TRANSFERS CLOSED
CVXVK00288	1	24	H	MANUAL VALVE 288 TRANSFERS CLOSED
CVXVK00289	1	24	H	MANUAL VALVE 289 TRANSFERS CLOSED
CVXVK00291	1	24	H	MANUAL VALVE 291 TRANSFERS CLOSED
CVXVK00321	1	24	H	MANUAL VALVE 321 TRANSFERS CLOSED
CVXVK00331	1	108	H	MANUAL VALVE 331 TRANSFERS CLOSED
CVXVK00334	1	108	H	MANUAL VALVE 334 TRANSFERS CLOSED
CVXVK00338	1	108	H	MANUAL VALVE 338 TRANSFERS CLOSED

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Basic Event	C	Factor	Units	Description
CVXVK00341	1	108	H	MANUAL VALVE 341 TRANSFERS CLOSED
CVXVK00342	1	108	H	MANUAL VALVE 342 TRANSFERS CLOSED
CVXVK00345	1	108	H	MANUAL VALVE 345 TRANSFERS CLOSED
CVXVK00347	1	108	H	MANUAL VALVE 347 TRANSFERS CLOSED
CVXVK00360	1	108	H	MANUAL VALVE 360 TRANSFERS CLOSED
CVXVK00368	1	24	H	MANUAL VALVE 368 TRANSFERS CLOSED
CVXVK00399	1	24	H	MANUAL VALVE 399 TRANSFERS CLOSED
CVXVK01243	1	108	H	Manual valve 1243 transfers closed
CVXVK01257	1	108	H	Manual valve 1257 transfers closed
CVXVK01259	1	108	H	Manual valve 1259 transfers closed
CVXVK01260	1	108	H	Manual valve 1260 transfers closed
CVXVK01261	1	108	H	Manual valve 1261 transfers closed
CVXVK01262	1	36	H	Manual valve 1262 transfers closed
CVXVK01286	1	108	H	Manual valve 1286 transfers closed
CVXVK0293A	1	24	H	MANUAL VALVE 293A TRANSFERS CLOSED
CVXVK0293B	1	24	H	MANUAL VALVE 293B TRANSFERS CLOSED
CVXVK0300A	1	24	H	MANUAL VALVE 300A TRANSFERS CLOSED
CVXVK0300B	1	24	H	MANUAL VALVE 300B TRANSFERS CLOSED
CVXVK0303A	1	24	H	MANUAL VALVE 303A TRANSFERS CLOSED
CVXVK0303B	1	24	H	MANUAL VALVE 303B TRANSFERS CLOSED
CVXVK0304C	1	24	H	MANUAL VALVE 304C TRANSFERS CLOSED
CVXVK0304D	1	24	H	MANUAL VALVE 304D TRANSFERS CLOSED
CVXVK0315A	1	24	H	MANUAL VALVE 315A TRANSFERS CLOSED
CVXVK0315B	1	24	H	MANUAL VALVE 315B TRANSFERS CLOSED
CVXVK0348A	1	108	H	MANUAL VALVE 348A TRANSFERS CLOSED
CVXVK0348B	1	24	H	MANUAL VALVE 348B TRANSFERS CLOSED
CVXVK0362C	1	24	H	MANUAL VALVE 362C TRANSFERS CLOSED
CVXVK0363A	1	108	H	Manual valve 363A transfers closed
CVXVK0370A	1	24	H	MANUAL VALVE 370A TRANSFERS CLOSED
CVXVK0384A	1	24	H	MANUAL VALVE 384A TRANSFERS CLOSED
CVXVK0384B	1	24	H	MANUAL VALVE 384B TRANSFERS CLOSED
CVXVK0385A	1	24	H	MANUAL VALVE 385A TRANSFERS CLOSED
CVXVK0385B	1	24	H	MANUAL VALVE 385B TRANSFERS CLOSED
CVXVK09301	1	24	H	MANUAL VALVE 9301 TRANSFERS CLOSED
CVXVK09303	1	24	H	MANUAL VALVE 9303 TRANSFERS CLOSED
CVXVK1247B	1	48	H	Manual valve 1247B transfers closed
CVXVR0330D	1	108	H	MANUAL VALVE 330D TRANSFERS OPEN - FLOW TO BA BATCH TANK
DC026		1.00E-03		NO DC POWER TO D/G A (NORMAL - E19) LONG TERM CIRCULAR LOGIC CLIP
DC027		1.00E-03		NO DC POWER TO D/G B (EMERGENCY - E160) LONG TERM CIRCULAR LOGIC CLIP
DC076		1.00E-03		NO DC POWER TO D/G B (NORMAL - E89) LONG TERM CIRCULAR LOGIC CLIP
DC077		1.00E-03		NO DC POWER TO D/G A (EMERGENCY - E18) LONG TERM CIRCULAR LOCIC CLIP
DC235				NO POWER ON MCB DC DISTRIBUTION PANEL B (DCPDPCB04B) (LONG-TERM)

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Basic Event	C Factor	Units	Description
DC285			NO POWER ON MCB DC DISTRIBUTION PANEL B (DCPDPCB04B) (SHORT-TERM)
DC300	1E-3		No DC Power TO MCC B (Circuit E21)
DC301			Loss Of DC Control Power To Motor Control Center H
DC303			No DC Power To Bus 11A (Normal) and Bus 12B (Emergency) (Circuit E25)
DC304			Loss Of DC Control Power To 4160 VAC Bus 12A
DC306			No DC Power to TDAFW Pump Steam Admission Valve 3505A (Circuit E32)
DC308			Loss Of DC Power From Main Distribution Panel A Position 15 (DCPDPCB03A/15)
DC311	1.00E-03		No DC Power to Bus 14 (Normal) and Bus 16 (Emergency) UV Control Cabinet (E274)
DC312			Loss Of DC Control Power To Motor Control Center H (Circular Logic Clip)
DC321	1.00E-03		No DC Power To Motor Control Center MCCC (Long Term)
DC326			Loss Of DC Control Power To Motor Control Center C (Circular Logic Clip)
DC340	1.00E-03		NO DC POWER TO D/G A (NORMAL) (CIRCUIT E19)
DC341	1.00E-03		NO DC POWER TO D/G B (EMERGENCY) (CIRCUIT E160)
DC347	1.00E-03		No DC Power to Bus 18 (Normal) and Bus 17 (Emergency) UV Control Cabinet (XXXX)
DC355	1.00E-03		NO DC POWER TO STEAM DUMP VALVES TRAIN A (CIRCUIT XXXX)
DC356			Loss Of DC Power To Lockout And Differential Relays
DC357	1.00E-03		No DC Power To Bus 11A UV Relays (Circuit E202)
DC359	1.00E-03		No DC Power To SI-A1 Train A (Circuit E214)
DC360	1E-3		No DC Power To RA Racks Train A (Circuit E215)
DC365	1.00E-03		NO DC POWER TO RCS OVERPRESSURIZATION HEAD VENT VALVES TRAIN A (CIRCUIT XXXX)
DC502			Loss Of DC Control Power To Motor Control Center J
DC503	1E-3		No DC Power to MCC K (Circuit E92)
DC505			No DC Power To Bus 11B (Normal) and Bus 12A (Emergency) (Circuit E104)
DC506			Loss Of DC Control Power To 4160 VAC Bus 12B
DC508			Loss Of DC Power From Main Distribution Panel A Position 14 (DCPDPCB03A/14) ST
DC509			Loss Of DC Power From Main Distribution Panel B Position 15 (DCPDPCB03B/15) LT
DC510			No DC Power to TDAFW Pump Steam Admission Valve 3504A (Circuit E108)
DC511	1.00E-03		No DC Power to Bus 16 (Normal) and Bus 14 (Emergency) UV Control Cabinet (E275)
DC512			
DC520	1E-3		No DC Power TO Auxiliary Building HVAC Control Panel (Circuit E166)
DC521			Loss Of DC Control Power To Motor Control Center D
DC526			Loss Of DC Control Power To Motor Control Center D (Circular Logic Clip)
DC541	1.00E-03		NO DC POWER TO D/G B (NORMAL) (CIRCUIT E89)
DC542	1.00E-03		NO DC POWER TO D/G A (EMERGENCY) (CIRCUIT E18)
DC549	1.00E-03		No DC Power to Bus 17 (Normal) and Bus 18 (Emergency) UV Control Cabinet (E270)
DC551	1.00E-03		NO DC POWER TO STEAM DUMP VALVES, TDAFW PUMP GOVENOR, AND MCB TB (CIRCUIT XXXX)
DC552			Loss Of DC Power To Lockout And Differential Relays
DC555	1.00E-03		No DC Power To SI-B1 Train B (Circuit E211)
DC556	1E-3		No DC Power TO RA Racks Train B (Circuit E212)
DC560	1.00E-03		No DC Power To Bus 11B UV Relays (Circuit E203)
DC561	1.00E-03		NO DC POWER TO RCS OVERPRESSURIZATION HEAD VENT VALVES TRAIN B (CIRCUIT XXXX)
DC571	1E-3		No DC Power TO MCC A (Circuit E178)

Basic Event	C Factor	Units	Description
DC576	1.00E-03		No DC Power to TDAFW Pump DC Oil Pump (Circuit E187)
DC591	1.00E-03		LOSS OF POWER ON DISTRIBUTION PANEL A (IBPDPCBA) - LONG TERM
DC592	1.00E-03		Loss Of Power On 120 VAC Distribution Panel C (IBPDPCBC) - Long Term
DC593	1.00E-03		LOSS OF POWER ON 120 VAC DISTRIBUTION PANEL C (IBPDPCBC) - LONG TERM
DC594	1.00E-03		LOSS OF POWER ON 120 VAC DISTRIBUTION PANEL B (IBPDPCBB)
DC595	1.00E-03		LOSS OF POWER ON 120 VAC DISTRIBUTION PANEL D (IBPDPCBD)
DC597			No power on 120VAC Dist Panel E (long term)
DC605			Loss Of 125 VDC DC Control Power To 480 VAC Bus 14 (Long Term)
DC610	1.00E-03		Loss of Power On 120 VAC Instrument Bus A (IBPDPCBAR) - Short Term
DC615			Loss Of 125 VDC Control Power To 480 VAC Bus 16 (Long term)
DC660	1.00E-03		LOSS OF POWER ON 120 VAC INSTRUMENT BUS B (IBPDPCBBW)
DC710	1.00E-03		Loss of Power On 120 VAC Instrument Bus C (IBPDPCBCB) - Short Term
DC745	1.00E-03		Loss of Power From 120 VAC Inverter MQ483 - Long Term
DC810	1.00E-03		Loss of Power On 120 VAC Instrument Bus D (IBPDPCBDY)
DC910			No Power On 120 VAC Instrument Bus 1A (Long Term)
DC913	1.00E-03		Loss of DC Control Power to Bus 13
DC914	1.00E-03		Loss of DC Control Power to Bus 14
DC915	1.00E-03		Loss of DC Control Power to Bus 15
DC916	1.00E-03		Loss of DC Control Power to Bus 16
DC917			Loss Of DC Control Power To 480 VAC 17
DC918			Loss Of DC Control Power To 480 VAC Bus 18
DC960	1.00E-03		LOSS OF POWER ON 120 VAC INSTRUMENT BUS C (IBPDPCBCB) - LONG TERM
DCBCF0000A 1	24	H	Battery Charger A (BYCA) No Output
DCBCF0000B 1	24	H	Battery Charger B (BYCB) No Output
DCBCF000A1 1	24	H	Battery Charger A1 (BYCA1) No Output
DCBCF000B1 1	24	H	Battery Charger B1 (BYCB1) No Output
DCBDFAUXA1 1	24	H	Auxiliary Building DC Distribution Panel A1 (DCPDPAB02A) Local Fault
DCBDFAUXA2 1	24	H	Auxiliary Building DC Distribution Panel A2 (DCPDPAB03A) Local Fault
DCBDFAUXB1 1	24	H	Auxiliary Building DC Distribution Pánel B1 Local Fault (DCPDPAB02B)
DCBDFAUXDA 1	24	H	Auxiliary Building DC Distribution Panel A (DCPDPAB01A) Local Fault
DCBDFAUXDB 1	24	H	Auxiliary Building DC Distribution Panel B (DCPDAB01B) Local Fault
DCBDFDG00A 1	24	H	D/G DC Distribution Panel A (DCPDPDG01A) Local Fault
DCBDFDG00B 1	24	H	D/G DC Distribution Panel B (DCPDPDG01B) Local Fault
DCBDFFUSEA 1	24	H	Battery A Main DC Fuse Cabinet (DCPDPCB02A) Local Fault
DCBDFFUSEB 1	24	H	Battery B Main DC Fuse Cabinet (DCPDPCB02B) Local Fault
DCBDFMAINA 1	24	H	Main DC Distribution Panel A (DCPDPCB03A) Local Fault
DCBDFMAINB 1	24	H	Main DC Distribution Panel B (DCPDPCB03B) Local Fault
DCBDFMCB0A 1	24	H	MCB Distribution Panel (DCPDPCB04A) Local Fault
DCBDFMCB0B 1	24	H	MCB DC Distribution Panel B (DCPDPCB04B) Local Fault
DCBDFSCRNA 1	24	H	Screen House DC Distribution Panel 1A (DCPDPSH01A) Local Fault
DCBDFSCRNB 1	24	H	Screen House DC Distribution Panel 1B (DCPDPSH01B) Local Fault
DCBDFTBPNL 1	24	H	Turbine Building DC Distribution Panel (DCPDPTB01B) Local Fault

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Basic Event	C	Factor	Units	Description
DCBTD0001A	1	1		125 VDC Battery A (BTRYA) No Output On Demand
DCBTD0001B	1	1		125 VDC Battery B (BTRYB) No Output On Demand
DCBTDOCCF$		0.1		BATTERY NO OUTPUT (DEMAND) COMMON CAUSE BETA FACTOR
DCBTF0001A	1	24	H	Battery A (BTRYA) No Output (Hourly)
DCBTF0001B	1	24	H	Battery B (BTRYB) No Output (Hourly)
DCBTFOCCF$		0.1		BATTERY NO OUTPUT (HOURLY) COMMON CAUSE BETA FACTOR
DCCCOBATTD		1.190E-06		Batteries A/B No Output on Demand <Common Cause>
DCCCOBATTH		2.254E-06		Batteries A/B No Output (Hourly) <Common Cause>
DCCDR1ACB1	1	24	H	Inverter INVTA DC Breaker INVTCVTA/01 Transfers Open
DCCDR1ACB5	1	24	H	Inverter INVTA Fault Protection Breaker INVTCVTA/05 Transfers Open
DCCDR1CCB2	1	24	H	Inverter INVTB Output Breaker INVTCVTB/02 Transfers Open
DCCDR1CCB5	1	24	H	Inverter INVTB Fault Protection Breaker INVTCVTB/05 Transfers Open
DCCDRVTB01	1	24	H	Inverter INVTB DC Breaker INVTCVTB/01 Transfers Open
DCCFR/06MN	1	0	H	FUSE FUMCCD/6M-N FAILS OPEN
DCCFR/06MP	1	0	H	FUSE FUMCCD/6M-P FAILS OPEN
DCCFR/12CN	1	0	H	FUSE FUMCCC/12C-N FAILS OPEN
DCCFR/12CP	1	0	H	FUSE FUMCCC/12C-P FAILS OPEN
DCCFR/12JN	1	0	H	FUSE FUMCCD/12J-N FAILS OPEN
DCCFR/12JP	1	0	H	FUSE FUMCCD/12J-P FAILS OPEN
DCCFR/12MN	1	0	H	FUSE FUMCCD/12M-N FAILS OPEN
DCCFR/12MP	1	0	H	FUSE FUMCCD/12M-P FAILS OPEN
DCCFR/2B-N	1	0	H	FUSE FUBUS15/2B-N FAILS OPEN
DCCFR/2B-P	1	0	H	FUSE FUBUS15/2B-P FAILS OPEN
DCCFR/2H-N	1	0	H	FUSE FUMCCC/2H-N FAILS OPEN
DCCFR/2H-P	1	0	H	FUSE FUMCCC/2H-P FAILS OPEN
DCCFR/4B-N	1	0	H	FUSE FUBUS15/4B-N FAILS OPEN
DCCFR/4B-P	1	0	H	FUSE FUBUS15/4B-P FAILS OPEN
DCCFR/6MN	1	0	H	FUSE FUMCCC/6M-N FAILS OPEN
DCCFR/6MP	1	0	H	FUSE FUMCCC/6M-P FAILS OPEN
DCCFR/9A-N	1	0	H	FUSE FUBUS13/9A-N FAILS OPEN
DCCFR/9A-P	1	0	H	FUSE FUBUS13/9A-P FAILS OPEN
DCCFR/9B-N	1	0	H	FUSE FUBUS13/9B-N FAILS OPEN
DCCFR/9B-P	1	0	H	FUSE FUBUS13/9B-P FAILS OPEN
DCCFR/V5FN	1	0	H	Fuse FURA2/V5F-N Fails Open
DCCFR/V5FP	1	0	H	Fuse FURA2/V5F-P Fails Open
DCCFR/V7RN	1	0	H	Fuse FURA1/V7R-N Fails Open
DCCFR/V7RP	1	0	H	Fuse FURA1/V7R-P Fails Open
DCCFR/V8FN	1	0	H	Fuse FURA2/V8F-N Fails Open
DCCFR/V8FP	1	0	H	Fuse FURA2/V8F-P Fails Open
DCCFR014CN	1	0	H	FUSE FUBUS16/14C-N FAILS OPEN
DCCFR014CP	1	0	H	FUSE FUBUS16/14C-P FAILS OPEN
DCCFR017CN	1	0	H	FUSE FUBUS16/17C-N FAILS OPEN

Basic Event	C	Factor	Units	Description
DCCFR017CP	1	0	H	FUSE FUBUS16/17C-P FAILS OPEN
DCCFR01A1P	1	384	H	FUSE FUDGACP/1A1-P FAILS OPEN
DCCFR01A2N	1	384	H	FUSE FUDGACP/1A2-N FAILS OPEN
DCCFR01B1P	1	720	H	FUSE FUDGBCP/1B1-P FAILS OPEN
DCCFR01B2N	1	720	H	FUSE FUDGBCP/1B2-N FAILS OPEN
DCCFR01BNP	1	0	H	FUSE FUDCPDPTB01B/NP FAILS OPEN
DCCFR01NNN	1	0	H	FUSE FUDCPDPTB01B/NN FAILS OPEN
DCCFR021CN	1	0	H	FUSE FUBUS14/21C-N FAILS OPEN
DCCFR021CP	1	0	H	FUSE FUBUS14/21C-P FAILS OPEN
DCCFR03AMN	1	0	H	Fuse FUDCPDPCB03A/MN Fails Open
DCCFR03AMP	1	0	H	Fuse FUDCPDPCB03A/MP Fails Open
DCCFR03BSN	1	0	H	Fuse FUDCPDPCB03B/SN Fails Open
DCCFR03BSP	1	0	H	Fuse FUDCPDPCB03B/SN Fails Open
DCCFR0856N	2	0	H	FUSE FUUMCC/10C-N FAILS OPEN
DCCFR0856P	2	0	H	FUSE FUMMC/10C-P FAILS OPEN
DCCFR0A15P	1	0	H	FUSE FUCIA1/FB5-P TRANSFERS OPEN
DCCFR0A16N	1	0	H	FUSE FUCIA1/FB6-N TRANSFERS OPEN
DCCFR0B15P	1	0	H	FUSE FUCIB1/FB5-P TRANSFERS OPEN
DCCFR0B16N	1	0	H	FUSE FUCIB1/FB6-N TRANSFERS OPEN
DCCFR0C6FN	1	0	M	DC Fuse FUMCCC/6F-N Fails
DCCFR0C6FP	1	0	M	DC Fuse FUMCCC/6F-P Fails
DCCFR0D6FN	1	0	M	DC Fuse FUMCCD/6F-N Fails
DCCFR0D6FP	1	0	M	DC Fuse FUMCCD/6F-P Fails
DCCFR0H2JN	1	0	M	DC Fuse FUMCCH/2J-N Fails
DCCFR0H2JP	1	0	M	DC Fuse FUMCCH/2J-P Fails
DCCFR0H2MN	1	0	M	DC Fuse FUMCCH/2M-N Fails
DCCFR0H2MP	1	0	M	DC Fuse FUMCCH/2M-P Fails
DCCFR0J2MN	1	0	M	DC Fuse FUMCCJ/2M-N Fails
DCCFR0J2MP	1	0	M	DC Fuse FUMCCJ/2M-P Fails
DCCFR0XHDN		0		FUSE FUMCB/XHD-N FAILS OPEN
DCCFR0XHDP		0		FUSE FUMCB/XHD-P FAILS OPEN
DCCFR0XHEN		0		FUSE FUMCB/XHE-N FAILS OPEN
DCCFR0XHEP		0		FUSE FUMCB/XHE-P FAILS OPEN
DCCFR0XRDN	1	24	H	DC Fuse FUMCB/XRD-N Fails
DCCFR0XRDP	1	24	H	DC Fuse FUMCB/XRD-P Fails
DCCFR0XRGN	1	24	H	DC Fuse FUMCB/XRG-N Fails
DCCFR0XRGP	1	24	H	DC Fuse FUMCB/XRG-P Fails
DCCFR0XSAN	1	24	H	DC Fuse FUMCB/XSA-N Fails
DCCFR0XSAP	1	24	H	DC Fuse FUMCB/XSA-P Fails
DCCFR0XXAN	1	24	H	DC Fuse FUMCB/XXA-N Fails
DCCFR0XXAP	1	24	H	DC Fuse FUMCB/XXA-P Fails
DCCFR101AP	1	24	H	DC Fuse FUBUS11A/10-1AP Fails

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Basic Event	C	Factor	Units	Description
DCCFR102AN	1	24	H	DC Fuse FUBUS11A/10-2AN Fails
DCCFR1419N	1	0	H	FUSE FUBUS14/19A-N FAILS OPEN
DCCFR1419P	1	0	H	FUSE FUBUS14/19A-P FAILS OPEN
DCCFR1420N	1	0	H	FUSE FUBUS14/20A-N FAILS OPEN
DCCFR1420P	1	0	H	FUSE FUBUS14/20A-P FAILS OPEN
DCCFR1422N	1	0	H	FUSE FUBUS14/22A-N FAILS OPEN
DCCFR1422P	1	0	H	FUSE FUBUS14/22A-P FAILS OPEN
DCCFR1423N	1	0	H	FUSE FUBUS14/23A-N FAILS OPEN
DCCFR1423P	1	0	H	FUSE FUBUS14/23A-P FAILS OPEN
DCCFR1612N	1	0	H	FUSE FUBUS16/12A-N FAILS OPEN
DCCFR1612P	1	0	H	FUSE FUBUS16/12A-P FAILS OPEN
DCCFR1613N	1	0	H	FUSE FUBUS16/13A-N FAILS OPEN
DCCFR1613P	1	0	H	FUSE FUBUS16/13A-P FAILS OPEN
DCCFR1614N	1	0	H	FUSE FUBUS16/14C-N FAILS OPEN
DCCFR1614P	1	0	H	FUSE FUBUS16/14C-P FAILS OPEN
DCCFR1615N	1	0	H	FUSE FUBUS16/15A-N FAILS OPEN
DCCFR1615P	1	0	H	FUSE FUBUS16/15A-P FAILS OPEN
DCCFR1616N	1	0	H	FUSE FUBUS16/16B-N FAILS OPEN
DCCFR1616P	1	0	H	FUSE FUBUS16/16B-P FAILS OPEN
DCCFR16F-N	1	0	H	FUSE FUMCC/16F-N FAILS OPEN
DCCFR16F-P	1	0	H	FUSE FUMCCC/16F-P FAILS OPEN
DCCFR221AP	1	24	H	DC Fuse FUBUS11B/22-1AP Fails
DCCFR222AN	1	24	H	DC Fuse FUBUS11B/22-2AN Fails
DCCFR2LX1A	1	0	H	FUSE FUMCCCL/2M-X1A FAILS OPEN
DCCFR2LX1B	1	0	H	FUSE FUMCCL/2M-X1B FAILS OPEN
DCCFR2MX1A	1	0	H	FUSE FUMCCM/2M-X1A FAILS OPEN
DCCFR2MX1B	1	0	H	FUSE FUMCCD/2M-X1B FAILS OPEN
DCCFR420BN	1	0	H	DC Fuse FUBUS14/20B-N Fails Open
DCCFR420BP	1	0	H	DC Fuse FUBUS14/20B-P Fails Open
DCCFR422NR	1	0	H	FUSE FUBUS14/22-N FAILS OPEN (RECIRCULATION)
DCCFR422PR	1	0	H	FUSE FUBUS14/22-P FAILS OPEN (RECIRCULATION)
DCCFR423CN	1	0	H	FUSE FUBUS14/23C-N FAILS OPEN
DCCFR423CP	1	0	H	FUSE FUBUS14/23C-P FAILS OPEN
DCCFR4B18N	1	720	H	FUSE FUBUS14/18B-N FAILS OPEN
DCCFR4B18P	1	720	H	FUSE FUBUS14/18B-P FAILS OPEN
DCCFR4C18N	1	720	H	FUSE FUBUS14/18C-N FAILS OPEN
DCCFR4C18P	1	720	H	FUSE FUBUS14/18C-P FAILS OPEN
DCCFR613BN	1	0	H	DC Fuse FUBUS16/13B-N Fails Open
DCCFR613BP	1	0	H	DC Fuse FUBUS16/13B-P Fails Open
DCCFR615NR	1	0	H	FUSE FUBUS16/15-N FAILS OPEN (RECIRICULATION)
DCCFR615PR	1	0	H	FUSE FUBUS16/15-P FAILS OPEN (RECIRCULATION)
DCCFR6B11N	1	720	H	FUSE FUBUS16/11B-N FAILS OPEN

Basic Event	C	Factor	Units	Description
DCCFR6B11P	1	720	H	FUSE FUBUS16/11B-1P FAILS OPEN
DCCFR6C11N	1	720	H	FUSE FUBUS16/11C-N FAILS OPEN
DCCFR6C11P	1	720	H	FUSE FUBUS16/11C-P FAILS OPEN
DCCFR727CN	1	0	M	DC Fuse FUBUS17/27C-N Fails
DCCFR727CP	1	0	M	DC Fuse FUBUS17/27C-P Fails
DCCFR727DN	1	0	M	DC Fuse FUBUS17/27D-N Fails
DCCFR727DP	1	0	M	DC Fuse FUBUS17/29D-P Fails
DCCFR7B25N	1	720	H	FUSE FUBUS17/25B-N FAILS OPEN
DCCFR7B25P	1	720	H	FUSE FUBUS17/25B-P FAILS OPEN
DCCFR7B31P	1	720	H	FUSE FUBUS17/31B-P FAILS OPEN
DCCFR7C25N	1	720	H	FUSE FUBUS17/25C-N FAILS OPEN
DCCFR7C25P	1	720	H	FUSE FUBUS17/25C-P FAILS OPEN
DCCFR829CN	1	0	M	DC Fuse FUBUS18/29C-N Fails
DCCFR829CP	1	0	M	DC Fuse FUBUS18/29C-P Fails
DCCFR829DN	1	0	M	DC Fuse FUBUS18/29D-N Fails
DCCFR829DP	1	0	M	DC Fuse FUBUS18/29D-P Fails
DCCFR8B31N	1	720	H	FUSE FUBUS18/31B-N FAILS OPEN
DCCFR8C31P	1	720	H	FUSE FUBUS18/31C-P FAILS OPEN
DCCFRA121P	1	24	H	DC Fuse FUBUS12A/12-1P Fails
DCCFRA122N	1	24	H	DC Fuse FUBUS12A/12-2N Fails
DCCFRA151N	2	8760	H	FUSE FURA1/V51F-N FAILS OPEN
DCCFRA151P	2	8760	H	FUSE FURA1/V51F-P FAILS OPEN
DCCFRA1AAN	1	24	H	Fuse FUDCPDPAB01A/1N Fails Open (To MCC E)
DCCFRA1AAP	1	24	H	Fuse FUDCPDPAB01A/1P Fails Open (To MCC E)
DCCFRA1ABN	1	24	H	Fuse FUDCPDPAB01A/2N Fails Open (To MCC C)
DCCFRA1ABP	1	24	H	Fuse FUDCPDPAB01A/2P Fails Open (To MCC C)
DCCFRA1ACN	1	24	H	Fuse FUDCPDPAB01A/3N Fails Open (To MCC C Auxiliary Circuit Breaker Cabinet)
DCCFRA1ACP	1	24	H	Fuse FUDCPDPAB01A/3P Fails Open (To MCC C Auxiliary Circuit Breaker Cabinet)
DCCFRA1ADN	1	24	H	Fuse FUDCPDPAB01A/4N Fails Open (To Bus 14 - Normal)
DCCFRA1ADP	1	24	H	Fuse FUDCPDPAB01A/4P Fails Open (To Bus 14 - Normal)
DCCFRA1AEN	1	24	H	Fuse FUDCPDPAB01A/5N Fails Open (To Bus 16 - Emergency)
DCCFRA1AEP	1	24	H	Fuse FUDCPDPAB01A/5P Fails Open (To Bus 16 - Emergency)
DCCFRA1AFN	1	24	H	Fuse FUDCPDPAB01A/6N Fails Open (To SI Pump Fan Control Panel)
DCCFRA1AFP	1	24	H	Fuse FUDCPDPAB01A/6P Fails Open (To SI Pump Fan Control Panel)
DCCFRA1BAN	1	24	H	Fuse FUDCPDPAB01B/1N Fails Open (To Auxiliary Building HVAC Control Panel)
DCCFRA1BAP	1	24	H	Fuse FUDCPDPAB01B/1P Fails Open (To Auxiliary Building HVAC Control Panel)
DCCFRA1BBN	1	24	H	Fuse FUDCPDPAB01B/2N Fails Open (To MCC D)
DCCFRA1BBP	1	24	H	Fuse FUDCPDPAB01B/2P Fails Open (To MCC D)
DCCFRA1BCN	1	24	H	Fuse FUDCPDPAB01B/3N Fails Open (To Gas Analyzer Control Panel)
DCCFRA1BCP	1	24	H	Fuse FUDCPDPAB01B/3P Fails Open (To Gas Analyzer Control Panel)
DCCFRA1BDN	1	24	H	Fuse FUDCPDPAB01B/4N Fails Open (To Bus 16 - Normal)
DCCFRA1BDP	1	24	H	Fuse FUDCPDPAB01B/4P Fails Open (To Bus 16 - Normal)

Basic Event	C	Factor	Units	Description
DCCFRA1BEN	1	24	H	Fuse FUDCPDPAB01B/5N Fails Open (To Bus 14 - Emergency)
DCCFRA1BEP	1	24	H	Fuse FUDCPDPAB01B/5P Fails Open (To Bus 14 - Emergency)
DCCFRA1BFN	1	24	H	Fuse FUDCPDPAB01B/6N Fails Open (To MCC D Auxiliary Circuit Breaker Cabinet)
DCCFRA1BFP	1	24	H	Fuse FUDCPDPAB01B/6P Fails Open (To MCC D Auxiliary Circuit Breaker Cabinet)
DCCFRA2AAN	1	24	H	Fuse FUDCPDPAB02A/1N Fails Open (To H2 Recombiner A Control Panel)
DCCFRA2AAP	1	24	H	Fuse FUDCPDPAB02A/1P Fails Open (To H2 Recombiner A Control Panel)
DCCFRA2ABN	1	24	H	Fuse FUDCPDPAB02A/2N Fails Open (To Boron R&WD Control Panel W1)
DCCFRA2ABP	1	24	H	Fuse FUDCPDPAB02A/2P Fails Open (To Boron R&WD Control Panel W1)
DCCFRA2AEN	1	24	H	Fuse FUDCPDPAB02A/5N Fails Open (To Rx Trip Switchgear Breaker RTA/BYB)
DCCFRA2AEP	1	24	H	Fuse FUDCPDPAB02A/5P Fails Open (To Rx Trip Switchgear Breaker RTA/BYB)
DCCFRA2AFN	1	24	H	Fuse FUDCPDPAB02A/6N Fails Open (To Auxiliary Building DC Distribution Pnl A2)
DCCFRA2AFP	1	24	H	Fuse FUDCPDPAB02A/6P Fails Open (To Auxiliary Building DC Distribution Pnl A2)
DCCFRA2BAN	1	24	H	Fuse FUDCPDPAB02B/1N Fails Open (To H2 Recombiner B Control Panel)
DCCFRA2BAP	1	24	H	Fuse FUDCPDPAB02B/1P Fails Open (To H2 Recombiner B Control Panel)
DCCFRA2BBN	1	24	H	Fuse FUDCPDPAB02B/2N Fails Open (To Boron R&WD Control Panel W2)
DCCFRA2BBP	1	24	H	Fuse FUDCPDPAB02B/2P Fails Open (To Boron R&WD Control Panel W2)
DCCFRA2BEN	1	24	H	Fuse FUDCPDPAB02B/5N Fails Open (To Rx Trip Switchgear Breaker RTB/BYA)
DCCFRA2BEP	1	24	H	Fuse FUDCPDPAB02B/5P Fails Open (To Rx Trip Switchgear Breaker RTB/BYA)
DCCFRA3AAN	1	24	H	Fuse FUDCPDPAB03A/1N Fails Open (To Charging Pump A Alternate DC Power)
DCCFRA3AAP	1	24	H	Fuse FUDCPDPAB03A/1P Fails Open (To Charging Pump A Alternate DC Power)
DCCFRAFU01	1	720	H	FUSE FUDGACP/1-P FAILS OPEN
DCCFRAFU02	1	720	H	FUSE FUDGACP/2-N FAILS OPEN
DCCFRAFU03	1	720	H	FUSE FUDGACP/3-P FAILS OPEN
DCCFRAFU04	1	720	H	FUSE FUDGACP/4-N FAILS OPEN
DCCFRAXTPN	1	0	H	FUSE FUMCB/XTP-N FAILS OPEN
DCCFRAXTPP	1	0	H	FUSE FUMCB/XTP-P FAILS OPEN
DCCFRB/02N	1	0	H	FUSE MCCB/02M-N FAILS OPEN
DCCFRB/02P	1	0	H	FUSE FUMCCB/02M-P FAILS OPEN
DCCFRB02MN	1	0	H	FUSE FUMCCB/02MM-N FAILS OPEN
DCCFRB02MP	1	0	H	FUSE FUMCCB/02MM-P FAILS OPEN
DCCFRB201P	1	24	H	DC Fuse FUBUS12B/20-1P Fails
DCCFRB202N	1	24	H	DC Fuse FUBUS12B/20-2N Fails
DCCFRBFU01	1	720	H	FUSE FUDGBCP/EGB-P FAILS OPEN
DCCFRBFU02	1	720	H	FUSE FUDGBCP/EGB-N FAILS OPEN
DCCFRBFU03	1	720	H	FUSE FUDGBCP/EGA-P FAILS OPEN
DCCFRBFU04	1	720	H	FUSE FUDGBCP/EGA-1N FAILS OPEN
DCCFRBXEDN	1	0	H	FUSE FUMCB/XED-N FAILS OPEN
DCCFRBXEDP	1	0	H	FUSE FUMCB/XED-P FAILS OPEN
DCCFRBXEFN	1	0	H	FUSE FUMCCB/XEF-N FAILS OPEN
DCCFRBXEFP	1	0	H	FUSE FUMCCB/XEF-P FAILS OPEN
DCCFRBXTHN	1	0	H	FUSE FUMCB/XTH-N FAILS OPEN
DCCFRBXTHP	1	0	H	FUSE FUMCB/XTH-P FAILS OPEN

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Basic Event	C	Factor	Units	Description
DCCFRBXTON	1	0	H	FUSE FUMCB/XTOP-N FAILS OPEN
DCCFRBXTOP	1	0	H	FUSE FUMCB/XTO-P FAILS OPEN
DCCFRC/06N		0		FUSE FUMCCC06C-N FAILS OPEN
DCCFRC/06P		0		FUSE FUMCCC/6C-P FAILS OPEN
DCCFRC/A-N	1	0	H	FUSE FUJBTADC/A-N FAILS OPEN
DCCFRC/A-P	1	0	H	FUSE FUJBTADC/A-P FAILS OPEN
DCCFRC01FN	1	0	H	FUSE FUMCCC/01F-N FAILS OPEN
DCCFRC01FP	1	0	H	FUSE FUMCCC/01F-P FAILS OPEN
DCCFRC06JN	1	0	H	FUSE FUMCCC/06J-N FAILS OPEN
DCCFRC06JP	1	0	H	FUSE FUMCCC/06J-P FAILS OPEN
DCCFRC07JN	1	0	H	FUSE MCCC/7J-N FAILS OPEN
DCCFRC07JP	1	0	H	FUSE FUMCCC/7J-P FAILS OPEN
DCCFRC07MN	1	0	H	FUSE FUMCCC/7M-N FAILS OPEN
DCCFRC07MP	1	0	H	FUSE FUMCCC/7M-P FAILS OPEN
DCCFRC08JN	1	0	H	DC Fuse FUMCCC/8J-N Fails Open
DCCFRC08JP	1	0	H	DC Fuse FUMCCC/8J-P Fails Open
DCCFRC08MN	1	0	H	DC Fuse FUMCCC/8M-N Fails Open
DCCFRC08MP	1	0	H	DC Fuse FUMCCC/8M-P Fails Open
DCCFRC09MN	1	0	H	FUSE FUMCCC/09M-N FAILS OPEN
DCCFRC09MP	1	0	H	FUSE FUMCCC/09M-P FAILS OPEN
DCCFRC10JN	1	0	H	FUSE FUMCCC/10J-N FAILS OPEN
DCCFRC10JP	1	0	H	FUSE FUMCCC/10J-P FAILS OPEN
DCCFRC11FN	1	0	H	DC Fuse FUMCCC/11F-N Fails Open
DCCFRC11FP	1	0	H	DC Fuse FUMCCC/11F-P Fails Open
DCCFRC11MN	1	0	M	DC Fuse FUMCCC/11M-N Fails
DCCFRC11MP	1	0	M	DC Fuse FUMCCC/11M-P Fails
DCCFRC12JN	1	0	H	FUSE FUMCCC/12J-N FAILS OPEN
DCCFRC12JP	1	0	H	FUSE FUMCCC/12J-P FAILS OPEN
DCCFRC13BN	1	0	H	FUSE MCCC/13B-N FAILS OPEN
DCCFRC13BP	1	0	H	FUSE FUMCCC/13B-P FAILS OPEN
DCCFRC13JN	1	0	H	DC Fuse FUMCCC/13J-N Fails Open
DCCFRC13JP	1	0	H	DC Fuse FUMCCC/13J-P Fails Open
DCCFRC14JN	1	0	M	DC Fuse FUMCCC/14J-N Fails
DCCFRC14JP	1	0	M	DC Fuse FUMCCC/16J-P Fails
DCCFRC14MN	1	0	M	DC Fuse FUMCCC/14M-N Fails
DCCFRC14MP	1	0	M	DC Fuse FUMCCC/14M-P Fails
DCCFRC15CN	1	720	H	FUSE FUMCCC/15C-N FAILS OPEN
DCCFRC15CP	1	720	H	FUSE FUMCCC/15C-P FAILS OPEN
DCCFRC15JN	1	0	H	FUSE MCCC/15J-N FAILS OPEN
DCCFRC15JP	1	0	H	FUSE MCCC/15J-P FAILS OPEN
DCCFRC2AAN	1	24	H	Fuse FUDCPDPCB02A/1N Fails Open (To Battery Charger A)
DCCFRC2AAP	1	24	H	Fuse FUDCPDPCB02A/1P Fails Open (To Battery Charger A)

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Basic Event	C Factor	Units	Description
DCCFRC2ABN	1	24 H	Fuse FUDCPDPCB02A/2N Fails Open (To Main DC Distribution Panel A)
DCCFRC2ABP	1	24 H	Fuse FUDCPDPCB02A/2P Fails Open (To Main DC Distribution Panel A)
DCCFRC2AEN	1	24 H	Fuse FUDCPDPCB02A/5N Fails Open (To Battery Charger A1)
DCCFRC2AEP	1	24 H	Fuse FUDCPDPCB02A/5P Fails Open (To Battery Charger A1)
DCCFRC2BAN	1	24 H	Fuse FUDCPDPCB02B/1N Fails Open (To Battery Charger B)
DCCFRC2BAP	1	24 H	Fuse FUDCPDPCB02B/1P Fails Open (To Battery Charger B)
DCCFRC2BBN	1	24 H	Fuse FUDCPDPCB02B/2N Fails Open (To Main DC Distribution Panel B)
DCCFRC2BBP	1	24 H	Fuse FUDCPDPCB02B/2P Fails Open (To Main DC Distribution Panel B)
DCCFRC2BDN	1	24 H	Fuse FUDCPDCB02B/4N Fails Open (To Turbine Building DC Distribution Panel)
DCCFRC2BDP	1	24 H	Fuse FUDCPDPCB02B/4P Fails Open (To Turbine Building DC Distribution Panel)
DCCFRC2BEN	1	24 H	Fuse FUDCPDPCB02B/5N Fails Open (To Screen House DC Distribution Panel B)
DCCFRC2BEP	1	24 H	Fuse FUDCPDPCB02B/5P Fails Open (To Screen House DC Distribution Panel B)
DCCFRC2BFN	1	24 H	Fuse FUDCPDPCB02A/6N Fails Open (To Battery Charger B1)
DCCFRC2BFP	1	24 H	Fuse FUDCPDPCB02A/6P Fails Open (To Battery Charger B1)
DCCFRC3ABN	1	24 H	Fuse FUDCPDPCB03A/BN Fails Open (To MCC B)
DCCFRC3ABP	1	24 H	Fuse FUDCPDPCB03A/BP Fails Open (To MCC B)
DCCFRC3ACN	1	24 H	Fuse FUDCPDPCB03A/CN Fails Open (To MCC H)
DCCFRC3ACP	1	24 H	Fuse FUDCPDPCB03A/CP Fails Open (To MCC H)
DCCFRC3ADN	1	24 H	Fuse FUDCPDPCB03A/DN Fails Open (To Rod Drive MG Set Control Panel)
DCCFRC3ADP	1	24 H	Fuse FUDCPDPCB03A/DP Fails Open (To Rod Drive MG Set Control Panel)
DCCFRC3AGN	1	24 H	Fuse FUDCPDPCB03A/GN Fails Open (To D/G DC Distribution Panel A)
DCCFRC3AGP	1	24 H	Fuse FUDCPDPCB03A/GP Fails Open (To D/G DC Distribution Panel A)
DCCFRC3AHN	1	24 H	Fuse FUDCPDPCB03A/HN Fails Open (To Bus 11A)
DCCFRC3AHP	1	24 H	Fuse FUDCPDPCB03A/HP Fails Open (To Bus 11A)
DCCFRC3AJN	1	24 H	Fuse FUDCPDPCB03A/JN Fails Open (To Bus 12A)
DCCFRC3AJP	1	24 H	Fuse FUDCPDPCB03A/JP Fails Open (To Bus 12A)
DCCFRC3AKN	1	24 H	Fuse FUDCPDPCB03A/KN Fails Open (To Bus 13)
DCCFRC3AKP	1	24 H	Fuse FUDCPDPCB03A/KP Fails Open (To Bus 13)
DCCFRC3ALN	1	24 H	Fuse FUDCPDPCB03A/LN Fails Open (To Screen House DC Distribution Panel A)
DCCFRC3ALP	1	24 H	Fuse FUDCPDPCB03A/LP Fails Open (To Screen House DC Distribution Panel A)
DCCFRC3AMN	1	24 H	Fuse FUDCPDPCB03A/MN Fails Open (To TDAFW Valve 3505A)
DCCFRC3AMP	1	24 H	Fuse FUDCPDPCB03A/MP Fails Open (To TDAFW Valve 3505A)
DCCFRC3ANN	1	24 H	Fuse FUDCPDPCB03A/NN Fails Open (To MFW Pump A DC Oil Pump)
DCCFRC3ANP	1	24 H	Fuse FUDCPDPCB03A/NP Fails Open (To MFW Pump A DC Oil Pump)
DCCFRC3APN	1	24 H	Fuse FUDCPDPCB03A/PN Fails Open (To MCB DC Distribution Panel A)
DCCFRC3APP	1	24 H	Fuse FUDCPDPCB03A/PP Fails Open (To MCB DC Distribution Panel A)
DCCFRC3AQN	1	24 H	Fuse FUDCPDPCB03A/QN Fails Open (To Inverter A)
DCCFRC3AQP	1	24 H	Fuse FUDCPDPCB03A/QP Fails Open (To Inverter A)
DCCFRC3ARN	1	24 H	Fuse FUDCPDPCB03A/RN Fails Open (To PA System Inverter)
DCCFRC3ARP	1	24 H	Fuse FUDCPDPCB03A/RP Fails Open (To PA System Inverter)
DCCFRC3ASN	1	24 H	Fuse FUDCPDPCB03A/SN Fails Open (To Battery Room Ventilation Control Panel)
DCCFRC3ASP	1	24 H	Fuse FUDCPDPCB03A/SP Fails Open (To Battery Room Ventilation Control Panel)

Basic Event	C	Factor	Units	Description
DCCFRC3ATN	1	24	H	Fuse FUDCPDPCB03A/TN Fails Open (To Bus 14 UV Control Cabinet)
DCCFRC3ATP	1	24	H	Fuse FUDCPDPCB03A/TP Fails Open (To Bus 14 UV Control Cabinet)
DCCFRC3AUN	1	24	H	Fuse FUDCPDPCB03A/UN Fails Open (To Auxiliary Building DC Distribution Pnl 1A)
DCCFRC3AUP	1	24	H	Fuse FUDCPDPCB03A/UP Fails Open (To Auxiliary Building DC Distribution Pnl 1A)
DCCFRC3BBN	1	24	H	Fuse FUDCPDPCB03B/BN Fails Open (To MOV 5171)
DCCFRC3BBP	1	24	H	Fuse FUDCPDPCB03B/BP Fails Open (To MOV 5171)
DCCFRC3BCN	1	24	H	Fuse FUDCPDPCB03B/CN Fails Open (To Rod Drive MG Set Control Panel)
DCCFRC3BCP	1	24	H	Fuse FUDCPDPCB03B/CP Fails Open (To Rod Drive MG Set Control Panel)
DCCFRC3BDN	1	24	H	Fuse FUDCPDPCB03B/DN Fails Open (To MCC J)
DCCFRC3BDP	1	24	H	Fuse FUDCPDPCB03B/DP Fails Open (To MCC J)
DCCFRC3BEN	1	24	H	Fuse FUDCPDPCB03B/EN Fails Open (To MCC K)
DCCFRC3BEP	1	24	H	Fuse FUDCPDPCB03B/EP Fails Open (To MCC K)
DCCFRC3BFN	1	24	H	Fuse FUDCPDPCB03B/FN Fails Open (To MOV 3996)
DCCFRC3BFP	1	24	H	Fuse FUDCPDPCB03B/FP Fails Open (To MOV 3996)
DCCFRC3BJN	1	24	H	Fuse FUDCPDPCB03B/JN Fails Open (To MCB DC Distribution Panel B)
DCCFRC3BJP	1	24	H	Fuse FUDCPDPCB03B/JP Fails Open (To MCB DC Distribution Panel B)
DCCFRC3BKN	1	24	H	Fuse FUDCPDPCB03B/KN Fails Open (To Bus 11B - Normal, Bus 12A - Emergency)
DCCFRC3BKP	1	24	H	Fuse FUDCPDPCB03B/KP Fails Open (To Bus 11B - Normal, Bus 12A - Emergency)
DCCFRC3BLN	1	24	H	Fuse FUDCPDPCB03B/LN Fails Open (To Bus 12B - Normal, Bus 11A - Emergency)
DCCFRC3BLP	1	24	H	Fuse FUDCPDPCB03B/LP Fails Open (To Bus 12B - Normal, Bus 11A - Emergency)
DCCFRC3BMN	1	24	H	Fuse FUDCPDPCB03B/MN Fails Open (To Bus 15 - Normal, Bus 13 - Emergency)
DCCFRC3BMP	1	24	H	Fuse FUDCPDPCB03B/MP Fails Open (To Bus 15 - Normal, Bus 13 - Emergency)
DCCFRC3BPN	1	24	H	Fuse FUDCPDPCB03B/PN Fails Open (To MFW Pump B DC Oil Pump)
DCCFRC3BPP	1	24	H	Fuse FUDCPDPCB03B/PP Fails Open (To MFW Pump B DC Oil Pump)
DCCFRC3BQN	1	24	H	Fuse FUDCPDPCB03B/QN Fails Open (To Inverter B)
DCCFRC3BQP	1	24	H	Fuse FUDCPDPCB03B/QP Fails Open (To Inverter B)
DCCFRC3BRN	1	24	H	Fuse FUDCPDPCB03B/RN Fails Open (To D/G DC Distribution Panel B)
DCCFRC3BRP	1	24	H	Fuse FUDCPDPCB03B/RP Fails Open (To D/G DC Distribution Panel B)
DCCFRC3BSN	1	24	H	Fuse FUDCPDPCB03B/SN Fails Open (To TDAFW Valve 3504A)
DCCFRC3BSP	1	24	H	Fuse FUDCPDPCB03B/SP Fails Open (To TDAFW Valve 3504A)
DCCFRC3BTN	1	24	H	Fuse FUDCPDPCB03B/TN Fails Open (To Bus 16 UV Control Cabinet)
DCCFRC3BTP	1	24	H	Fuse FUDCPDPCB03B/TP Fails Open (To Bus 16 UV Control Cabinet)
DCCFRC3BUN	1	24	H	Fuse FUDCPDPCB03B/UN Fails Open (To Auxiliary Building DC Distribution Pnl B)
DCCFRC3BUP	1	24	H	Fuse FUDCPDPCB03B/UP Fails Open (To Auxiliary Building DC Distribution Pnl B)
DCCFRC4AAN	1	24	H	Fuse FUDCPDPCB04A/AN Fails Open (To PPS Switchgear Unit 6 Train A)
DCCFRC4AAP	1	24	H	Fuse FUDCPDPCB04A/AP Fails Open (To PPS Switchgear Unit 6 Train A)
DCCFRC4ABN	1	24	H	Fuse FUDCPDPCB04A/BN Fails Open (To Main Transformer Annunciator)
DCCFRC4ABP	1	24	H	Fuse FUDCPDPCB04A/BP Fails Open (To Main Transformer Annunciator)
DCCFRC4ACN	1	24	H	Fuse FUDCPDPAB04A/CN Fails Open (To Aux Station Transformer #11 Annunciator)
DCCFRC4ACP	1	24	H	Fuse FUDCPDPAB04A/CP Fails Open (To Station Aux Transformer #11 Annunciator)
DCCFRC4ADN	1	24	H	Fuse FUDCPDPAB04A/DN Fails Open (To Station Aux Transformer #12A Annunciator)
DCCFRC4ADP	1	24	H	Fuse FUDCPDPAB04A/DP Fails Open (To Station Aux Transformer #12A Annunciator)

Basic Event	C Factor	Units	Description
DCCFRC4AEN	1	24 H	Fuse FUDCPDPCB04A/EN Fails Open (To MCB Alarm System)
DCCFRC4AEP	1	24 H	Fuse FUDCPDPCB04A/EP Fails Open (To MCB Alarm System)
DCCFRC4AFN	1	24 H	Fuse FUDCPDPCB04A/FN Fails Open (To Steam Dump Valves Train A)
DCCFRC4AFP	1	24 H	Fuse FUDCPDPCB04A/FP Fails Open (To Steam Dump Valves Train A)
DCCFRC4AGN	1	24 H	Fuse FUDCPDPCB04A/GN Fails Open (To Lockout and Differential Relays)
DCCFRC4AGP	1	24 H	Fuse FUDCPDPCB04A/GP Fails Open (To Lockout and Differential Relays)
DCCFRC4AHN	1	24 H	Fuse FUDCPDPCB04A/HN Fails Open (To Bus 11A UV Relays)
DCCFRC4AHP	1	24 H	Fuse FUDCPDPCB04A/HP Fails Open (To Bus 11A UV Relays)
DCCFRC4AJN	1	24 H	Fuse FUDCPDPCB04A/JN Fails Open (To H2 Monitor Isolation Valves 921 and 922)
DCCFRC4AJP	1	24 H	Fuse FUDCPDPCB04A/JP Fails Open (To H2 Monitor Isolation Valves 921 and 922)
DCCFRC4AMN	1	24 H	Fuse FUDCPDPCB04A/MN Fails Open (To SI-A1 Train A)
DCCFRC4AMP	1	24 H	Fuse FUDCPDPCB04A/MP Fails Open (To SI-A1 Train A)
DCCFRC4ANN	1	24 H	Fuse FUDCPDPCB04A/NN Fails Open (To RA Racks Train A)
DCCFRC4ANP	1	24 H	Fuse FUDCPDPCB04A/NP Fails Open (To RA Racks Train A)
DCCFRC4APN	1	24 H	Fuse FUDCPDPCB04A/PN Fails Open (To MQ 483 Inverter)
DCCFRC4APP	1	24 H	Fuse FUDCPDPCB04A/PP Fails Open (To MQ 483 Inverter)
DCCFRC4AQN	1	24 H	Fuse FUDCPDPCB04A/QN Fails Open (To Reactor Trip Targets)
DCCFRC4AQP	1	24 H	Fuse FUDCPDPCB04A/QP Fails Open (To Reactor Trip Targets)
DCCFRC4ARN	1	24 H	Fuse FUDCPDPCB04A/RN Fails Open (To Condensate Booster Pump Relay Panel)
DCCFRC4ARP	1	24 H	Fuse FUDCPDPCB04A/RP Fails Open (To Condensate Booster Pump Relay Panel)
DCCFRC4ASN	1	24 H	Fuse FUDCPDPCB04A/SN Fails Open (To Circulating Water Pump Trip Logic Relays)
DCCFRC4ASP	1	24 H	Fuse FUDCPDPCB04A/SP Fails Open (To Circulating Water Pump Trip Logic Relays)
DCCFRC4ATN	1	24 H	Fuse FUDCPDPCB04A/TN Fails Open (To RCS Overpressure Head Vent Valves Train A)
DCCFRC4ATP	1	24 H	Fuse FUDCPDPCB04A/TP Fails Open (To RCS Overpressure Head Vent Valves Train A)
DCCFRC4AVN	1	24 H	Fuse FUDCPDPCB04A/VN Fails Open (To Containment Isolation Rack CI-A1)
DCCFRC4AVP	1	24 H	Fuse FUDCPDPCB04A/VP Fails Open (To Containment Isolation Rack CI-A1)
DCCFRC4AWN	1	24 H	Fuse FUDCPDPCB04A/WN Fails Open (To Turbine Trip Aux Relays and Rack RLTR-1)
DCCFRC4AWP	1	24 H	Fuse FUDCPDPCB04A/WP Fails Open (To Turbine Trip Relays and Rack RLTR-1)
DCCFRC4BAN	1	24 H	Fuse FUDCPDPCB04B/AN Fails Open (To PPS Switchgear Unit 1 Train B)
DCCFRC4BAP	1	24 H	Fuse FUDCPDPCB04B/AP Fails Open (To PPS Switchgear Unit 1 Train B)
DCCFRC4BBN	1	24 H	Fuse FUDCPDPCB04B/BN Fails Open (To Steam Dump Valves, TDAFW Pump Govenor)
DCCFRC4BBP	1	24 H	Fuse FUDCPDPCB04B/BP Fails Open (To Steam Dump Valves, TDAFW Pump Govenor)
DCCFRC4BDN	1	24 H	Fuse FUDCPDPCB04B/DN Fails Open (To Lockout and Differential Relays)
DCCFRC4BDP	1	24 H	Fuse FUDCPDPCB04B/DP Fails Open (To Lockout and Differential Relays)
DCCFRC4BFN	1	24 H	Fuse FUDCPDPAB04B/FN Fails Open (To Control Room Ventilation Radiation Monitor)
DCCFRC4BFP	1	24 H	Fuse FUDCPDPAB04B/FP Fails Open (To Control Room Ventilation Radiation Monitor)
DCCFRC4BHN	1	24 H	Fuse FUDCPDPCB04B/HN Fails Open (To RLTR-2)
DCCFRC4BHP	1	24 H	Fuse FUDCPDPCB04B/HP Fails Open (To RLTR-2)
DCCFRC4BJN	1	24 H	Fuse FUDCPDPCB04B/JN Fails Open (To SI-B1 Train B)
DCCFRC4BJP	1	24 H	Fuse FUDCPDPCB04B/JP Fails Open (To SI-B1 Train B)
DCCFRC4BKN	1	24 H	Fuse FUDCPDPCB04B/KN Fails Open (To RA Racks Train B)
DCCFRC4BKP	1	24 H	Fuse FUDCPDPCB04B/KP Fails Open (To RA Racks Train B)

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Basic Event	C	Factor	Units	Description
DCCFRC4BNN	1	24	H	Fuse FUDCPDPCB04B/NN Fails Open (To H2 Monitor Isolation Valves 923 and 924)
DCCFRC4BNP	1	24	H	Fuse FUDCPDPCB04B/NP Fails Open (To H2 Monitor Isolation Valves 923 and 924)
DCCFRC4BPN	1	24	H	Fuse FUDCPDPCB04B/PN Fails Open (To Circulating Water Pump Trip Logic Relays)
DCCFRC4BPP	1	24	H	Fuse FUDCPDPCB04B/PP Fails Open (To Circulating Water Pump Trip Logic Relays)
DCCFRC4BQN	1	24	H	Fuse FUDCPDPCB04B/QN Fails Open (To MCB Annunciator Standby Power)
DCCFRC4BQP	1	24	H	Fuse FUDCPDPCB04B/QP Fails Open (To MCB Annunciator Standby Power)
DCCFRC4BSN	1	24	H	Fuse FUDCPDPCB04B/SN Fails Open (To Bus 11B UV Relays)
DCCFRC4BSP	1	24	H	Fuse FUDCPDPCB04B/SP Fails Open (To Bus 11B UV Relays)
DCCFRC4BTN	1	24	H	Fuse FUDCPDPCB04B/TN Fails Open (To RCS Overpressure Head Vent Valves Train B)
DCCFRC4BTP	1	24	H	Fuse FUDCPDPCB04B/TP Fails Open (To RCS Overpressure Head Vent Valves Train B)
DCCFRC4BUN	1	24	H	Fuse FUDCPDPCB04B/UN Fails Open (To CNMT Isolation Rack CI-B1)
DCCFRC4BUP	1	24	H	Fuse FUDCPDPCB04B/UP Fails Open (To CNMT Isolation Rack CI-B1)
DCCFRC4BVN	1	24	H	Fuse FUDCPDPCB04B/VN Fails Open (To Control Room Ventilation Fan)
DCCFRC4BVP	1	24	H	Fuse FUDCPDPCB04B/VP Fails Open (To Control Room Ventilation Fan)
DCCFRC4BXN	1	24	H	Fuse FUDCPDPCB04B/XN Fails Open (To MCB Alarm System)
DCCFRC4BXP	1	24	H	Fuse FUDCPDPCB04B/XP Fails Open (To MCB Alarm System)
DCCFRCB1AN	1	24	H	Fuse FUDCPDPCB01A/N Fails Open On Main Disconnect Switch A
DCCFRCB1AP	1	24	H	Fuse FUDCPDPCB01A/P Fails Open On Main Disconnect Switch A
DCCFRCB1BN	1	24	H	Fuse FUDCPDPCB01B/N Fails Open On Main Disconnect Switch A
DCCFRCB1BP	1	24	H	Fuse FUDCPDPCB01B/P Fails Open On Main Disconnect Switch B
DCCFRCP2-N	1	0	H	FUSE FUABHVCP/2-N FAILS OPEN
DCCFRCP2-P	1	0	H	FUSE FUABHVCP/2-P FAILS OPEN
DCCFRD/06N		0		FUSE FUMCCD/6C-N FAILS OPEN
DCCFRD/06P		0		FUSE FUMCCD/6C-P FAILS OPEN
DCCFRD01BN	1	0	H	FUSE FUMCCD/01B-N FAILS OPEN
DCCFRD01BP	1	0	H	FUSE FUMCCD/01B-P FAILS OPEN
DCCFRD02FN	1	0	H	FUSE FUMCCD/02F-N FAILS OPEN
DCCFRD02FP	1	0	H	FUSE FUMCCD/02F-P FAILS OPEN
DCCFRD04BN	1	720	H	FUSE FUMCCD/4B-N FAILS OPEN
DCCFRD04BP	1	720	H	FUSE FUMCCD/4B-P FAILS OPEN
DCCFRD06JN	1	0	H	FUSE FUMCCD/06J-N FAILS OPEN
DCCFRD06JP	1	0	H	FUSE FUMCCD/06J-P FAILS OPEN
DCCFRD07JN	1	0	H	FUSE FUMCCD/7J-N FAILS OPEN
DCCFRD07JP	1	0	H	FUSE MCCD/7J-P FAILS OPEN
DCCFRD08JN	1	0	H	DC Fuse FUMCCD/8J-N Fails Open
DCCFRD08JP	1	0	H	DC Fuse FUMCCD/8J-P Fails Open
DCCFRD08MN	1	0	H	DC Fuse FUMCCD/8M-N Fails Open
DCCFRD08MP	1	0	H	DC Fuse FUMCCD/8M-P Fails Open
DCCFRD09MN	1	0	H	FUSE FUMCC/D09M-N FAILS OPEN
DCCFRD09MP	1	0	H	FUSE FUMCCD/09M-P FAILS OPEN
DCCFRD10JN	1	0	H	FUSE FUMCCD/10J-N FAILS OPEN
DCCFRD10JP	1	0	H	FUSE FUMCCD/10J-P FAILS OPEN

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Basic Event	C	Factor	Units	Description
DCCFRD11FN	1	0	H	DC Fuse FUMCCD/11F-N Fails Open
DCCFRD11FP	1	0	H	DC Fuse FUMCCD/11F-P Fails Open
DCCFRD11JN	1	0	M	DC Fuse FUMCCD/11J-N Fails
DCCFRD11JP	1	0	M	DC Fuse FUMCCD/11J-P Fails
DCCFRD11MN	1	0	H	FUSE FUMCCD/11M-N FAILS OPEN
DCCFRD11MP	1	0	H	FUSE FUMCCD/11M-P FAILS OPEN
DCCFRD12FN	1	0	H	FUSE FUMCCD/12F-N FAILS OPEN
DCCFRD12FP	1	0	H	FUSE FUMCCD/12F-P FAILS OPEN
DCCFRD13CN	1	0	M	DC Fuse FUMCCD/13C-N Fails
DCCFRD13CP	1	0	M	DC Fuse FUMCCD/13C-P Fails
DCCFRD13FN	1	0	M	DC Fuse FUMCCD/13F-N Fails
DCCFRD13FP	1	0	M	DC Fuse FUMCCD/13F-P Fails
DCCFRD14JN	1	0	M	DC Fuse FUMCCD/14J-N Fails
DCCFRD14JP	1	0	M	DC Fuse FUMCCD/14J-P Fails
DCCFRD15FN	1	0	H	FUSE FUMCCD/15F-N FAILS OPEN
DCCFRD15FP	1	0	H	FUSE FUMCCD/15F-P FAILS OPEN
DCCFRD1ACN	1	24	H	Fuse FUDCPDPDG01A/3N Fails Open (To D/G A - Normal)
DCCFRD1ACP	1	24	H	Fuse FUDCPDPDG01A/3P Fails Open (To D/G A - Normal)
DCCFRD1ADN	1	24	H	Fuse FUDCPDPDG01A/4N Fails Open (To D/G B - Emergency)
DCCFRD1ADP	1	24	H	Fuse FUDCPDPDG01A/4P Fails Open (To D/G B - Emergency)
DCCFRD1BAN	1	24	H	Fuse FUDCPDPDG01B/1N Fails Open (To Circuit Breaker 52/EG1B3)
DCCFRD1BAP	1	24	H	Fuse FUDCPDPDG01B/1P Fails Open (To Circuit Breaker 52/EG1B3)
DCCFRD1BCN	1	24	H	Fuse FUDCPDPDG01B/3N Fails Open (To D/G B - Normal)
DCCFRD1BCP	1	24	H	Fuse FUDCPDPDG01B/3P Fails Open (To D/G B - Normal)
DCCFRD1BDN	1	24	H	Fuse FUDCPDPDG01B/4N Fails Open (To D/G A - Emergency)
DCCFRD1BDP	1	24	H	Fuse FUDCPDPDG01B/4P Fails Open (To D/G A - Emergency)
DCCFRD7MN	1	0	H	FUSE FUMCCD/7M-N FAILS OPEN
DCCFRD7MP	1	0	H	FUSE FUMCCD/7M-P FAILS OPEN
DCCFRH01KN	1	720	H	FUSE MCCH/1K-N FAILS OPEN
DCCFRH01KP	1	720	H	FUSE FUMCCC/1K-P FAILS OPEN
DCCFRH02BN	1	720	H	FUSE FUMCCH/2B-N FAILS OPEN
DCCFRH02BP	1	720	H	FUSE FUMCCH/2B-P FAILS OPEN
DCCFRH02DN	1	720	H	FUSE FUMCCH/2D-N FAILS OPEN
DCCFRH02DP	1	720	H	FUSE FUMCCH/2D-P FAILS OPEN
DCCFRJ01KN	1	720	H	FUSE FUMCCJ/1K-N FAILS OPEN
DCCFRJ01KP	1	720	H	FUSE FUMCCJ/1K-P FAILS OPEN
DCCFRJ02BN	1	720	H	FUSE FUMCCJ/2B-N FAILS OPEN
DCCFRJ02BP	1	720	H	FUSE FUMCCJ/2B-P FAILS OPEN
DCCFRJ02DN	1	720	H	FUSE FUMCCJ/2D-N FAILS OPEN
DCCFRJ02DP	1	720	H	FUSE FUMCCJ/2D-P FAILS OPEN
DCCFRK01BN	1	0	H	FUSE FUMCCK/1B-N FAILS OPEN
DCCFRK01BP	1	0	H	FUSE FUMCCK/1B-P FAILS OPEN

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Basic Event	C	Factor	Units	Description
DCCFRK01FN	1	0	H	FUSE FUMCCK/1F-N FAILS OPEN
DCCFRK01FP	1	0	H	FUSE FUMCCK/0F-P FAILS OPEN
DCCFRS1AAN	1	24	H	Fuse FUDCPDPSH01A/1N Fails Open (To Bus 17 - Emergency)
DCCFRS1AAP	1	24	H	Fuse FUDCPDPSH01A/1P Fails Open (To Bus 17 - Emergency)
DCCFRS1ABN	1	24	H	Fuse FUDCPDPSH01A/2N Fails Open (To Bus 13 - Normal)
DCCFRS1ABP	1	24	H	Fuse FUDCPDPSH01A/2P Fails Open (To Bus 13 - Normal)
DCCFRS1ADN	1	24	H	Fuse FUDCPDPSH01A/4N Fails Open (To Bus 18 - Norm, Bus 17 - Emerg UV Ctrl Cab)
DCCFRS1ADP	1	24	H	Fuse FUDCPDPSH01A/4P Fails Open (To Bus 18 - Norm, Bus 17 - Emerg UV Ctrl Cab)
DCCFRS1BAN	1	24	H	Fuse FUDCPDPSH01B/1N Fails Open (To Travelling Screen Control Panel)
DCCFRS1BAP	1	24	H	Fuse FUDCPDPSH01B/1P Fails Open (To Travelling Screen Control Panel)
DCCFRS1BBN	1	24	H	Fuse FUDCPDPSH01B/2N Fails Open (To MCC G)
DCCFRS1BBP	1	24	H	Fuse FUDCPDPSH01B/2P Fails Open (To MCC G)
DCCFRS1BFN	1	24	H	Fuse FUDCPDPSH01B/6N Fails Open (To Bus 18 - Emergency)
DCCFRS1BFP	1	24	H	Fuse FUDCPDPSH01B/6P Fails Open (To Bus 18 - Emergency)
DCCFRS1BGN	1	24	H	Fuse FUDCPDPSH01B/7N Fails Open (To Bus 17 - Normal)
DCCFRS1BGP	1	24	H	Fuse FUDCPDPSH01B/7P Fails Open (To Bus 17 - Normal)
DCCFRS1BHN	1	24	H	Fuse FUDCPDPSH01B/8N Fails Open (To Bus 17 - Norm, Bus 18 - Emerg UV Ctrl Cab)
DCCFRS1BHP	1	24	H	Fuse FUDCPDPSH01B/8P Fails Open (To Bus 17 - Norm, Bus 18 - Emerg UV Ctrl Cab)
DCCFRT1BCN	1	24	H	Fuse FUDCPDPTB01B/CN Fails Open (To Hydrogen Panel)
DCCFRT1BCP	1	24	H	Fuse FUDCPDPTB01B/CP Fails Open (To Hydrogen Panel)
DCCFRT1BDN	1	24	H	Fuse FUDCPDPTB01B/DN Fails Open (To MCC A)
DCCFRT1BDP	1	24	H	Fuse FUDCPDPTB01B/DP Fails Open (To MCC A)
DCCFRT1BEN	1	24	H	Fuse FUDCPDPTB01B/FN Fails Open (To MCC F)
DCCFRT1BEP	1	24	H	Fuse FUDCPDPTB01B/FP Fails Open (To MCC F)
DCCFRT1BHN	1	24	H	Fuse FUDCPDPTB01B/HN Fails Open (To IBELIP Inverter)
DCCFRT1BHP	1	24	H	Fuse FUDCPDPTB01B/HP Fails Open (To IBELIP Inverter)
DCCFRT1BJN	1	24	H	Fuse FUDCPDPTB01B/JN Fails Open (To Fire Relay Panel)
DCCFRT1BJP	1	24	H	Fuse FUDCPDPTB01B/JP Fails Open (To Fire Relay Panel)
DCCFRT1BLN	1	24	H	Fuse FUDCPDPTB01B/LN Fails Open (To Nuclear Sample Panel)
DCCFRT1BLP	1	24	H	Fuse FUDCPDPTB01B/LP Fails Open (To Nuclear Sample Panel)
DCCFRT1BNN	1	24	H	Fuse FUDCPDPTB01B/NN Fails Open (To TDAFW Pump DC Oil Pump)
DCCFRT1BNP	1	24	H	Fuse FUDCPDPTB01B/NP Fails Open (To TDAFW Pump DC Oil Pump)
DCCFRV37RN	1	0	H	DC FUSE FURA3/V37R-N FAILS OPEN
DCCFRV37RP	1	0	H	DC FUSE FURA3/V37R-P FAILS OPEN
DCCFRV52FN	1	0	H	Fuse FURA1/V52F-N Fails Open
DCCFRV52FP	1	0	H	Fuse FURA1/V52F-P Fails Open
DCCFRV52RP	2	8760	H	DC Fuse FURA1/V53R-P Fails Open
DCCFRV53RN	2	8760	H	DC Fuse FURA1/V53R-N Fails Open
DCCFRXDC-N	1	0	H	FUSE FUMCB/XDC-N FAILS OPEN
DCCFRXDC-P	1	0	H	FUSE FUMCB/XDC-P FAILS OPEN
DCCFRXDD-N	1	0	H	FUSE FUMCB/XDD-N FAILS OPEN
DCCFRXDD-P	1	0	H	FUSE FUMCB/XDD-P FAILS OPEN

Basic Event	C Factor	Units	Description
DCCFRXJR0N	0		FUSE FUMCB/XJR-N FAILS OPEN
DCCFRXJR0P	0		FUSE FUMCB/XJR-P FAILS OPEN
DCCFRXJS0N	0		FUSE FUMCB/XJS-N FAILS OPEN
DCCFRXJS0P	0		FUSE FUMCB/XJS-P FAILS OPEN
DCCFRXJT0N	0		FUSE FUMCB/XJT-N FAILS OPEN
DCCFRXJT0P	0		FUSE FUMCB/XJT-P FAILS OPEN
DCCFRXJU0N	0		FUSE FUMCB/XJU-N FAILS OPEN
DCCFRXJU0P	0		FUSE FUMCB/XJU-P FAILS OPEN
DCCFRXTK0N	0		FUSE FUMCB/XTK-N FAILS OPEN
DCCFRXTK0P	0		FUSE FUMCB/XTK-P FAILS OPEN
DCCFX419CN 1	24	H	FUSE FUBUS14/19C-N FAILS OPEN (POST TRIP)
DCCFX419CP 1	24	H	FUSE FUBUS14/19C-P FAILS OPEN (POST TRIP)
DCCFX420AN 1	24	H	FUSE FUBUS14/20A-N FAILS OPEN (POST TRIP)
DCCFX420AP 1	24	H	FUSE FUBUS14/20A-P FAILS OPEN (POST TRIP)
DCCFX420CN 1	24	H	FUSE FUBUS14/20C-N FAILS OPEN (POST TRIP)
DCCFX420CP 1	24	H	FUSE FUBUS14/20C-P FAILS OPEN (POST TRIP)
DCCFX421AN 1	24	H	FUSE FUBUS14/21A-N FAILS OPEN (POST TRIP)
DCCFX421AP 1	24	H	FUSE FUBUSA4/21A-P FAILS OPEN (POST TRIP)
DCCFX421CN 1	24	H	FUSE FUBUS14/21C-N FAILS OPEN (POST TRIP)
DCCFX421CP 1	24	H	FUSE FUBUS14/21C-P FAILS OPEN (POST TRIP)
DCCFX422AN 1	24	H	FUSE FUBUS14/22A-N FAILS OPEN (POST TRIP)
DCCFX422AP 1	24	H	FUSE FUBUS14/22A-P FAILS OPEN (POST TRIP)
DCCFX422BN 1	24	H	FUSE FUBUS14/22B-N FAILS OPEN (POST TRIP)
DCCFX422BP 1	24	H	FUSE FUBUS14/22B-P FAILS OPEN (POST TRIP)
DCCFX423AN 1	24	H	FUSE FUBUS14/23A-N FAILS OPEN (POST TRIP)
DCCFX423AP 1	24	H	FUSE FUBUS14/23A-P FAILS OPEN (POST TRIP)
DCCFX423BN 1	24	H	FUSE FUBUS14/23B-N FAILS OPEN (POST TRIP)
DCCFX423BP 1	24	H	FUSE FUBUS14/23B-P FAILS OPEN (POST TRIP)
DCCFX423CN 1	24	H	FUSE FUBUS14/23C-N FAILS OPEN (POST TRIP)
DCCFX423CP 1	24	H	FUSE FUBUS14/23C-P FAILS OPEN (POST TRIP)
DCCFX612AN 1	24	H	FUSE FUBUS16/12A-N FAILS OPEN (POST TRIP)
DCCFX612AP 1	24	H	FUSE FUBUS16/12A-P FAILS OPEN (POST TRIP)
DCCFX613CN 1	24	H	FUSE FUBUS16/13C-N FAILS OPEN (POST TRIP)
DCCFX613CP 1	24	H	FUSE FUBUS16/13C-P FAILS OPEN (POST TRIP)
DCCFX614AN 1	24	H	FUSE FUBUS16/14A-N FAILS OPEN (POST TRIP)
DCCFX614AP 1	24	H	FUSE FUBUS16/14A-P FAILS OPEN (POST TRIP)
DCCFX614CN 1	24	H	FUSE FUBUS16/14C-N FAILS OPEN (POST TRIP)
DCCFX614CP 1	24	H	FUSE FUBUS16/14C-P FAILS OPEN (POST TRIP)
DCCFX615AN 1	24	H	FUSE FUBUS16/15A-N FAILS OPEN (POST TRIP)
DCCFX615AP 1	24	H	FUSE FUBUS16/15A-P FAILS OPEN (POST TRIP)
DCCFX615BN 1	24	H	FUSE FUBUS16/15B-N FAILS OPEN (POST TRIP)
DCCFX615BP 1	24	H	FUSE FUBUS16/15B-P FAILS OPEN (POST TRIP)

Basic Event	C	Factor	Units	Description
DCCFX615CN	1	24	H	FUSE FUBUS16/15C-N FAILS OPEN (POST TRIP)
DCCFX615CP	1	24	H	FUSE FUBUS16/15C-P FAILS OPEN (POST TRIP)
DCCFX616AN	1	24	H	FUSE FUBUS16/16A-N FAILS OPEN (POST TRIP)
DCCFX616AP	1	24	H	FUSE FUBUS16/16A-P FAILS OPEN (POST TRIP)
DCCFX616BN	1	24	H	FUSE FUBUS16/16B-N FAILS OPEN (POST TRIP)
DCCFX616BP	1	24	H	FUSE FUBUS16/16B-P FAILS OPEN (POST TRIP)
DCCFX617AN	1	24	H	FUSE FUBUS16/17A-N FAILS OPEN (POST TRIP)
DCCFX617AP	1	24	H	FUSE FUBUS16/17A-P FAILS OPEN (POST TRIP)
DCCFX726CN	1	24	H	FUSE FUBUS17/26C-N FAILS OPEN (POST TRIP)
DCCFX726CP	1	24	H	FUSE FUBUS17/26C-P FAILS OPEN (POST TRIP)
DCCFX727AN	1	24	H	FUSE FUBUS17/27A-N FAILS OPEN (POST TRIP)
DCCFX727AP	1	24	H	FUSE FUBUS17/27A-P FAILS OPEN (POST TRIP)
DCCFX727BN	1	24	H	FUSE FUBUS17/27B-N FAILS OPEN (POST TRIP)
DCCFX727BP	1	24	H	FUSE FUBUS17/27B-P FAILS OPEN (POST TRIP)
DCCFX727CN	1	24	H	FUSE FUBUS17/27C-N FAILS OPEN (POST TRIP)
DCCFX727CP	1	24	H	FUSE FUBUS17/27C-P FAILS OPEN (POST TRIP)
DCCFX727DN	1	24	H	FUSE FUBUS17/27D-N FAILS OPEN (POST TRIP)
DCCFX727DP	1	24	H	FUSE FUBUS17/27D-P FAILS OPEN (POST TRIP)
DCCFX829AN	1	24	H	FUSE FUBUS18/29A-N FAILS OPEN (POST TRIP)
DCCFX829AP	1	24	H	FUSE FUBUS18/29A-P FAILS OPEN (POST TRIP)
DCCFX829BN	1	24	H	FUSE FUBUS18/29B-N FAILS OPEN (POST TRIP)
DCCFX829BP	1	24	H	FUSE FUBUS18/29B-P FAILS OPEN (POST TRIP)
DCCFX829CN	1	24	H	FUSE FUBUS18/29C-N FAILS OPEN (POST TRIP)
DCCFX829CP	1	24	H	FUSE FUBUS18/29C-P FAILS OPEN (POST TRIP)
DCCFX829DN	1	24	H	FUSE FUBUS18/29D-N FAILS OPEN (POST TRIP)
DCCFX829DP	1	24	H	FUSE FUBUS18/29D-P FAILS OPEN (POST TRIP)
DCCFX830CN	1	24	H	FUSE FUBUS18/30C-N FAILS OPEN (POST TRIP)
DCCFX830CP	1	24	H	FUSE FUBUS18/30C-P FAILS OPEN (POST TRIP)
DCCSRA1AAX	1	24	H	Disconnect Switch DCPDPAB01A/01 Transfers Open (To MCC E)
DCCSRA1ABX	1	24	H	Disconnect Switch DCPDPAB01A/02 Transfers Open (To MCC C)
DCCSRA1ACX	1	24	H	Disconnect Switch DCPDPAB01A/03 Transfers Open (To MCC C Aux Breaker Circuit)
DCCSRA1ADX	1	24	H	Disconnect Switch DCPDPAB01A/04 Transfers Open (To Bus 14 - Normal)
DCCSRA1AEX	1	24	H	Disconnect Switch DCPDPAB01A/05 Transfers Open (To Bus 16 - Emergency)
DCCSRA1AFX	1	24	H	Disconnect Switch DCPDPAB01A/06 Transfers Open (To SI Pump Fan Control Panel)
DCCSRA1BAX	1	24	H	Disconnect Switch DCPDPAB01B/01 Transfers Open (To Aux Building HVAC Control)
DCCSRA1BBX	1	24	H	Disconnect Switch DCPDPAB01B/02 Transfers Open (To MCC D)
DCCSRA1BCX	1	24	H	Disconnect Switch DCPDPAB01B/03 Transfers Open (To Gas Analyzer Control Panel)
DCCSRA1BDX	1	24	H	Disconnect Switch DCPDPAB01B/04 Transfers Open (To Bus 16 - Normal)
DCCSRA1BEX	1	24	H	Disconnect Switch DCPDPAB01B/05 Transfers Open (To Bus 14 - Emergency)
DCCSRA1BFX	1	24	H	Disconnect Switch DCPDPAB01B/06 Transfers Open (To MCC D Aux Circuit Bkr Cab)
DCCSRA2AAX	1	24	H	Disconnect Switch DCPDPAB02A/01 Transfers Open (To H2 Recombiner A Control Pnl)
DCCSRA2ABX	1	24	H	Disconnect Switch DCPDPAB02A/02 Transfers Open (To Boron R&WD Panel W1)

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Table [illegible]2
Integrated C.[illegible] BE File

Basic Event	C Factor	Units	Description
DCCSRA2AEX	1	24 H	Disconnect Switch FUDCPDPAB02A/05 Transfers Open (To Reactor Trip Switchgear)
DCCSRA2AFX	1	24 H	Disconnect Switch DCPDPAB02A/06 Transfers Open (To AuxiliaryBuilding Panel A2)
DCCSRA2BAX	1	24 H	Disconnect Switch DCPDPAB02B/01 Transfers Open (To H2 Recombiner B Control Pnl)
DCCSRA2BBX	1	24 H	Disconnect Switch DCPDPAB02B/02 Transfers Open (To Boron R&WD Panel W2)
DCCSRA2BEX	1	24 H	Disconnect Switch FUDCPDPAB02B/05 Transfers Open (To Reactor Trip Switchgear)
DCCSRA3AAX	1	24 H	Disconnect Switch DCPDPAB03A/01 Transfers Open (To Charging Pump A Alt DC)
DCCSRC2AAX	1	24 H	Disconnect Switch DCPDPCB02A/01 Transfers Open (To Battery Charger A)
DCCSRC2ABX	1	24 H	Disconnect Switch DCPDPCB02A/02 Transfers Open (To Main DC Distribution Pnl A)
DCCSRC2AEX	1	24 H	Disconnect Switch DCPDPCB02A/05 Transfers Open (To Battery Charger A1)
DCCSRC2BAX	1	24 H	Disconnect Switch DCPDPCB02B/01 Transfers Open (To Battery Charger B)
DCCSRC2BBX	1	24 H	Disconnect Switch DCPDPCB02B/02 Transfers Open (To Main DC Panel B)
DCCSRC2BDX	1	24 H	Disconnect Switch DCPCB02B/04 Transfers Open (To Turbine Building DC Dist Pnl)
DCCSRC2BEX	1	24 H	Disconnect Switch DCPDPCB02B/05 Transfers Open (To Screen House DC Dist Pnl B)
DCCSRC2BFX	1	24 H	Disconnect Switch DCPDPCB02A/06 Transfers Open (To Battery Charger B1)
DCCSRC3ABX	1	24 H	Disconnect Switch DCPDPCB03A/02 Transfers Open (To MCC B)
DCCSRC3ACX	1	24 H	Disconnect Switch DCPDPCB03A/03 Transfers Open (To MCC H)
DCCSRC3ADX	1	24 H	Disconnect Switch DCPDPCB03A/04 Transfers Open (To Rod Drive MG Set Ctrl Pnl)
DCCSRC3AGX	1	24 H	Disconnect Switch DCPDPCB03A/07 Transfers Open (To D/G A DC Dist Panel A)
DCCSRC3AHX	1	24 H	Disconnect Switch DCPDPCB03A/08 Transfers Open (To Bus 11A)
DCCSRC3AJX	1	24 H	Disconnect Switch DCPDPCB03A/09 Transfers Open (To Bus 12A)
DCCSRC3AKX	1	24 H	Disconnect Switch DCPDPCB03A/10 Transfers Open (To Bus 13)
DCCSRC3ALX	1	24 H	Disconnect Switch DCPDPCB03A/11 Transfers Open (To Screen House Dist Panel A)
DCCSRC3AMX	1	24 H	Disconnect Switch DCPDPCB03A/12 Transfers Open (To TDAFW Valve 3505A)
DCCSRC3ANX	1	24 H	Disconnect Switch DCPDPCB03A/13 Transfers Open (To MFW Pump A Oil Pump)
DCCSRC3APX	1	24 H	Disconnect Switch DCPDPCB03A/P Transfers Open (To MCB Distribution Panel A)
DCCSRC3AQX	1	24 H	Disconnect Switch DCPDPCB03A/15 Transfers Open (To Inverter A)
DCCSRC3ARX	1	24 H	Disconnect Switch DCPDPCB03A/16 Transfers Open (To PA System Inverter)
DCCSRC3ASX	1	24 H	Disconnect Switch DCPDPCB03A/17 Transfers Open (To Battery Room Vent Ctrl Pnl)
DCCSRC3ATX	1	24 H	Disconnect Switch DCPDPCB03A/18 Transfers Open (To Bus 14 UV Control)
DCCSRC3AUX	1	24 H	Disconnect Switch FUDCPDPCB03A/19 Transfers Open (To Auxiliary Bldg Panel 1A)
DCCSRC3BBX	1	24 H	Disconnect Switch DCPDPCB03B/02 Transfers Open (To MOV 5171)
DCCSRC3BCX	1	24 H	Disconnect Switch DCPDPCB03B/03 Transfers Open (To Rod Drive MG Set Ctrl Panel)
DCCSRC3BDX	1	24 H	Disconnect Switch DCPDPCB03B/04 Transfers Open (To MCC J)
DCCSRC3BEX	1	24 H	Disconnect Switch DCPDPCB03B/05 Transfers Open (To MCC K)
DCCSRC3BFX	1	24 H	Disconnect Switch DCPDPCB03B/06 Transfers Open (To MOV 3996)
DCCSRC3BJX	1	24 H	Disconnect Switch DCPDPCB03B/09 Transfers Open (To MCB DC Distribution Panel B)
DCCSRC3BKX	1	24 H	Disconnect Switch DCPDPCB03B/10 Transfers Open (To Bus 11B - Norm, 12A - Emerg)
DCCSRC3BLX	1	24 H	Disconnect Switch DCPDPCB03B/11 Transfers Open (To Bus 12B - Norm, 11A - Emerg)
DCCSRC3BMX	1	24 H	Disconnect Switch DCPDPCB03B/12 Transfers Open (To Bus 15 - Norm, 13 - Emerg)
DCCSRC3BPX	1	24 H	Disconnect Switch DCPDPCB03B/14 Transfers Open (To MFW Pump B DC Oil Pump)
DCCSRC3BQX	1	24 H	Disconnect Switch DCPDPCB03B/15 Transfers Open (To Inverter B)
DCCSRC3BRX	1	24 H	Disconnect Switch DCPDPCB03B/16 Transfers Open (To D/G B DC Dist Panel B)

Basic Event	C	Factor	Units	Description
DCCSRC3BSX	1	24	H	Disconnect Switch DCPDPCB03B/17 Transfers Open (To TDAFW Valve 3504A)
DCCSRC3BTX	1	24	H	Disconnect Switch DCPDPCB03B/18 Transfers Open (To Bus 16 UV Control)
DCCSRC3BUX	1	24	H	Disconnect Switch DCPDPCB03B/19 Transfers Open (To AuxiliaryBldg DC Panel B)
DCCSRC4AAX	1	24	H	Disconnect Switch DCPDPCB04A/01 Transfers Open (To PPS Switchgear Train A)
DCCSRC4ABX	1	24	H	Disconnect Switch DCPDPCB04A/02 Transfers Open (To Main Transformer Ann)
DCCSRC4ACX	1	24	H	Disconnect Switch DCPDPAB01A/03 Transfers Open (To SAT 11 Annuciator)
DCCSRC4ADX	1	24	H	Disconnect Switch DCPDPAB04A/04 Transfers Open (To SAT #12A Annunciator)
DCCSRC4AEX	1	24	H	Disconnect Switch DCPDPCB04A/E Transfers Open (To MCB Alarm System)
DCCSRC4AFX	1	24	H	Disconnect Switch DCPDPCB04A/06 Transfers Open (To Steam Dump Valves Train A)
DCCSRC4AGX	1	24	H	Disconnect Switch DCPDPCB04A/07 Transfers Open (To Lockout & Diff Relays)
DCCSRC4AHX	1	24	H	Disconnect Switch DCPDPCB04A/08 Transfers Open (To Bus 11A UV Relays)
DCCSRC4AJX	1	24	H	Disconnect Switch DCPDPCB01A/09 Transfers Open (To H2 Monitor Valves)
DCCSRC4AMX	1	24	H	Disconnect Switch DCPDPCB04A/12 Transfers Open (To SI-A1 Train A)
DCCSRC4ANX	1	24	H	Disconnect Switch DCPDPCB04A/N Transfers Open (To RA Racks Train A)
DCCSRC4APX	1	24	H	Disconnect Switch DCPDPCB04A/14 Transfers Open (To MQ 483 Inverter)
DCCSRC4AQX	1	24	H	Disconnect Switch DCPDPCB04A/15 Transfers Open (To Reactor Trip Targets)
DCCSRC4ARX	1	24	H	Disconnect Switch DCPDPCB04A/16 Transfers Open (To Condensate Booster Pumps)
DCCSRC4ASX	1	24	H	Disconnect Switch DCPDPCB04A/17 Transfers Open (To Circulating Water Pumps)
DCCSRC4ATX	1	24	H	Disconnect Switch DCPDPAB04A/18 Transfers Open (To RCS Head Vent Valves)
DCCSRC4AVX	1	24	H	Disconnect Switch DCPDPCB04A/20 Transfers Open (To CNMT Isolation Rack CI-A1)
DCCSRC4AWX	1	24	H	Disconnect Switch DCPDPCB04A/21 Transfers Open (To Turbine Trip Relays)
DCCSRC4BAX	1	24	H	Disconnect Switch DCPDPCB04B/01 Transfers Open (To PPS Switchgear Train B)
DCCSRC4BBX	1	24	H	Disconnect Switch DCPDPCB04B/02 Transfers Open (To Steam Dump Valves, TDAFW)
DCCSRC4BDX	1	24	H	Disconnect Switch DCPDPAB04B/04 Transfers Open (To Lockout and Diff Relays)
DCCSRC4BFX	1	24	H	Disconnect Switch DCPDPAB04B/06 Transfers Open (To Control Room Vent Radiation)
DCCSRC4BHX	1	24	H	Disconnect Switch DCPDPCB04B/08 Transfers Open (To RLTR-2)
DCCSRC4BJX	1	24	H	Disconnect Switch DCPDPCB04B/09 Transfers Open (To SI-B1 Train B)
DCCSRC4BKX	1	24	H	Disconnect Switch DCPDPCB04B/10 Transfers Open (To RA Racks Train B)
DCCSRC4BNX	1	24	H	Disconnect Switch DCPDPCB04B/13 Transfers Open (To H2 Monitor Vlvs 923 and 924)
DCCSRC4BPX	1	24	H	Disconnect Switch DCPDPCB01B/14 Transfers Open (To Circ Water Trip Logic Rly)
DCCSRC4BQX	1	24	H	Disconnect Switch DCPDPCB04B/15 Transfers Open (To MCB Annuciator Standby Pwr)
DCCSRC4BSX	1	24	H	Disconnect Switch DCPDPCB04B/17 Transfers Open (To Bus 11B UV Relays)
DCCSRC4BTX	1	24	H	Disconnect Switch DCPDPCB04B/18 Transfers Open (To RCS Head Vent Vlvs Train B)
DCCSRC4BUX	1	24	H	Disconnect Switch DCPDPCB04B/19 Transfers Open (To CNMT Isolation Rack CI-B1)
DCCSRC4BVX	1	24	H	Disconnect Switch DCPDPCB04B/20 Transfers Open (To Control Room Vent Fan)
DCCSRC4BXX	1	24	H	Disconnect Switch DCPDPCB04B/22 Transfers Open (To MCB Alarm System)
DCCSRCB1AX	1	24	H	Disconnect Switch DCPDPCB01A Transfers Open
DCCSRCB1BP	1	24	H	Disconnect Switch DCPDPCB01B Transfers Open
DCCSRD1ACX	1	24	H	Disconnect Switch DCPDPDG01A/03 Transfers Open (To D/G A - Normal)
DCCSRD1ADX	1	24	H	Disconnect Switch DCPDPDG01A/04 Transfers Open (To D/G B - Emergency)
DCCSRD1BAX	1	24	H	Disconnect Switch DCPDPDG01B/01 Transfers Open (To Breaker 52/EG1B3)
DCCSRD1BCX	1	24	H	Disconnect Switch DCPDPDG01B/03 Transfers Open (To D/G B - Normal)

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Basic Event	C Factor	Units	Description
DCCSRD1BDX	1	24 H	Disconnect Switch DCPDPDG01B/04 Transfers Open (To D/G A - Emergency)
DCCSRS1AAX	1	24 H	Disconnect Switch DCPDPSH01A/01 Transfers Open (To Bus 17 - Emergency)
DCCSRS1ABX	1	24 H	Disconnect Switch DCPDPSH01A/02 Transfers Open (To Bus 13 - Normal)
DCCSRS1ADX	1	24 H	Disconnect Switch DCPDPSH01A/04 Transfers Open (To Bus 18 and 17 UV Ctrl Cab)
DCCSRS1BAX	1	24 H	Disconnect Switch DCPDPSH01B/01 Transfers Open (To Travelling Screen Ctrl Pnl)
DCCSRS1BBX	1	24 H	Disconnect Switch DCPDPSH01B/02 Transfers Open (To MCC G)
DCCSRS1BFX	1	24 H	Disconnect Switch DCPDPSH01B/06 Transfers Open (To Bus 18 - Emergency)
DCCSRS1BGX	1	24 H	Disconnect Switch DCPDPSH01B/07 Transfers Open (To Bus 17 - Normal)
DCCSRS1BHX	1	24 H	Disconnect Switch DCPDPSH01B/08 Transfers Open (To Bus 17 - Norm UV Ctrl Cab)
DCCSRT1BCX	1	24 H	Disconnect Switch DCPDPTB01B/03 Transfers Open (To Hydrogen Panel)
DCCSRT1BDX	1	24 H	Disconnect Switch DCPDPTB01B/04 Transfers Open (MCC A)
DCCSRT1BEX	1	24 H	Disconnect Switch DCPDPTB01B/05 Transfers Open (To MCC F)
DCCSRT1BHX	1	24 H	Disconnect Switch DCPDPTB01B/08 Transfers Open (To IBELIP Inverter)
DCCSRT1BJX	1	24 H	Disconnect Switch DCPDPTB01B/09 Transfers Open (To Fire Relay Panel)
DCCSRT1BLX	1	24 H	Disconnect Switch DCPDPTB01B/11 Transfers Open (To Nuclear Sample Panel)
DCCSRT1BNX	1	24 H	Disconnect Switch DCPDPTB01B/13 Transfers Open (To TDAFW Pump Oil Pump)
DCINFBUS1A	1	24 H	Failure Of Instrument Bus A (IBPDPCBAR) Inverter INVTA
DCINFBUS1B	1	24 H	Faulure Of Instrument Bus C (IBPDPCBCB) Inverter INVTB
DCINFMQ483	1	24 H	Failure Of 120 VAC Inverter MQ483
DCMM0BATTA	4.746E-05		Failure of Battery A (BTRYA) To Battery A Main DC Fuse Cabinet
DCMM0BATTB	4.746E-05		Failure of Battery B To Battery B Main DC Fuse Cabinet
DCMMAB01AA	3.556E-05		Failure of Circuit E60 (To MCC E)
DCMMAB01AB	3.556E-05		Failure of Circuit E61 (To MCC C)
DCMMAB01AC	3.556E-05		Failure of Circuit E282 (To MCC C Auxiliary Circuit Breaker Cabinet)
DCMMAB01AD	3.556E-05		Failure of Circuit E63 (To Bus 14 - Normal)
DCMMAB01AE	3.556E-05		Failure of Circuit E169 (To Bus 16 - Emergency)
DCMMAB01AF	3.556E-05		Failure of Circuit E62 (To SI Pump Fan Control Panel)
DCMMAB01BA	3.556E-05		Failure of Circuit E166 (Circuit E166)
DCMMAB01BB	3.556E-05		Failure of Circuit E167 (To MCC D)
DCMMAB01BC	3.556E-05		Failure of Circuit E170 (To Gas Analyzer Control Panel)
DCMMAB01BD	3.556E-05		Failure of Circuit E168 (To Bus 16 - Normal)
DCMMAB01BE	3.556E-05		Failure of Circuit E64 (To Bus 14 - Emergency)
DCMMAB01BF	3.556E-05		Failure of Circuit E284 (To MCC D Auxiliary Circuit Breaker Cabinet)
DCMMAB02AA	3.556E-05		Failure of Circuit E222 (To H2 Recombiner A Control Panel)
DCMMAB02AB	3.556E-05		Failure of Circuit E225 (To Boron R&WD Control Panel W1)
DCMMAB02AE	3.556E-05		Failure of Circuit E224 (To Reactor Trip Switchgear Breaker RTA/BYB)
DCMMAB02BA	3.556E-05		Failure of Circuit E232 (To H2 Recombiner B Control Panel)
DCMMAB02BB	3.556E-05		Failure of Circuit E235 (To Boron R&WD Control Panel W2)
DCMMAB02BE	3.556E-05		Failure of Circuit E233 (To Reactor Trip Switchgear Breaker RTB/BYA)
DCMMAB03AA	3.556E-05		Failure of Circuit E307 (To Charging Pump A Alternate DC Power)
DCMMAUX00A	3.556E-05		Failure of Circuit E128 (To Auxiliary Building DC Distribution Panel A)
DCMMAUX00B	3.556E-05		Failure of Circuit E128 (To Auxiliary Building DC Distribution Panel B)

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Basic Event	C Factor	Units	Description
DCMMAUX0A2	3.556E-05		Failure of Circuit E306 (To Auxiliary Building DC Distribution Panel A2)
DCMMCB03AB	3.556E-05		Failure of Circuit E21 (To MCC B)
DCMMCB03AC	3.556E-05		Failure of Circuit E22 (To MCC H)
DCMMCB03AD	3.556E-05		Failure of Circuit E40 (To Rod Drive MG Set Control Panel)
DCMMCB03AH	3.556E-05		Failure of Circuit E25 (To Bus 11A - Normal, Bus 12B - Emergency)
DCMMCB03AJ	3.556E-05		Failure of Circuit E26 (To Bus 12A - Normal, Bus 11B - Emergency)
DCMMCB03AK	3.556E-05		Failure of Circuit E28 (To Bus 13 - Normal, Bus 15 - Emergency)
DCMMCB03AM	3.556E-05		Failure of Circuit E32 (To TDAFW Valve 3505A)
DCMMCB03AN	3.556E-05		Failure of Circuit E41 (To MFW Pump A DC Oil Pump)
DCMMCB03AQ	3.556E-05		Failure of Circuit E50 (To Inverter A)
DCMMCB03AR	3.556E-05		Failure of Circuit XXXX (To PA System Inverter)
DCMMCB03AS	3.556E-05		Failure of Circuit C5136 (To Battery Room Ventilation Control Panel)
DCMMCB03AT	3.556E-05		Failure of Circuit E274 (To Bus 14 - Normal, Bus 16 - Emergency UV Ctrl Cab)
DCMMCB03BB	3.556E-05		Failure of Circuit E81 Control Panel (To MOV 5171)
DCMMCB03BC	3.556E-05		Failure of Circuit E86 (To Rod Drive MG Set Control Panel)
DCMMCB03BD	3.556E-05		Failure of Circuit E91 (To MCC J)
DCMMCB03BE	3.556E-05		Failure of Circuit E92 (To MCC K)
DCMMCB03BF	3.556E-05		Failure of Circuit E93 (To MOV 3996)
DCMMCB03BK	3.556E-05		Failure of Circuit E104 (To Bus 11B - Normal, Bus 12A - Emergency)
DCMMCB03BL	3.556E-05		Failure of Circuit E105 (To Bus 12B - Normal, Bus 11A - Emergency)
DCMMCB03BM	3.556E-05		Failure of Circuit E107 (To Bus 15 - Normal, Bus 13 - Emergency)
DCMMCB03BP	3.556E-05		Failure of Circuit E116 (To MFW Pump B DC Oil Pump)
DCMMCB03BQ	3.556E-05		Failure of Circuit E123 (To Inverter B)
DCMMCB03BS	3.556E-05		Failure of Circuit E108 (To TDAFW Steam Admission Valve 3504A)
DCMMCB03BT	3.556E-05		Failure of Circuit E275 (To Bus 16 - Normal, Bus 14 - Emergency UV Ctrl Cab)
DCMMCB04AA	3.556E-05		Failure of Circuit E201 (To PPS Switchgear Unit 6 Train A)
DCMMCB04AB	3.556E-05		Failure of Circuit T7 (To Main Transformer Annunciator)
DCMMCB04AC	3.556E-05		Failure of Circuit T18 (To Station Auxiliary Transformer #11 Annunciator)
DCMMCB04AD	3.556E-05		Failure of Circuit T27 (To Station Auxiliary Transformer #12A Annunciator)
DCMMCB04AE	3.556E-05		Failure of Circuit XXXX (To MCB Alarm System)
DCMMCB04AF	3.556E-05		Failure of Circuit XXXX (To Steam Dump Valves Train A)
DCMMCB04AG	3.556E-05		Failure of Circuit XXXX (To Lockout and Differential Relays)
DCMMCB04AH	3.556E-05		Failure of Circuit E202 (To Bus 11A UV Relays)
DCMMCB04AJ	3.556E-05		Failure of Circuit To H2 Monitor Isolation Valves 921 and 922
DCMMCB04AM	3.556E-05		Failure of Circuit E214 (To SI-A1 Train A)
DCMMCB04AN	3.556E-05		Failure of Circuit E215 (To RA Racks Train A)
DCMMCB04AP	3.556E-05		Failure of Circuit E217 (To MQ 483 Inverter)
DCMMCB04AQ	3.556E-05		Failure of Circuit XXXX (To Reactor Trip Targets)
DCMMCB04AR	3.556E-05		Failure of Circuit COC-1 (To Condensate Booster Pump Relay Panel)
DCMMCB04AS	3.556E-05		Failure of Circuit M11A (To Circulating Water Pump Trip Logic Relays)
DCMMCB04AT	3.556E-05		Failure of Circuit XXXX (To Reactor Overpressurization Heat Vent Valve Train A)
DCMMCB04AV	3.556E-05		Failure of Circuit E266 (To Containment Isolation Rack CI-A1)

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Table [illegible]2
Integrated C[illegible] BE File

Basic Event	C Factor	Units	Description
DCMMCB04AW	3.556E-05		Failure of Circuits G888 and E213 (To Turbine Trip Aux Relays and Rack RLTR-1)
DCMMCB04BA	3.556E-05		Failure of Circuit E200 (To PPS Switchgear Unit 1 Train B)
DCMMCB04BB	3.556E-05		Failure of Circuit XXXX (To Steam Dump Valves, TDAFW Pump Govenor, MCB TB)
DCMMCB04BD	3.556E-05		Failure of Circuit XXXX (To Lockout and Differential Relays)
DCMMCB04BF	3.556E-05		Failure of Circuit E298 (To Control Room Ventilation Radiation Monitors)
DCMMCB04BH	3.556E-05		Failure of Circuit E210 (To RLTR-2)
DCMMCB04BJ	3.556E-05		Failure of Circuit E211 (To SI-B1 Train B)
DCMMCB04BK	3.556E-05		Failure of Circuit E212 (To RA Racks Train B)
DCMMCB04BN	3.556E-05		Failure of Circuit To H2 Monitor Isolation Valves 923 and 924
DCMMCB04BP	3.556E-05		Failure of Circuit M178C (To Circulating Water Pump Trip Logic Relays)
DCMMCB04BQ	3.556E-05		Failure of Circuit XXXX (To MCB Annunciator Standby Power)
DCMMCB04BS	3.556E-05		Failure of Circuit E203 (To Bus 11B UV Relays)
DCMMCB04BT	3.556E-05		Failure of Circuit XXXX (To RCS Overpressurization Head Vent Valves Train B)
DCMMCB04BU	3.556E-05		Failure of Circuit E267 (To Containment Isolation Rack CI-B1)
DCMMCB04BV	3.556E-05		Failure of Circuit C5129 (To Control Room Ventilation Fan)
DCMMCB04BX	3.556E-05		Failure of Circuit XXXX (To MCB Alarm System)
DCMMCHG01A	3.723E-04		Failure of Battery Charger A (BYCA)
DCMMCHG01B	3.723E-04		Failure of Battery Charger B (BYCB)
DCMMCHG1A1	3.723E-04		Failure of Battery Charger A1 (BYCA1)
DCMMCHG1B1	3.723E-04		Failure of Battery Charger B1 (BYCB1)
DCMMDG01AC	3.556E-05		Failure of Circuit E19 (To D/G A - Normal)
DCMMDG01AD	3.556E-05		Failure of Circuit E160 (To D/G B - Emergency)
DCMMDG01BA	3.556E-05		Failure of Circuit E300 (To Circuit Breaker 52/EG1B3)
DCMMDG01BC	3.556E-05		Failure of Circuit E89 (To D/G B - Normal)
DCMMDG01BD	3.556E-05		Failure of Circuit E18 (To D/G A - Emergency)
DCMMDGPNLA	3.556E-05		Failure Of Circuit E20 (To D/G A DC Distribution Panel A)
DCMMDGPNLB	3.556E-05		Failure Of Circuit E90 (To D/G B DC Distribution Panel B)
DCMMMAIN1A	3.556E-05		Failure of Circuit E14 (To Main DC Distribution Panel 1A)
DCMMMAIN1B	3.556E-05		Failure of Circuit E76 (To Main DC Distribution Panel B)
DCMMMCB01A	3.556E-05		Failure of Circuit E49 (To MCB DC Distribution Panel A)
DCMMMCB01B	3.556E-05		Failure of Circuit E103 (To MCB DC Distribution Panel 1B)
DCMMSCRN1A	3.556E-05		Failure of Circuit E30 (To Screen House DC Distribution Panel A)
DCMMSCRN1B	3.556E-05		Failure of Circuit E127 (To Screen House DC Distribution Panel 1B)
DCMMSH01AA	3.556E-05		Failure of Circuit E31 (Bus 17 - Emergency)
DCMMSH01AB	3.556E-05		Failure of Circuit E160 (To Bus 13 - Normal)
DCMMSH01AD	3.556E-05		Failure of Circuit XXXX (To Bus 18 - Normal, Bus 17 - Emergency UV Control Cab)
DCMMSH01BA	3.556E-05		Failure of Circuit E136 (To Travelling Screen Control Panel)
DCMMSH01BB	3.556E-05		Failure of Circuit E137 (To MCC G)
DCMMSH01BF	3.556E-05		Failure of Circuit E159 (To Bus 18 - Emergency)
DCMMSH01BG	3.556E-05		Failure of Circuit E31A (To Bus 17 - Normal)
DCMMSH01BH	3.556E-05		Failure of Circuit E270 (To Bus 17 - Normal, Bus 18 - Emerg UV Control Cabinet)
DCMMTB01BC	3.556E-05		Failure of Circuit E177 (To Hydrogen Panel)

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Basic Event	C	Factor	Units	Description
DCMMTB01BD		3.556E-05		Failure of Circuit E178 (To MCC A)
DCMMTB01BE		3.556E-05		Failure of Circuit E179 (To MCC F)
DCMMTB01BH		3.556E-05		Failure of Circuit E301 (To IBELIP Inverter)
DCMMTB01BJ		3.556E-05		Failure of Circuit E174 (To Fire Relay Panel)
DCMMTB01BL		3.556E-05		Failure of Circuit E187 (To Nuclear Sample Panel)
DCMMTB01BN		3.556E-05		Failure of Circuit E191 (To TDAFW Pump DC Oil Pump)
DCMMTBDIST		3.556E-05		Failure of Circuit E74 (To Turbine Building DC Distribution Panel)
DCREB83DGA	1	1	N	RELAY 83/DGA (THROWOVER) FAILS TO DEENERGIZE
DCREB83DGB	1	1	N	RELAY 83/DGB (THROWOVER) FAILS TO DEENERGIZE
DCREBBUS13	1	1	N	RELAY 83E/13 (BUS 13 DC THROWOVER) FAILS TO DEENERGIZE
DCREBBUS14	1	1	N	RELAY 83E/14 (BUS 14 DC THROWOVER) FAILS TO DEENERGIZE
DCREBBUS15	1	1	N	RELAY 83E/15 (BUS 15 DC THROWOVER) FAILS TO DEENERGIZE
DCREBBUS16	1	1	N	RELAY 83E/16 (BUS 16 DC THROWOVER) FAILS TO DEENERGIZE
DCREBBUS17	1	1	N	RELAY 83E/17 (BUS 17 DC THROWOVER) FAILS TO DEENERGIZE
DCREBBUS18	1	1	N	RELAY 83E/18 (BUS 18 DC THROWOVER) FAILS TO DEENERGIZE
DCREE86MCC	1	1	N	RELAY 86/MCCC FAILS TO ENERGIZE
DCREE86MCD	1	1	N	RELAY 86/MCCD FAILS TO ENERGIZE
DCREEVFX1A	1	1	N	RELAY VFX1-A FAILS TO ENERGIZE
DCREEVFX1B	1	1	N	RELAY VFX1-B FAILS TO ENERGIZE
DCREEVFX2A	1	1	N	RELAY VFX2-A FAILS TO ENERGIZE
DCREEVFX2B	1	1	N	RELAY VFX2-B FAILS TO ENERGIZE
DCRTD011CX	1	1	N	TIME DELAY RELAY 11CX/TD1/EG1B1 FAILS TO ENERGIZE
DCRTD018CX	1	1	N	TIME DELAY RELAY 18CX/TD1/EG1A1 FAILS TO ENERGIZE
DG00WINTER		0.1		Extreme winter temperatures (< 6 F)
DG011				Loss Of Power To 480 VAC Bus 14 From KDG01A (DC Power Logic Clip)
DG0RUNTRIP		1.59E-02		DG RUNNING WITH OTHER DG IN T/M AND TRIPS FOLLOWING AN INITIATING EVENT
DG113				Large Loads On 480 VAC Bus 16 Fail To Shed Following An Undervoltage
DG115				No Starting Signal To KDG01B Following An Undervoltage On 480 VAC Bus 16
DG209				No Starting Signal To KDG01A Following An Undervoltage On 480 VAC Bus 14
DG226				480 VAC Bus 14 / Bus 13 Tie Circ. Breaker 52/BT14-13 (BUS14/19B) Fails To Open
DG234				KDG01A 480 VAC Circuit Breaker 52/EG1A1 (BUS14/18C) To Bus 14 Fails To Close
DG326				480 VAC Bus 16 / Bus 15 Tie Circ. Breaker 52/BT16-15 (BUS16/12B) Fails To Open
DG334				KDG01A 480 VAC Circuit Breaker 52/EG1B1 (BUS16/11C) To Bus 16 Fails To Close
DG359				Large Loads On 480 VAC Bus 14 Fail To Shed Following An Undervoltage
DG400				Loss Of Power To 480 VAC Bus 14 From Emergency Diesel Generator KDG01A
DG600				Loss Of Power To 480 VAC Bus 16 From Emergency Diesel Generator KDG01B
DG700				Loss Of Power To 480 VAC Bus 17 From Emergency Diesel Generator KDG01B
DG800				Loss Of Power To 480 VAC Bus 18 From Emergency Diesel Generator KDG01A
DGCC000RUN		2.343E-03		DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)
DGCC0START		3.597E-04		DIESEL GENERATORS FAIL TO START (COMMON CAUSE)
DGCCCV5919		1.360E-05		FOOT VALVES 5919/5920 FAIL TO OPEN (COMMON CAUSE)
DGCCCV5955		1.360E-05		CHECK VALVES 5955/5956 FAIL TO OPEN (COMMON CAUSE)

Basic Event	C	Factor	Units	Description
DGCCCV5961		1.360E-05		CHECK VALVES 5961/5962 FAIL TO OPEN (COMMON CAUSE)
DGCCFDP012		6.384E-05		FUEL OIL STRAINERS JDG01/02 PLUG (COMMON CAUSE)
DGCCFDP090		6.384E-05		FOOT VALVE 5919/5920 STRAINERS PLUG (COMMON CAUSE)
DGCCNOPRIM		3.580E-05		CHECK AND FOOT VALVES FAIL TO CLOSE (COMMON CAUSE)
DGCCPMA2AB		1.180E-04		FUEL OIL PUMPS PDG02A/02B FAIL TO START (COMMON CAUSE)
DGCCPMF2AB		1.778E-04		FUEL OIL PUMPS PDG02A/02B FAIL TO RUN (COMMON CAUSE)
DGCVC05919	1	1		FOOT VALVE 5919 FAILS TO CLOSE
DGCVC05920	1	1		FOOT VALVE 5920 FAILS TO CLOSE
DGCVC05955	1	1		CHECK VALVE 5955 FAILS TO CLOSE
DGCVC05956	1	1		CHECK VALVE 5956 FAILS TO CLOSE
DGCVCCCF$$		0.1		BETA FACTOR FOR FUEL OIL CHECK VALVES FAIL TO CLOSE
DGCVN05919	1	1		FOOT VALVE 5919 FAILS TO OPEN
DGCVN05920	1	1		FOOT VALVE 5920 FAILS TO OPEN
DGCVN05955	1	1		CHECK VALVE 5955 FAILS TO OPEN
DGCVN05956	1	1		CHECK VALVE 5956 FAILS TO OPEN
DGCVN05961	1	1		CHECK VALVE 5961 FAILS TO OPEN
DGCVN05962	1	1		CHECK VALVE 5962 FAILS TO OPEN
DGCVNCCF$$		0.1		BETA FACTOR FOR DG FUEL OIL CHECK VALVES FAIL TO OPEN
DGCWINTAKE		0.583		CW INTAKE HEATERS ENERGIZED (OCT 1 TO MAY 1)
DGDGA0001A	1	1		DIESEL GENERATOR KDG01A FAILS TO START
DGDGA0001B	1	1		DIESEL GENERATOR KDG01B FAILS TO START
DGDGACCF$$		7.37E-02		BETA FACTOR FOR DIESEL GENERATOR FAILS TO START
DGDGF0001A	1	24	H	DIESEL GENERATOR KDG01A FAILS TO RUN
DGDGF0001B	1	24	H	DIESEL GENERATOR KDG01B FAILS TO RUN
DGDGFCCF$$		7.81E-02		BETA FACTOR FOR DIESEL GENERATOR FAILS TO RUN
DGFDP05919	1	24	H	FOOT VALVE 5919 STRAINER PLUGS
DGFDP05920	1	24	H	FOOT VALVE 5920 STRAINER PLUGS
DGFDPCCF$$		0.1		BETA FACTOR FOR FUEL OIL STRAINER PLUGS
DGFDPJDG01	1	24	H	STRAINER JDG01 PLUGS
DGFDPJDG02	1	24	H	STRAINER JDG02 PLUGS
DGMM0AAF04		3.852E-03		AAF04 BREAKER FAILS TO OPEN FOR LOAD SHED
DGMM0FILLA		3.425E-03		FAILURE OF 5907 AND 5907A TO SHIFT FROM RECIRC ALIGNMENT TO FILL ALIGNMENT
DGMM0FILLB		3.732E-03		FAILURE OF 5908 AND 5908A TO SHIFT FROM RECIRC ALIGNMENT TO FILL ALIGNMENT
DGMM12A014		3.901E-03		CIRCUIT BREAKER BUS14/18B FAILS TO OPEN
DGMM12A018		3.901E-03		CIRCUIT BREAKER BUS18/31B FAILS TO OPEN
DGMM12B016		3.901E-03		CIRCUIT BREAKER BUS16/11B FAILS TO OPEN
DGMM12B017		3.901E-03		CIRCUIT BREAKER BUS17/25B FAILS TO OPEN
DGMM1ATO14		3.933E-03		CIRCUIT BREAKER BUS14/18C FAILS TO CLOSE OR TRANSFERS OPEN
DGMM1ATO18		3.933E-03		CIRCUIT BREAKER BUS18/31C FAILS TO CLOSE OR TRANSFERS OPEN
DGMM1BTO16		3.933E-03		CIRCUIT BREAKER BUS16/11C FAILS TO CLOSE OR TRANSFERS OPEN
DGMM1BTO17		4.887E-03		CIRCUIT BREAKER BUS17/25C FAILS TO CLOSE OR TRANSFERS OPEN
DGMMACF08A		3.852E-03		ACF08A BREAKER FAILS TO OPEN FOR LOAD SHED

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Basic Event	C Factor	Units	Description
DGMMACF08B	3.852E-03		ACF08B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMACF08C	3.852E-03		ACF08C BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMACF08D	3.852E-03		ACF08D BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMBAEVAP	3.901E-03		BORIC ACID EVAPORATOR PACKAGE REMAINS LOADED ON MCC D
DGMMDEPLTA	3.321E-03		OVERFILL OF TDG04A, CAUSING DEPLETION OF FUEL INVENTORY
DGMMDEPLTB	3.604E-03		OVERFILL OF TDG04B, CAUSING DEPLETION OF FUEL INVENTORY
DGMMDG1AEP	1.280E-04		FAILURE OF DGACP - KDG01A CONTROL PANEL - EMERGENCY DC SUPPLY FUSES
DGMMDG1ANP	5.155E-05		FAILURE OF DGACP - KDG01A CONTROL PANEL - NORMAL DC SUPPLY FUSES
DGMMDG1BEP	1.280E-04		FAILURE OF DGBCP - KDG01B CONTROL PANEL - EMERGENCY DC SUPPLY FUSES
DGMMDG1BNP	5.155E-05		FAILURE OF DGBCP - KDG01B CONTROL PANEL - NORMAL DC SUPPLY FUSES
DGMMDGADAY	2.949E-04		FUEL OIL SUPPLY TO TDG04A RELATED FAULTS
DGMMDGAFOL	1.015E-03		DG A FUEL OIL SUPPLY RELATED FAULTS
DGMMDGATSW	7.064E-04		TEMPERATURE SWITCHES FOR DG ROOM A FAIL HIGH
DGMMDGBDAY	2.949E-04		FUEL OIL SUPPLY TO TDG04B RELATED FAULTS
DGMMDGBFOL	1.015E-03		DG 1B FUEL OIL SUPPLY RELATED FAULTS
DGMMDGBTSW	7.064E-04		TEMPERATURE SWITCHES FOR DG ROOM B FAIL HIGH
DGMMMCCC14	2.045E-04		MOTOR CONTROL CENTER C LOAD SHED RELAY (86/MCCC) FAILS TO ENERGIZE
DGMMMCCD16	2.045E-04		MOTOR CONTROL CENTER D LOAD SHED RELAY (86/MCCD) FAILS TO ENERGIZE
DGMMMCCG17	3.852E-03		BUS 17 TO MCCG BREAKER (BUS17/26C) FAILS TO OPEN FOR LOAD SHED
DGMMMCCG18	3.852E-03		BUS 18 TO MCCG BREAKER (BUS18/30C) FAILS TO OPEN FOR LOAD SHED
DGMMPAC01B	3.852E-03		PAC01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPAC02B	3.852E-03		PAC02B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPAC07B	3.852E-03		PAC07B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPAF01A	3.852E-03		PAF01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPAF01B	3.852E-03		PAF01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPCA01A	3.852E-03		PCA01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPCA02A	3.852E-03		PCA02A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPCH01A	3.852E-03		PCH01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPCH01B	3.852E-03		PCH01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPCH01C	3.852E-03		PCH01C BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPDG02A	7.647E-03		LOSS OF FLOW FROM PDG02A
DGMMPDG02B	7.647E-03		LOSS OF FLOW FROM PDG02B
DGMMPSI01A	3.852E-03		PSI01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPSI01B	3.852E-03		PSI01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPSI01C	3.852E-03		
DGMMPSW01A	3.852E-03		PSW01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPSW01B	3.852E-03		PSW01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPSW01C	3.852E-03		PSW01C BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMPSW01D	3.852E-03		PSW01D BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMRCW01A	3.852E-03		EHTRCW01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMRCW01B	3.852E-03		EHTRCW01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMRCW01C	3.852E-03		EHTRCW01C BREAKER FAILS TO OPEN FOR LOAD SHED

Basic Event	C	Factor	Units	Description
DGMMRCW01D		3.852E-03		EHTRCW01D BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMRRC01A		3.852E-03		EHTRRC01A BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMRRC01B		3.852E-03		EHTRRC01B BREAKER FAILS TO OPEN FOR LOAD SHED
DGMMVFX12A		5.852E-09		RELAYS VFX1-A AND VFX2-A FAIL TO ENERGIZE
DGMMVFX12B		5.852E-09		RELAYS VFX1-B AND VFX2-B FAIL TO ENERGIZE
DGMPACCF$$		0.1		BETA FACTOR FOR FUEL OIL TRANSFER PUMPS FAIL TO START
DGMPAPDG2A	1	1		FUEL OIL PUMP PDG02A FAILS TO START
DGMPAPDG2B	1	1		FUEL OIL PUMP PDG02B FAILS TO START
DGMPFCCF$$		0.1		BETA FACTOR FOR FUEL OIL TRANSFER PUMPS FAIL TO RUN
DGMPFPDG2A	1	24	H	FUEL OIL PUMP PDG02A FAILS TO RUN
DGMPFPDG2B	1	24	H	FUEL OIL PUMP PDG02B FAILS TO RUN
DGPSH2050A	1	384	H	PRESSURE SWITCH LC-2050A FAILS, INDICATING FALSE HIGH LEVEL IN TDG04A
DGPSH2051A	1	720	H	PRESSURE SWITCH LC-2051A FAILS, INDICATING FALSE HIGH LEVEL IN TDG04B
DGPSL2050A	1	384	H	PRESSURE SWITCH LC-2050A FAILS, INDICATING FALSE LOW LEVEL IN TDG04A
DGPSL2051A	1	720	H	PRESSURE SWITCH LC-2051A FAILS, INDICATING FALSE LOW LEVEL IN TDG04B
DGREE0AR93	1	1		RELAY AR93 FAILS TO ENERGIZE
DGREE0AR94	1	1		RELAY AR94 FAILS TO ENERGIZE
DGRVR05959	1	24	H	RELIEF VALVE 5959 SPURIOUSLY OPENS
DGRVR05960	1	24	H	RELIEF VALVE 5960 SPURIOUSLY OPENS
DGSVP05907	1	384	H	SOLENOID 5907 FAILS TO OPEN
DGSVP05908	1	384	H	SOLENOID VALVE 5908 FAILS TO OPEN
DGSVP5907A	1	384	H	SOLENOID 5907A FAILS TO OPEN
DGSVP5908A	1	384	H	SOLENOID VALVE 5908A FAILS TO OPEN
DGSVX05907	1	384	H	SOLENOID 5907 FAILS TO CLOSE
DGSVX05908	1	384	H	SOLENOID VALVE 5908 FAILS TO CLOSE
DGSVX5907A	1	384	H	SOLENOID 5907A FAILS TO CLOSE
DGSVX5908A	1	384	H	SOLENOID VALVE 5908A FAILS TO CLOSE
DGTKJDG01A	1	24	H	TANK TDG01A RUPTURE
DGTKJDG01B	1	24	H	TANK TDG01B RUPTURES
DGTM00001A		5.86E-03		DIESEL GENERATOR KDG01A UNAVAILABLE DUE TO TESTING OR MAINTENANCE
DGTM00001B		5.86E-03		DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE
DGTSH05327	1	384	H	TEMPERATURE SWITCH 5327 FAILS HIGH
DGTSH05328	1	384	H	TEMPERATURE SWITCH 5328 FAILS HIGH
DGTSH05329	1	384	H	TEMPERATURE SWITCH 5329 FAILS HIGH
DGTSH05330	1	384	H	TEMPERATURE SWITCH 5330 FAILS HIGH
DGTSL05327	1	384	H	TEMPERATURE SWITCH 5327 FAILS LOW
DGTSL05328	1	384	H	TEMPERATURE SWITCH 5328 FAILS LOW
DGTSL05329	1	384	H	TEMPERATURE SWITCH 5329 FAILS LOW
DGTSL05330	1	384	H	TEMPERATURE SWITCH 5330 FAILS LOW
DGXVK05847	1	720	H	MANUAL VALVE 5847 TRANSFERS CLOSED
DGXVK05948	1	720	H	MANUAL VALVE 5948 TRANSFERS CLOSED
DGXVK05949	1	384	H	MANUAL VALVE 5949 TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
DGXVK05950	1	384	H	MANUAL VALVE 5950 TRANSFERS CLOSED
DGXVK05953	1	384	H	MANUAL VALVE 5953 TRANSFERS CLOSED
DGXVK05954	1	384	H	MANUAL VALVE 5954 TRANSFERS CLOSED
DGXVK05963	1	384	H	MANUAL VALVE 5963 TRANSFERS CLOSED
DGXVK05964	1	384	H	MANUAL VALVE 5964 TRANSFERS CLOSED
DGXVK05965	1	384	H	MANUAL VALVE 5965 TRANSFERS CLOSED
DGXVK05966	1	384	H	MANUAL VALVE 5966 TRANSFERS CLOSED
DGXVK05973	1	720	H	MANUAL VALVE 5973 TRANSFERS CLOSED
DGXVK05974	1	720	H	MANUAL VALVE 5974 TRANSFERS CLOSED
DGXVK5947A	1	720	H	MANUAL VALVE 5947A TRANSFERS CLOSED
DGXVK5948A	1	720	H	MANUAL VALVE 5948A TRANSFERS CLOSED
ES002		1.00E-03		SAFETY INJECTION SIGNAL AUXILIARY RELAY SI-10X FAILS TO ENERGIZE
ES039				SAFETY INJECTION SIGNAL AUXILIARY RELAY SI-11X FAILS TO ENERGIZE
ES044				Safety Injection Signal Auxiliary Relay SI-17X Fails To Energize <Transfer>
ES047		1.00E-03		SAFETY INJECTION SIGNAL AUXILIARY RELAY SI-18X FAILS TO ENERGIZE
ES102		1.00E-03		SAFETY INJECTION SIGNAL AUXILIARY RELAY SI-20X FAILS TO ENERGIZE
ES139				SAFETY INJECTION SIGNAL AUXILIARY RELAY SI-21X FAILS TO ENERGIZE
ES144				Safety Injection Signal Auxiliary Relay SI-27X Fails To Energize <Transfer>
ES147		1.00E-03		SAFETY INJECT SIGNAL AUXILIARY RELAY SI-28X FAILS TO ENERGIZE
ES159				Steam Line Isolation Loop A Master Relay MS2 Fails To Energize
ES180				Steam Line Isolation Loop A Master Relay MS1 Fails To Energize
ES180A				Steam Line Isolation Loop B Master Relay MS4 Fails To Energize
ES226				Steam Line Isolation Loop B Master Relay MS3 Fails To Energize
ES250				Containment Spray Initiation Signal Master Relay S1 Fails To Energize On Demand
ES360				Containment Ventilation Isolation Master Relay V2 Fails to Energize
ES450				Containment Spray Initiation Signal Master Relay S2 Fails To Energize On Demand
ES540				ESFAS Signal For Safety Injection Train A Is Unavailable
ES550				ESFAS Signal For Safety Injection Train B Is Unavailable
ES570				Containment Isolation Signal Train B Relay C25X Fails to Energize
ES575				Containment Isolation Signal Train A Relay C15X Fails to Energize
ES800				Loss Of 125 VDC Control Power To Rack SIA1
ES900				Conditions For A Safety Injection (SI) Actuation Exist
ES910		1E-3		CONTAINMENT ISOLATION HAS OCCURRED
ES920				Conditions Which Do Not Cause An Early SI Signal
ESBIN0401A	1	1		RCS Loop A Tavg Dual Alarm / Comparator TC-401A Circuit Fails To Respond
ESBIN0402A	1	1		RCS Loop A Tavg Dual Alarm / Comparator TC-402A Circuit Fails To Respond
ESBIN0403A	1	1		RCS Loop B Tavg Dual Alarm / Comparator TC-403A Circuit Fails To Respond
ESBIN0404A	1	1		RCS Loop B Tavg Dual Alarm / Comparator TC-404A Circuit Fails To Respond
ESBIN0429C	1	1		Dual Alarm / Comparator PC-429C Circuit Fails To Respond On Demand
ESBIN0430E	1	1		Dual Alarm / Comparator PC-430E Circuit Fails To Respond On Demand
ESBIN0431G	1	1		Dual Alarm / Comparator PC-431G Circuit Fails To Respond On Demand
ESBIN0464A	1	1		Steam Generator A Bistable Circuit FC-464A Fails To Respond On Demand

Table

Integrated C. BE File

Basic Event	C	Factor	Units	Description
ESBIN0465A	1	1		Steam Generator A Bistable Circuit FC-465A Fails To Respond On Demand
ESBIN0468A	1	1		SG A Low Pressure Bistable PC-468A Circuit Fails To Respond On Demand
ESBIN0469A	1	1		SG A Low Pressure Bistable PC-469A Circuit Fails To Respond On Demand
ESBIN0474A	1	1		Steam Generator B Bistable Circuit FC-474A Fails TO Respond On Demand
ESBIN0475A	1	1		Steam Generator B Bistable Circuit FC-475A Fails To Respond On Demand
ESBIN0478A	1	1		SG B Low Pressure Bistable PC-478A Circuit Fails To Respond On Demand
ESBIN0479A	1	1		SG B Low Pressure Bistable PC-479A Circuit Fails To Respond On Demand
ESBIN0482A	1	1		SG A Low Pressure Bistable PC-482A Circuit Fails To Respond On Demand
ESBIN0483A	1	1		SG B Low Pressure Bistable PC-483A Circuit Fails To Respond On Demand
ESBIN945AB	1	1		Dual Alarm / Comparator PC-945A/B Circuit Fails To Respond On Demand
ESBIN946AB	1	1		Dual Alarm / Comparator Circuit PC-946A/B Fails To Respond On Demand
ESBIN947AB	1	1		Dual Alarm / Comparator PC-947A/B Circuit Fails To Respond On Demand
ESBIN948AB	1	1		Dual Alarm / Comparator Circuit PC-948A/B Fails To Respond On Demand
ESBIN949AB	1	1		Dual Alarm / Comparator PC-949A/B Circuit Fails To Respond On Demand
ESBIN950AB	1	1		Dual Alarm / Comparator Circuit PC-950A/B Fails To Respond On Demand
ESCC0SIAUX		7.650E-06		Common Cause Failure Of Safety Injection Signal Auxiliary Relays
ESCCMASTER		7.650E-06		Common Cause Failure OF Safety Injection Signal Master Relays
ESCCMSIAGA		7.650E-06		Common Cause Failure Of SI Agastat Time Delay Relays
ESCFRSIAF1	1	4	H	Fuse FUSIA1/SIAF1-P Fails Open
ESCFRSIAF2	1	4	H	Fuse FUSIA1/SIAF2-N Fails Open
ESCFRSIBF1	1	4	H	Fuse FUSIB1/SIBF1-P Fails Open
ESCFRSIBF2	1	4	H	Fuse FUSIB/SIBF2-N Fails Open
ESFTL00464	2	8760		Steam Generator A Flow Transmiter FT-464 Fails To Respond
ESFTL00465	2	8760		Steam Generator A Flow Transmiter FT-465 Fails To Respond
ESFTL00474	2	8760		Steam Generator B Flow Transmiter FT-474 Fails To Respond On Demand
ESFTL00475	2	8760		Steam Generator B Flow Transmiter FT-475 Fails To Respond On Demand
ESHFD000SI		1E-4		Operators Fail To Manually Actuate A Safety Injection Signal When Required
ESLCD01C2X	1	4392	H	Logic circuit failure of 2/1C2X
ESLCDLT461	1	4404	H	Logic circuit failure in LT-461 loop
ESLCDLT462	1	4404	H	Logic circuit failure in LT-462 loop
ESLCDLT463	1	4404	H	Logic circuit failure in LT-463 loop
ESLCDLT471	1	4404	H	Logic circuit failure in LT-471 loop
ESLCDLT472	1	4404	H	Logic circuit failure in LT-472 loop
ESLCDLT473	1	4404	H	Logic circuit failure in LT-473 loop
ESMMSIA1DC		2.864E-07		
ESMMSIB1DC		2.864E-07		DC Fuse Failures to Rack SIB1
ESPTDPT429	1	6594		Pressurizer Low Pressure Transmitter PT-429 Fails To Respond On Demand
ESPTDPT430	1	6594		Pressurizer Low Pressure Transmitter PT-430 Fails To Respond On Demand
ESPTDPT431	1	6594		Pressurizer Low Pressure Transmitter PT-431 Fails To Respond On Demand
ESPTDPT468	1	6594		SG A Low Pressure Transmitter PT-468 Fails To Respond On Demand
ESPTDPT469	1	6594		SG A Low Pressure Transmitter PT-469 Fails To Respond On Demand
ESPTDPT478	1	6594		SC B Low Pressure Transmitter PT-478 Fails To Respond On Demand

Basic Event	C Factor	Units	Description
ESPTDPT479	1	6594	SG B Low Pressure Transmitter PT-479 Fails To Respond On Demand
ESPTDPT482	1	6594	SG A Low Pressure Transmitter PT-482 Fails To Respond On Demand
ESPTDPT483	1	6594	SG B Low Pressure Transmitter PT-483 Fails To Respond On Demand
ESPTDPT945	1	6594	Containment High Pressure Transmitter PT-945 Fails To Respond On Demand
ESPTDPT946	1	6594	Containment High Pressure Transmitter PT-946 Fails To Respond On Demand
ESPTDPT947	1	6594	Containment High Pressure Transmitter PT-947 Fails To Respond On Demand
ESPTDPT948	1	6594	Containment High Pressure Transmitter PT-948 Fails To Respond On Demand
ESPTDPT949	1	6594	Containment High Pressure Transmitter PT-949 Fails To Respond On Demand
ESPTDPT950	1	6594	Containment High Pressure Transmitter PT-950 Fails To Respond On Demand
ESPXFPQ945	1	24	Containment High Pressure Instrument String Power Supply PQ-945 Fails
ESPXFPQ946	1	24	Containment High Pressure Instrument String Power Supply PQ-946 Fails
ESPXFPQ947	1	24	Containment High Pressure Instrument String Power Supply PQ-947 Fails
ESPXFPQ948	1	24	Containment High Pressure Instrument String Power Supply PQ-948 Fails
ESPXFPQ949	1	24	Containment High Pressure Instrument String Power Supply PQ-949 Fails
ESPXFPQ950	1	24	Containment High Pressure Instrument String Power Supply PQ-950 Fails
ESRAFORM11	1	24	Radiation Monitor RM-11 Fails To Respond On Demand
ESRAFORM12	1	24	Radiation Monitor RM-12 Fails To Respond On Demand
ESREB01AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay TC-401AX1 Fails To Deenergize
ESREB01AX2	1	1	Steam Line Isolation Signal Auxiliary Relay TC-401AX2 Fails To Deenergize
ESREB02AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay TC-402AX1 Fails To Deenergize
ESREB02AX2	1	1	Steam Line B Isolation Signal Auxiliary Relay TC-402AX2 Fails To Deenergize
ESREB03AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay TC-403AX1 Fails To Deenergize
ESREB03AX2	1	1	Steam Line Isolation Signal Auxiliary Relay TC-403AX2 Fails To Deenergize
ESREB04AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay TC-404AX1 Fails To Deenergize
ESREB04AX2	1	1	Steam Line Isolation Signal Auxiliary Relay TC-404AX2 Fails To Deenergize
ESREB29CX1	1	1	Pressurizer Low Pressure Aux. Relay PC-429CX1 Fails To Deenergize On Demand
ESREB29CX2	1	1	Pressurizer Low Pressure Aux. Relay PC-429CX2 Fails To Deenergize On Demand
ESREB30EX1	1	1	Pressurizer Low Pressure Aux. Relay PC-430EX1 Fails To Deenergize On Demand
ESREB30EX2	1	1	Pressurizer Low Pressure Aux. Relay PC-430EX2 Fails To Deenergize On Demand
ESREB31GX1	1	1	Pressurizer Low Pressure Aux. Relay. PC-431GX1 Fails To Deenergize On Demand
ESREB31GX2	1	1	Pressurizer Low Pressure Aux. Relay. PC-431GX2 Fails To Deenergize On Demand
ESREB45AX1	1	1	Containment High Pressure Aux. Relay PC-945AX1 Fails To Deenergize On Demand
ESREB45AX2	1	1	Containment High Pressure Aux. Relay PC-945AX2 Fails To Deenergize On Demand
ESREB461X1	1	1	Relay LC461B-X-1 fails to de-energize
ESREB461X2	1	1	Relay LC461B-X-2 fails to de-energize
ESREB462X1	1	1	Relay LC462A-X-1 fails to de-energize
ESREB462X2	1	1	Relay LC462A-X-2 fails to de-energize
ESREB463X1	1	1	Relay LC463C-X-1 fails to de-energize
ESREB463X2	1	1	Relay LC463C-X-2 fails to de-energize
ESREB46AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay PC-946AX1 Fails To Deenergize
ESREB46AX2	1	1	Steam Line Isolation Signal Auxiliary Relay PC-946AX2 Fails To Deenergize
ESREB471X1	1	1	Relay LC471B-X-1 fails to de-energize

[illegible]

Table [illegible]-2
Integrated C[illegible] BE File

Basic Event	C Factor	Units	Description
ESREB471X2	1	1	Relay LC471B-X-2 fails to de-energize
ESREB472X1	1	1	Relay LC472A-X-1 fails to de-energize
ESREB472X2	1	1	Relay LC472A-X-2 fails to de-energize
ESREB473X1	1	1	Relay LC473C-X-1 fails to de-energize
ESREB473X2	1	1	Relay LC473C-X-2 fails to de-energize
ESREB47AX1	1	1	Containment High Pressure Aux. Relay PC-947AX1 Fails To Deenergize On Demand
ESREB47AX2	1	1	Containment High Pressure Aux. Relay PC-947AX2 Fails To Deenergize On Demand
ESREB48AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay PC-948AX1 Fails To Deenergize
ESREB48AX2	1	1	Steam Line Isolation Signal Auxiliary Relay PC-948AX2 Fails To Deenergize
ESREB49AX1	1	1	Containment High Pressure Aux. Relay PC-949AX1 Fails To Deenergize On Demand
ESREB49AX2	1	1	Containment High Pressure Aux. Relay PC-949AX2 Fails To Deenergize On Demand
ESREB50AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay PC-950AX1 Fails To Deenergize
ESREB50AX2	1	1	Steam Line Isolation Signal Auxiliary Relay PC-950AX2 Fails To Deenergize
ESREB50R11	1	1	Radiation Monitoring Auxiliary Relay K850-R11 Fails To Deenergize On Demand
ESREB50R12	1	1	Radiation Monitoring Auxiliary Relay K850-R12 Fails To Deenergize On Demend
ESREB64AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-464AX1 Fails To Deenergize
ESREB64AX2	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-464AX2 Fails To Deenergize
ESREB64BX1	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-464BX1 Fails To Deenergize
ESREB64BX2	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-464BX2 Fails To Deenergize
ESREB65AX1	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-465AX1 Fails To Deenergize
ESREB65AX2	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-465AX2 Fails To Deenergize
ESREB65BX1	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-465BX1 Fails To Deenergize
ESREB65BX2	1	1	Steam Line A Isolation Signal Auxiliary Relay FC-465BX2 Fails To Deenergize
ESREB68AX1	1	1	SG A Low Pressure Aux. Relay PC-468AX1 Fails To Deenergize On Demand
ESREB68AX2	1	1	SG A Low Pressure Aux. Relay PC-468AX2 Fails To Deenergize On Demand
ESREB69AX1	1	1	SG A Low Pressure Aux. Relay PC-469AX1 Fails To Deenergize On Demand
ESREB69AX2	1	1	SG A Low Pressure Aux. Relay PC-469AX2 Fails To Deenergize On Demand
ESREB74AX1	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-474AX1 Fails To Deenergize
ESREB74AX2	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-474AX2 Fails To Deenergize
ESREB74BX1	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-474BX1 Fails To Energize
ESREB74BX2	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-474BX2 Fails To Energize
ESREB75AX1	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-475AX1 Fails To Deenergize
ESREB75AX2	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-475AX2 Fails To Deenergize
ESREB75BX1	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-475BX1 Fails To Deenergize
ESREB75BX2	1	1	Steam Line B Isolation Signal Auxiliary Relay FC-475BX2 Fails To Deenergize
ESREB78AX1	1	1	SG B Low Pressure Aux. Relay PC-478AX1 Fails To Deenergize On Demand
ESREB78AX2	1	1	SG B Low Pressure Aux. Relay PC-478AX2 Fails To Deenergize On Demand
ESREB79AX1	1	1	SG B Low Pressure Aux. Relay PC-479AX1 Fails To Deenergize On Demand
ESREB79AX2	1	1	SG B Low Pressure Aux. Relay PC-479AX2 Fails To Deenergize On Demand
ESREB82AX1	1	1	SG A Low Pressure Aux. Relay PC-482AX1 Fails To Deenergize On Demand
ESREB82AX2	1	1	SG A Low Pressure Aux. Relay PC-482AX2 Fails To Deenergize On Demand
ESREB83AX1	1	1	SG B Low Pressure Aux. Relay PC-483AX1 Fails To Deenergize On Demand

Basic Event	C	Factor	Units	Description
ESREB83AX2	1	1		SG B Low Pressure Aux. Relay PC-483AX2 Fails To Deenergize On Demand
ESREE000C1	1	1		Containment Isolation Signal Master Relay C1 Fails To Energize On Demand
ESREE000C2	1	1		Containment Isolation Signal Master Relay C2 Fails To Energize On Demand
ESREE000S1	1	1		Containment Spray Actuation Signal Master Relay S1 Fails To Energize On Demand
ESREE000S2	1	1		Containment Spray Actuation Signal Master Relay S2 Fails To Energize On Demand
ESREE000V1	1	1		Containment Ventilation Isolation Signal Master Relay V1 Fails To Energize
ESREE000V2	1	1		Containment Ventilation Isolation Signal Master Relay V2 Fails To Energize
ESREE00MS1	1	1		Steam Line A Isolation Signal Master Relay MS1 Fails To Deenergize On Demand
ESREE00MS2	1	1		Steam Line B Isolation Signal Master Relay MS2 Fails To Deenergize On Demand
ESREE00MS3	1	1		Steam Line B Isolation Signal Master Relay MS3 Fails To Energize On Demand
ESREE00MS4	1	1		Steam Line B Isolation Signal Master Relay MS4 Fails To Energize On Demand
ESREE0C15X	1	1		Containment Isolation Signal Auxiliary Relay C15X Fails To Energize On Demand
ESREE0C25X	1	1		Containment Isolation Signal Auxiliary Relay C25X Fails To Energize On Demand
ESREE0S10X	1	1	N	CS Initiation Signal Slave Relay S10X Fails To Energize On Demand
ESREE0S20X	1	1	N	CS Initiation Signal Slave Relay S20X Fails To Energize On Demand
ESREE0SIA1	1	1		Safety Injection Signal Master Relay SI-A1 Fails To Energize On Demand
ESREE0SIA2	1	1		Safety Injection Signal Master Relay SI-A2 Fails To Energize On Demand
ESREE0SIM1	1	1		SI Signal Manual Actuation Relay SI-M1 Fails To Energize On Demand
ESREE0SIM2	1	1		SI Signal Manual Actuation Relay SI-M2 Fails To Energize On Demand
ESREE45BX1	1	1	N	Containment Pressure Auxiliary Relay PC-945BX1 Fails To Energize On Demand
ESREE45BX2	1	1	N	Containment Pressure Auxiliary Relay PC-945BX2 Fails To Energize On Demand
ESREE46BX1	1	1		Containment Pressure Auxiliary Relay PC-946BX1 Fails To Energize On Demand
ESREE46BX2	1	1		Containment Pressure Auxiliary Relay PC-946BX2 Fails To Energize On Demand
ESREE47BX1	1	1		Containment Pressure Auxiliary Relay PC-947BX1 Fails To Energize On Demand
ESREE47BX2	1	1		Containment Pressure Auxiliary Relay PC-947BX2 Fails To Energize On Demand
ESREE48BX1	1	1		Containment Pressure Auxiliary Relay PC-948BX1 Fails To Energize On Demand
ESREE48BX2	1	1		Containment Pressure Auxiliary Relay PC-948BX2 Fails To Energize On Demand
ESREE49BX1	1	1		Containment Pressure Auxiliary Relay PC-949BX1 Fails To Energize On Demand
ESREE49BX2	1	1		Containment Pressure Auxiliary Relay PC-949BX2 Fails To Energize On Demand
ESREE50BX1	1	1		Containment Pressure Auxiliary Relay PC-950BX1 Fails To Energize On Demand
ESREE50BX2	1	1		Containment Pressure Auxiliary Relay PC-950BX2 Fails To Energize On Demand
ESREECCF$$	0	.1		Beta Factor For Common Cause Failure Of SI Signal Auxiliary Relays
ESREELSGAA	1	1		Relay LLSGAA fails to energize
ESREELSGAB	1	1		Relay LLSGAB fails to energize
ESREELSGBA	1	1		Relay LLSGBA fails to energize
ESREELSGBB	1	1		Relay LLSGBB fails to energize
ESREEMFPA1	1	1	N	RELAY MFPX1A1 FAILS TO ENERGIZE
ESREEMFPA2	1	1	N	RELAY MFPX1A2 FAILS TO ENERGIZE
ESREEMFPB1	1	1	N	RELAY MFPX1B1 FAILS TO ENERGIZE
ESREEMFPB2	1	1	N	RELAY MFPX1B2 FAILS TO ENERGIZE
ESREEMFPXA	1	1		Relay MFPX1A1 fails to energize
ESREEMFPXB	1	1		Relay MFPX1B1 fails to energize

Basic Event	C	Factor	Units	Description
ESREESI10X	1	1		SI Signal Auxilairy Relay SI-10X Fails To Energize On Demand
ESREESI11X	1	1		Safety Injection Signal Auxiliary Relay SI-11X Fails To Energize On Demand
ESREESI12X	1	1		Safety Injection Signal Auxiliary Relay SI-12X Fails To Energize On Demand
ESREESI13X	1	1		Safety Injection Signal Auxiliary Relay SI-13X Fails To Energize On Demand
ESREESI14X	1	1		Safety Injection Signal Auxiliary Relay SI-14X Fails To Energize On Demand
ESREESI15X	1	1		Safety Injection Signal Auxiliary Relay SI-15X Fails To Energize On Demand
ESREESI16X	1	1		Safety Injection Signal Auxiliary Relay SI-16X Fails To Energize On Demand
ESREESI17X	1	1		Safety Injection Signal Auxiliary Relay SI-17X Fails To Energize On Demand
ESREESI18X	1	1		Safety Injection Signal Auxiliary Relay SI-18X Fails To Energize On Demand
ESREESI20X	1	1		SI Signal Auxilairy Relay SI-20X Fails To Energize On Demand
ESREESI21X	1	1		Safety Injection Signal Auxiliary Relay SI-21X Fails To Energize On Demand
ESREESI22X	1	1		Safety Injection Signal Auxiliary Relay SI-22X Fails To Energize On Demand
ESREESI23X	1	1		Safety Injection Signal Auxiliary Relay SI-23X Fails To Energize On Demand
ESREESI24X	1	1		Safety Injection Signal Auxiliary Relay SI-24X Fails To Energize On Demand
ESREESI25X	1	1		Safety Injection Signal Auxiliary Relay SI-25X Fails To Energize On Demand
ESREESI26X	1	1		Safety Injection Signal Auxiliary Relay SI-26X Fails To Energize On Demand
ESREESI27X	1	1		Safety Injection Signal Auxiliary Relay SI-27X Fails To Energize On Demand
ESREESI28X	1	1		Safety Injection Signal Auxiliary Relay SI-28X Fails To Energize On Demand
ESREESISPA	1	1		Safety Injection Signal Slave Relay SISP1A Fails To Energize On Demand
ESREESISPB	1	1		Safety Injection Signal Slave Relay SISP1B Fails To Energize On Demand
ESREK0SIA1	1	24	H	SI Signal Master Relay SI-A1 Spuriously Energizes
ESREK0SIA2	1	24	H	SI Signal Master Relay SI-A2 Spuriously Energizes
ESREK0SIM1	1	24	H	SI Signal Manual Actuation Relay SI-M1 Spuriously Energizes
ESREK0SIM2	1	24	H	SI Signal Manual Actuation Relay SI-M2 Spuriously Energizes
ESREKSI10X	1	24	H	SI Signal Auxiliary Relay SI-10X Spuriously Energizes
ESREKSI12X	1	24	H	SI Signal Auxiliary Relay SI-12X Spuriously Energizes
ESREKSI16X	1	24	H	SI Signal Auxiliary Relay SI-16X Spuriously Energizes
ESREKSI17X	1	24	H	SI Signal Auxiliary Relay SI-17X Spuriously Energizes
ESREKSI20X	1	24	H	SI Signal Auxiliary Relay SI-20X Spuriously Energizes
ESREKSI22X	1	24	H	SI Signal Auxiliary Relay SI-22X Spuriously Energizes
ESREKSI26X	1	24	H	SI Signal Auxiliary Relay SI-26X Spuriously Energizes
ESREKSI27X	1	24	H	SI Signal Auxiliary Relay SI-27X Spuriously Energizes
ESRTD2CF1A	1	1		TIME DELAY RELAY 2/CF1A FAILS TO ENERGIZE
ESRTD2CF1B	1	1		TIME DELAY RELAY 2/CF1B FAILS TO ENERGIZE
ESRTD2CF1C	1	1		TIME DELAY RELAY 2/CF1C FAILS TO ENERGIZE
ESRTD2CF1D	1	1		TIME DELAY RELAY 2/CF1D FAILS TO ENERGIZE
ESRTDCCF$$	0	0.10		Beta Factor For Common Cause Failure Of Agastat Time Delay Relays
ESRTDMAF1A	1	1		Timing Relay (Agastat) 2/MAFP1A fails to operate
ESRTDMAF1B	1	1		Timing Relay (Agastat) 2/MAFP1B fails to operate
ESRTDRHR1A	1	1		TIMING RELAY (AGASTAT) 2/RHRP1A FAILS TO OPERATE
ESRTDRHR1B	1	1		TIMING RELAY (AGASTAT) 2/RHRP1B FAILS TO OPERATE
ESRTDSI1C1	1	1		Agastat timing relay 2/SIP1C1 fails to operate

Table 3.3.7-2
Integrated C[illegible]A BE File

Basic Event	C Factor	Units	Description
ESRTDSI1C2 1	1		Agastat timing relay 2/SIP1C2 fails to operate
ESRTDWP1AC 1	1		Agastat Time Delay Relay 2/SWP1AC Fails To Energize After An SI Signal
ESRTDWP1BD 1	1		Agastat Time Delay Relay 2/SWP1BD Fails To Energize After An SI Signal
ESTM429CX1	1E-2		SI Signal Channel For Auxiliary Relay PC-429CX1 Is In Test
ESTM429CX2	1E-2		SI Signal Channel For Auxiliary Relay PC-429CX2 Is In Test
ESTM430EX1	1E-2		SI Signal Channel For Auxiliary Relay PC-430EX1 Is In Test
ESTM430EX2	1E-2		SI Signal Channel For Auxiliary Relay PC-430EX2 Is In Test
ESTM431GX1	1E-2		SI Signal Channel For Auxiliary Relay PC-431GX1 Is In Test
ESTM431GX2	1E-2		SI Signal Channel For Auxiliary Relay PC-431GX2 Is In Test
ESTM468AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-468AX1 Is In Test
ESTM468AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-468AX2 Is In Test
ESTM469AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-469AX1 Is In Test
ESTM469AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-469AX2 Is In Test
ESTM478AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-478AX1 Is In Test
ESTM478AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-478AX2 Is In Test
ESTM479AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-479AX1 Is In Test
ESTM479AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-479AX2 Is In Test
ESTM482AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-482AX1 Is In Test
ESTM482AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-482AX2 Is In Test
ESTM483AX1	1E-2		SI Signal Channel For Auxilairy Relay PC-483AX1 Is In Test
ESTM483AX2	1E-2		SI Signal Channel For Auxilairy Relay PC-483AX2 Is In Test
ESTM945AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-945AX1 Is In Test
ESTM945AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-945AX2 Is In Test
ESTM945BX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-945BX1 Test
ESTM945BX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-945BX2 Test
ESTM946AX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-946AX1 Test
ESTM946AX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-946AX2 Test
ESTM946BX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-946BX1 Test
ESTM946BX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-946BX2 Test
ESTM947AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-947AX1 Is In Test
ESTM947AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-947AX2 Is In Test
ESTM947BX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-947BX1 Test
ESTM947BX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-947BX2 Test
ESTM948AX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-948AX1 Test
ESTM948AX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-948AX2 Test
ESTM948BX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-948BX1 Test
ESTM948BX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-948BX2 Test
ESTM949AX1	1E-2		SI Signal Channel For Auxiliary Relay PC-949AX1 Is In Test
ESTM949AX2	1E-2		SI Signal Channel For Auxiliary Relay PC-949AX2 Is In Test
ESTM949BX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-949BX1 Test
ESTM949BX2	1E-2		Channel For Containment High Pressure Aux. Relay PC-949BX2 Test
ESTM950AX1	1E-2		Channel For Containment High Pressure Aux. Relay PC-950AX1 Test

Table [illegible]2
Integrated C[illegible]BE File

Basic Event	C	Factor	Units	Description
ESTM950AX2		1E-2		Channel For Containment High Pressure Aux. Relay PC-950AX2 Test
ESTM950BX1		1E-2		Channel For Containment High Pressure Aux. Relay PC-950BX1 Test
ESTM950BX2		1E-2		Channel For Containment High Pressure Aux. Relay PC-950BX2 Test
ESTTD0401A	2	8760		RCS Loop A Hot Leg Temperature Transmiter TE-401A Fails To Respond On Demand
ESTTD0401B	2	8760		RCS Loop A Cold Leg Temperature Transmiter TE-401B Fails To Respond On Demand
ESTTD0402A	2	8760		RCS Loop A Hot Leg Temperature Transmiter TE-402A Fails To Respond On Demand
ESTTD0402B	2	8760		RCS Loop A Cold Leg Temperature Transmiter TE-402B Fails To Respond On Demand
ESTTD0403A	2	8760		RCS Loop B Hot Leg Temperature Transmiter TC-403A Fails To Respond On Demand
ESTTD0403B	2	8760		RCS Loop B Cold Leg Temperature Transmiter TE-403B Fails To Respond On Demand
ESTTD0404A	2	8760		RCS Loop B Hot Leg Temperature Transmiter TE-404A Fails To Respond On Demand
ESTTD0404B	2	8760		RCS Loop B Cold Leg Temperature Transmiter TE-404B Fails To Respond On Demand
HELB_IB		1E-3		High Energy Line Breaks in the Intermediate Building
HV610				HVAC causes SAFW Train A failure
HV620				HVAC causes SAFW Train B failure
HV700				IB ventilation and recirculation fails so AFW pump area receives no air flow
HV800				Failure of Containment HVAC System (Four of Four Fail)
HVAFFAAL38	1	24		HEPA FILTER AAL38 FAILS TO DELIVER FLOW
HVAFFACL7A	1	24		AIR FILTER ACL7A FAILS TO DELIVER FLOW (CONTAINMENT)
HVAFFACL7B	1	24		AIR FILTER ACL7B FAILS TO DELIVER FLOW (CONTAINMENT)
HVAFFACL8A	1	24		AIR FILTER ACL8A FAILS TO DELIVER FLOW (CONTAINMENT)
HVAFFACL8B	1	24		AIR FILTER ACL8B FAILS TO DELIVER FLOW (CONTAINMENT)
HVAVC07445	1	1		AOV 7445 Fails to Close
HVAVC07478	1	1		AOV 7448 Fails to Close
HVAVC07970	1	1		AOV 7970 Fails to Close
HVAVCCCF$$		0.191		Beta Factor for HVAC AOVs Fail to Close
HVAVX07971	1	1		AOV 7971 Fails to Close
HVCCDG0RUN		1.877E-05		FAN UNIT FOR DG FAILS TO RUN (COMMON CAUSE)
HVCCDGOPEN		1.990E-05		FAN UNIT DAMPER FOR DG FAILS TO OPEN (COMMON CAUSE)
HVCCDGSTRT		6.910E-05		FAN UNIT FOR DG FAILS TO START (COMMON CAUSE)
HVHEFSAFWA	1	4		SAFW ROOM HEATER A FAILS
HVHEFSAFWB	1	4		SAFW ROOM HEATER B FAILS
HVHFDRELRM		1		OPERATOR FAILS TO START HVAC IN RELAY ROOM FOLLOWING A LOOP
HVHFD_CTMT		1		OPERATOR FAILS TO RE-START CONTAINMENT COOLING
HVHFLSAFWA		3E-3		LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION
HVHFLSAFWB		3E-3		LATENT HUMAN ERRORS IN SAFW-B COOLING INCL. SWITCH-B POSITION
HVHFL_SAFW		3E-3		OPERATOR FAILS TO DISCOVER ROOM HEATING FAILURE IN SAFW ROOM
HVHRDRELRM		.1		Operator fails to start HVAC in relay room following a loop
HVHXFACA1A	1	24		HEAT EXCHANGER ACA1A COOLING CAP. FAILS (CONTAINMENT)
HVHXFACA1B	1	24		HEAT EXCHANGER ACA1B COOLING CAP. FAILS (CONTAINMENT)
HVHXFACA1C	1	24		HEAT EXCHANGER ACA1C COOLING CAP. FAILS (CONTAINMENT)
HVHXFACA1D	1	24		HEAT EXCHANGER ACA1D COOLING CAP. FAILS (CONTAINMENT)
HVHXFECH3A	1	24		HEAT EXCHANGER ECH3A COOLING CAP. FAILS (CHARGING PUMP RM)

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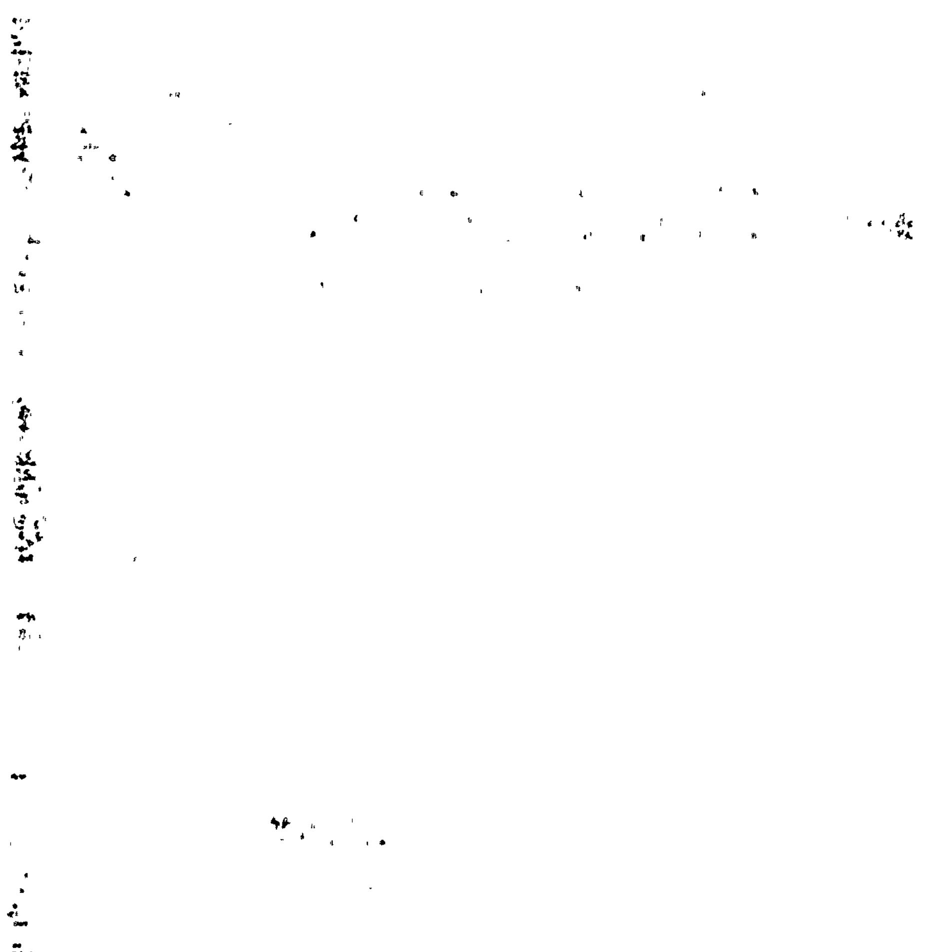
Basic Event	C	Factor	Units	Description
HVHXFECH3B	1	24		HEAT EXCHANGER ECH3B COOLING CAP. FAILS (CHARGING PUMP RM)
HVHXFGB01A	1	24		HEAT EXCHANGER GB01A COOLING CAP. FAILS
HVMBNDD03A	1	1		DAMPER ADD03A FAILS TO OPEN
HVMBNDD03B	1	1		DAMPER ADD03B FAILS TO OPEN
HVMBNDD03C	1	1		Damper ADD03C fails to open
HVMBNDD03D	1	1		Damper ADD03D fails to open
HVMBNDD04A	1	1		DAMPER ADD04A FAILS TO OPEN
HVMBNDD04B	1	1		DAMPER ADD04B FAILS TO OPEN
HVMBNDD04C	1	1		DAMPER ADD04C FAILS TO OPEN
HVMBNDD04D	1	1		DAMPER ADD04D FAILS TO OPEN
HVMCK05077	1	24		AIR-OP DAMPER 5077 TRANSFERS CLOSED
HVMCK05880	1	24		AIR-OP DAMPER 05880 TRANSFERS CLOSED
HVMCKAAD11	1	24		AIR-OP DAMPER AAD11 TRANSFERS CLOSED
HVMCKAAS03	1	24		FIRE DAMPER AAS03 TRANSFERS CLOSED
HVMCKAD08A	1	24		AIR-OP DAMPER AD08A TRANSFERS CLOSED
HVMCKAD08B	1	24		AIR-OP DAMPER AAD08B TRANSFERS CLOSED
HVMCKAD09A	1	24		AIR-OP DAMPER AD09A TRANSFERS CLOSED
HVMCKAD09B	1	24		AIR-OP DAMPER AAD09B TRANSFERS CLOSED
HVMCKAD10A	1	24		DAMPER AAD10A TRANSFERS CLOSED
HVMCKAD10B	1	24		DAMPER AAD10B TRANSFERS CLOSED
HVMCKAKD06	1	24		AIR-OP DAMPER AKD6 TRANSFERS CLOSED (CONTROL RM)
HVMCKAKD13	1	24		AIR-OP DAMPER AKD13 TRANSFERS CLOSED (CONTROL RM)
HVMCKAKD14	1	24		AIR-OP DAMPER AKD14 TRANSFERS CLOSED (CONTROL RM)
HVMCKCP13A	1	24		AIR-OP DAMPER CP-13-P/A TRANSFERS CLOSED (CHARGING PUMP RM)
HVMCKCP13B	1	24		AIR-OP DAMPER CP-13-P/B TRANSFERS CLOSED (CHARGING PUMP RM)
HVMCKID01A	1	24		AIR-OP DAMPER AID01A TRANSFERS CLOSED
HVMCKID01B	1	24		AIR-OP DAMPER AID01B TRANSFERS CLOSED
HVMCKID02A	1	24		AIR-OP DAMPER AID02A TRANSFERS CLOSED
HVMCKID02B	1	24		AIR-OP DAMPER AID02B TRANSFERS CLOSED
HVMCKID03A	1	24		DAMPER AID03A TRANSFERS CLOSED
HVMCKID03B	1	24		DAMPER AID03B TRANSFERS CLOSED
HVMCKID04A	1	24		DAMPER AID04A TRANSFERS CLOSED
HVMCKID04B	1	24		DAMPER AID04B TRANSFERS CLOSED
HVMCKID05H	1	24		DAMPER AID05H TRANSFERS CLOSED
HVMCKRETA1	1	24		SAFW RETURN DAMPER A1 TRANSFERS CLOSED
HVMCKRETA2	1	24		SAFW RETURN DAMPER A2 TRANSFERS CLOSED
HVMCKRETA3	1	24		SAFW RETURN DAMPER A3 TRANSFERS CLOSED
HVMCKRETB1	1	24		SAFW RETURN DAMPER B1 TRANSFERS CLOSED
HVMCKRETB2	1	24		SAFW RETURN DAMPER B2 TRANSFERS CLOSED
HVMCKRETB3	1	24		SAFW RETURN DAMPER B3 TRANSFERS CLOSED
HVMCNAAD11	1	1		AIR-OPERATED DAMPER AAD11 FAILS TO OPEN
HVMCNCCF$$		0.1		BETA FACTOR FOR DG VENTILATION DAMPER FAILS TO OPEN



Basic Event	C	Factor	Units	Description
HVMCNDD01A	1	1		AIR-OPERATED DAMPER ADD01A FAILS TO OPEN
HVMCNDD01B	1	1		AIR-OPERATED DAMPER ADD01B FAILS TO OPEN
HVMCNDD02A	1	1		AIR-OPERATED DAMPER ADD02A FAILS TO OPEN
HVMCNDD02B	1	1		AIR-OPERATED DAMPER ADD02B FAILS TO OPEN
HVMCP05871	2	8760		AIR-OPERATED DAMPER 5871 FAILS TO OPEN (CONTAINMENT)
HVMCP05872	2	8760		AIR-OPERATED DAMPER 5872 FAILS TO OPEN (CONTAINMENT)
HVMCP05874	2	8760		AIR-OPERATED DAMPER 5874 FAILS TO OPEN (CONTAINMENT)
HVMCP05876	2	8760		AIR-OPERATED DAMPER 5876 FAILS TO OPEN (CONTAINMENT)
HVMFAAAF1A	1	1		MOTOR-DRIVEN FAN AAF1A FAILS TO START (CHARGING PUMP RM)
HVMFAAAF1B	1	1		MOTOR-DRIVEN FAN AAF1B FAILS TO START (CHARGING PUMP RM)
HVMFAACF8A	1	1		MOTOR-DRIVEN FAN ACF8A FAILS TO START (CONTAINMENT)
HVMFAACF8B	1	1		MOTOR-DRIVEN FAN ACF8B FAILS TO START (CONTAINMENT)
HVMFAACF8C	1	1		MOTOR-DRIVEN FAN ACF8C FAILS TO START (CONTAINMENT)
HVMFAACF8D	1	1		MOTOR-DRIVEN FAN ACF8D FAILS TO START (CONTAINMENT)
HVMFAAKF03	1	1		MOTOR-DRIVEN FAN AKF03 FAILS TO START (CONTROL RM)
HVMFAAKF08	1	1		MOTOR-DRIVEN FAN AKF08 FAILS TO START (CONTROL RM)
HVMFAAKF1A	1	1		MOTOR-DRIVEN FAN AKF1A FAILS TO START
HVMFAAKF1B	1	1		MOTOR-DRIVEN FAN AKF1B FAILS TO START
HVMFACCF$$		0.1		BETA FACTOR FOR DG FAN UNIT FAILS TO START
HVMFADF01A	1	1		FAN UNIT ADF01A FAILS TO START
HVMFADF01B	1	1		FAN UNIT ADF01B FAILS TO START
HVMFADF02A	1	1		FAN UNIT ADF02A FAILS TO START
HVMFADF02B	1	1		FAN UNIT ADF02B FAILS TO START
HVMFFAAF1A	1	24		MOTOR-DRIVEN FAN AAF1A FAILS TO RUN (CHARGING PUMP RM)
HVMFFAAF1B	1	24		MOTOR-DRIVEN FAN AAF1B FAILS TO RUN (CHARGING PUMP RM)
HVMFFACF8A	1	24		MOTOR-DRIVEN FAN ACF8A FAILS TO RUN (CONTAINMENT)
HVMFFACF8B	1	24		MOTOR-DRIVEN FAN ACF8B FAILS TO RUN (CONTAINMENT)
HVMFFACF8C	1	24		MOTOR-DRIVEN FAN ACF8C FAILS TO RUN (CONTAINMENT)
HVMFFACF8D	1	24		MOTOR-DRIVEN FAN ACF8D FAILS TO RUN (CONTAINMENT)
HVMFFAF08A	1	24		MOTOR-DRIVEN FAN AF08A FAILS TO RUN
HVMFFAF08B	1	24		MOTOR-DRIVEN FAN AAF08B FAILS TO RUN
HVMFFAFF1A	1	24		MOTOR-DRIVEN FAN AFF1A FAILS TO RUN
HVMFFAFF1B	1	24		MOTOR-DRIVEN FAN AFF1B FAILS TO RUN
HVMFFAIF02	1	24		MOTOR-DRIVEN FAN AIF02 FAILS TO RUN
HVMFFAKF03	1	24		MOTOR-DRIVEN FAN AKF03 FAILS TO RUN
HVMFFAKF08	1	24		MOTOR-DRIVEN FAN AKF08 FAILS TO RUN
HVMFFAKF1A	1	24		MOTOR-DRIVEN FAN AKF1A FAILS TO RUN (RELAY RM)
HVMFFAKF1B	1	24		MOTOR-DRIVEN FAN AKF1B FAILS TO RUN (RELAY RM)
HVMFFCCF$$		0.1		BETA FACTOR FOR DG FAN UNIT FAILS TO RUN
HVMFFDF01A	1	24	H	FAN UNIT ADF01A FAILS TO RUN
HVMFFDF01B	1	24	H	FAN UNIT ADF01B FAILS TO RUN
HVMFFDF02A	1	24	H	FAN UNIT ADF02A FAILS TO RUN

Basic Event	C	Factor	Units	Description
HVMFFDF02B	1	24	H	FAN UNIT ADF02B FAILS TO RUN
HVMFFIF01A	1	24		MOTOR-DRIVEN FAN AIF01A FAILS TO RUN
HVMFFIF01B	1	24		MOTOR-DRIVEN FAN AIF01B FAILS TO RUN
HVMFSAFF1A	1	2190		MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START
HVMFSAFF1B	1	2190		MOTOR-DRIVEN FAN AFF1B (SAFW-B) FAILS TO START
HVMM0AAD11		2.210E-04		
HVMMABSTRA		2.317E-04		FAILURE OF AB EXHAUST TRAIN A TO RUN
HVMMABSTRB		2.317E-04		FAILURE OF AB EXHAUST TRAIN B TO RUN
HVMMACF8AA		6.910E-04		ACF08A fails to start
HVMMACF8AF		1.877E-04		ACF08A fails to run
HVMMACF8BA		6.910E-04		ACF08B fails to start
HVMMACF8BF		1.877E-04		ACF08B fails to run
HVMMACF8CA		6.910E-04		ACF08C fails to start
HVMMACF8CF		1.877E-04		ACF08C fails to run
HVMMACF8DA		6.910E-04		ACF08D fails to start
HVMMACF8DF		1.877E-04		
HVMMADF01A		5.006E-03		ADF01A FAILS TO START AND RUN
HVMMADF01B		5.006E-03		ADF01B FAILS TO START AND RUN
HVMMADF02A		5.006E-03		NO FLOW FROM DG FAN ADF02A
HVMMADF02B		5.006E-03		NO FLOW FROM DG FAN ADF02B
HVMMAKF1AA		6.910E-04		AKF01A fails to start
HVMMAKF1BA		6.910E-04		AKF01B fails to start
HVMMC-AFTR		7.348E-03		SAFW COOLING UNIT-A FAILURE
HVMMC-BFTR		7.348E-03		SAFW COOLING UNIT-B FAILURE
HVMMCHAR-A		5.271E-02		COMPONENTS IN CHARCOAL FILTER UNIT-A FAIL TO RUN
HVMMCHAR-C		5.271E-02		COMPONENTS IN CHARCOAL FILTER UNIT-C FAIL TO RUN
HVMMCOOL-A		6.791E-04		COOLING UNIT A FAILS TO RUN
HVMMCOOL-B		6.791E-04		COOLING UNIT B FAILS TO RUN
HVMMCOOLAA		6.910E-04		AAF01A Fails to Start
HVMMCOOLBA		6.910E-04		AAF01B Fails to Start
HVMMCR_FTR		3.973E-04		EQUIPMENT IN CONTROL ROOM VENTILATION FAILS TO RUN
HVMMCTRFTS		1.382E-03		EQUIPMENT IN CONTROL ROOM FAIL TO START
HVMMIBEXHA		2.317E-04		IB EXHAUST TRAIN A FAILURES
HVMMIBEXHB		2.317E-04		IB EXHAUST TRAIN B FAILURES
HVMMIBRECR		2.538E-04		IB RECIRCULATION EQUIPMENT FAILS TO OPERATE
HVMMIB_EXH		2.856E-04		DAMPER AND FILTER FAILURES IN THE IB-TO-AB HVAC FLOWPATH
HVMMRELRMA		6.713E-04		RELAY ROOM TRAIN A EQUIPMENT FAILURES
HVMMRELRMB		2.019E-04		RELAY ROOM TRAIN B EQUIPMENT FAILURES
HVMMSWCU-A		4.710E-04		SERVICE WATER COOLING UNIT-A FAILURES
HVMMSWCU-B		4.710E-04		SERVICE WATER COOLING UNIT-B FAILURES
HVMMSWCU-C		4.710E-04		SERVICE WATER COOLING UNIT-C FAILURES
HVMMSWCU-D		4.710E-04		SERVICE WATER COOLING UNIT-D FAILURES

Basic Event	C Factor	Units	Description
HVMMSWTR-A	5.070E-04		COOLING UNIT-A FAILED DUE TO SW EQUIPMENT FAILURE
HVMMSWTR-B	5.070E-04		COOLING UNIT-B FAILED DUE TO SW EQUIPMENT FAILURE
HVTMAAIF02	1.56E-03		IB EXHAUST FAN AAIF02 IN MAINTENANCE
HVTMABSTRA	1.28E-03		AB HVAC TRAIN A IN MAINTENANCE
HVTMABSTRB	1.28E-03		AB HVAC TRAIN B IN MAINTENANCE
HVTMAIF01A	1.28E-03		IB FAN AIF01A IN MAINTENANCE
HVTMAIF01B	1.28E-03		IB FAN AIF01B IN MAINTENANCE
HVTMCHARGA	1.03E-03		A CHARGING PUMP ROOM HVAC STRING IN MAINTENANCE
HVTMCHARGB	1.03E-03		B CHARGING PUMP ROOM HVAC STRING IN MAINTENANCE
HVTMCTMT_A	3.24E-03		A CONTAINMENT HVAC TRAIN OUT OF SERVICE FOR MAINTENANCE
HVTMCTMT_B	1.02E-03		B CONTAINMENT HVAC TRAIN OUT OF SERVICE FOR MAINTENANCE
HVTMCTMT_C	3.24E-03		C CONTAINMENT HVAC TRAIN OUT OF SERVICE FOR MAINTENANCE
HVTMCTMT_D	1.02E-03		D CONTAINMENT HVAC TRAIN OUT OF SERVICE FOR MAINTENANCE
HVTMCTRLRM	2.28E-03		CONTROL ROOM HVAC IN MAINTENANCE
HVTMRELAYA	9.05E-04		A RELAY ROOM HVAC STRING IN MAINTENANCE
HVTMRELAYB	8.93E-04		B RELAY ROOM HVAC STRING IN MAINTENANCE
HVTMSAFW_A	3.80E-03		A SAFW ROOM HVAC STRING IN MAINTENANCE
HVTMSAFW_B	3.80E-03		B SAFW ROOM HVAC STRING IN MAINTENANCE
HVTVLCTLRM 1	24		CONTROL ROOM TEMPERATURE CONTROL SYSTEM FAILS LOW - CAN BE MANUALLY OVERRIDEN
HV_COLDOUT	0.42		OUTDOOR TEMPERATURE LESS THAN 45 DEGREES F
IA000			No Air to 2" Instrument Air Header by Both Dryers
IA121	1E-3		INSTRUMENT AIR TO INTERMEDIATE LOAD HEADER (ARVS AND OTHER LOADS) NOT AVAILABLE
IA123			IA to AFW valves not available
IA161	1.00E-03		INSTRUMENT AIR DOWNSTREAM OF 7067 NOT AVAILABLE (LONG-TERM)
IA171	1.00E-03		INSTRUMENT AIR DOWNSTREAM OF 7070 NOT AVAILABLE (LONG-TERM)
IA190	1E-3		INSTRUMENT AIR DOWNSTREAM OF 7605 NOT AVAILABLE - SERVES CONT. VENT. SYSTEM
IA200	1E-3		INSTRUMENT AIR TO CONTROL ROOM NOT AVAILABLE
IA270	1.0E-03		INSTRUMENT AIR DOWNSTREAM OF 7370 NOT AVAILABLE - SERVES AUX BLDG
IA272	1.0e-03		IA NOT AVAILABLE TO HEADER DOWNSTREAM OF 7002 SERVING VALVES IN THE AUX BLDG
IA274	1.0e-03		INSTRUMENT AIR TO CHARGING PUMP B FAILS
IA277	1.0e-03		INSTRUMENT AIR TO CHARGING PUMP A FAILS
IA278	1.0e-03		INSTRUMENT AIR TO CHARGING PUMP C FAILS
IA279	1.0e-03		INSTRUMENT AIR TO VALVE AOV-112B FAILS
IAADFDRY-A 1	24		AIR DRYER A FAILS TO DELIVER FLOW
IAADFDRY-B 1	24		AIR DRYER B FAILS TO DELIVER FLOW
IAAFFFIA52 1	24		AIR FILTER FIA52 FAILS TO DELIVER FLOW
IAAFFFIA53 1	24		AIR FILTER FIA53 FAILS TO DELIVER FLOW
IAAFFFIA70 1	24		AIR FILTER FIA70 FAILS TO DELIVER FLOW
IAAFFFIA71 1	24		AIR FILTER FIA71 FAILS TO DELIVER FLOW
IAAFFFSA07 1	24		AIR FILTER FSA07 FAILS TO DELIVER FLOW
IAAMA_C02A 1	1		AIR COMPRESSOR CIA02A FAILS TO START
IAAMA_C02B 1	1		AIR COMPRESSOR CIA02B FAILS TO START

Table [illegible]2
Integrated C[illegible]BE File

Basic Event	C	Factor	Units	Description
IAHXJE_01A	1	24		HEAT EXCHANGER EIA01A TUBE RUPTURE
IAHXJE_01B	1	24		HEAT EXCHANGER EIA01B TUBE RUPTURE
IAHXJE_01C	1	24		HEAT EXCHANGER EIA01C TUBE RUPTURE
IAHXPE_01A	1	24		HEAT EXCHANGER EIA01A PLUGS
IAHXPE_01B	1	24		HEAT EXCHANGER EIA01B PLUGS
IAHXPE_01C	1	24		HEAT EXCHANGER EIA01C PLUGS
IAIPD0431A	1	8	H	CONVERTER I/P-431A FAILS TO RESPOND
IAIPD0431B	1	8	H	CONVERTER I/P-431B FAILS TO RESPOND
IAMM02AFTS		3.935E-03		IA COMPRESSOR EIA01A FAILS TO START
IAMM02BFTS		3.935E-03		IA COMPRESSOR EIA01B FAILS TO START
IAMM02CFTS		3.935E-03		IA COMPRESSOR EIA01C FAILS TO START
IAMMAV112B		9.312E-06		Manual valves to AOV-112B transfer closed
IAMMCHARGA		9.312E-06		IA VALVES TO CHARGING PUMP A TRANSFER CLOSED
IAMMCHARGB		1.397E-05		IA VALVES TO CHARGING PUMP B
IAMMCHARGC		1.397E-05		IA VALVES TO CHARGING PUMP C TRANSFER CLOSED
IAMMCIA02A		2.701E-03		IA COMPRESSOR A FAILS TO OPERATE
IAMMCIA02B		2.701E-03		IA COMPRESSOR B FAILS TO OPERATE
IAMMCIA02C		2.701E-03		IA COMPRESSOR C FAILS TO OPERATE
IAMMCONTIA		3.422E-05		Flow Path to Containment Instrument Air Distribution Blocked
IAMMDCTOCA		0.000E+00		DC fuses to CIA02A breaker or compressor solenoid valves fail open
IAMMDCTOCB		0.000E+00		DC fuses to CIA02B breaker or compressor solenoid valves fail open
IAMMDCTOCC		0.000E+00		DC fuses to CIA02C breaker or compressor solenoid valves fail open
IAMMDCTOSA		0.000E+00		DC fuses to CSA02 breaker or compressor solenoid valves fail open
IAMMDRYERA		1.605E-03		AIR DRYER TRAIN A EQUIPMENT FAILURES
IAMMDRYERB		1.605E-03		AIR DRYER TRAIN B EQUIPMENT FAILURES
IAMMPS2302		4.056E-05		PRESSURE SWITCHES PS-2302 OR PS-2302A CAUSE LOSS OF SYSTEM PRESSURE CONTROL
IAMMSERAIR		3.137E-03		SERVICE AIR SUPPLY EQUIPMENT FAILURES
IAMMSWC02A		5.005E-05		IA COMPRESSOR A COOLING WATER FAILURES
IAMMSWC02B		1.426E-05		IA COMPRESSOR B COOLING WATER FAILURES
IAMMSWC02C		1.130E-05		IA COMPRESSOR C TRAIN COOLING WATER FAILURES
IAMMSWTOSA		4.858E-05		SERVICE WATER COOLING TO SA COMPRESSOR FAILURES
IAMM_SV-IA		3.262E-03		EQUIPMENT FAILURES CAUSE SA TO FAIL TO BACK-UP IA
IAPSD02033	1	1		PRESSURE SWITCH PS-2033 FAILS TO RESPOND
IAPSD02065	1	1		PRESSURE SWITCH PS-2065 FAILS TO RESPOND
IAPSD02105	1	1		PRESSURE SWITCH PS-2105 FAILS TO RESPOND
IAPSH02033	1	24		PRESSURE SWITCH PS-2033 FAILS HIGH
IAPSH02065	1	24		PRESSURE SWITCH PS-2065 FAILS HIGH
IAPSH02105	1	24		PRESSURE SWITCH PS-2105 FAILS HIGH
IAPSH2302A	1	24		PRESSURE SWITCH PS-2302A FAILS HIGH
IAPSH_2302	1	24		PRESSURE SWITCH PS-2302 FAILS HIGH
IAPVK09012	2	8760		AIR-OPERATED PRESSURE CONTROL VALVE 09012 TRANSFER CLOSED
IAPVK09013	2	8760		AIR-OPERATED PRESSURE CONTROL VALVE 9013 TRANSFER CLOSED

Basic Event	C	Factor	Units	Description
IAPVK15153	1	8	H	PRESSURE CONTROL VLV 15153 TRANSFERS CLOSED
IAPVK15154	1	8	H	PRESSURE CONTROL VLV 15154 TRANSFERS CLOSED
IAPVK15155	1	8	H	PRESSURE CONTROL VLV 15155 TRANSFERS CLOSED
IAPVK15156	1	8	H	PRESSURE CONTROL VLV 15156 TRANSFERS CLOSED
IAPVK15163	1	8760	H	PRESSURE CONTROL VLV 15163 TRANSFERS CLOSED
IAPVK15165	1	2214	H	PRESSURE CONTROL VALVE 15165 TRANSFERS CLOSED
IAPVK15925	1	2214	H	PRESSURE CONTROL VALVE 15925 TRANSFERS CLOSED
IAPVK15928	1	108	H	PRESSURE CONTROL VALVE 15928 TRANSFERS CLOSED
IAPVK15929	1	108	H	PRESSURE CONTROL VALVE 15929 TRANSFERS CLOSED
IAPVK15930	1	2214	H	PRESSURE CONTROL VALVE 15930 TRANSFERS CLOSED
IAPVK15933	1	2214	H	PRESSURE CONTROL VALVE 15933 TRANSFERS CLOSED
IAPVK15972	1	12	H	PRESSURE CONTROL VLV 15972 TRANSFERS CLOSED
IAPVK15973	1	12	H	PRESSURE CONTROL VLV 15973 TRANSFERS CLOSED
IAPVK15974	1	12	H	PRESSURE CONTROL VLV 15974 TRANSFERS CLOSED
IAPVK15975	1	12	H	PRESSURE CONTROL VLV 15975 TRANSFERS CLOSED
IAPVK5905A	1	720	H	PRESSURE CONTROL VALVE 5905A TRANSFERS CLOSED
IAPVK5905B	1	720	H	PRESSURE CONTROL VALVE 5905B TRANSFERS CLOSED
IAPVK5906A	1	720	H	PRESSURE CONTROL VALVE 5906A TRANSFERS CLOSED
IAPVK5906B	1	720	H	PRESSURE CONTROL VALVE 5906B TRANSFERS CLOSED
IAPVK8612A	1	8760	H	PRESSURE CONTROL VLV 8612A TRANSFERS CLOSED
IAPVK8612B	1	8760	H	PRESSURE CONTROL VLV 8612B TRANSFERS CLOSED
IARVR8606A	1	8	H	RELIEF VALVE 8606A SPURIOUS OPEN
IARVR8606B	1	8	H	RELIEF VALVE 8606B SPURIOUS OPEN
IARVR8615A	1	8	H	RELIEF VALVE 8615A SPURIOUS OPEN
IARVR8615B	1	8	H	RELIEF VALVE 8615B SPURIOUS OPEN
IASVC7445Y	1	1		Solenoid Valve 7445S1 for AOV 7445 Fails to Deenergize
IASVC7445Z	1	1		Solenoid Valve 7445S for AOV 7445 Fails to Deenergize
IASVC7478Y	1	1		Solenoid Valve 7448S1 for AOV 7448 Fails to Deenergize
IASVC7478Z	1	1		Solenoid Valve 7448S for AOV 7448 Fails to Deenergize
IASVC7970Y	1	1		Solenoid Valve 14101S for AOV 7970 Fails to Deenergize
IASVC7970Z	1	1		Solenoid Valve 14101S1 for AOV 7970 Fails to Deenergize
IASVC7971Y	1	1		Solenoid Valve 14280S for AOV 7971 Fails to Deenergize
IASVC7971Z	1	1		Solenoid Valve 14280S1 for AOV 7971 Fails to Deenergize
IASVK14109	1	2214	H	SOLENOID VALVE 14109S TRANSFERS CLOSED
IASVK14313	1	2214	H	SOLENOID VALVE 14313 TRANSFERS CLOSED
IASVK14424	1	24	H	SOLENOID VALVE 14424S TRANSFERS CLOSED
IASVP00111	1	108	H	SOLENOID VALVE 00111S FAILS TO OPEN (STANDBY)
IASVP14107	2	8760	H	SOLENOID VALVE 14107S FAILS TO OPEN
IASVP14206	1	2214	H	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)
IASVP14307	1	2214	H	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)
IASVP35163	1	2214	H	Solenoid Valve 3516S3 For MSIV 3516 Fails To Open
IASVP35164	1	2214	H	Solenoid Valve 3516S4 For MSIV 3516 Fails To Open

Basic Event	C	Factor	Units	Description
IASVP35173	1	2214	H	Solenoid Valve 3517S3 For MSIV 3517 Fails To Open
IASVP35174	1	2214	H	Solenoid Valve 3517S4 For MSIV 3517 Fails To Open
IASVP5933A	1	720	H	SOLENOID VALVE 5933A FAILS TO OPEN (STANDBY)
IASVP5933B	1	720	H	SOLENOID VALVE 5933B FAILS TO OPEN (STANDBY)
IASVP5934A	1	720	H	SOLENOID VALVE 5934A FAILS TO OPEN (STANDBY)
IASVP5934B	1	720	H	SOLENOID VALVE 5934B FAILS TO OPEN (STANDBY)
IASVP8616A	2	8760	H	SOLENOID VALVE 8616A FAILS TO OPEN
IASVP8616B	2	8760	H	SOLENOID VALVE 8616B FAILS TO OPEN
IASVP8619A	2	8760	H	SOLENOID VALVE 8619A FAILS TO OPEN
IASVP8619B	2	8760	H	SOLENOID VALVE 8619B FAILS TO OPEN
IASVP8620A	2	8760	H	SOLENOID VALVE 8620A FAILS TO OPEN
IASVP8620B	2	8760	H	SOLENOID VALVE 8620B FAILS TO OPEN
IASVX00202	1	2214	H	Solenoid Valve 14167S for AOV 202 Fails to Deenergize
IASVX00371	1	2214	H	Solenoid Valve 14204S for AOV 371 Fails to Deenergize
IASVX01721	1	1119	H	Solenoid Valve 14284S for AOV 1721 Fails to Deenergize
IASVX01723	1	1119	H	Solenoid Valve 14293S for AOV 1723 Fails to Deenergize
IASVX01728	1	1119	H	Solenoid Valve 14292S for AOV 1728 Fails to Deenergize
IASVX0200A	1	2214	H	Solenoid Valve 14169S for AOV 200A Fails to Deenergize
IASVX0200B	1	2214	H	Solenoid Valve 14168S for AOV 200B Fails to Deenergize
IASVX05392	1	4404	H	Solenoid Valve 14424S for AOV 5392 Fails to Deenergize
IASVX05735	1	1119	H	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize
IASVX05736	1	1119	H	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize
IASVX05737	1	1119	H	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize
IASVX05738	1	1119	H	Solenoid Valve 5738S for AOV 5738 Fails to Deenergize
IASVX1003A	1	1119	H	Solenoid Valve 14282S for AOV 1003A Fails to Deenergize
IASVX1003B	1	1119	H	Solenoid Valve 14281S for AOV 1003B Fails to Deenergize
IASVX35161	1	2214	H	Solenoid Valve 3516S1 for MSIV 3516 Fails to Deenergize
IASVX35162	1	2214	H	Solenoid Valve 3516S2 for MSIV 3516 Fails to Deenergize
IASVX35171	1	2214	H	Solenoid Valve 3516S1 for MSIV 3517 Fails to Deenergize
IASVX35172	1	2214	H	Solenoid Valve 3516S2 for MSIV 3517 Fails to Deenergize
IATKG09026	2	8		N2 TANK 9026 LEAKAGE
IATKG09027	2	8		N2 TANK 9026 LEAKAGE
IATKG09028	2	8		N2 TANK 9028 LEAKAGE
IATKG09029	2	8		N2 TANK 9029 LEAKAGE
IATKG09030	2	8		N2 TANK 9030 LEAKAGE
IATKG09031	2	8		N2 TANK 9031 LEAKAGE
IATKG09032	2	8		N2 TANK 9032 LEAKAGE
IATKG09033	2	8		N2 TANK 9033 LEAKAGE
IATKG09034	2	8		N2 TANK 9034 LEAKAGE
IATKG09035	2	8		N2 TANK 9035 LEAKAGE
IATKG09036	2	8		N2 TANK 9036 LEAKAGE
IATKG09037	2	8		N2 TANK 9037 LEAKAGE

Basic Event	C	Factor	Units	Description
IATMCIA02A		1.00E+00		
IATMCIA02B		1.00E+00		
IATMCIA02C		1.00E+00		
IATMCOMPRA		6.74E-03		CIA02A COMPRESSOR IN MAINTENANCE
IATMCOMPRB		6.74E-03		CIA02B COMPRESSOR IN MAINTENANCE
IATMCOMPRC		4.51E-03		CIA02C COMPRESSOR IN MAINTENANCE
IATMDRYERA		1.00E+00		
IATMDRYERB		1.00E+00		
IATMSACOMP		6.74E-03		SA COMPRESSOR IN MAINTENANCE
IATM_CIA02		1.00E+00		
IAXVK00371	1	2214	H	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE
IAXVK05252	1	24		MANUAL VALVE 5252 TRANSFERS CLOSED
IAXVK05303	1	24		MANUAL VALVE 5303 TRANSFERS CLOSED
IAXVK05304	1	24		MANUAL VALVE 5304 TRANSFERS CLOSED
IAXVK05311	1	24		MANUAL VALVE 5311 TRANSFERS CLOSED
IAXVK05314	1	24		MANUAL VALVE 5314 TRANSFERS CLOSED
IAXVK05315	1	24		MANUAL VALVE 5315 TRANSFERS CLOSED
IAXVK05316	1	24		MANUAL VALVE 5316 TRANSFERS CLOSED
IAXVK05317	1	24		MANUAL VALVE 5317 TRANSFERS CLOSED
IAXVK05357	1	24		MANUAL VALVE 5357 TRANSFER CLOSED
IAXVK05362	2	8760		MANUAL VALVE 5362 TRANSFERS CLOSED
IAXVK05363	2	8760		MANUAL VALVE 5363 TRANSFERS CLOSED
IAXVK05394	1	24		MANUAL VALVE 5394 TRANSFERS CLOSED
IAXVK05397	1	24		MANUAL VALVE 5397 TRANSFERS CLOSED
IAXVK06880	1	24		MANUAL VALVE 6880 TRANSFERS CLOSED
IAXVK06891	1	24		MANUAL VALVE 6891 TRANSFERS CLOSED
IAXVK06928	1	24		MANUAL VALVE 6928 TRANSFERS CLOSED
IAXVK07002	1	24		MANUAL VALVE 7002 TRANSFERS CLOSED
IAXVK07006	1	24		MANUAL VALVE 7006 TRANSFERS CLOSED
IAXVK07007	1	24		MANUAL VALVE 7007 TRANSFERS CLOSED
IAXVK07009	1	24		MANUAL VALVE 7009 TRANSFERS CLOSED
IAXVK07037	1	24		MANUAL VALVE 7037 TRANSFERS CLOSED
IAXVK07041	1	24		MANUAL VALVE 7041 TRANSFERS CLOSED
IAXVK07062	1	24		MANUAL VALVE 7062 TRANSFERS CLOSED
IAXVK07063	1	24		MANUAL VALVE 7063 TRANSFERS CLOSED
IAXVK07065	1	24		MANUAL VALVE 7065 TRANSFERS CLOSED
IAXVK07067	1	24		MANUAL VALVE 7067 TRANSFERS CLOSED
IAXVK07070	1	24		MANUAL VALVE 7070 TRANSFERS CLOSED
IAXVK07350	1	24		MANUAL VALVE 7350 TRANSFERS CLOSED
IAXVK07370	1	24		MANUAL VALVE 7370 TRANSFERS CLOSED
IAXVK07375	1	12	H	MANUAL VALVE 07375 TRANSFERS CLOSED
IAXVK07376	1	12	H	MANUAL VALVE 07376 TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
IAXVK07402	1	24		MANUAL VALVE 7402 TRANSFERS CLOSED
IAXVK07605	1	24		MANUAL VALVE 7605 TRANSFERS CLOSED
IAXVK08217	1	24		MANUAL VALVE 8217 TRANSFERS CLOSED
IAXVK08318	1	24		MANUAL VALVE 8318 TRANSFERS CLOSED
IAXVK08319	1	24		MANUAL VALVE 8319 TRANSFERS CLOSED
IAXVK09000	1	24		MANUAL VALVE 9000 TRANSFERS CLOSED
IAXVK09001	1	24		MANUAL VALVE 9001 TRANSFERS CLOSED
IAXVK09006	1	4404		MANUAL VALVE 9006 TRANSFERS CLOSED
IAXVK09007	1	4404		MANUAL VALVE 9007 TRANSFERS CLOSED
IAXVK14232	1	24		MANUAL VALVE 14232H TRANSFERS CLOSED
IAXVK14402	1	24		MANUAL VALVE 14402T TRANSFERS CLOSED
IAXVK7007A	1	24		MANUAL VALVE 7007A TRANSFERS CLOSED
IAXVK7007B	1	24		MANUAL VALVE 7007B TRANSFERS CLOSED
IAXVK7007C	1	24		MANUAL VALVE 7007C TRANSFERS CLOSED
IAXVK7007D	1	24		MANUAL VALVE 7007D TRANSFERS CLOSED
IAXVK7007E	1	24		MANUAL VALVE 7007E TRANSFERS CLOSED
IAXVK7008A	1	24		MANUAL VALVE 7008A TRANSFERS CLOSED
IAXVK7008B	1	24		MANUAL VALVE 7008B TRANSFERS CLOSED
IAXVK7008C	1	24		MANUAL VALVE 7008C TRANSFERS CLOSED
IAXVK7009A	1	24		MANUAL VALVE 7009A TRANSFERS CLOSED
IAXVK7009B	1	24		MANUAL VALVE 7009B TRANSFERS CLOSED
IAXVK7009C	1	24		MANUAL VALVE 7009C TRANSFERS CLOSED
IAXVK7067F	1	8760	H	MANUAL VALVE 7067F TRANSFERS CLOSED
IAXVK7067G	1	8	H	MANUAL VALVE 7067G TRANSFERS CLOSED
IAXVK7067H	1	8	H	MANUAL VALVE 7067H TRANSFERS CLOSED
IAXVK7067J	1	8	H	MANUAL VALVE 7067J TRANSFERS CLOSED
IAXVK7067K	1	8	H	MANUAL VALVE 7067K TRANSFERS CLOSED
IAXVK7067L	1	8760	H	MANUAL VALVE 7067L TRANSFERS CLOSED
IAXVK7070A	1	8760	H	MANUAL VALVE 7070A TRANSFERS CLOSED
IAXVK7070C	1	2214	H	MANUAL VALVE 7070C TRANSFERS CLOSED
IAXVK7375A	1	12	H	MANUAL VALVE 7375A TRANSFERS CLOSED
IAXVK7375B	1	12	H	MANUAL VALVE 7375B TRANSFERS CLOSED
IAXVK7376A	1	12	H	MANUAL VALVE 7376A TRANSFERS CLOSED
IAXVK7376B	1	12	H	MANUAL VALVE 7376B TRANSFERS CLOSED
IAXVK8607A	1	8760	H	MANUAL VALVE 8607A TRANSFERS CLOSED
IAXVK8607B	1	8760	H	MANUAL VALVE 8607B TRANSFERS CLOSED
IAXVK8618A	1	8760	H	MANUAL VALVE 8618A TRANSFERS CLOSED
IAXVK8618B	1	8760	H	MANUAL VALVE 8618B TRANSFERS CLOSED
IAXVK9000B	1	24		MANUAL VALVE 9000B TRANSFERS CLOSED
IAXVK9001B	1	24		MANUAL VALVE 9001B TRANSFERS CLOSED
IAXVK9026A	1	4404		MANUAL VALVE 9026A TRANSFERS CLOSED
IAXVK9027A	1	4404		MANUAL VALVE 9027A TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
IAXVK9028A	1	4404		MANUAL VALVE 9028A TRANSFERS CLOSED
IAXVK9029A	1	4404		MANUAL VALVE 9029A TRANSFERS CLOSED
IAXVK9030A	1	4404		MANUAL VALVE 9030A TRANSFERS CLOSED
IAXVK9031A	1	4404		MANUAL VALVE 9031A TRANSFERS CLOSED
IAXVK9032A	1	4404		MANUAL VALVE 9032A TRANSFERS CLOSED
IAXVK9033A	1	4404		MANUAL VALVE 9033A TRANSFERS CLOSED
IAXVK9034A	1	4404		MANUAL VALVE 9034A TRANSFERS CLOSED
IAXVK9035A	1	4404		MANUAL VALVE 9035A TRANSFERS CLOSED
IAXVK9036A	1	4404		MANUAL VALVE 9036A TRANSFERS CLOSED
IAXVK9037A	1	4404		MANUAL VALVE 9037A TRANSFERS CLOSED
IAXVR8613A	1	8	H	MANUAL VALVE 8613A TRANSFERS OPEN
IAXVR8613B	1	8	H	MANUAL VALVE 8613B TRANSFERS OPEN
LI0SGTRA		3.77E-03	Y	Steam Generator Tube Rupture in S/G A
LI0SGTRB		8.25E-03	Y	Steam Generator Tube Rupture in S/G B
LILBLOCA		1.80E-04	Y	Large LOCA (>5.5")
LIMBLOCA		4.00E-04	Y	Medium LOCA (1.5"-5.5")
LIRVRUPT		1.00E-08	Y	Reactor Vessel Rupture
LISBLOCA		3.70E-04	Y	Small LOCA (1-1.5")
LISSLOCA		7.30E-04	Y	Small-Small LOCA (0-1")
MF105		1E-3		High energy line break in turbine building
MFCVC03992	1	1		Check Valve 3992 Fails to Close
MFCVC03993	1	1		Check Valve 3993 Fails to Close
MFHFDMF100		1.00E-01		Operator Fails To Reestablish Main Feedwater Flow
MFLTD00461	1	384	H	Level transmitter LT-461 fails to respond
MFLTD00462	1	384	H	Level transmitter LT-462 fails to respond
MFLTD00463	1	384	H	Level transmitter LT-463 fails to respond
MFLTD00471	1	384	H	Level transmitter LT-471 fails to respond
MFLTD00472	1	384	H	Level transmitter LT-472 fails to respond
MFLTD00473	1	384	H	Level transmitter LT-473 fails to respond
MS511				ARV Failure For S/G A
MS551				ARV Failure For S/G B
MSAVCCCF$$		1.46E-01		Beta factor for MSIV fails to close
MSAVP03410	2	8760		AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)
MSAVP03411	2	8760		AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)
MSAVX03516	1	2214	H	MSIV 3516 Fails to Close
MSAVX03517	1	2214	H	MSIV 3517 Fails to Close
MSCCARVAIR		1.476E-02		COMMON CAUSE FAILURE OF AIR OPERATED ARVS
MSCCARVMAN		4.218E-04		COMMON CAUSE FAILURE OF ARVS IN MANUAL OPERATION
MSCCCARVSG		5.971E-05		Common Cause Failure Of ARVs To Close
MSCCCMSIVX		5.043E-03		Common Cause Failure Of MSIVs To Close
MSCCPSGCVS		8.893E-06		Common cause failure of check valves 3504B and 3505B to open
MSCCPSGMOV		1.856E-04		Common cause failure of MOVs 3504A and 3505A to open

Basic Event	C	Factor	Units	Description
MSCVP3504B	1	384	H	Check valve 3504B fails to open
MSCVP3505B	1	384	H	Check valve 3505B fails to open
MSCVPCCF$$		6.00E-02		Beta factor for Main Steam check valve fails to open
MSHFDLARVA		1		OPERATOR FAILS TO LOCALL OPERATE ARV 3411
MSHFDLARVB		1		OPERATOR FAILS TO LOCALLY OPERATED ARV 3410
MSHFLARV-A		.003		LATENT HUMAN ERROR DISABLES ARV 3411
MSHFLARV-B		.003		LATENT HUMAN ERROR DISABLES ARV 3410
MSMMIATO_A		7.101E-05		IA VALVE FAILURES SUPPORTING ARV 3411
MSMMIATO_B		7.101E-05		IA VALVE FAILURES SUPPORTING ARV 3410
MSMMN2BOTA		3.106E-02		NITROGEN BOTTLES FAIL TO SUPPLY ARV 3411
MSMMN2BOTB		3.106E-02		NITROGEN BOTTLES FAIL TO SUPPLY ARV 3410
MSMVC3504A	1	1		MOV 3504A Fails to Close
MSMVC3505A	1	1		MOV 3505A Fails to Close
MSMVP3504A	1	384	H	Motor operated valve 3504A fails to open
MSMVP3505A	1	384	H	Motor operated valve 3505A fails to open
MSMVPCCF$$		7.61E-02		Beta factor for Main Steam motor-operated valve fails to open
MSPSD33AST	1	1	N	PRESSURE SWITCH 63-3/AST FAILS TO RESPOND
MSPSD34AST	1	1	N	PRESSURE SWITCH 63-4/AST FAILS TO RESPOND
MSPSD35AST	1	1	N	PRESSURE SWITCH 63-5/AST FAILS TO RESPOND
MSRTD062SV	1	1	N	Turbine Stop Valves Timer Relay 62SV Fails On Demand
MSRVC03410	1	1		Air-Operated Valve 3410 (ARV) Fails to Close
MSRVC03411	1	1		Air-Operated Valve 3411 (ARV) Fails to Close
MSRVCCCF$$		7.00E-02		Beta Factor for ARV Fails to Close
MSRVPCCF$$		.1		CCF PROBABILITY FACTOR FOR AIR OPERATION OF ARVs
MSRVZ03410	1	1		Air-Operated Valve 3410 (ARV) Fails to Close After Liquid Relief
MSRVZ03411	1	1		Air-Operated Valve 3411 (ARV) Fails to Close After Liquid Relief
MSRYT03508	1	1		Steam Generator Relief Valve 3508 Fails to Close After Steam Release
MSRYT03509	1	1		Steam Generator Relief Valve 3509 Fails to Close After Steam Release
MSRYT03510	1	1		Steam Generator Relief Valve 3510 Fails to Close After Steam Release
MSRYT03511	1	1		Steam Generator Relief Valve 3511 Fails to Close After Steam Release
MSRYT03512	1	1		Steam Generator Relief Valve 3512 Fails to Close After Steam Release
MSRYT03513	1	1		Steam Generator Relief Valve 3513 Fails to Close After Steam Release
MSRYT03514	1	1		Steam Generator Relief Valve 3514 Fails to Close After Steam Release
MSRYT03515	1	1		Steam Generator Relief Valve 3515 Fails to Close After Steam Release
MSSZC03544	1	1	N	Main Steam Stop Valve Limit Switch 33/3544 Fails To Close On Demand
MSSZC03545	1	1	N	Main Steam Stop Valve Limit Switch 33/3545 Fails To Close On Demand
MSTM003410		3.98E-04		ARV 3410 IN TEST OR MAINTENANCE
MSTM003411		3.98E-04		ARV 3411 IN TEST OR MAINTENANCE
MSXVK03504	1	384	H	Manual valve 3504 transfers closed
MSXVK03505	1	384	H	Manual valve 3505 transfers closed
MSXVK03506	1	4404		ARV 3410 ISOLATION MANUAL VALVE 03506 TRANSFERS CLOSED
MSXVK03507	1	4404		ARV 3411 ISOLATION MANUAL VALVE 03507 TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
MSXVK3570E	1	384	H	Manual valve 3570E transfers closed
MSXVP03410	2	8760		ARV 3410 OPERATED AS A MANUAL VALVE FAILS TO OPEN
MSXVP03411	2	8760		ARV 3411 OPERATED AS A MANUAL VALVE FAILS TO OPEN
MSXVPCCF$$		.1		CCF PROBABILITY FACTOR FOR MANUAL OPERATION OF ARVs
MSXVX03412	1	4404	H	Manual Valve 3412A Fails to Close
MSXVX03520	1	4404	H	Manual Valve 3520 Fails to Close
MSXVX03521	1	4404	H	Manual Valve 3521 Fails to Close
MSXVX03668	1	4404	H	Manual Valve 3668 Fails to Close
MSXVX03669	1	4404	H	Manual Valve 3669 Fails to Close
MSXVX3413A	1	4404	H	Manual Valve 3413A Fails to Close
RC100				Failure Of Pressurizer Spray (Manual Actuation)
RC150				Failure Of Pressurizer Spray (Automatic Actuation)
RC200		1.00E-03		Both Pressurizer PORVS Fail To Automatically Open On Demand
RC250		1.00E-03		Either Pressurizer PORV Fails to Automatically Open on Demand
RC300				Either Pressurizer PORV Fails To Open When Manually Demanded
RC600				PORV Block Valve 515 Fails To Close On Demand
RC700				PORV Block Valve 516 Fails To Close On Demand
RCAVN0431A	1	1	N	AIR-OPERATED VALVE PCV-431A FAILS TO OPEN
RCAVN0431B	1	1	N	AIR-OPERATED VALVE PCV-431B FAILS TO OPEN
RCAVNCCF$$		0.1		BETA FACTOR FOR AIR-OPERATED VALVE FAILS TO OPEN
RCBINP429B	1	1	N	ALARM PC-429B FAILS TO OPERATE ON DEMAND
RCBINP430B	1	1	N	ALARM PC-430B FAILS TO OPERATE ON DEMAND
RCBINP431B	1	1	N	BISTABLE ALARM PC-431B FAILS TO OPERATE ON DEMAND
RCBINP431F	1	1	N	ALARM BISTABLE PC-431F FAILS TO OPERATE ON DEMAND
RCBINPC450	1	1	N	ALARM PC-450 FAILS TO OPERATE ON DEMAND
RCBINPC451	1	1	N	ALARM PC-451 FAILS TO OPERATE ON DEMAND
RCBINPC452	1	1	N	ALARM PC-452 FAILS TO OPERATE ON DEMAND
RCCC00430P		1.288E-03		COMMON CAUSE FAILURE OF PCV-430 AND PCV-431C TO OPEN ON DEMAND
RCCC431A/B		3.940E-04		COMMON CAUSE FAILURE OF PCV-431A AND PCV-431B TO OPEN ON DEMAND
RCHFD00RCP		1.00E-01		Operators Fail to Trip RCPs After Loss of CCW Support
RCHFD01BAF		1.00E-01		Operators Fail To Implement Bleed And Feed
RCHFDCD0SS		1.00E-01		Operator Fails to Cooldown to RHR After SI Fails - SSLOCA
RCHFDCDDPR		1.00E-01		Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation
RCHFDCDTR1		1.00E-01		Failure to Cooldown to RHR After Ruptured S/G Isolation Fails
RCHFDCDTR2		1.00E-01		Operator Fails to Cooldown to RHR After SI Fails - SGTR
RCHFDHEATR		0.1		Failure Of Operators To Manually Load Pressurizer Heater Following LOSP
RCHFDPLOCA		1.00E-01		Operators Fail To Close PORV Block Valve (515/516) To Terminate LOCA
RCHFDSCRAM		1.00E-02		Operators Fail to Trip Rod Drive MG Sets During ATWS
RCHFL0431K		3.00E-03		CONTROLLER PC-431K MISCALIBRATED
RCHFLC429B		3.00E-03		ALARM PC-429B MISCALIBRATED
RCHFLC430B		3.00E-03		ALARM PC-430B MISCALIBRATED
RCHFLC431B		3.00E-03		ALARM PC-431B MISCALIBRATED

Basic Event	C	Factor	Units	Description
RCHFLC431F		3.00E-03		ALARM BISTABLE PC-431F MISCALIBRATED
RCHFLPC450		3.00E-03		ALARM PC-450 MISCALIBRATED
RCHFLPC451		3.00E-03		ALARM PC-451 MISCALIBRATED
RCHFLPC452		3.00E-03		ALARM PC-452 MISCALIBRATED
RCHFLPL451		3.00E-03		PRESSURE TRANSMITTER PT-451 MISCALIBRATED
RCHFLPT429		3.00E-03		PRESSURE TRANSMITTER PT-429 MISCALIBRATED
RCHFLPT430		3.00E-03		PRESSURE TRANSMITTER PT-430 MISCALIBRATED
RCHFLPT431		3.00E-03		PRESSURE TRANSMITTER PT-431 MISCALIBRATED
RCHFLPT449		3.00E-03		PRESSURE TRANSMITTER PT-449 MISCALIBRATED
RCHFLPT450		3.00E-03		PRESSURE TRANSMITTER PT-450 MISCALIBRATED
RCHFLPT452		3.00E-03		PRESSURE TRANSMITTER PT-452 MISCALIBRATED
RCLYD0431K	1	8	H	CONTROLLER PC-431K FAILS TO RESPOND
RCLYDA431C	1	24	H	CONTROLLER PC-431C FAILS TO RESPOND WHILE IN AUTOMATIC OPERATION
RCLYDA431H	1	24	H	CONTROLLER PC-431H FAILS TO RESPOND WHILE IN AUTOMATIC OPERATION
RCLYDM429A	1	8	H	REPEATER PM-429A FAILS TO RESPOND
RCLYDM430A	1	8	H	REPEATER PM-430A FAILS TO RESPOND
RCLYDM431A	1	8	H	REPEATER PM-431A FAILS TO RESPOND
RCLYDM431C	1	24	H	CONTROLLER PC-431C FAILS TO RESPOND WHILE IN MANUAL OPERATION
RCLYDM431H	1	24	H	CONTROLLER PC-431H FAILS TO RESPOND WHILE IN MANUAL OPERATION
RCLYDM449A	1	8	H	REPEATER PM-449A FAILS TO RESPOND
RCMM000515		1.380E-03		ELECTRICAL FAILURES PREVENT MOVING MOV-515
RCMM000516		1.380E-03		ELECTRICAL FAILURES PREVENT MOVING MOV-516
RCMM00431A		3.997E-03		NORMAL PRZR SPRAY VALVE PCV-431A FAILS TO OPEN
RCMM00431B		3.997E-03		NORMAL PRZR SPRAY VALVE PCV-431B FAILS TO OPEN
RCMM00SRVS		2.800E-04		Either Pressurizer Relief Valve Fails to Open
RCMM0429BX		7.672E-05		RELAY PC-429BX FAILS TO OPERATE
RCMM0430BX		7.672E-05		RELAY PC-430BX FAILS TO OPERATE
RCMM0430IA		3.443E-02		SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND
RCMM0430N2		3.450E-02		SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND
RCMM0431BX		7.672E-05		RELAY PC-431BX FAILS TO OPERATE
RCMM0449BX		7.672E-05		RELAY PC-449BX FAILS TO OPERATE
RCMM0PT450		1.460E-03		PRESSURE TRANSMITTER PT-450 FAILS TO RESPOND TO HIGH PRESSURE CONDITION
RCMM0PT451		1.460E-03		PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION
RCMM0PT452		1.460E-03		PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION
RCMM431CIA		3.443E-02		SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND
RCMM431CN2		3.450E-02		SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND
RCMMAUXSPX		7.497E-02		AUXILIARY SPRAY VALVE 296 FAILS TO OPEN
RCMMTRC04A		6.594E-02		FAILURE OF NITROGEN SUPPLY TO PCV-430
RCMMTRC04B		6.594E-02		FAILURE OF NITROGEN SUPPLY TO PCV-431C
RCMPFRCP1A	1	24	H	REACTOR COOLANT PUMP PRC01A FAILS TO RUN
RCMPFRCP1B	1	24	H	REACTOR COOLANT PUMP PRC01B FAILS TO RUN
RCMVD00515		6.47E-02		Motor-Operated Valve 515 Is Closed Due to PORV Leakage

Basic Event	C	Factor	Units	Description
RCMVD00516		5.32E-04		Motor-Operated Valve 516 Is Closed Due To PORV Leakage
RCMVK00515	1	1061	H	MOTOR-OPERATED VALVE 515 TRANSFERS CLOSED
RCMVK00516	1	1061	H	MOTOR-OPERATED VALVE 516 TRANSFERS CLOSED
RCMVP00515	2	2075	H	MOTOR-OPERATED VALVE 515 FAILS TO OPEN
RCMVP00516	2	2075	H	MOTOR-OPERATED VALVE 516 FAILS TO OPEN
RCMVX00515	1	8760	H	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE
RCMVX00516	1	8760	H	MOTOR-OPERATED VALVE 516 FAIL TO CLOSE
RCPTLPT429	1	8	H	PRESSURE TRANSMITTER PT-429 FAILS LOW
RCPTLPT430	1	8	H	PRESSURE TRANSMITTER PT-430 FAILS LOW
RCPTLPT431	1	8	H	PRESSURE TRANSMITTER PT-431 FAILS LOW
RCPTLPT449	1	8	H	PRESSURE TRANSMITTER PT-449 FAILS LOW
RCPTLPT450	1	8	H	PRESSURE TRANSMITTER PT-450 FAILS LOW
RCPTLPT451	1	8	H	PRESSURE TRANSMITTER PT-451 FAILS LOW
RCPTLPT452	1	8	H	PRESSURE TRANSMITTER PT-452 FAILS LOW
RCPXFPQ429	1	8	H	POWER SUPPLY PQ-429 NO OUTPUT
RCPXFPQ430	1	8	H	POWER SUPPLY PQ-430 NO OUTPUT
RCPXFPQ431	1	8	H	POWER SUPPLY PQ-431 NO OUTPUT
RCPXFPQ449	1	8	H	POWER SUPPLY PQ-449 NO OUTPUT
RCPXFPQ450	1	8	H	POWER SUPPLY PQ-450 NO OUTPUT
RCPXFPQ451	1	8	H	POWER SUPPLY PQ-451 NO OUTPUT
RCPXFPQ452	1	8	H	POWER SUPPLY PQ-452 NO OUTPUT
RCREE000C1	1	1	N	RELAY C1 FAILS TO ENERGIZE
RCREE000C2	1	1	N	RELAY C2 FAILS TO ENERGIZE
RCREE429BX	1	1	N	RELAY PC-429BX FAILS TO ENERGIZE
RCREE430BX	1	1	N	RELAY PC-430BX FAILS TO ENERGIZE
RCREE431BX	1	1	N	RELAY PC-431BX FAILS TO ENERGIZE
RCREE449BX	1	1	N	RELAY PC-449BX FAILS TO ENERGIZE
RCREE450AX	1	1	N	RELAY PC-450AX FAILS TO ENERGIZE
RCREE450BX	1	1	N	RELAY PC-450BX FAILS TO ENERGIZE
RCREE451AX	1	1	N	RELAY PC-451AX FAILS TO ENERGIZE
RCREE451BX	1	1	N	RELAY PC-451BX FAILS TO ENERGIZE
RCREE452AX	1	1	N	RELAY PC-452AX FAILS TO ENERGIZE
RCREE452BX	1	1	N	RELAY PC-452BX FAILS TO ENERGIZE
RCRYN00434	1	1	N	Pressurizer Relief Valve 434 Fails to Open
RCRYN00435	1	1	N	Pressurizer Relief Valve 435 Fails to Open
RCRYT00434	1	1		Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief
RCRYT00435	1	1		Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief
RCRZP00430	2	8760	H	PORV PCV-430 FAILS TO OPEN
RCRZP0431C	2	8760	H	PORV PCV-431C FAILS TO OPEN
RCRZPCCF$$		0.1		BETA FACTOR FOR PORV FAILS TO OPEN
RCRZT00430	1	1		PORV PCV-430 Fails To Reseat After Steam Relief
RCRZT0431C	1	1		PORV PCV-431C Fails To Reseat After Steam Relief

Table [illegible]-2
Integrated C[illegible] BE File

Basic Event	C	Factor	Units	Description
RCSWC0415	1	1	N	HAND SWITCH HIS-415 FAILS TO TRANSFER TO "ARM" POSITION
RCSWC0450	1	1	N	HAND SWITCH HIS-450 FAILS TO TRANSFER TO "ARM" POSITION
RCSWC1P430	1	1	N	HAND SWITCH 1/P430 FAILS TO TRANSFER TO "OPEN" POSITION
RCSWC1P431	1	1	N	HAND SWITCH 1/P431 FAILS TO TRANSFER TO "OPEN" POSITION
RCSWC8616A	1	1	N	HAND SWITCH FOR 8616A FAILS TO TRANSFER TO "OPEN" POSITION
RCSWC8616B	1	1	N	HAND SWITCH FOR 8616B FAILS TO TRANSFER TO "OPEN" POSITION
RCSWCAUXSP	1	1	N	HAND SWITCH FOR AUXILIARY PRZR SPRAY FAILS TO CLOSE
RCSWR1P430	1	8760	H	HAND SWITCH 1/P430 TRANSFERS OPEN
RCSWR1P431	1	8760	H	HAND SWITCH 1/P431C TRANSFERS OPEN
RCSWRP429A	1	8	H	SELECTOR SWITCH P/429A TRANSFERS OPEN
RCXVK00510	1	8760	H	MANUAL VALVE 510 TRANSFERS CLOSED
RCXVK00512	1	8760	H	MANUAL VALVE 512 TRANSFERS CLOSED (COMMON TO PT-449 AND PT-431)
RCXVK00533	1	8760	H	MANUAL VALVE 533 TRANSFERS CLOSED
RCXVK0501A	1	8760	H	MANUAL VALVE 501A TRANSFERS CLOSED
RCXVK0501C	1	8760	H	MANUAL VALVE 501C TRANSFERS CLOSED
RCXVK0506A	1	8760	H	MANUAL VALVE 506A TRANSFERS CLOSED
RCXVK12236	1	8760	H	MANUAL VALVE 12236 TRANSFERS CLOSED
RCXVK12237	1	8760	H	MANUAL VALVE 12237 TRANSFERS CLOSED
RCXVK12238	1	8760	H	MANUAL VALVE 12238 TRANSFERS CLOSED
RCXVK12239	1	8760	H	MANUAL VALVE 12239 TRANSFERS CLOSED
RCXVK12425	1	8760	H	MANUAL VALVE 12425 TRANSFERS CLOSED
RH200				Failure To Provide Any Flow From RHR In Injection Phase
RHAVK00624	1	16	H	AIR-OPERATED VALVE 624 TRANSFER CLOSED [INJECTION]
RHAVK00625	1	16	H	AIR-OPERATED VALVE 625 TRANSFERS CLOSED [INJECTION]
RHCC697A/B		8.935E-05		CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>
RHCC710A/B		7.446E-06		CHECK VALVES 710A, 710B FAIL TO OPEN <common cause event>
RHCC852A/B		3.819E-03		MOVS 852A, 852B FAIL TO OPEN <common cause event>
RHCC853A/B		8.935E-05		CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>
RHCCPUMPAB		4.072E-04		PUMPS A AND B FAIL TO START <common cause event>
RHCCPUMPBA		1.637E-05		PUMPS A AND B FAIL TO RUN <common cause event>
RHCVP00854	1	4380	H	CHECK VALVE 854 FAILS TO OPEN [INJECTION]
RHCVP0697A	1	4380	H	CHECK VALVE 697A FAILS TO OPEN [INJECTION]
RHCVP0697B	1	4380	H	CHECK VALVE 697B FAILS TO OPEN [INJECTION]
RHCVP0710A	1	365	H	CHECK VALVE 710A FAILS TO OPEN [INJECTION]
RHCVP0710B	1	365	H	CHECK VALVE 710B FAILS TO OPEN [INJECTION]
RHCVP0853A	1	4380	H	CHECK VALVE 853A FAILS TO OPEN [INJECTION]
RHCVP0853B	1	4380	H	CHECK VALVE 853B FAILS TO OPEN [INJECTION]
RHCVPCCF$$		6.00E-02		BETA FACTOR FOR CHECK VALVE FAILS TO OPEN [INJECTION]
RHHFD0SGTR		1.00E+00		Failure to Establish or Maintain RHR Cooling Following SGTR
RHHFLAC01A		3.00E-03		LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)
RHHFLAC01B		3.00E-03		LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)
RHHXFACO2A	1	12	H	HEAT EXCHANGER EACO2A COOLING CAP. FAILS [INJECTION]

Basic Event	C	Factor	Units	Description
RHHXPAC02A	1	377	H	HEAT EXCHANGER EAC02A PLUGS [INJECTION]
RHHXPACO2B	1	377	H	HEAT EXCHANGER EACO2B PLUGS [INJECTION]
RHMM00852A		4.774E-02		852a Fails to Open
RHMM00852B		4.774E-02		852B Fails to Open
RHMMAC01AA		2.529E-03		PAC01A fails to start
RHMMAC01AF		1.488E-04		PAC01A fails to run
RHMMAC01BA		2.529E-03		AC01B Fails to Start
RHMMAC01BF		1.488E-04		AC01B Fails to Run
RHMMHXACOM		2.243E-03		Failure of RHR Heat Exchanger A
RHMMHXBFLW		2.331E-03		Failure of RHR Heat Exchanger B
RHMPFAC01A	1	12	H	MOTOR-DRIVEN PUMP PAC01A FAILS TO RUN [INJECTION]
RHMPFAC01B	1	12	H	MOTOR-DRIVEN PUMP PAC01B FAILS TO RUN [INJECTION]
RHMPFCCF$$		1.10E-01		BETA FACTOR FOR MOTOR-DRIVEN PUMP FAILS TO RUN [INJECTION]
RHMPSAC01A	1	365	H	MOTOR-DRIVEN PUMP PAC01A FAILS TO START [INJECTION]
RHMPSAC01B	1	365	H	MOTOR-DRIVEN PUMP PAC01B FAILS TO START [INJECTION]
RHMPSCCF$$		1.61E-01		BETA FACTOR FOR MOTOR-DRIVEN PUMP FAILS TO START [INJECTION]
RHMVK00856	1	16	H	MOTOR-OPERATED VALVE 856 TRANSFERS CLOSED [INJECTION]
RHMVK0704A	1	16	H	MOTOR-OPERATED VALVE 704A TRANSFERS CLOSED ISOLATING SUCTION PATH [INJECTION]
RHMVK0704B	1	16	H	MOTOR-OP VALVE 704B TRANSFERS CLOSED, ISOLATING SUCTION PATH [INJECTION]
RHMVP0852A	1	4380	H	MOTOR-OPERATED VALVE 852A FAILS TO OPEN [INJECTION]
RHMVP0852B	1	4380	H	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]
RHMVPCCF$$		8.00E-02		BETA FACTOR FOR MOTOR-OPERATED VALVE FAILS TO OPEN [INJECTION]
RHMVR0850A	1	16	H	MOTOR-OP VALVE 850A TRANSFERS OPEN [INJECTION]
RHMVR0850B	1	16	H	MOTOR-OP VALVE 850B TRANSFERS OPEN [INJECTION]
RHMVR0857A	1	16	H	MOTOR-OPERATED VALVE 857A TRANSFERS OPEN
RHMVR0857B	1	16	H	MOTOR-OPERATED VALVE 857B TRANSFERS OPEN - LOSS OF FLOW
RHMVR0857C	1	16	H	MOTOR-OPERATED VALVE 857C TRANSFERS OPEN
RHPPJINJLN	1	12	H	PIPING - COMMON INJECTION LINE RUPTURE [INJECTION]
RHPPJSUCHD	1	12	H	RWST Suction Piping To RHR System Ruptures (Injection)
RHTM00000A		2.90E-03		TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]
RHTM00000B		2.90E-03		TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]
RHXVK00714	1	377	H	MANUAL VALVE 714 TRANSFERS CLOSED [INJECTION]
RHXVK00715	1	4392	H	MANUAL VALVE 715 TRANSFERS CLOSED [INJECTION]
RHXVK00716	1	377	H	MANUAL VALVE 716 TRANSFERS CLOSED [INJECTION]
RHXVK00717	1	4392	H	MANUAL VALVE 717 TRANSFERS CLOSED [INJECTION]
RHXVK0694A	1	377	H	MANUAL VALVE 694A TRANSFERS CLOSED [INJECTION]
RHXVK0694B	1	377	H	MANUAL VALVE 694B TRANSFERS CLOSED [INJECTION]
RHXVK0696A	1	377	H	MANUAL VALVE 696A TRANSFERS CLOSED [INJECTION]
RHXVK0696B	1	377	H	MANUAL VALVE 696B TRANSFERS CLOSED [INJECTION]
RHXVK0709A	1	377	H	MANUAL VALVE 709A TRANSFERS CLOSED [INJECTION]
RHXVK0709B	1	377	H	MANUAL VALVE 709B TRANSFERS CLOSED [INJECTION]
RHXVR1816A	1	377	H	MANUAL VALVE 1816A TRANSFERS OPEN

Basic Event	C	Factor	Units	Description
RHXVR1816B	1	377	H	MANUAL VALVE 1816B TRANSFERS OPEN
RP100		1.00E-02		ATWS Mitigation System Actuation Circuitry Fails
RPHFD00MRI		0.21		Operators Fail To Manually Insert Rods
RR100				Failure Of RHR Sump Recirculation
RR610				Insufficient flow/cooling to SI 857C valve and crosstie (for CS in recirc)
RR690				Insufficient flow/cooling to SI MOV 857B from "B" train
RRAVF00624	1	12	H	Failure of AOV 624 to throttle flow
RRAVF00625	1	12	H	Failure of AOV 625 to throttle flow
RRAVK00624	1	12	H	AIR-OPERATED VALVE 624 TRANSFER CLOSED [RECIRC]
RRAVK00625	1	12	H	AIR-OPERATED VALVE 625 TRANSFERS CLOSED [RECIRC]
RRCC697A/B		2.448E-07		CHECK VALVES 697A/B FAIL TO OPEN <common cause event>
RRCC710A/B		2.448E-07		CHECK VALVES 710A/B FAIL TO OPEN <common cause event>
RRCC850A/B		9.238E-04		MOVS 850A/B FAIL TO OPEN <common cause event>
RRCC853A/B		2.448E-07		CHECK VALVES 853A/B FAIL TO OPEN <common cause event>
RRCCM0857M		9.213E-04		MOVs 857A, 857B and 857C fail to open due to common cause
RRCCPUMPAB		1.339E-05		PUMPS A/B FAIL TO START <common cause event>
RRCCPUMPBA		1.637E-05		PUMPS A/B FAIL TO RUN <common cause event>
RRCVC00854	1	1	N	CHECK VALVE 854 FAILS TO CLOSE
RRCVP0697A	1	12	H	CHECK VALVE 697A FAILS TO OPEN [RECIRC]
RRCVP0697B	1	12	H	CHECK VALVE 697B FAILS TO OPEN [RECIRC]
RRCVP0710A	1	12	H	CHECK VALVE 710A FAILS TO OPEN [RECIRC]
RRCVP0710B	1	12	H	CHECK VALVE 710B FAILS TO OPEN [RECIRC]
RRCVP0853A	1	12	H	CHECK VALVE 853A FAILS TO OPEN [RECIRC]
RRCVP0853B	1	12	H	CHECK VALVE 853B FAILS TO OPEN [RECIRC]
RRCVPCCF$$		6.00E-02		BETA FACTOR FOR CHECK VALVE FAILS TO OPEN [RECIRC]
RRHFDRCR0A		1.00E-01		Failure to Switch to Recirculation After LLOCA
RRHFDRCR0M		1.00E-01		Failure to Switch to Recirculation After MLOCA
RRHFDRCR0S		1.00E-01		Failure to Switch to Recirculation After SLOCA
RRHFDRCRSS		1.00E-01		Failure to Switch to Recirculation After SSLOCA
RRHFDRECRC		1.00E-02		OPERATOR FAILS TO CORRECTLY SHIFT THE RHR SYSTEM TO RECIRCULATION AND ISOL CS
RRHFL00856		3.00E-03		LATENT HUMAN FAILURE ON MOV 856
RRHFL0850A		3.00E-03		LATENT HUMAN FAILURE OF MOV 850A
RRHFL0850B		3.00E-03		LATENT HUMAN FAILURE OF MOV 850B
RRHXFAC02A	1	4392		HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]
RRHXFAC02B	1	4392	H	HEAT EXCHANGER EAC02B COOLING CAP. FAILS [RECIRC]
RRHXPAC02A	1	12	H	HEAT EXCHANGER EAC02A PLUGS [RECIRC]
RRHXPAC02B	1	12	H	HEAT EXCHANGER EAC02B PLUGS [RECIRC]
RRIPD0624	1	12	H	I/P CONVERTER 0624 FAILS TO RESPOND
RRIPD0625	1	12	H	I/P CONVERTER 0625 FAILS TO RESPOND
RRLYD0624	1	12	H	SIGNAL PROCESS MODULE 0624 FAILS TO RESPOND
RRLYD0625	1	12	H	SIGNAL PROCESS MODULE 0625 FAILS TO RESPOND
RRMM000624		1.382E-04		AVO-624 FAILS TO THROTTLE

Tabl[illegible]2
Integrated C[illegible]BE File

Basic Event	C	Factor	Units	Description
RRMM000625		1.382E-04		AOV-625 FAILS TO THROTTLE
RRMM000856		2.913E-02		
RRMM00850A		1.194E-02		MOV 850A FAILS TO OPEN (RECIRCULATION)
RRMM00850B		1.194E-02		MOV 850B FAILS TO OPEN (RECIRCULATION)
RRMMAC01AA		8.316E-05		PAC01A FAILS TO START (RECIRCULATION)
RRMMAC01AF		1.488E-04		PAC01A FAILS TO RUN (RECIRCULATION)
RRMMAC01BA		8.316E-05		AC01B FAILS TO START (RECIRCULATION)
RRMMAC01BF		1.488E-04		AC01B RUNS TO RUN (RECIRCULATION)
RRMMHXACOM		2.563E-05		FAILURES IN FLOW PATH FROM HX A LINE TO COMMON DISCHARGE HEADER
RRMMHXBFLW		2.840E-02		Failure of components for RHR Heat Exchanger B
RRMPFAC01A	1	12	H	MOTOR-DRIVEN PUMP PAC01A FAILS TO RUN [RECIRC]
RRMPFAC01B	1	12	H	MOTOR-DRIVEN PUMP PAC01B FAILS TO RUN [RECIRC]
RRMPFCCF$$		1.10E-01		BETA FACTOR FOR MOTOR-DRIVEN PUMP FAILS TO RUN [RECIRC]
RRMPSAC01A	1	12	H	MOTOR-DRIVEN PUMP PAC01A FAILS TO START [RECIRC]
RRMPSAC01B	1	12	H	MOTOR-DRIVEN PUMP PAC01B FAILS TO START [RECIRC]
RRMPSCCF$$		1.61E-01		BETA FACTOR FOR MOTOR-DRIVEN PUMP FAILS TO START [RECIRC]
RRMVP0850A	1	1095	H	MOTOR-OPERATED VALVE 850A FAILS TO OPEN [RECIRC]
RRMVP0850B	1	1095	H	MOTOR-OPERATED VALVE 850B FAILS TO OPEN [RECIRC]
RRMVP0857A	1	1092	H	MOV 857A fails to open
RRMVP0857B	1	1092	H	MOV 857B fails to open
RRMVP0857C	1	1092	H	MOV 857C fails to open
RRMVPCCF$$		7.74E-02		Beta factor for common cause failure of an MOV to open
RRMVX00856	2	8760	H	MOTOR-OPERATED VALVE 00856 FAILS TO CLOSE (STANDBY)
RRPPJLBL0A		1.00E+00		
RRPPJLBL0B		1.00E+00		
RRPPJMBL0A		5.20E-03		CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE
RRPPJMBL0B		3.90E-03		CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE
RRPPJSBL0A		3.47E-04		CONDITIONAL PROBABILITY OF SBLOCA IN "A" RHR LINE
RRPPJSBL0B		3.13E-04		CONDITIONAL PROBABILITY OF SBLOCA IN "B" RHR LINE
RRPTHPC629	1	4392	H	Pressure transmitter PIC-629 fails high
RRSMP00A/B	1	1		CONTAINMENT SUMP SCREENS PLUGGED [RECIRC]
RRXVK00714	1	12	H	MANUAL VALVE 714 TRANSFERS CLOSED [RECIRC]
RRXVK00715	1	12	H	MANUAL VALVE 715 TRANSFERS CLOSED [RECIRC]
RRXVK00716	1	12	H	MANUAL VALVE 716 TRANSFERS CLOSED [RECIRC]
RRXVK00717	1	12	H	MANUAL VALVE 717 TRANSFERS CLOSED [RECIRC]
RRXVK0694A	1	12	H	MANUAL VALVE 694A TRANSFERS CLOSED [RECIRC]
RRXVK0694B	1	12	H	MANUAL VALVE 694B TRANSFERS CLOSED [RECIRC]
RRXVK0696A	1	12	H	MANUAL VALVE 696A TRANSFERS CLOSED [RECIRC]
RRXVK0696B	1	12	H	MANUAL VALVE 696B TRANSFERS CLOSED [RECIRC]
RRXVK0709A	1	12	H	MANUAL VALVE 709A TRANSFERS CLOSED [RECIRC]
RRXVK0709B	1	12	H	MANUAL VALVE 709B TRANSFERS CLOSED [RECIRC]
RRXVK0851A	1	16	H	DE-POWERED MOV 851A TRANSFERS CLOSED [RECIRC]

Basic Event	C	Factor	Units	Description
RRXVK0851B	1	16	H	DE-POWERED MOV 851B TRANSFERS CLOSED [RECIRC]
RRXVR1813A	1	12	H	MANUAL VALVE 1813A TRANSFERS OPEN [RECIRC]
RRXVR1813B	1	12	H	MANUAL VALVE 1813B TRANSFERS OPEN [RECIRC]
SGTR		1E-3		STEAM GENERATOR TUBE RUPTURES
SI100				Failure To Deliver Flow From 1 Of 3 SI Pumps To The RCS During Injection
SI500				Inadequate Flow From Both Accumulators (TSI03A and TSI03B)
SICCINJCHK		1.146E-04		Common Cause Failure of Check valves for Penetrations 101 and 113
SICCM0842X		1.450E-05		Common Cause Failure To Open Of Check Valves 842A & 842B
SICCM0867X		7.668E-05		Common Cause Failure To Open Of Check Valves 867A & 867B
SICCM0878X		7.668E-05		Check valves 878G and 878J fail to open due to common cause
SICCM0889X		6.495E-06		Check valves 870A, 870B, 889A and 889B fail to open due to common cause
SICCM0891X		1.907E-05		Check valves 891A, 891B & 891C fail to open due to common cause during inj.
SICCMLTHT3		1.770E-03		Common Cause Failure (High) Of Accumulator Level Transmitters
SICCMPSI1X		5.489E-04		PSI01A, PSI01B & PSI01C fail to start for injection due to common cause
SICCMPSI1Y		8.388E-04		PSI01A, PSI01B & PSI01C fail to run during injection due to common cause
SICCMPTHT3		1.305E-03		Common Cause Failure (High) Of Accumulator Pressure Transmitters
SICVC0867A	1	1		Check Valve 867A Fails to Close
SICVC0867B	1	1		Check Valve 867B Fails to Close
SICVC0870A	1	1		Check Valve 870A Fails to Close
SICVC0870B	1	1		Check Valve 870B Fails to Close
SICVC0878G	1	1		Check Valve 878G Fails to Close
SICVC0878J	1	1		Check Valve 878J Fails to Close
SICVC0889A	1	1		Check Valve 889A Fails to Close
SICVC0889B	1	1		Check Valve 889B Fails to Close
SICVCCCF$$		0.06		Beta Factor for SI Check Valves Fail to Close
SICVN0842A	1	1	N	Check Valve 842A Fails To Open On Demand
SICVN0842B	1	1	N	Check Valve 842B Fails To Open On Demand
SICVN0867A	1	1	N	Check Valve 867A Fails To Open On Demand
SICVN0867B	1	1	N	Check Valve 867B Fails TO Open On Demand
SICVNCCF$$		0.1		Beta Factor For Common Cause Failure Events SICCM0842X And SICCM0867X
SICVP0867A	1	4392	H	Check valve 867A fails to open
SICVP0867B	1	4392	H	Check valve 867B fails to open
SICVP0870A	1	372	H	Check valve 870A fails to open
SICVP0870B	1	372	H	Check valve 870B fails to open
SICVP0878G	1	4392	H	Check valve 878G fails to open
SICVP0878J	1	4392	H	Check valve 878J fails to open
SICVP0889A	1	372	H	Check valve 889A fails to open
SICVP0889B	1	372	H	Check valve 889B fails to open
SICVP0891A	1	1092	H	Check valve 891A fails to open
SICVP0891B	1	1092	H	Check valve 891B fails to open
SICVP0891C	1	1092	H	Check valve 891C fails to open
SICVPCCF$$		6.00E-02		Beta factor for common cause failure of a check valve to open

Basic Event	C	Factor	Units	Description
SICVR0842A	1	372	H	Check valve 842A transfers open
SICVR0842B	1	372	H	Check valve 842B transfers open
SIHFL0857B		3.00E-03		Latent Human Failure of MOV 857B
SIHFL0871A		3.00E-03		Laten Human Failure of MOV 871A
SIHFL0871B		3.00E-03		Latent Human Failure of MOV 871B
SIHFL857AC		3.00E-03		Latent Human Failure of MOV 857A OR 857C
SIHFLPSI1A		3.00E-03		Operators fail to restore PSI01A equipment after test or maintenance
SIHFLPSI1B		3.00E-03		Operators fail to restore PSI01B equipment after test or maintenance
SIHFLPSI1C		3.00E-03		Operators fail to restore PSI01C equipment after test or maintenance
SILCDSI01C	2	4392	H	Logic circuit failure shows wrong position of 52/PSI01C2 (Bus 14)
SILTHCCF$$		0.1		Beta Factor For Common Cause Failure (High) Of Accumulator Level Transmitters
SILTHLT934	1	8760	H	Level Transmitter LT-934 Fails High
SILTHLT935	1	8760	H	Level Transmitter LT-935 Fails High
SILTHLT938	1	8760	H	Level Transmitter LT-938 Fails High
SILTHLT939	1	8760	H	Level Transmitter LT-939 Fails High
SIMMCB0897		0.000E+00		897 CIrcuit Breaker or Fuse Failure Prevents Operation
SIMMCB0898		0.000E+00		898 CIrcuit Breaker or Fuse Failure Prevents Operation
SIMMCB857A		0.000E+00		857A CIrcuit Breaker or Fuse Failure Prevents Operation
SIMMCB857B		0.000E+00		857B CIrcuit Breaker or Fuse Failure Prevents Operation
SIMMCB857C		0.000E+00		857C CIrcuit Breaker or Fuse Failure Prevents Operation
SIMMCBUS14		0.000E+00		PSI01C Circuit Breaker or DC Fuse Failure Prevents Start From Bus 14
SIMMCBUS16		0.000E+00		PSI01C Circuit Breaker or DC Fuse Failure Prevents Start From Bus 16
SIMMPSI01A		0.000E+00		PSI01A Circuit Breaker or DC Fuse Failure Prevents Start
SIMMPSI01B		0.000E+00		PSI01B Circuit Breaker or DC Fuse Failure Prevents Start
SIMPFCCF$$		1.50E-01		Beta factor for common cause failure of a pump to run
SIMPFSI01A	1	12	H	PSI01A fails to run
SIMPFSI01B	1	12	H	PSI01B fails to run
SIMPFSI01C	1	12	H	PSI01C fails to run
SIMPSCCF$$		3.10E-01		Beta factor for common cause failure of a pump to start
SIMPSSI01A	1	372	H	PSI01A fails to start
SIMPSSI01B	1	372	H	PSI01B fails to start
SIMPSSI01C	1	372	H	PSI01C fails to start
SIMVK0825A	1	372	H	MOTOR-OPERATED VALVE 825A TRANSFERS CLOSED
SIMVK0825B	1	372	H	MOTOR-OPERATED VALVE 825B TRANSFERS CLOSED
SIMVK0871A	1	372	H	MOV 871A transfers closed
SIMVK0871B	1	372	H	MOV 871B transfers closed
SIPPJLBL0A		1.89E-02		CONDITIONAL PROBABILITY OF LBLOCA IN THE "A" SI LINE
SIPPJLBL0B		1.89E-02		CONDITIONAL PROBABILITY OF LBLOCA IN THE "B" SI LINE
SIPPJLOOPA		1.00E+00		
SIPPJLOOPB		1.00E+00		
SIPPJMBL0A		1.45E-03		CONDITIONAL PROBABILITY OF MBLOCA IN THE "A" SI LINE
SIPPJMBL0B		1.93E-03		CONDITIONAL PROBABILITY OF MBLOCA IN THE "B" SI LINE

Basic Event	C	Factor	Units	Description
SIPPJSBL0A		6.25E-04		CONDITIONAL PROBABILITY OF SBLOCA IN THE "A" SI LINE
SIPPJSBL0B		6.94E-04		CONDITIONAL PROBABILITY OF SBLOCA IN THE "B" SI LINE
SIPTHCCF$$		0.1		Beta Factor For Common Cause Failure (High) Of Accumulator Pressure Transmitter
SIPTHPT936	1	8760	H	Pressure Transmitter PT-936 Fails High
SIPTHPT937	1	8760	H	Pressure Transmitter PT-937 Fails High
SIPTHPT940	1	8760	H	Pressure Transmitter PT-940 Fails High
SIPTHPT941	1	8760	H	Pressure Transmitter PT-941 Fails High
SITKGSI3AL	1	8760	H	LONG-TERM TANK SI03A LIQUID LEAKAGE
SITKGSI3AN	1	8760	H	LONG-TERM TANK SI03A N2 LEAKAGE
SITKGSI3AS	1	15	H	SHORT-TERM TANK SI03A LIQUID OR N2 LEAKAGE
SITKGSI3BL	1	8760	H	LONG-TERM TANK SI03B LIQUID LEAKAGE
SITKGSI3BN	1	8760	H	LONG-TERM TANK SI03B N2 LEAKAGE
SITKGSI3BS	1	15	H	SHORT-TERM TANK SI03B LIQUID OR N2 LEAKAGE
SITM00825A		1.00E+00		
SITM00825B		1.00E+00		
SITM00871A		3.20E-03		MOV 871A or check valve 870A unavailable due to maintenance
SITM00871B		9.84E-04		MOV 871B or check valve 807B unavailable due to maintenance
SITM0PSI1A		2.37E-03		PSI01A unavailable due to test or maintenance
SITM0PSI1B		2.37E-03		PSI01B unavailable due to test or maintenance
SITM0PSI1C		2.82E-03		PSI01C unavailable due to test or maintenance
SITMTRAINA		3.65E-03		SI train A discharge valves unavailable due to test or maintenance
SITMTRAINB		2.54E-03		SI train B discharge valves unavailable due to test or maintenance
SIXVK00841	1	4404	H	Motor Operated Valve 841 Transfers Closed
SIXVK00865	1	4404	H	Motor Operated Valve 865 Transfers Closed
SIXVK0878B	1	4392	H	MOV 878B transfers closed
SIXVK0878D	1	4392	H	MOV 878D transfers closed
SIXVK0878E	1	4392	H	Manual valve 878E transfers closed
SIXVK0888A	1	372	H	Manual valve 888A transfers closed
SIXVK0888B	1	372	H	Manual valve 888B transfers closed
SIXVK0890A	1	372	H	Manual valve 890A transfers closed
SIXVK0890B	1	372	H	Manual valve 890B transfers closed
SIXVK1815A	1	372	H	MOV 1815A transfers closed
SIXVK1815B	1	372	H	MOV 1815B transfers closed
SIXVK1820A	1	372	H	Manual valve 1820A transfers closed
SIXVK1820B	1	372	H	Manual valve 1820B transfers closed
SIXVK1820C	1	372	H	Manual valve 1820C transfers closed
SIXVR0878A	1	4392	H	MOV 878A transfers open
SIXVR0878C	1	4392	H	MOV 878C transfers open
SR500				Failure To Deliver Flow From 1 Of 3 SI Pumps To The RCS During Recirculation
SR610				No Recirculation Flow Available From The RHR System
SRCCM0867X		2.095E-07		Check valves 867A and 867B fail to open due to common cause
SRCCM0878X		2.095E-07		Check valves 878G and 878J fail to open due to common cause

Basic Event	C Factor	Units	Description
SRCCM0889X	2.095E-07		Check valves 870A, 870B, 889A and 889B fail to open due to common cause
SRCCM897/8	1.537E-03		MOVs 897 and 898 fail to close due to common cause
SRCCMPSI1X	8.568E-06		PSI01A, PSI01B & PSI01C fail to start for recirc. due to common cause
SRCCMPSI1Y	8.388E-04		PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause
SRCVP0867A	1	12 H	Check valve 867A fails to open
SRCVP0867B	1	12 H	Check valve 867B fails to open
SRCVP0870A	1	12 H	Check valve 870A fails to open
SRCVP0870B	1	12 H	Check valve 870B fails to open
SRCVP0878G	1	12 H	Check valve 878G fails to open
SRCVP0878J	1	12 H	Check valve 878J fails to open
SRCVP0889A	1	12 H	Check valve 889A fails to open
SRCVP0889B	1	12 H	Check valve 889B fails to open
SRCVPCCF$$	6.00E-02		Beta factor for common cause failure of a check valve to open
SRCVR0842A	1	12 H	Check valve 842A transfers open
SRCVR0842B	1	12 H	Check valve 842B transfers open
SRMMCCWP1A	3.907E-03		Failure of PSI01A cooling components
SRMMCCWP1B	3.907E-03		Failure of PSI01B cooling components
SRMMCCWP1C	3.907E-03		Failure of PSI01C cooling components
SRMPFCCF$$	1.50E-01		Beta factor for common cause failure of a pump to run
SRMPFSI01A	1	12 H	PSI01A fails to run
SRMPFSI01B	1	12 H	PSI01B fails to run
SRMPFSI01C	1	12 H	PSI01C fails to run
SRMPSCCF$$	1.50E-01		Beta factor for common cause failure of a pump to start
SRMPSSI01A	1	12 H	PSI01A fails to start
SRMPSSI01B	1	12 H	PSI01B fails to start
SRMPSSI01C	1	12 H	PSI01C fails to start
SRMVK0825A	1	12 H	MOV 825A transfers closed
SRMVK0825B	1	12 H	MOV 825B transfers closed
SRMVK0871A	1	372 H	MOV 871A transfers closed
SRMVK0871B	1	372 H	MOV 871B transfers closed
SRPPPAC08A	1	1 H	Heat exchanger EAC08A plugs
SRPPPAC08B	1	1 H	Heat exchanger EAC08B plugs
SRPPPAC09A	1	1 H	Heat exchanger EAC09A plugs
SRPPPAC09B	1	1 H	Heat exchanger EAC09B plugs
SRPPPAC10A	1	1 H	Heat exchanger EAC10A plugs
SRPPPAC10B	1	1 H	Heat exchanger EAC10B plugs
SRXVK0878B	1	12 H	MOV 878B transfers closed
SRXVK0878D	1	12 H	MOV 878D transfers closed
SRXVK0878E	1	12 H	Manual valve 878E transfers closed
SRXVK0888A	1	12 H	Manual valve 888A transfers closed
SRXVK0888B	1	12 H	Manual valve 888B transfers closed
SRXVK0890A	1	12 H	Manual valve 890A transfers closed

Basic Event	C	Factor	Units	Description
SRXVK0890B	1	12	H	Manual valve 890B transfers closed
SRXVK1815A	1	12	H	MOV 1815A transfers closed
SRXVK1815B	1	12	H	MOV 1815B transfers closed
SRXVR0878A	1	12	H	MOV 878A transfers open
SRXVR0878C	1	12	H	MOV 878C transfers open
SW100		0.001		Loss Of Service water Flow To KDG01A
SW150		0.001		Loss Of Service Water Flow To KDG01B
SW200				Loss of SW Flow to IA Compressors CIA02A, CIA02C and Relay Room AC Units
SW250		1E-3		SERVICE WATER TO SA AND IA - B COMPRESSORS
SW300		1E-3		Loss of service water flow to SAFW pump PFW03A and ventilation fan AFA01A
SW350		1E-3		Loss of service water flow to SAFW pump PFWO3B and ventilation fan AFAO1B
SW400				Loss Of SW Flow To SI Pumps PSI01A, PSI01B, and PSI01C and Room Coolers
SW406		1E-3		LOSS OF SERVICE WATER A TO SI PUMP PSI01A, PSI01B, AND PSI01C AND ROOM COOLERS
SW431		1E-3		LOSS OF SW HEADER B TO SI PUMPS PSI01A, PSI01B, PSI01C AND ROOM COOLERS
SW500		1E-2		LOSS OF SERVICE WATER FLOW TO CCW HX EAC01A
SW513		1E-2		LOSS OF SERVICE WATER FLOW TO CCW HX EAC01A THROUGH MOV 4735
SW531		1E-2		SERVICE WATER VALVE 4616 OR 4735 IN TEST OR MAINTENANCE
SW550		1E-2		LOSS OF SERVICE WATER FLOW TO CCW HX EAC01B
SW563		1E-2		LOSS OF SERVICE WATER FLOW THROUGH MOV 4734
SW580		1E-2		SERVICE WATER MOV 4734 OR 4615 AND CCW HX A OUT OF SERVICE
SW600		1E-3		Loss of SW to CNMT fan coolers ACA01A and ACA01B and TDAFW pump
SW650		1E-3		Loss of SW flow to fan coolers ACA01C and ACA01A and AFW pump
SWAVK04561	1	24		AIR-OP VALVE 4561 TRANSFERS CLOSED (CONTAINMENT)
SWAVK04562	1	24		AIR-OP VALVE 4562 TRANSFERS CLOSED (CONTAINMENT)
SWAVN04561	1	1		AIR-OPERATED VALVE 4561 FAILS TO OPEN
SWAVN04562	1	1		AIR-OPERATED VALVE 4562 FAILS TO OPEN
SWAVN9632A	1	1		AIR-OPERATED VALVE 9632A FAILS TO OPEN
SWAVN9632B	1	1		AIR-OPERATED VALVE 9632B FAILS TO OPEN
SWCCBFMOVC		3.662E-04		Common Cause Failure Of Service Water Butterfly Isolation Valves To Close
SWCCBFMOVN		3.105E-04		Common Cause Failure Of Service Water Butterfly Isolation Valves To Open
SWCCCHECKN		7.260E-06		Common Cause Failure Of Service Water Pump Discharge Check Valves To Open
SWCCEXPANJ		6.840E-08		Common Cause Failure Of Service Water Pump Discharge Expansion Joints
SWCCGTMOVC		3.662E-04		Common Cause Failure Of Service Water Gate Isolation Valves To Close
SWCCGTMOVN		3.105E-04		Common Cause Failure Of Service Water Gate Isolation Valves To Open
SWCCPPMPSV		1.348E-03		Common cause failure of solenoid valves 4324, 4325, and 4326 to open
SWCCPSWCVS		8.594E-06		Common cause failure of check valves 9627A and 9627B to open
SWCCPSWMVA		1.017E-03		Common cause failure of MOVs 4013, 4027, and 4028 to open
SWCCPSWMVB		1.017E-03		Common cause failure of MOVs 9629A and 9629B to open
SWCCPUMPSR		7.560E-07		Common Cause Failure Of Service Water Pumps To Run
SWCCPUMPSS		2.196E-05		Common Cause Failure Of Service Water Pumps To Start
SWCVC04601	1	1		Service Water Pump PSW01A Discharge Check Valve 4601 Fails To Close On Demand
SWCVC04602	1	1		Service Water Pump PSW01B Discharge Check Valve 4602 Fails To Close On Demand

Basic Event	C	Factor	Units	Description
SWCVC04603	1	1		Service Water Pump PSW01C Discharge Check Valve 4603 Fails To Close On Demand
SWCVC04604	1	1		Service Water Pump PSW01D Discharge Check Valve 4604 Fails To Close On Demand
SWCVK04601	1	24	H	Service Water Pump PSW01A Discharge Check Valve 4601 Transfers Closed
SWCVK04602	1	24	H	Service Water Pump PSW01B Discharge Check Valve 4602 Transfers Closed
SWCVK04603	1	24	H	Service Water Pump PSW01C Discharge Check Valve 4603 Transfers Closed
SWCVK04604	1	24	H	Service Water Pump PSW01D Discharge Check Valve 4604 Transfers Closed
SWCVK05333	1	24		CHECK VALVE 5333 TRANSFERS CLOSED
SWCVK05370	1	24		CHECK VALVE 5370 TRANSFERS CLOSED
SWCVK9633A	1	24		STOP CHECK VALVE 9633A TRANSFERS CLOSED
SWCVK9633B	1	24		STOP CHECK VALVE 9633B TRANSFERS CLOSED
SWCVN04601	1	1		Service Water Pump PSW01A Discharge Check Valve 4601 Fails To Open On Demand
SWCVN04602	1	1		Service Water Pump PSW01B Discharge Check Valve 4602 Fails To Open On Demand
SWCVN04603	1	1		Service Water Pump PSW01C Discharge Check Valve 4603 Fails To Open On Demand
SWCVN04604	1	1		Service Water Pump PSW01D Discharge Check Valve 4604 Fails To Open On Demand
SWCVNCCF$$		6.00E-02		Beta Factor For Common Cause Failure Event SWCCFCHKVO
SWCVP9627A	1	384	H	Standby AFW Pump PSF01A Inlet Check Valve 9627A Fails To Open On Demand
SWCVP9627B	1	384	H	Standby AFW Pump PSF01B Inlet Check Valve 9627B Fails To Open On Demand
SWCVPCCF$$		6.00E-02		Beta factor for SW check valves fail to open
SWEJFCCF$$		.1		Beta Factor For Common Cause Event SWCCFEXPJR
SWEJFSSW02	1	24	H	Service Water Pump PSW01A Discharge Expansion Joint SSW02 Fails
SWEJFSSW03	1	24	H	Service Water Pump PSW01B Discharge Expansion Joint SSW03 Fails
SWEJFSSW04	1	24	H	Service Water Pump PSW01C Discharge Expansion Joint SSW04 Fails
SWEJFSSW05	1	24	H	Service Water Pump PSW01D Discharge Expansion Joint SSW05 Fails
SWFDFNFW02	1	1116	H	Service Water Filter NFW02 plugged
SWFDFNFW03	1	1116	H	Service Water Filter NFW03 plugged
SWFDFNFW04	1	1116	H	Service Water Filter NFW04 plugged
SWHFDCIA2A		1.00E-01		Operators Fail To Restore SW Flow To IA Comp A&C Following SW Header Isolation
SWHFDCIA2B		1.00E-01		Operators Fail To Restore SW Flow To SA Comp and IA Comp B Following SW Isol
SWHFDSW01A		1.00E-01		Operators Fail To Start PSW01A After No Auto Start Or Failure Of Other Pump
SWHFDSW01B		1.00E-01		Operators Fail To Start PSW01B After No Auto Start Or Failure Of Other Pump
SWHFDSW01C		1.00E-01		Operators Fail To Start PSW01C After No Auto Start Of Failure Of Other Pump
SWHFDSW01D		1.00E-01		Operators Fail To Start PSW01D After No Auto Start Or Failure Of Other Pump
SWHXFAFA1A	1	24		HEAT EXCHANGER AFA1A COOLING CAP. FAILS
SWHXFAFA1B	1	24		HEAT EXCHANGER AFA1B COOLING CAP. FAILS
SWMMDGXCON		2.952E-06		Manual SW Valve On The EDG A-B Cross Connect Header Transfers Closed
SWMMSWXTIE		2.952E-06		Failure of Service Water Header A to Service Water Header B Crosstie
SWMPACCF$$		3.00E-02		Beta Factor For Common Cause Failure Event SWCCFPMPSS
SWMPASW01A	1	1		Service Water Pump PSW01A Fails To Start On Demand
SWMPASW01B	1	1		Service Water Pump PSW01B Fails To Start On Demand
SWMPASW01C	1	1		Service Water Pump PSW01C Fails To Start On Demand
SWMPASW01D	1	1		Service Water Pump PSW01D Fails To Start On Demand
SWMPFCCF$$		3.00E-02		Beta Factor For Common Cause Failure Event SWCCFPMPSR

Table [illegible]-2
Integrated C[illegible] BE File

Basic Event	C	Factor	Units	Description
SWMPFSW01A	1	24	H	Service Water Pump PSW01A Fails To Run For The Required Mission Time
SWMPFSW01B	1	24	H	Service Water Pump PSW01B Fails To Run For The Required Mission Time
SWMPFSW01C	1	24	H	Service Water Pump PSW01C Fails To Run For The Required Mission Time
SWMPFSW01D	1	24	H	Service Water Pump PSW01D Fails To Run For The Required Mission Time
SWMVC04609	1	1		Service Water Header Isolation MOV 4609 Fails To Close On Demand
SWMVC04613	1	1		Service Water Header Isolation MOV 4613 Fails To Close On Demand
SWMVC04614	1	1		Service Water Header Isolation MOV 4614 Fails To Close On Demand
SWMVC04615	1	1		Service Water Header Isolation MOV 4615 Fails To Close On Demand
SWMVC04616	1	1		Service Water Header Isolation MOV 4616 Fails To Close On Demand
SWMVC04663	1	1		Service Water Header Isolation MOV 4663 Fails To Close On Demand
SWMVC04664	1	1		Service Water Header Isolation MOV 4664 Fails To Close On Demand
SWMVC04670	1	1		Service Water Header Isolation MOV 4670 Fails To Close On Demand
SWMVC04733	1	1		Service Water Header Isolation MOV 4733 Fails To Close On Demand
SWMVC04734	1	1		Service Water Header Isolation MOV 4734 Fails To Close On Demand
SWMVC04735	1	1		Service Water Header Isolation MOV 4735 Fails To Close On Demand
SWMVC04780	1	1		Service Water Header Isolation MOV 4780 Fails To Close On Demand
SWMVCCCF$$		6.26E-02		Beta Factor For Common Cause Failure Events SWCCBFMOVC And SWCCGTMOVC
SWMVK04613	1	24	H	Service Water Header Isolation MOV 4613 Transfers Closed
SWMVK04614	1	24	H	Service Water Header Isolation MOV 4614 Transfers Closed
SWMVK04615	1	24	H	Service Water Header Isolation MOV 4615 Transfers Closed
SWMVK04616	1	24	H	Service Water Header Isolation MOV 4616 Transfers Closed
SWMVK04664	1	24	H	Service Water Header Isolation MOV 4664 Transfers Closed
SWMVK04670	1	24	H	Service Water Header Isolation MOV 4670 Transfers Closed
SWMVK04734	1	24	H	Service Water Header Isolation MOV 4734 Transfers Closed
SWMVK04735	1	24	H	Service Water Header Isolation MOV 4735 Transfers Closed
SWMVN04613	1	1		Service Water Header Isolation MOV 4613 Fails To Open On Demand
SWMVN04614	1	1		Service Water Header Isolation MOV 4614 Fails To Open On Demand
SWMVN04615	1	1		Service Water Header Isolation MOV 4615 Fails To Open On Demand
SWMVN04616	1	1		Service Water Header Isolation MOV 4616 Fails To Open On Demand
SWMVN04664	1	1		Service Water Header Isolation MOV 4664 Fails To Open On Demand
SWMVN04670	1	1		Service Water Header Isolation MOV 4670 Fails To Open On Demand
SWMVN04734	1	1		Service Water Header Isolation MOV 4634 Fails To Open On Demand
SWMVN04735	1	1		Service Water Header Isolation MOV 4635 Fails To Open On Demand
SWMVNCCF$$		7.09E-02		Beta Factor For Common Cause Failure Events SWCCFBMOVN & SWCCFGMOVN
SWMVP04013	1	384	H	Motor operated valve 4013 fails to open
SWMVP04027	1	384	H	Motor operated valve 4027 fails to open
SWMVP04028	1	384	H	Motor operated valve 4028 fails to open
SWMVP9629A	1	384	H	Motor operated valve 9629A fails to open
SWMVP9629B	1	384	H	Motor operated valve 9629B fails to open
SWMVPCCF$$		6.95E-02		Beta factor for SW MOVs fail to open
SWPPJHEADA	1	24	H	SERVICE WATER HEADER "A" PIPING RUPTURE
SWPPJHEADB	1	24	H	SERVICE WATER HEADER "B" PIPING RUPTURE

Basic Event	C	Factor	Units	Description
SWPPJSYSTM	1	24	H	Pipe Break In SW Cross-Ties Fails Entire System
SWPSR02084	1	1116	H	Differential pressure switch DPS-2084 fails to respond
SWPSR02085	1	1116	H	Differential pressure switch DPS-2085 fails to respond
SWPSR02094	1	1116	H	Differential pressure switch DPS-2094 fails to respond
SWSVK05261	1	24		SOLENOID VALVE 5261 TRANSFERS CLOSED
SWSVK05262	1	24		SOLENOID VALVE 5262 TRANSFERS CLOSED
SWSVK05272	1	24		SOLENOID VALVE 5272 TRANSFERS CLOSED
SWSVK08242	1	24		SOLENOID VALVE 8242 TRANSFERS CLOSED
SWSVK4761E	1	24		SOLENOID VALVE 4761E TRANSFERS CLOSED
SWSVK4761K	1	24		SOLENOID VALVE 4761K TRANSFERS CLOSED
SWSVP04324	1	1116	H	Solenoid valve 4324 fails to open
SWSVP04325	1	1116	H	Solenoid valve 4325 fails to open
SWSVP04326	1	1116	H	Solenoid valve 4326 fails to open
SWSVPCCF$$		7.50E-02		Beta factor for Service Water SOV fails to open
SWTM1AMAIN		2.70E-02		Service Water Pump PSW01A Is Unavailable Due To Maintenance
SWTM1ATEST		0.00		Service Water Pump PSW01A Is Unavailable Due To Testing
SWTM1BMAIN		2.70E-02		Service Water Pump PSW01B Is Unavailable Due To Maintenance
SWTM1BTEST		0.00		Service Water Pump PSW01B Is Unavailable Due To Testing
SWTM1CMAIN		2.70E-02		Service Water Pump PSW01C Is Unavailable Due To Maintenance
SWTM1CTEST		0.00		Service Water Pump PSW01C Is Unavailable Due To Testing
SWTM1DMAIN		2.70E-02		Service Water Pump PSW01D Is Unavailable Due To Maintenance
SWTM1DTEST		0.00		Service Water Pump PSW01D Is Unavailable Due To Testing
SWTM4613MT		4.97E-04		SW Header Isolation MOV 4613 Is Unavailable Due To Maintenance
SWTM4613TS		0.00		SW Header Isolation MOV 4613 Is Unavailable Due To Testing
SWTM4614MT		4.97E-04		SW Header Isolation MOV 4614 Is Unavailable Due To Maintenance
SWTM4614TS		0.00		SW Header Isolation MOV 4614 Is Unavailable Due To Testing
SWTM4615MT		4.97E-04		SW Header Isolation MOV 4615 Is Unavailable Due To Maintenance
SWTM4615TS		0.00		SW Header Isolation MOV 4615 Is Unavailable Due To Testing
SWTM4616MT		4.97E-04		SW Header Isolation MOV 4615 Is Unavailable Due To Maintenance
SWTM4616TS		0.00		SW Header Isolation MOV 4615 Is Unavailable Due To Testing
SWTM4664MT		4.97E-04		SW Header Isolation MOV 4664 Is Unavailable Due To Maintenance
SWTM4664TS		0.00		SW Header Isolation MOV 4664 Is Unavailable Due To Testing
SWTM4670MT		4.97E-04		SW Header Isolation MOV 4670 Is Unavailable Due To Maintenance
SWTM4670TS		0.00		SW Header Isolation MOV 4670 Is Unavailable Due To Testing
SWTM4734MT		4.97E-04		SW Header Isolation MOV 4734 Is Unavailable Due To Maintenance
SWTM4734TS		0.00		SW Header Isolation MOV 4734 Is Unavailable Due To Testing
SWTM4735MT		4.97E-04		SW Header Isolation MOV 4735 Is Unavailable Due To Maintenance
SWTM4735TS		0.00		SW Header Isolation MOV 4735 Is Unavailable Due To Testing
SWTM9627AM		8.65E-06		SAFW Pump PSF01A Inlet Check Valve 9627A Is Unavailable Due To Maintenance
SWTM9627BM		8.65E-06		SAFW Pump PSF01B Inlet Check Valve 9627B Is Unavailable Due To Maintenance
SWXVK04029	1	1116	H	Manual valve 4029 transfers closed
SWXVK04030	1	1116	H	Manual valve 4030 transfers closed

Basic Event	C	Factor	Units	Description
SWXVK04031	1	1116	H	Manual valve 4031 transfers closed
SWXVK04032	1	1116	H	Manual valve 4032 transfers closed
SWXVK04085	1	1116	H	Manual valve 4085 transfers closed
SWXVK04087	1	1116	H	Manual valve 4087 transfers closed
SWXVK04088	1	1116	H	Manual valve 4088 transfers closed
SWXVK04089	1	1116	H	Manual valve 4089 transfers closed
SWXVK04090	1	1116	H	Manual valve 4090 transfers closed
SWXVK04091	1	1116	H	Manual valve 4091 transfers closed
SWXVK04092	1	1116	H	Manual valve 4092 transfers closed
SWXVK04093	1	1116	H	Manual valve 4093 transfers closed
SWXVK04094	1	1116	H	Manual valve 4094 transfers closed
SWXVK04095	1	1116	H	Manual valve 4095 transfers closed
SWXVK04605	1	24	H	Service Water Pump PSW01A Discharge Manual Valve 4605 Transfers Closed
SWXVK04606	1	24	H	Service Water Pump PSW01B Discharge Manual Valve 4606 Transfers Closed
SWXVK04607	1	24	H	Service Water Pump PSW01C Discharge Manual Valve 4607 Transfers Closed
SWXVK04608	1	24	H	Service Water Pump PSW01D Discharge Manual Valve 4608 Transfers Closed
SWXVK04617	1	24		MANUAL VALVE 4617 TRANSFERS CLOSED
SWXVK04618	1	24		MANUAL VALVE 4618 TRANSFERS CLOSED
SWXVK04619	1	24		MANUAL VALVE 4619 TRANSFERS CLOSED
SWXVK04620	1	24		MANUAL VALVE 4620 TRANSFERS CLOSED
SWXVK04623	1	24	H	Manual Service Water Valve 4623 Transfers Closed
SWXVK04627	1	24		MANUAL VALVE 4627 TRANSFER CLOSED (CONTAINMENT)
SWXVK04628	1	24		MANUAL VALVE 4628 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04629	1	24		MANUAL VALVE 4629 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04630	1	24		MANUAL VALVE 4630 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04639	1	24	H	Manual Valve 4639 Between The Service Water A & B Headers Transfers Closed
SWXVK04640	1	24	H	Manual Valve 4640 From SW Supply Header B Transfers Closed
SWXVK04641	1	24		MANUAL VALVE 4641 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04642	1	24		MANUAL VALVE 4642 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04643	1	24		MANUAL VALVE 4643 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04644	1	24		MANUAL VALVE 4644 TRANSFERS CLOSED (CONTAINMENT)
SWXVK04665	1	24	H	Manual Valve 4665 From SW Supply Header A Transfers Closed
SWXVK04667	1	24	H	Manual Valve 4667 To Diesel Generator KDG01A Transfers Closed
SWXVK04669	1	24	H	Manual Valve 4669 Between The Service Water A & B Headers Transfers Closed
SWXVK04738	1	24	H	Manual Valve 4738 From Service Water Supply Header B Transfers Closed
SWXVK04739	1	24	H	Manual Valve 4739 From Service Water Supply Header A Transfers Closed
SWXVK04750	1	24		MANUAL VALVE 4750 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04751	1	24		MANUAL VALVE 4751 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04752	1	24		MANUAL VALVE 4752 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04753	1	24		MANUAL VALVE 4753 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04756	1	24	H	Manual Valve 4756 Between The Service Water A & B Headers Transfers Closed
SWXVK04760	1	24	H	Manual Valve 4760 Between Service Water Headers A & B Transfers Closed

Basic Event	C	Factor	Units	Description
SWXVK04767	1	24		MANUAL VALVE 4767 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04768	1	24		MANUAL VALVE 4768 TRANSFERS CLOSED (CHARGING PUMP RM)
SWXVK04785	1	24		MANUAL VALVE 4785 TRANSFERS CLOSED
SWXVK04786	1	24		MANUAL VALVE 4786 TRANSFERS CLOSED
SWXVK04787	1	24		MANUAL VALVE 4787 TRANSFERS CLOSED
SWXVK04789	1	1104	H	Manual Valve 4789 Transfers Closed
SWXVK04790	1	1104	H	Manual Valve 4790 Transfers Closed
SWXVK04791	1	1104	H	Manual valve 4791 transfers closed
SWXVK04794	1	1104	H	Manual valve 4794 transfers closed
SWXVK04795	1	1104	H	Manual valve 4795 transfers closed
SWXVK05261	1	24		MANUAL VALVE 5261 TRANSFERS CLOSED
SWXVK05300	1	24		MANUAL VALVE 5300 TRANSFERS CLOSED
SWXVK05325	1	24		MANUAL VALVE 5325 TRANSFERS CLOSED
SWXVK05326	1	24		MANUAL VALVE 5326 TRANSFERS CLOSED
SWXVK05331	1	24		MANUAL VALVE 5331 TRANSFERS CLOSED
SWXVK05334	1	24		MANUAL VALVE 5334 TRANSFERS CLOSED
SWXVK05337	1	24		MANUAL VALVE 5337 TRANSFERS CLOSED
SWXVK05338	1	24		MANUAL VALVE 5338 TRANSFERS CLOSED
SWXVK05366	1	24		MANUAL VALVE 5366 TRANSFERS CLOSED
SWXVK05369	1	24		MANUAL VALVE 5369 TRANSFERS CLOSED
SWXVK05373	1	24		MANUAL VALVE 5373 TRANSFERS CLOSED
SWXVK05379	1	24		MANUAL VALVE 5379 TRANSFERS CLOSED
SWXVK08311	1	24		MANUAL VALVE 8311 TRANSFERS CLOSED
SWXVK08314	1	24		MANUAL VALVE 8314 TRANSFERS CLOSED
SWXVK4087B	1	1116	H	Manual valve 4087B transfers closed
SWXVK4087C	1	1116	H	Manual valve 4087C transfers closed
SWXVK4088B	1	1116	H	Manual valve 4088B transfers closed
SWXVK4668A	1	24	H	Manual Valve 4668A Transfers Closed
SWXVK4668B	1	24	H	Manual Valve 4668B From SW Supply Header B Transfers Closed
SWXVK4739A	1	1104	H	Manual valve 4739A transfers closed
SWXVK4761A	1	24		MANUAL VALVE 4761A TRANSFERS CLOSED
SWXVK4761B	1	24		MANUAL VALVE 4761B TRANSFERS CLOSED
SWXVK4761C	1	24		MANUAL VALVE 4761C TRANSFERS CLOSED
SWXVK4761D	1	24		MANUAL VALVE 4761D TRANSFERS CLOSED
SWXVK4761H	1	24		MANUAL VALVE 4761H TRANSFERS CLOSED
SWXVK4761J	1	24		MANUAL VALVE 4761J TRANSFERS CLOSED
SWXVK4761L	1	24		MANUAL VALVE 4761L TRANSFERS CLOSED
SWXVK4761N	1	24		MANUAL VALVE 4761N TRANSFERS CLOSED
SWXVK4761P	1	24		MANUAL VALVE 4761P TRANSFERS CLOSED
SWXVK4761Q	1	24		MANUAL VALVE 4761Q TRANSFERS CLOSED
SWXVK4761V	1	24		MANUAL VALVE 4761V TRANSFERS CLOSED
SWXVK4787B	1	24		MANUAL VALVE 4787B TRANSFERS CLOSED

Basic Event	C	Factor	Units	Description
SWXVK4791A	1	1104	H	Manual valve 4791A transfers closed
SWXVK4794A	1	1104	H	Manual valve 4794A transfers closed
SWXVK4795A	1	1104	H	Manual valve 4795A transfers closed
SWXVK9626A	1	24	H	Manual Valve 9626A In SAFW Pump PFW03A Suction Transfers Closed
SWXVK9626B	1	24	H	Manual Valve 9626B In SAFW Pump PFW03B Suction Transfers Closed
SWXVK9631A	1	24		MANUAL VALVE 9631A TRANSFERS CLOSED
SWXVK9631B	1	24		MANUAL VALVE 9631B TRANSFERS CLOSED
SWXVK9634A	1	24		MANUAL VALVE 9634A TRANSFERS CLOSED
SWXVP04098	1	384	H	Manual valve 4098 fails to open
SWXVP04344	1	384	H	Manual valve 4344 fails to open
SWXVP04345	1	384	H	Manual valve 4345 fails to open
TI000CCW		2.20E-03	Y	Loss of Component Cooling Water
TI000DCA		1.71E-04	Y	Loss of Main DC Distribution Panel A (DCPDPCB03A)
TI000DCB		1.71E-04	Y	Loss of Main DC Distribution Panel B (DCPDPCB03B)
TI000SWA		1.78E-03	Y	Loss of Service Water Header B
TI000SWB		1.78E-03	Y	Loss of Service Water Header B
TI0SLBSD		6.02E-03	Y	Steamline Break Through Steam Dump
TIFLB0TB		2.70E-03	Y	Feedline Break in Turbine Building
TIFLBACT		5.00E-05	Y	Feedline Break in Line for S/G A Inside Containment
TIFLBAIB		5.00E-05	Y	Feedline Break in Line for S/G A Inside Intermediate Building
TIFLBBCT		5.00E-05	Y	Feedline Break in Line for S/G B Inside Containment
TIFLBBIB		1.50E-04	Y	Feedline Break in Line for S/G B Inside Intermediate Building
TIFWEXCS		1.98E-02	Y	Excessive Feedwater
TIFWLOSS		1.24E-02	Y	Loss of Main Feedwater
TIGRLOSP		2.43E-03	Y	Loss of Offsite Power - Grid
TIIALOSS		9.20E-02	Y	Loss of Instrument Air
TIRXTRIP		2.35	Y	Reactor Trip
TISLB0TB		4.50E-04	Y	Steamline Break in Turbine Building
TISLBACT		8.33E-06	Y	Steamline Break in Line for S/G A Inside Containment
TISLBAIB		8.33E-06	Y	Steamline Break in Line for S/G A Inside Intermediate Building
TISLBBCT		8.33E-06	Y	Steamline Break in Line for S/G B Inside Containment
TISLBBIB		2.50E-05	Y	Steamline Break in Line for S/G B Inside Intermediate Building
TISLBSVA		7.55E-04	Y	Inadvertent Safety Valve Operation for S/G A
TISLBSVB		7.55E-04	Y	Inadvertent Safety Valve Operation for S/G B
TISWLOSP		1.07E-03	Y	Loss of Offsite Power - Switchyard
TL000UET1C		0.3079		UET for MRI Succeeds, AFW 100%, and 1 PORV Required
TL000UET1D		0.6921		UET for MRI Succeeds, AFW 100%, No PORVs Required
TL000UET2B		0.1240		UET for MRI Succeeds, AFW 50%, and 2 PORVs Required
TL000UET2C		0.1997		UET for MRI Succeeds, AFW 50%, and 1 PORV Required
TL000UET2D		0.6763		UET for MRI Succeeds, AFW 50%, and No PORVs Required
TL000UET3A		0.3210		UET for MRI Fails, AFW 100%, and Relief Capacity Required > Installed
TL000UET3B		0.1143		UET for MRI Fails, AFW 100%, and 2 PORVs Required

Basic Event	C Factor	Units	Description
TL000UET3C	0.0829		UET for MRI Fails, AFW 100%, and 1 PORV Required
TL000UET3D	0.4818		UET for MRI Fails, AFW 100%, and No PORVs Required
TL000UET4A	0.3814		UET for MRI Fails, AFW 50%, and Relief Capacity Required > Installed
TL000UET4B	0.0785		UET for MRI Fails, AFW 50%, and 2 PORVs Required
TL000UET4C	0.0853		UET for MRI Fails, AFW 50%, and 1 PORV Required
TL000UET4D	0.4566		UET for MRI Fails, AFW 50%, and No PORVs Required
TLCCFEATWS	1.44E-5		Electrical Scram Failure Probability (WOG Data)
TLCCFMATWS	1.80E-6		Mechanical Scram Failure Probability (WOG Data)
TLRXPWGT40	0.69		Probability That Reactor Power > 40% At Reactor Trip
TL_AM_FTO			Top Logic Event - AM (Failure Of AMSAC To Actuate)
TL_B1_AFW			Top Logic Event - B1 (Failure to Achieve Steam Generator Cooling)
TL_D_CDDPR			Top Logic Event - D (Failure To Cooldown and Depressurize Given SI Operation)
TL_FC			Top Logic Event - FC (Failure of Containment Fan Coolers)
TL_FF_FULL			Top Logic Event - FF (Failure To Achieve Full AFW Flow)
TL_I1_STM			Top Logic Event - I1 (Failure to Isolate Ruptured Steam Generator Steam Header)
TL_I2_AFW			Top Logic Event - I2 (Failure to Isolate Ruptured Steam Generator AFW Supply)
TL_I3L_ARV			Top Logic Event - I3L (Failure to Isolate Ruptured Steam Generator ARV - Steam)
TL_I3S_ARV			Top Logic Event - I3S (Failure to Isolate Ruptured Steam Generator ARV - Liq)
TL_KE_ATWS			Top Logic Event - KE (Subcriticality Fails - Electrical)
TL_KM_ATWS			Top Logic Event - KM (Subcriticality Fails - Mechanical)
TL_L1_FWRC			Top Logic Event - L1 (Failure To Restore Steam Generator Cooling)
TL_LT_EBOR			Top Logic Event - LT (Failure Of Long-Term Shutdown)
TL_MF			Top Logic Event - MF (Main Feedwater Fails During an ATWS)
TL_P1_TR			Top Logic Event - P1 (Failure to Open PORVs During BAF)
TL_P2_SL			Top Logic Event - P2 (Failure to Open PORVs During BAF - SLOCA)
TL_P3SS			Top Logic Event - P3SS (Failure to Cooldown to RHR After SI Fails - SSLOCAs)
TL_P3TR1			Top Logic Event - P3TR1 (Failure to Cooldown to RHR After ARV Fails Open-SGTR)
TL_P3TR2			Top Logic Event - P3TR2 (Failure to Cooldown to RHR After SI Fails - SGTR)
TL_PF_AFW			Top Logic Event - PF (Failure Of 50% AFW Flow)
TL_PL			Top Logic Event - PL (Reactor Power Greater Than 40%)
TL_PR_001			Top Logic Event - PR1 (Pressure Relief Fails Given MRI Succeeds and AFW 100%)
TL_PR_002			Top Logic Event - PR2 (Pressure Relief Fails Given MRI Succeeds and AFW 50%)
TL_PR_003			Top Logic Event - PR3 (Pressure Relief Fails Given MRI Fails and AFW 100%)
TL_PR_004			Top Logic Event - PR4 (Pressure Relief Fails Given MRI Fails and AFW 50%)
TL_Q1_SEAL			Top Logic Event - Q1 (Reactor Coolant Pump Seal LOCA)
TL_Q2_PORV			Top Logic Event - Q2 (Pressurizer Relief Valve LOCA)
TL_RI_SERT			Top Logic Event - RI (Failure To Manually Insert Rods [MRI])
TL_SC_RHR			Top Logic Event - SC (RHR Cooling Fails Following SGTR)
TL_UA_ACCU			Top Logic Event - UA (Failure of Accumulators)
TL_UCS			Top Logic Event - UCS (Failure of CS in Injection Mode)
TL_UH1_BAF			Top Logic Event - UH1 (Failure Of Bleed And Feed Cooling)
TL_UH2_HSI			Top Logic Event - UH2 (Failure of High Pressure SI)

Table [illegible]7-2
Integrated C[illegible] BE File

Basic Event	C Factor	Units	Description
TL_UL_LPI			Top Logic Event - UL (Failure Of Low Pressure Injection)
TL_XCS			Top Logic Event - XCS (Failure of CS in Recirculation Mode)
TL_XH_HPR			Top Logic Event - XH (Failure of HPR)
TL_XL_LPR			Top Logic Event - XL (Failure of RHR In Recirculation Mode)
TRANS1			System Level Transient Events
TRANS1X	1E-3		Transients Which Don't Cause High Pressure or High Rad. in Containment
UV401	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X1/14 NOT ENERGIZED
UV422	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X2/14 NOT ENERGIZED
UV423	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X3/14 NOT ENERGIZED
UV424	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X4/14 NOT ENERGIZED
UV425	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X5/14 NOT ENERGIZED
UV426	1.00E-03		Undervoltage Auxiliary Relay 27X6/14 Not Energized
UV451	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX1/14 NOT ENERGIZED
UV472	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX2/14 NOT ENERGIZED
UV473	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX3/14 NOT ENERIGIZED
UV474	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX4/14 NOT ENERGIZED
UV475	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX5/14 NOT ENERGIZED
UV476	1.00E-03		Undervoltage Auxiliary Relay 27BX6/14 Not Energized
UV601	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X1/16 NOT ENERGIZED
UV622	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X2/16 NOT ENERGIZED
UV623	1.00E-03		UNDERVOLTAGE AUXILAIRY RELAY 27X3/16 NOT ENERGIZED
UV624	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X4/16 NOT ENERGIZED
UV625	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X5/16 NOT ENERGIZED
UV626	1.00E-03		Undervoltage Auxiliary Relay 27X6/16 Not Energized
UV651	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX1/16 NOT ENERIGIZED
UV672	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX2/16 NOT ENERGIZED
UV673	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX3/16 NOT ENERGIZED
UV674	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX4/16 NOT ENERGIZED
UV675	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX5/16 NOT ENERGIZED
UV676	1.00E-03		Undervoltage Auxiliary Relay 27BX6/16 Not Energized
UV701	1.00E-03		UNDERVOLTAGE AUXILAIRY RELAY 27X1/17 NOT ENERGIZED
UV722	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X2/17 NOT ENERGIZED
UV723	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X3/17 NOT ENERGIZED
UV725	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X5/17 NOT ENERGIZED
UV751	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX1/17 NOT ENERGIZED
UV772	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX2/17 NOT ENERGIZED
UV773	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX3/17 NOT ENERGIZED
UV775	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX5/17 NOT ENERGIZED
UV801	1.00E-03		UNDERVOLTAGE AUXILAIRY RELAY 27X1/18 NOT ENERGIZED
UV822	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X2/18 NOT ENERGIZED
UV823	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X3/18 NOT ENERGIZED
UV825	1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27X5/18 NOT ENERGIZED

Basic Event	C	Factor	Units	Description
UV851		1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX1/18 NOT ENERGIZED
UV872		1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX2/18 NOT ENERGIZED
UV873		1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX3/18 NOT ENERGIZED
UV875		1.00E-03		UNDERVOLTAGE AUXILIARY RELAY 27BX5/18 NOT ENERGIZED
UV900		1.00E-03		AFW PP STARTING RELAY MFPX-1A2/1B2 FAIL TO RECEIVE SIGNAL FOLLOWINH UV 11A/11B
UVCBRL667B	1	4	H	Breaker IBPDPCBAR/20 in circuit L667 transfers open
UVCBRL668B	1	4	H	Breaker IBPDPCBCB/16 in circuit L668 transfers open
UVCBRL673B	1	4	H	Breaker IBPDPCBAR/23 in circuit L673 transfers open
UVCBRL674B	1	4	H	Breaker IBPDPCBCB/13 in circuit L674 transfers open
UVCFR14FU1	1	4	H	AC fuse #1 in Bus 14 UV relay cabinet fails open
UVCFR14FU2	1	4	H	Fuse #2 (FUARA1RC14/2-P) fails open (relay cabinet)
UVCFR14FU3	1	4	H	Fuse #3 (FUARA1RC14/3-N) fails open (relay cabinet)
UVCFR14FU4	1	4	H	AC fuse #4 in Bus 14 UV control cabinet fails open
UVCFR14FU5	1	4	H	Fuse #5 (FUARA1CC14/5-P) fails open (control cabinet)
UVCFR14FU6	1	4	H	Fuse #6 (FUARA1CC14/6-N) fails open (control cabinet)
UVCFR16FU1	1	4	H	AC fuse #1 in Bus 16 UV relay cabinet fails open
UVCFR16FU2	1	4	H	Fuse #2 (FUARB1RC16/2-P) fails open (relay cabinet)
UVCFR16FU3	1	4	H	Fuse #3 (FUARB1RC16/3-N) fails open (relay cabinet)
UVCFR16FU4	1	4	H	AC fuse #4 in Bus 16 UV control cabinet fails open
UVCFR16FU5	1	4	H	Fuse #5 (FUARB1CC16/5-P) fails open (control cabinet)
UVCFR16FU6	1	4	H	Fuse #6 (FUARB1CC16/6-N) fails open (control cabinet)
UVCFR17FU1	1	4	H	AC fuse #1 in Bus 17 UV relay cabinet fails open
UVCFR17FU2	1	4	H	Fuse #2 (FUARB2RC17/2-P) fails open (relay cabinet)
UVCFR17FU3	1	4	H	Fuse #3 (FUARB2RC17/3-N) fails open (relay cabinet)
UVCFR17FU4	1	4	H	AC fuse #4 in Bus 17 UV control cabinet fails open
UVCFR17FU5	1	4	H	Fuse #5 (FUARB2CC17/5-P) fails open (control cabinet)
UVCFR17FU6	1	4	H	Fuse #6 (FUARB2CC17/6-N) fails open (control cabinet)
UVCFR18FU1	1	4	H	AC fuse #1 in Bus 18 UV relay cabinet fails open
UVCFR18FU2	1	4	H	Fuse #2 (FUARA2RC18/2-P) fails open (relay cabinet)
UVCFR18FU3	1	4	H	Fuse #3 (FUARA2RC18/3-N) fails open (relay cabinet)
UVCFR18FU4	1	4	H	AC fuse #4 in Bus 18 UV control cabinet fails open
UVCFR18FU5	1	4	H	Fuse #5 (FUARA2CC18/5-P) fails open (control cabinet)
UVCFR18FU6	1	4	H	Fuse #6 (FUARA2CC18/6-N) fails open (control cabinet)
UVCFR4FU11	1	4	H	Fuse #11 (FUARB1CC16/11-P) fails open
UVCFR4FU12	1	4	H	Fuse #12 (FUARB1CC16/12-N) fails open
UVCFR6FU11	1	4	H	Fuse #11 (FUARA1CC14/11-P) fails open
UVCFR6FU12	1	4	H	Fuse #12 (FUARA1CC14/12-N) fails open
UVCFR7FU11	1	4	H	Fuse #11 (FUARA2CC18/11-P) fails open
UVCFR7FU12	1	4	H	Fuse #12 (FUARA2CC18/12-N) fails open
UVCFR8FU11	1	4	H	Fuse #11 (FUARB2CC17/11-P) fails open
UVCFR8FU12	1	4	H	Fuse #12 (FUARB2CC17/12-N) fails open
UVCFRA111P	1	4	H	DC FUSE FUBUS11A/11UV1P FAILS

Basic Event	C	Factor	Units	Description
UVCFRA112N	1	4	H	DC FUSE FUBUS11A/11UV2N FAILS
UVCFRB211P	1	4	H	DC FUSE FUBUS11B/21UV1P FAILS
UVCFRB212N	1	4	H	DC FUSE FUBUS11B/21UV2N FAILS
UVLCD0X114	2	720	H	Relay 27X1/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X116	2	720	H	Relay 27X1/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X117	2	720	H	Relay 27X1/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X118	2	720	H	Relay 27X1/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X214	2	720	H	Relay 27X2/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X216	2	720	H	Relay 27X2/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X217	2	720	H	Relay 27X2/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X218	2	720	H	Relay 27X2/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X314	2	720	H	Relay 27X3/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X316	2	720	H	Relay 27X3/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X317	2	720	H	Relay 27X3/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X318	2	720	H	Relay 27X3/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X414	2	720	H	Relay 27X4/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X416	2	720	H	Relay 27X4/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X417	2	720	H	Relay 27X4/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X418	2	720	H	Relay 27X4/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X514	2	720	H	Relay 27X5/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X516	2	720	H	Relay 27X5/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X517	2	720	H	Relay 27X5/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X518	2	720	H	Relay 27X5/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X614	2	720	H	Relay 27X6/14 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X616	2	720	H	Relay 27X6/16 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X617	2	720	H	Relay 27X6/17 driver (Heat Sink Assembly #1) fails to energize
UVLCD0X618	2	720	H	Relay 27X6/18 driver (Heat Sink Assembly #1) fails to energize
UVLCD14LB1	2	720	H	27/27D NOR logic circuit fault Bus 14 control logic board #1
UVLCD14LB2	2	720	H	27B/27DB NOR logic circuit fault Bus 14 control logic board #2
UVLCD14S#1	2	720	H	Bus 14 solid state switch #1 fails to transfer
UVLCD14S#2	2	720	H	Bus 14 solid state switch #2 fails to transfer
UVLCD16LB1	2	720	H	27/27D NOR logic circuit fault Bus 16 control logic board #1
UVLCD16LB2	2	720	H	27B/27DB NOR logic circuit fault Bus 16 control logic board #2
UVLCD16S#1	2	720	H	Bus 16 solid state switch #1 fails to transfer
UVLCD16S#2	2	720	H	Bus 16 solid state switch #2 fails to transfer
UVLCD17LB1	2	720	H	27/27D NOR logic circuit fault Bus 17 control logic board #1
UVLCD17LB2	2	720	H	27/27D NOR logic circuit fault Bus 17 control logic board #2
UVLCD17S#1	2	720	H	Bus 17 solid state switch #1 fails to transfer
UVLCD17S#2	2	720	H	Bus 17 solid state switch #2 fails to transfer
UVLCD18LB1	2	720	H	27/27D NOR logic circuit fault Bus 18 control logic board #1
UVLCD18LB2	2	720	H	27B/27DB NOR logic circuit fault Bus 18 control logic board #2
UVLCD18S#1	2	720	H	Bus 18 solid state switch #1 fails to transfer

Basic Event	C	Factor	Units	Description
UVLCD18S#2	2	720	H	Bus 18 solid state switch #2 fails to transfer
UVLCD27014	2	720	H	Opto-isolator for undervoltage relay 27/14 circuit fault
UVLCD27016	2	720	H	Opto-isolator for undervoltage relay 27/16 circuit fault
UVLCD27017	2	720	H	Opto-isolator for undervoltage relay 27/17 circuit fault
UVLCD27018	2	720	H	Opto-isolator for undervoltage relay 27/18 circuit fault
UVLCD27B14	2	720	H	Opto-isolator for undervoltage relay 27B/14 circuit fault
UVLCD27B16	2	720	H	Opto-isolator for undervoltage relay 27B/16 circuit fault
UVLCD27B17	2	720	H	Opto-isolator for undervoltage relay 27B/17 circuit fault
UVLCD27B18	2	720	H	Opto-isolator for undervoltage relay 27B/18 circuit fault
UVLCD27BD4	2	720	H	Opto-isolator for undervoltage relay 27D/B/14 circuit fault
UVLCD27BD6	2	720	H	Opto-isolator for undervoltage relay 27D/B/16 circuit fault
UVLCD27BD7	2	720	H	Opto-isolator for undervoltage relay 27D/B/17 circuit fault
UVLCD27BD8	2	720	H	Opto-isolator for undervoltage relay 27D/B/18 circuit fault
UVLCD27D14	2	720	H	Opto-isolator for undervoltage relay 27D/14 circuit fault
UVLCD27D16	2	720	H	Opto-isolator for undervoltage relay 27D/16 circuit fault
UVLCD27D17	2	720	H	Opto-isolator for undervoltage relay 27D/17 circuit fault
UVLCD27D18	2	720	H	Opto-isolator for undervoltage relay 27D/18 circuit fault
UVLCD4UV10	2	720	H	Circuit fault UV/1 Bus 14 decoder logic board #1
UVLCD4UV1B	2	720	H	Circuit fault UV/1B Bus 14 decoder logic board #1
UVLCD4UV20	2	720	H	Circuit fault UV/2 Bus 14 decoder logic board #2
UVLCD4UV2B	2	720	H	Circuit fault UV/2B Bus 14 decoder logic board #2
UVLCD6UV10	2	720	H	Circuit fault UV/1 Bus 16 decoder logic board #1
UVLCD6UV1B	2	720	H	Circuit fault UV/1B Bus 16 decoder logic board #1
UVLCD6UV20	2	720	H	Circuit fault UV/2 Bus 16 decoder logic board #2
UVLCD6UV2B	2	720	H	Circuit fault UV/2B Bus 16 decoder logic board #2
UVLCD7UV10	2	720	H	Circuit fault UV/1 Bus 17 decoder logic board #1
UVLCD7UV1B	2	720	H	Circuit fault UV/1B Bus 17 decoder logic board #1
UVLCD7UV20	2	720	H	Circuit fault UV/2 Bus 17 decoder logic board #2
UVLCD7UV2B	2	720	H	Circuit fault UV/2B Bus 17 decoder logic board #2
UVLCD8UV10	2	720	H	Circuit fault UV/1 Bus 18 decoder logic board #1
UVLCD8UV1B	2	720	H	Circuit fault UV/1B Bus 18 decoder logic board #1
UVLCD8UV20	2	720	H	Circuit fault UV/2 Bus 18 decoder logic board #2
UVLCD8UV2B	2	720	H	Circuit fault UV/2B Bus 18 decoder logic board #2
UVLCDBX114	2	720	H	Relay 27BX1/14 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX116	2	720	H	Relay 27BX1/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX117	2	720	H	Relay 27BX1/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX118	2	720	H	Relay 27BX1/18 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX214	2	720	H	Relay 27BX2/14 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX216	2	720	H	Relay 27BX2/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX217	2	720	H	Relay 27BX2/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX218	2	720	H	Relay 27BX2/18 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX314	2	720	H	Relay 27BX3/14 driver (Heat Sink Assembly #2) fails to energize

Basic Event	C	Factor	Units	Description
UVLCDBX316	2	720	H	Relay 27BX3/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX317	2	720	H	Relay 27BX3/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX318	2	720	H	Relay 27BX3/18 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX414	2	720	H	Relay 27BX4/14 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX416	2	720	H	Relay 27BX4/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX417	2	720	H	Relay 27BX4/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX418	2	720	H	Relay 27BX4/18 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX514	2	720	H	Relay 27BX5/14 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX516	2	720	H	Relay 27BX5/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX517	2	720	H	Relay 27BX5/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX518	2	720	H	Relay 27BX5/18 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX614	2	720	H	Relay 27BX6/14 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX616	2	720	H	Relay 27BX6/16 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX617	2	720	H	Relay 27BX6/17 driver (Heat Sink Assembly #2) fails to energize
UVLCDBX618	2	720	H	Relay 27BX6/18 driver (Heat Sink Assembly #2) fails to energize
UVMM1427X1		1.477E-03		Relay 27X1/14 fails to energize
UVMM1427X2		1.477E-03		Relay 27X1/14 fails to energize
UVMM1427X3		1.477E-03		Relay 27X3/14 fails to energize
UVMM1427X4		1.477E-03		Relay 27X4/14 fails to energize
UVMM1427X5		1.477E-03		Relay 27X5/14 fails to energize
UVMM1427X6		1.477E-03		Relay 27X6/14 fails to energize
UVMM14FUEM		2.864E-07		Failure of DC fuses for Bus 14 undervoltage relay cabinet emergency power
UVMM14FUSE		5.728E-07		Bus 14 undervoltage relay DC fuse failure
UVMM14L673		1.681E-05		Failure of circuit L673
UVMM14SS#1		2.803E-03		No signal from Bus 14 solid state switch #1
UVMM14SS#2		2.803E-03		No signal from Bus 14 solid state switch #2
UVMM1627X1		1.477E-03		Relay 27X1/16 fails to energize
UVMM1627X2		1.477E-03		Relay 27X2/16 fails to energize
UVMM1627X3		1.477E-03		Relay 27X3/16 fails to energize
UVMM1627X4		1.477E-03		Relay 27X4/16 fails to energize
UVMM1627X5		1.477E-03		Relay 27X5/16 fails to energize
UVMM1627X6		1.477E-03		Relay 27X6/16 fails to energize
UVMM16FUEM		2.864E-07		Failure of DC fuses for Bus 16 UV relay cabinet emergency power
UVMM16FUSE		5.728E-07		Bus 16 undervoltage relay DC fuse failure
UVMM16L674		1.681E-05		Failure of AC circuit L674
UVMM16SS#1		2.803E-03		No signal from Bus 16 solid state switch #1
UVMM16SS#2		2.803E-03		No signal from Bus 16 solid state switch #2
UVMM1727X1		1.477E-03		Relay 27X1/17 fails to energize
UVMM1727X2		1.477E-03		Relay 27X2/17 fails to energize
UVMM1727X3		1.477E-03		Relay 27X3/17 fails to energize
UVMM1727X4		1.477E-03		Relay 27X4/17 fails to energize
UVMM1727X5		1.477E-03		Relay 27X5/17 fails to energize

Basic Event	C Factor	Units	Description
UVMM1727X6	1.477E-03		Relay 27X6/17 fails to energize
UVMM17FUEM	2.864E-07		Failure of DC fuses for Bus 17 UV relay cabinet emergency power
UVMM17FUSE	5.728E-07		Bus 17 undervoltage relay DC fuse failure
UVMM17L668	1.681E-05		Failure of AC circuit L668
UVMM17SS#1	2.803E-03		No signal from Bus 17 solid state switch #1
UVMM17SS#2	2.803E-03		No signal from Bus 17 solid state switch #2
UVMM1827X1	1.477E-03		Relay 27X1/18 fails to energize
UVMM1827X2	1.477E-03		Relay 27X2/18 fails to energize
UVMM1827X3	1.477E-03		Relay 27X3/18 fails to energize
UVMM1827X4	1.477E-03		Relay 27X4/18 fails to energize
UVMM1827X5	1.477E-03		Relay 27X5/18 fails to energize
UVMM1827X6	1.477E-03		Relay 27X6/18 fails to energize
UVMM18FUEM	2.864E-07		Failure of DC fuses for Bus 18 UV relay cabinet emergency power
UVMM18FUSE	5.728E-07		Bus 18 undervoltage relay DC fuse failure
UVMM18L667	1.681E-05		Failure of AC circuit L667
UVMM18SS#1	2.803E-03		No signal from Bus 18 solid state switch #1
UVMM18SS#2	2.803E-03		No signal from Bus 18 solid state switch #2
UVMM427BX1	1.477E-03		Relay 27BX1/14 fails to energize
UVMM427BX2	1.477E-03		Relay 27BX2/14 fails to energize
UVMM427BX3	1.477E-03		Relay 27BX3/14 fails to energize
UVMM427BX4	1.477E-03		Relay 27BX4/14 fails to energize
UVMM427BX5	1.477E-03		Relay 27BX5/14 fails to energize
UVMM427BX6	1.477E-03		Relay 27BX6/14 fails to energize
UVMM627BX1	1.477E-03		Relay 27BX1/16 fails to energize
UVMM627BX2	1.477E-03		Relay 27BX2/16 fails to energize
UVMM627BX3	1.477E-03		Relay 27BX3/16 fails to energize
UVMM627BX4	1.477E-03		Relay 27BX4/16 fails to energize
UVMM627BX5	1.477E-03		Relay 27BX5/16 fails to energize
UVMM627BX6	1.477E-03		Relay 27BX6/16 fails to energize
UVMM727BX1	1.477E-03		Relay 27BX1/17 fails to energize
UVMM727BX2	1.477E-03		Relay 27BX2/17 fails to energize
UVMM727BX3	1.477E-03		Relay 27BX3/17 fails to energize
UVMM727BX4	1.477E-03		Relay 27BX4/17 fails to energize
UVMM727BX5	1.477E-03		Relay 27BX5/17 fails to energize
UVMM727BX6	1.477E-03		Relay 27BX6/17 fails to energize
UVMM827BX1	1.477E-03		Relay 27BX1/18 fails to energize
UVMM827BX2	1.477E-03		Relay 27BX2/18 fails to energize
UVMM827BX3	1.477E-03		Relay 27BX3/18 fails to energize
UVMM827BX4	1.477E-03		Relay 27BX4/18 fails to energize
UVMM827BX5	1.477E-03		Relay 27BX5/18 fails to energize
UVMM827BX6	1.477E-03		Relay 27BX6/18 fails to energize
UVPXFB14CC	1 4	H	No output on power supply for Bus 14 UV control cabinet

Basic Event	C	Factor	Units	Description
UVPXFB14RC	1	4	H	No output on power supply for Bus 14 UV relay cabinet
UVPXFB16CC	1	4	H	No output on power supply for Bus 16 UV control cabinet
UVPXFB16RC	1	4	H	No output on power supply for Bus 16 UV relay cabinet
UVPXFB17CC	1	4	H	No output on power supply for Bus 17 UV control cabinet
UVPXFB17RC	1	4	H	No output on power supply for Bus 17 UV relay cabinet
UVPXFB18CC	1	4	H	No output on power supply for Bus 18 UV control cabinet
UVPXFB18RC	1	4	H	No output on power supply for Bus 18 UV relay cabinet
UVREB83DC4	1	1	N	Relay 83DC/14 fails to de-energize
UVREB83DC6	1	1	N	Relay 83DC/16 fails to de-energize
UVREB83DC7	1	1	N	Relay 83DC/17 fails to de-energize
UVREB83DC8	1	1	N	Relay 83DC/17 fails to de-energize
UVREE0X114	1	1	N	Relay 27X1/14 fails to energize
UVREE0X116	1	1	N	Relay 27X1/16 fails to energize
UVREE0X117	1	1	N	Relay 27X1/17 fails to energize
UVREE0X118	1	1	N	Relay 27X1/18 fails to energize
UVREE0X214	1	1	N	Relay 27X2/14 fails to energize
UVREE0X216	1	1	N	Relay 27X2/16 fails to energize
UVREE0X217	1	1	N	Relay 27X2/17 fails to energize
UVREE0X218	1	1	N	Relay 27X2/18 fails to energize
UVREE0X314	1	1	N	Relay 27X3/14 fails to energize
UVREE0X316	1	1	N	Relay 27X3/16 fails to energize
UVREE0X317	1	1	N	Relay 27X3/17 fails to energize
UVREE0X318	1	1	N	Relay 27X3/18 fails to energize
UVREE0X414	1	1	N	Relay 27X4/14 fails to energize
UVREE0X416	1	1	N	Relay 27X4/16 fails to energize
UVREE0X417	1	1	N	Relay 27X4/17 fails to energize
UVREE0X418	1	1	N	Relay 27X4/18 fails to energize
UVREE0X514	1	1	N	Relay 27X5/14 fails to energize
UVREE0X516	1	1	N	Relay 27X5/16 fails to energize
UVREE0X517	1	1	N	Relay 27X5/17 fails to energize
UVREE0X518	1	1	N	Relay 27X5/18 fails to energize
UVREE0X614	1	1	N	Relay 27X6/14 fails to energize
UVREE0X616	1	1	N	Relay 27X6/16 fails to energize
UVREE0X617	1	1	N	Relay 27X6/17 fails to energize
UVREE0X618	1	1	N	Relay 27X6/18 fails to energize
UVREEBX114	1	1	N	Relay 27BX1/14 fails to energize
UVREEBX116	1	1	N	Relay 27BX1/16 fails to energize
UVREEBX117	1	1	N	Relay 27BX1/17 fails to energize
UVREEBX118	1	1	N	Relay 27BX1/18 fails to energize
UVREEBX214	1	1	N	Relay 27BX2/14 fails to energize
UVREEBX216	1	1	N	Relay 27BX2/16 fails to energize
UVREEBX217	1	1	N	Relay 27BX2/17 fails to energize

Basic Event	C	Factor	Units	Description
UVREEBX218	1	1	N	Relay 27BX2/18 fails to energize
UVREEBX314	1	1	N	Relay 27BX3/14 fails to energize
UVREEBX316	1	1	N	Relay 27BX3/16 fails to energize
UVREEBX317	1	1	N	Relay 27BX3/17 fails to energize
UVREEBX318	1	1	N	Relay 27BX3/18 fails to energize
UVREEBX414	1	1	N	Relay 27BX4/14 fails to energize
UVREEBX416	1	1	N	Relay 27BX4/16 fails to energize
UVREEBX417	1	1	N	Relay 27BX4/17 fails to energize
UVREEBX418	1	1	N	Relay 27BX4/18 fails to energize
UVREEBX514	1	1	N	Relay 27BX5/14 fails to energize
UVREEBX516	1	1	N	Relay 27BX5/16 fails to energize
UVREEBX517	1	1	N	Relay 27BX5/17 fails to energize
UVREEBX518	1	1	N	Relay 27BX5/18 fails to energize
UVREEBX614	1	1	N	Relay 27BX6/14 fails to energize
UVREEBX616	1	1	N	Relay 27BX6/16 fails to energize
UVREEBX617	1	1	N	Relay 27BX6/17 fails to energize
UVREEBX618	1	1	N	Relay 27BX6/18 fails to energize
UVRUB1/11A	1	1	N	BUS 11A UNDERVOLTAGE RELAY 27-1/11A FAILS TO DEENERGIZE ON DEMAND
UVRUB1/11B	1	1	N	BUS 11B UNDERVOLTAGE RELAY 27-1/11B FAILS TO DEENERGIZE ON DEMAND
UVRUB2/11A	1	1	N	BUS 11A UNDERVOLTAGE RELAY 27-2/11A FAILS TO DEENERGIZE ON DEMAND
UVRUB2/11B	1	1	N	BUS 11B UNDERVOLTAGE RELAY 27-2/11B FAILS TO DEENERGIZE ON DEMAND
UVRUB27014	1	1	N	Undervoltage relay 27/14 fails to de-energize
UVRUB27016	1	1	N	Undervoltage relay 27/16 fails to de-energize
UVRUB27017	1	1	N	Undervoltage relay 27/17 fails to de-energize
UVRUB27018	1	1	N	Undervoltage relay 27/18 fails to de-energize
UVRUB27B14	1	1	N	Undervoltage relay 27B/14 fails to de-energize
UVRUB27B16	1	1	N	Undervoltage relay 27B/16 fails to de-energize
UVRUB27B17	1	1	N	Undervoltage relay 27B/17 fails to de-energize
UVRUB27B18	1	1	N	Undervoltage relay 27B/18 fails to de-energize
UVRUB27BD4	1	1	N	Undervoltage relay 27D/B/14 fails to de-energize
UVRUB27BD6	1	1	N	Undervoltage relay 27D/B/16 fails to de-energize
UVRUB27BD7	1	1	N	Undervoltage relay 27D/B/17 fails to de-energize
UVRUB27BD8	1	1	N	Undervoltage relay 27D/B/18 fails to de-energize
UVRUB27D14	1	1	N	Undervoltage relay 27D/14 fails to de-energize
UVRUB27D16	1	1	N	Undervoltage relay 27D/16 fails to de-energize
UVRUB27D17	1	1	N	Undervoltage relay 27D/17 fails to de-energize
UVRUB27D18	1	1	N	Undervoltage relay 27D/18 fails to de-energize
UVRUEX111A	1	1	N	BUS 11A UNDERVOLTAGE AUXILIARY RELAY 27X1/11A FAILS TO ENERGIZE ON DEMAND
UVRUEX111B	1	1	N	BUS 11B UNDERVOLTAGE AUXILIARY RELAY 27X1/11B FAILS TO ENERGIZE ON DEMAND
UVRUEX211A	1	1	N	BUS 11A UNDERVOLTAGE AUXILIARY RELAY 27X2/11A FAILS TO ENERGIZE ON DEMAND
UVRUEX211B	1	1	N	BUS 11B UNDERVOLTAGE AUXILIARY RELAY 27X2/11B FAILS TO ENERGIZE ON DEMAND

Table [illegible]7-3
Integrated C[illegible] TC File

AC AC POWER:

Type Code	Rate	U	Description	Source
AC B1 F	4.07E-08	H	>4 KV BUS @@@@@ FAULT	BAYES
AC B2 F	7.84E-07	H	<4 KV BUS @@@@@ FAULT	BAYES
AC B4 F	7.03E-08	H	120 V BUS @@@@@ FAULT	BAYES
AC CB D	3.85E-03		AC BREAKER @@@@@ FAILS TO OPERATE	PLANT-SPECIFIC
AC CB N	3.85E-03		AC BREAKER @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
AC CB O	6.91E-07	H	AC BREAKER @@@@@ STANDBY FAILS TO OPERATE	PLANT-SPECIFIC
AC CB R	1.33E-06	H	AC BREAKER @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
AC CF R	6.38E-07	H	FUSE @@@@@ FAILS OPEN	SAIC GDN
AC IV F	7.11E-06	H	STATIC VOLTAGE REGULATOR @@@@@ NO OUTPUT	SAIC GDN
AC LC D	3.89E-06	H	LOGIC CIRCUIT @@@@@ FAILS TO GENERATE SIGNAL	SAIC GDN
AC PX F	1.40E-06	H	POWER SUPPLY @@@@@ NO OUTPUT	SAIC GDN
AC RE B	7.65E-05	N	RELAY @@@@@ FAILS TO DEENERGIZE	SAIC GDN
AC RE E	7.65E-05	N	RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
AC RE K	3.94E-07	H	RELAY @@@@@ TRANSFERS TO ENERGIZED	SAIC GDN
AC RT D	7.65E-05		TIME DELAY RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
AC SZ C	2.46E-04	N	VLV POSITION SWITCH @@@@@ FAILS TO CLOSE	
AC T1 F	8.42E-07	H	KV TRANSFORMERS @@@@@ FAULT	BAYES
AC T6 F	6.05E-07	H	480V-240V TRANSFORMER @@@@@ FAULT	BAYES

Table 3.3.7-3
Integrated C[illegible] TC File

AF **AUXILIARY FEEDWATER:**

Type Code	Rate	U	Description	Source
AF AV K	1.01E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
AF AV P	2.55E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
AF AV X	6.06E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
AF CV C	1.87E-03		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
AF CV P	2.87E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN (STANDBY RATE)	BAYES
AF FT D	1.81E-06	H	FLOW TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
AF FT H	2.04E-06	H	FLOW TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
AF HX F	1.95E-05	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	SAIC GDN
AF LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
AF MP F	3.81E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
AF MP S	3.20E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
AF MV C	1.19E-03		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
AF MV D	2.25E-06	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO TRTL	BAYES
AF MV K	9.23E-07	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
AF MV P	8.50E-06	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN (STANDBY)	PLANT-SPECIFIC
AF MV X	7.88E-06	H	MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE (STANDBY)	PLANT-SPECIFIC
AF PC D	1.47E-06	H	PRESSURE CONTROLLER @@@@@ FAILS TO RESP	SAIC GDN
AF PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
AF TK B	3.31E-06	H	TANK BLADDER @@@@@ RUPTURES	SAIC GDN
AF TK J	4.39E-06	H	TANK @@@@@ RUPTURE	BAYES
AF TP F	8.80E-05	H	TURBINE-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
AF TP S	2.55E-05	H	TURBINE-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
AF XV K	1.07E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
AF XV P	3.77E-07	H	MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES
AF XV X	9.97E-08	H	MANUAL VALVE @@@@@ FAILS TO CLOSE	BAYES

Table [illegible]7-3
Integrated C[illegible]A TC File

CC COMPONENT COOLING WATER:

Type Code	Rate	U	Description	Source
CC AV K	2.27E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
CC CV C	3.85E-03		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CC CV K	1.08E-06	H	CHECK VALVE @@@@@ TRANSFERS CLOSED	BAYES
CC HX F	1.19E-07	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	BAYES
CC HX J	2.92E-07	H	HEAT EXCHANGER @@@@@ TUBE RUPTURE	BAYES
CC HX P	3.66E-07	H	HEAT EXCHANGER @@@@@ PLUGS	BAYES
CC MP A	1.85E-03		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
CC MP F	1.18E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	PLANT-SPECIFIC
CC MV C	7.43E-03		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
CC MV K	1.02E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
CC MV P	1.28E-05		MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CC PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
CC PS D	4.50E-05		PRESSURE SWITCH @@@@@ FAILS TO RESPOND	SAIC GDN
CC PS H	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS HIGH	SAIC GDN
CC TK J	5.08E-06	H	TANK @@@@@ RUPTURE	BAYES
CC XV K	8.90E-08	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
CC XV N	2.11E-04		MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES

CR **CONTAINMENT SPRAY - RECIRCULATION**

Type Code	Rate	U	Description	Source
CR AV P	1.27E-05		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CR CV P	3.57E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
CR LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
CR LT H	2.02E-06	H	LEVEL TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
CR MP F	1.49E-02	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	PLANT-SPECIFIC
CR MP S	2.80E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	BAYES
CR MV P	1.11E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CR MV R	7.22E-07	H	MOTOR-OP VALVE @@@@@ TRANSFERS OPEN	BAYES
CR MV X	5.70E-05	H	MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE (STANDBY)	PLANT-SPECIFIC
CR MV Z	2.89E-06	H	MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE (STANDBY)	P/S DATA FOR 896A&B
CR PP P	5.53E-07	H	PIPING @@@@@ PLUGGED	SAIC GDN
CR TK J	4.71E-06	H	TANK @@@@@ RUPTURE	BAYES
CR XV K	1.53E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
CR XV R	1.14E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

Tabl 7-3
Integrated C A TC File

CS **CONTAINMENT SPRAY:**

Type Code	Rate	U	Description	Source
CS AV P	1.27E-05		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CS CV C	1.61E-03		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CS CV P	3.57E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
CS LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
CS LT H	2.02E-06	H	LEVEL TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
CS LT L	2.06E-06	H	LEVEL TRANSMITTER @@@@@ FAILS LOW	SAIC GDN
CS MP F	1.49E-02	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	PLANT-SPECIFIC
CS MP S	2.80E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	BAYES
CS MV C	8.56E-03		MOTOR-OP VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CS MV K	1.31E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
CS MV P	1.11E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CS PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
CS TK J	4.71E-06	H	TANK @@@@@ RUPTURE	BAYES
CS VB P	1.03E-06		VACUUM BREAKER @@@@@ FAILS	SAIC GDN
CS XV K	1.53E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
CS XV N	1.18E-04		MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES
CS XV R	1.14E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

Table 3.3.7-3
Integrated C[illegible]A TC File

CT **CONTAINMENT ISOLATION:**

Type Code	Rate	U	Description	Source
CT AV R	1.64E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
CT AV X	8.31E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CT BE F	1.00E-06	H	ELECTRICAL PENETRATION @@@@@ FAILS	SAIC GDN
CT BF F	1.73E-06	H	BLIND FLANGE @@@@@ FAILS	PLANT-SPECIFIC
CT BF P	1.73E-06	H	PENETRATION FLANGE @@@@@ FAILS	P/D (CT BF F)
CT CV R	3.26E-07	H	CHECK VALVE @@@@@ TRANSFERS OPEN	BAYES
CT PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
CT XV R	8.76E-08	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

CV **CHEMICAL VOLUME AND CONTROL:**

Type Code	Rate	U	Description	Source
CV AV C	3.47E-04		AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CV AV K	1.17E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
CV AV N	9.92E-05		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CV AV P	1.58E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CV AV X	2.60E-05	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CV CV K	8.96E-07	H	CHECK VALVE @@@@@ TRANSFERS CLOSED	BAYES
CV CV N	4.06E-05		CHECK VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CV CV P	5.30E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
CV HT F	1.56E-04	H	HEAT TRACE @@@@@ FAILS	PLANT-SPECIFIC
CV HX P	8.82E-07	H	HEAT EXCHANGER @@@@@ PLUGS	BAYES
CV LT D	1.27E-05	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	PLANT-SPECIFIC
CV LT H	1.05E-04	H	LEVEL TRANSMITTER @@@@@ FAILS HIGH	PLANT-SPECIFIC
CV LT L	2.06E-06	H	LEVEL TRANSMITTER @@@@@ FAILS LOW	SAIC GDN
CV MP A	1.08E-03		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
CV MP F	2.72E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	PLANT-SPECIFIC
CV MV K	1.43E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
CV MV N	3.76E-03		MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	BAYES
CV MV X	1.56E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
CV PP J	1.56E-05	H	PIPING @@@@@ RUPTURE	PLANT-SPECIFIC
CV PP P	6.24E-05	H	PIPING @@@@@ PLUGGED	PLANT-SPECIFIC
CV RV N	2.07E-04		RELIEF VALVE @@@@@ FAILS TO OPEN	BAYES
CV RV P	1.97E-07	H	RELIEF VALVE @@@@@ FAILS TO OPEN (STANDBY)	BAYES
CV RV R	2.72E-05	H	RELIEF VALVE @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
CV TK J	4.11E-06	H	TANK @@@@@ RUPTURE	BAYES
CV XV K	8.05E-08	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
CV XV N	3.47E-04	N	MANUAL VALVE @@@@@ FAILS TO OPEN	SAIC GDN
CV XV R	1.12E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

Tabl[illegible]3.7-3
Integrated [illegible]A TC File

DC **DC POWER:**

Type Code	Rate	U	Description	Source
DC BC F	1.27E-05	H	BATTERY CHARGE @@@@@ NO OUTPUT	PLANT-SPECIFIC
DC BD F	2.41E-08	H	DC BUS @@@@@ FAULT	BAYES
DC BT D	1.19E-05		BATTERY @@@@@ NO OUTPUT (DEMAND)	SAIC GDN
DC BT F	9.39E-07	H	BATTERY @@@@@ NO OUTPUT (HOURLY)	BAYES
DC CB R	1.87E-06	H	AC BREAKER @@@@@ TRANSFERS OPEN	SAIC GDN
DC CD R	3.80E-06	H	DC BREAKER @@@@@ TRANSFERS OPEN	SAIC GDN
DC CF R	3.58E-08	H	FUSE @@@@@ FAILS OPEN	BAYES
DC CF X	3.58E-08	H	FUSE @@@@@ FAILS OPEN (POST TRIP)	BAYES
DC CS R	1.41E-06	H	DC DISCONNECT SWITCH @@@@@ TRANSFERS OPEN	SAIC GDN
DC IN F	1.27E-05	H	INVERTER @@@@@ NO OUTPUT	PLANT-SPECIFIC
DC RE B	7.65E-05	N	RELAY @@@@@ FAILS TO DEENERGIZE	SAIC GDN
DC RE E	7.65E-05	N	RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
DC RT D	7.65E-05	N	TIME DELAY RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN

Table [illegible]7-3
Integrated C[illegible]A TC File

DG EMERGENCY AC POWER (DIESEL GENERATORS):

Type Code	Rate	U	Description	Source
DG CF R	6.38E-07	H	FUSE @@@@@ FAILS OPEN	SAIC GDN
DG CV C	3.58E-04		CHECK VALVE @@@@@ FAILS TO CLOSE	BAYES
DG CV N	1.36E-04		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
DG DG A	4.88E-03		DIESEL GENERATOR @@@@@ FAILS TO START	PLANT-SPECIFIC
DG DG F	1.25E-03	H	DIESEL GENERATOR @@@@@ FAILS TO RUN	PLANT-SPECIFIC
DG FD P	2.66E-05		FUEL OIL STRAINER @@@@@ PLUGGED	SAIC GDN
DG LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
DG MP A	1.18E-03		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	BAYES
DG MP F	7.41E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
DG PS H	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS HIGH	SAIC GDN
DG PS L	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS LOW	SAIC GDN
DG RE E	7.65E-05		RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
DG RU B	7.65E-05		UNDERVOLTAGE RELAY @@@@@ FAILS TO DEENER	SAIC GDN
DG RV R	1.31E-06	H	RELIEF VALVE @@@@@ TRANSFERS OPEN	BAYES
DG SV P	6.34E-06	H	SOLENOID VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
DG SV X	1.47E-06	H	SOLENOID VALVE @@@@@ FAILS TO CLOSE	BAYES
DG TK J	4.71E-06	H	TANK @@@@@ RUPTURE	BAYES
DG TS H	9.20E-07	H	TEMPERATURE SWITCH @@@@@ FAILS HIGH	SAIC GDN
DG TS L	9.20E-07	H	TEMPERATURE SWITCH @@@@@ FAILS LOW	SAIC GDN
DG XV K	1.66E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES

ES **SAFEGUARDS ACTUATION:**

Type Code	Rate	U	Description	Source
ES BI N	2.25E-07	N	BISTABLE @@@@@ FAILS TO OPERATE ON DEMAND	SAIC GDN
ES CF R	3.58E-08	H	FUSE @@@@@ FAILS OPEN	BAYES
ES FT D	1.81E-06	H	FLOW TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
ES FT L	1.83E-06	H	FLOW TRANSMITTER @@@@@ FAILS LOW	SAIC GDN
ES LC D	3.89E-06	H	LOGIC CIRCUIT @@@@@ FAILS	SAIC GDN
ES LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
ES LY D	6.42E-07	H	SIGNAL PROCES MOD @@@@@ FAILS TO RESPOND	SAIC GDN
ES PT D	1.47E-06	H	PRESSURE TRANSMIT @@@@@ FAILS TO RESPOND	SAIC GDN
ES PX F	1.40E-06	H	POWER SUPPLY @@@@@ NO OUTPUT	SAIC GDN
ES RA F	3.42E-06	H	RADIATION ELEMENT @@@@@ FAILS TO RESPOND	SAIC GDN
ES RE B	7.65E-05	N	RELAY @@@@@ FAILS TO DEENERGIZE	SAIC GDN
ES RE E	7.65E-05		RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
ES RE K	3.94E-07	H	RELAY @@@@@ TRANSFERS TO ENERGIZED	SAIC GDN
ES RT D	7.65E-05		TIME DELAY RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
ES TR D	6.80E-06	H	AGASTAT TIMING RELAY @@@@@ FAILS TO RESP	SAIC GDN
ES TT D	1.47E-06	H	TEMP TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN

HV HEATING, VENTILATION,& AIR CONDITIONING:

Type Code	Rate	U	Description	Source
HV AC A	2.08E-04		AIR COOLING UNIT @@@@@ FAILS TO START	SAIC GDN
HV AC F	1.05E-05	H	AIR COOLING UNIT @@@@@ FAILS TO RUN	SAIC GDN
HV AF F	7.31E-06	H	AIR FILTER @@@@@ FAILS TO DELIVER FLOW	PLANT-SPECIFIC
HV AV C	2.17E-03		AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	SAIC GDN
HV AV X	6.03E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	SAIC GDN
HV HE F	1.16E-06		ROOM HEATER @@@@ FAILS TO OPERATE	BAYES
HV HX F	1.95E-05	H	HEAT EXCHANGER @@@@@ COOLING.CAP. FAILS	SAIC GDN
HV MB N	2.18E-03		BACKFLOW DAMPER @@@@@ FAILS TO OPEN	SAIC GDN
HV MC K	9.18E-07	H	AIR-OP DAMPER @@@@@ TRANSFERS CLOSED	PLANT-SPECIFIC
HV MC N	1.99E-04		AIR-OPERATED DAMPER @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
HV MC P	6.06E-06	H	AIR-OPERATED DAMPER @@@@@ FAILS TO OPEN	SAIC GDN
HV MF A	6.91E-04		MOTOR-DRIVEN FAN @@@@@ FAILS TO START	PLANT-SPECIFIC
HV MF F	7.82E-06	H	MOTOR-DRIVEN FAN @@@@@ FAILS TO RUN	PLANT-SPECIFIC
HV MF S	3.27E-06		MOTOR-DRIVEN FAN @@@@@ FAILS TO START	PLANT-SPECIFIC
HV TV L	1.36E-06	H	TEMP INDICATING CTRL @@@@@ FAILS LOW	SAIC GDN

Table 3.3.7-3
Integrated CAFTA TC File

IA COMPRESSED AIR SYSTEMS:

Type Code	Rate	U	Description	Source
IA AD F	6.34E-05	H	AIR DRYER @@@@@ FAILS TO DELIVER FLOW	PLANT-SPECIFIC
IA AF F	1.74E-06	H	AIR FILTER @@@@@ FAILS TO DELIVER FLOW	BAYES
IA AM A	3.87E-03		AIR COMPRESSOR @@@@@ FAILS TO START	PLANT-SPECIFIC
IA AM F	7.83E-05	H	AIR COMPRESSOR @@@@@ FAILS TO RUN	PLANT-SPECIFIC
IA AR F	4.61E-06	H	AIR RECEIVER @@@@@ LOCAL FAULTS	PLANT-SPECIFIC
IA AV K	8.84E-07	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
IA AV N	2.79E-05		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	BAYES
IA AV X	1.44E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	BAYES
IA CV C	2.26E-05		CHECK VALVE @@@@@ FAILS TO CLOSE	BAYES
IA CV K	1.21E-06	H	CHECK VALVE @@@@@ TRANSFERS CLOSED	BAYES
IA CV N	6.17E-05		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
IA CV P	3.50E-07		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
IA HX F	1.95E-05	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	SAIC GDN
IA HX J	2.61E-05	H	HEAT EXCHANGER @@@@@ TUBE RUPTURE	SAIC GDN
IA HX P	2.20E-06	H	HEAT EXCHANGER @@@@@ PLUGS	SAIC GDN
IA IP D	1.00E-07	H	I/P CONVERTER @@@@@ FAILS TO RESPOND	SAIC GDN
IA PP J	5.07E-05	H	PIPING @@@@@ RUPTURE	PLANT-SPECIFIC
IA PS D	4.50E-05		PRESSURE SWITCH @@@@@ FAILS TO RESPOND	SAIC GDN
IA PS H	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS HIGH	SAIC GDN
IA PS L	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS LOW	SAIC GDN
IA PV K	3.33E-06	H	PRESSURE CONTROL VLV @@@@@ TRANSFERS CLOSED	TEMP CHANGE GD-3
IA RV R	1.69E-06	H	RELIEF VALVE @@@@@ SPURIOUS OPEN	SAIC GDN
IA SV C	2.83E-03		SOLENOID VALVE @@@@@ FAILS TO CLOSE	SAIC GDN
IA SV K	3.48E-07	H	SOLENOID VALVE @@@@@ TRANSFERS CLOSED	BAYES
IA SV P	7.86E-06	H	SOLENOID VALVE @@@@@ FAILS TO OPEN	SAIC GDN
IA SV X	1.47E-06	H	SOLENOID VALVE @@@@@ FAILS TO CLOSE	BAYES
IA TK G	5.52E-06	H	TANK @@@@@ LEAKAGE/RUPTURE	SAIC GDN
IA XV K	1.94E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	SAIC GDN
IA XV N	3.47E-04	N	MANUAL VALVE @@@@@ FAILS TO OPEN	SAIC GDN
IA XV R	1.30E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	SAIC GDN

Table [illegible].7-3
Integrated C. [illegible] TC File

MF MAIN FEEDWATER:

Type Code	Rate	U	Description	Source
MF CV C	8.71E-04		CHECK VALVE @@@@@ FAILS TO CLOSE	BAYES
MF LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN

MS MAIN STEAM:

Type Code	Rate	U	Description	Source
MS AV C	8.81E-03		MSIV @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
MS AV K	1.83E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
MS AV P	3.37E-05		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
MS AV X	1.56E-05	H	AIR-OPERATED VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
MS CV C	2.64E-03		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
MS CV P	3.86E-07		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
MS MV C	2.28E-03		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
MS MV P	6.35E-06	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
MS MV R	1.11E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS OPEN	BAYES
MS PS D	4.50E-05		PRESSURE SWITCH @@@@@ FAILS TO RESPOND	SAIC GDN
MS PV K	1.06E-05	H	PRESSURE CONTROL VLV @@@@@ TRANSFERS CLOSED	SAIC GDN (PV R)
MS RT D	7.65E-05		TIME DELAY RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
MS RV C	8.53E-04		ARV @@@@@ FAILS TO CLOSE	BAYES
MS RV P	6.34E-06		ARV @@@@@ FAILS TO OPEN (STANDBY)	PLANT-SPECIFIC
MS RV Z	1.00E-01		ARV @@@@@ FAILS TO CLOSE AFTRER LIQUID RELIEF	SAIC GDN
MS RY T	6.88E-03		PSV,S/G SAFETY VLV @@@@@ FAILS RESEAT(S)	BAYES
MS SZ C	2.46E-04	N	VLV POSITION SWITCH @@@@@ FAILS TO CLOSE	
MS TK G	5.52E-06	H	TANK @@@@@ LEAKAGE	SAIC GDN
MS XV C	3.38E-04		MANUAL VALVE @@@@@ FAILS TO CLOSE	BAYES
MS XV K	1.79E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
MS XV P	9.63E-07		MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES
MS XV X	5.10E-07	H	MANUAL VALVE @@@@@ FAIL TO CLOSE	BAYES

RC PRIMARY PRESSURE CONTROL:

Type Code	Rate	U	Description	Source
RC AV K	2.45E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
RC AV N	3.94E-03		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
RC AV P	2.28E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
RC BI N	2.25E-07	N	BISTABLE @@@@@ FAILS TO OPERATE ON DEMAND	SAIC GDN
RC CV N	1.44E-04		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
RC HN F	1.67E-06	H	HEATER @@@@@ FAILS	SAIC GDN
RC LY D	6.42E-07	H	SIGNAL PROCES MOD @@@@@ FAILS TO RESPOND	SAIC GDN
RC MP F	1.44E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
RC MV K	1.31E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
RC MV P	1.41E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	BAYES
RC MV X	2.89E-06		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	BAYES
RC PT D	1.47E-06	H	PRESSURE TRANSMIT @@@@@ FAILS TO RESPOND	SAIC GDN
RC PT H	1.49E-06	H	PRESSURE TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
RC PT L	1.47E-06	H	PRESSURE TRANSMITTER @@@@@ FAILS LOW	SAIC GDN
RC PX F	1.40E-06	H	POWER SUPPLY @@@@@ NO OUTPUT	SAIC GDN
RC RE E	7.65E-05	N	RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
RC RV R	1.31E-06	H	RELIEF VALVE @@@@@ TRANSFERS OPEN	BAYES
RC RY N	1.40E-04	N	SAFETY VALVE @@@@@ FAILS TO OPEN	SAIC GDN
RC RY T	7.45E-03		PSV,S/G SAFETY VLV @@@@@ FAILS RESEAT(S)	SAIC GDN
RC RZ P	2.94E-06		PORV @@@@@ FAILS TO OPEN	BAYES
RC RZ T	5.00E-03		PORV @@@@@ FAILS TO RESEAT AFTER STEAM	SAIC GDN
RC SV P	8.13E-07	H	SOLENOID VALVE @@@@@ FAILS TO OPEN	BAYES
RC SW C	2.59E-08	N	HAND SWITCH @@@@@ FAILS TO CLOSE	SAIC GDN
RC SW R	8.00E-08	H	HAND SWITCH @@@@@ TRANSFERS OPEN	SAIC GDN
RC XV K	1.64E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES

Table 3.3.7-3
Integrated CAFTA TC File

RH RESIDUAL HEAT REMOVAL:

Type Code	Rate	U	Description	Source
RH AV K	1.63E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
RH AV R	2.36E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFERS OPEN	BAYES
RH CV C	1.43E-04		CHECK VALVE @@@@@ FAILS TO CLOSE	BAYES
RH CV P	3.40E-07		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
RH HX F	6.46E-06	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	BAYES
RH HX P	2.07E-06	H	HEAT EXCHANGER @@@@@ PLUGS	BAYES
RH MP F	1.24E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
RH MP S	6.93E-06		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
RH MV K	1.04E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
RH MV P	1.09E-05		MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
RH MV R	5.95E-07	H	MOTOR-OP VALVE @@@@@ TRANSFERS OPEN	BAYES
RH MV X	6.65E-06		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
RH PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
RH PS H	8.45E-07	H	PRESSURE SWITCH @@@@@ FAILS HIGH	SAIC GDN
RH XV K	1.66E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
RH XV P	5.21E-07		MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES
RH XV R	1.18E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

RR RHR - RECIRCULATION

Type Code	Rate	U	Description	Source
RR AV F	3.53E-06	H	AIR-OPERATED VALVE @@@@@ FAILS TO THROTTLE	BAYES
RR AV K	1.63E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
RR CV C	1.43E-04		CHECK VALVE @@@@@ FAILS TO CLOSE	BAYES
RR CV P	3.40E-07		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
RR HX F	6.46E-06	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	BAYES
RR HX P	2.07E-06	H	HEAT EXCHANGER @@@@@ PLUGS	BAYES
RR IP D	1.00E-07	H	I/P CONVERTER @@@@@ FAILS TO RESPOND	SAIC GDN
RR LY D	6.42E-07	H	SIGNAL PROCES MOD @@@@@ FAILS TO RESPOND	SAIC GDN
RR MP F	1.24E-05	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
RR MP S	6.93E-06		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
RR MV K	1.04E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
RR MV P	1.09E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
RR MV X	6.65E-06		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
RR PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
RR PT H	1.49E-06	H	PRESSURE TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
RR SM P	2.20E-05		CONTAINMENT SUMP @@@@@ PLUGGED	SAIC GDN
RR XV K	1.66E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
RR XV R	1.18E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	BAYES

SI **SAFETY INJECTION:**

Type Code	Rate	U	Description	Source
SI CV C	1.91E-03		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
SI CV N	1.45E-04	N	CHECK VALVE @@@@@ FAILS TO OPEN	SAIC GDN
SI CV P	2.91E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
SI CV R	7.04E-07	H	CHECK VALVE @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
SI LC D	3.89E-06	H	LOGIC CIRCUIT @@@@@ FAILS	SAIC GDN
SI LT D	2.14E-06	H	LEVEL TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
SI LT H	2.02E-06	H	LEVEL TRANSMITTER @@@@@ FAILS HIGH	SAIC GDN
SI MP F	4.66E-04	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
SI MP S	4.76E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
SI MV C	2.68E-03		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
SI MV K	8.42E-07	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
SI MV P	9.51E-06	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
SI MV X	8.87E-06		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
SI PT D	1.47E-06	H	PRESSURE TRANSMITTER @@@@@ FAILS TO RESPOND	SAIC GDN
SI PT H	1.49E-06	H	PRESSURE TRANSMITTER @@@@@ FAISL HIGH	SAIC GDN
SI TK G	5.52E-06	H	TANK @@@@@ LEAKAGE	SAIC GDN
SI TK J	5.56E-06	H	TANK @@@@@ RUPTURE	SAIC GDN
SI XV K	1.53E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
SI XV R	1.30E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	SAIC GDN

Table 3.3.7-3
Integrated C. TC File

SR **SI - RECIRCULATION**

Type Code	Rate	U	Description	Source
SR CV P	2.91E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
SR CV R	7.04E-07	H	CHECK VALVE @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
SR MP F	4.66E-04	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
SR MP S	4.76E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
SR MV K	8.42E-07	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	BAYES
SR MV X	8.87E-06	H	MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
SR PP P	5.53E-07	H	PIPING @@@@@ PLUGGED	SAIC GDN
SR XV K	1.53E-07	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
SR XV R	1.30E-07	H	MANUAL VALVE @@@@@ TRANSFERS OPEN	SAIC GDN

SW SERVICE WATER:

Type Code	Rate	U	Description	Source
SW AV K	1.33E-06	H	AIR-OPERATED VALVE @@@@@ TRANSFER CLOSED	BAYES
SW AV N	3.19E-06		AIR-OPERATED VALVE @@@@@ FAILS TO OPEN	BAYES
SW CV C	4.84E-04		CHECK VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
SW CV K	1.43E-06	H	CHECK VALVE @@@@@ TRANSFERS CLOSED	BAYES
SW CV N	1.21E-04		CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
SW CV P	3.73E-07	H	CHECK VALVE @@@@@ FAILS TO OPEN	BAYES
SW EJ F	2.85E-08	H	EXPANSION JOINT @@@@@ FAILS	SAIC GDN
SW FD F	4.07E-06		WATER FILTER @@@@@ FAILS (PLUGGED)	SAIC GDN
SW HX F	1.95E-05	H	HEAT EXCHANGER @@@@@ COOLING CAP. FAILS	SAIC GDN
SW MP A	7.32E-04		MOTOR-DRIVEN PUMP @@@@@ FAILS TO START	PLANT-SPECIFIC
SW MP F	1.05E-06	H	MOTOR-DRIVEN PUMP @@@@@ FAILS TO RUN	BAYES
SW MV C	5.85E-03		MOTOR-OPERATED VALVE @@@@@ FAIL TO CLOSE	PLANT-SPECIFIC
SW MV K	2.11E-06	H	MOTOR-OP VALVE @@@@@ TRANSFERS CLOSED	PLANT-SPECIFIC
SW MV N	4.38E-03		MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
SW MV P	3.81E-05	H	MOTOR-OPERATED VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
SW PP J	5.53E-07	H	PIPING @@@@@ RUPTURE	SAIC GDN
SW PS R	4.50E-05		PRESSURE SWITCH @@@@@ FAILS TO RESPOND	SAIC GDN
SW SV K	3.48E-07	H	SOLENOID VALVE @@@@@ TRANSFERS CLOSED	BAYES
SW SV P	1.61E-05	H	SOLENOID VALVE @@@@@ FAILS TO OPEN	PLANT-SPECIFIC
SW XV C	3.21E-04		MANUAL VALVE @@@@@ FAILS TO CLOSE	PLANT-SPECIFIC
SW XV K	6.15E-08	H	MANUAL VALVE @@@@@ TRANSFERS CLOSED	BAYES
SW XV P	3.47E-07	H	MANUAL VALVE @@@@@ FAILS TO OPEN	BAYES

Type Code	Rate	U	Description	Source
UV CB R	1.33E-06	H	AC BREAKER @@@@@ TRANSFERS OPEN	PLANT-SPECIFIC
UV CF R	3.58E-08	H	FUSE @@@@@ FAILS OPEN	BAYES
UV LC D	3.89E-06	H	LOGIC CIRCUIT @@@@@ FAILS TO GENERATE SIGNAL	SAIC GDN
UV PX F	1.40E-06	H	POWER SUPPLY @@@@@ NO OUTPUT	SAIC GDN
UV RE B	7.65E-05	N	RELAY @@@@@ FAILS TO DEENERGIZE	SAIC GDN
UV RE E	7.65E-05	N	RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN
UV RU B	7.65E-05	N	UNDERVOLTAGE RELAY @@@@@ FAILS TO DEENERGIZE	SAIC GDN
UV RU E	7.65E-05	N	UNDERVOLTAGE RELAY @@@@@ FAILS TO ENERGIZE	SAIC GDN

Table 3.3.7-4
As Quantified Configuration Logic Flags (Page 1 of 2)

Logic Flag	*Description*	*Set To*	*Comments*
AAAACCHX_A	CCW Heat Exchanger EAC01A Is In Service	TRUE	Normal configuration is one CCW pump and its associated heat exchanger in service. Assumes that Component Cooling Water Heat Exchanger A (EAC01A) is in service.
AAAACCPMPA	CCW Pump A Is Aligned To Run	TRUE	Assumes that Component Cooling Water Pump A (PAC02A) is in service.
AAAAHVCT_A	Containment Cooling Train A Is Running	TRUE	Normal configuration is two containment recirculating fan cooling units in operation. Assumes that Containment Recirculating Fan Cooling Unit A (Fan ACF08A) is in service.
AAAAHVCT_B	Containment Cooling Train B Is Running	FALSE	Assumes that Containment Recirculating Fan Cooling Unit B (Fan ACF08B) is in standby.
AAAAHVCT_C	Containment Cooling Train C Is Running	TRUE	Assumes that Containment Recirculating Fan Cooling Unit C (Fan ACF08C) is in service.
AAAAHVCT_D	Containment Cooling Train D Is Running	FALSE	Assumes that Containment Recirculating Fan Cooling Unit D (Fan ACF08D) is in standby.
AAAAIAC02A	IA Compressor CIA02A Is Running	TRUE	Normal IA System configuration is two compressors in AUTO and the remaining compressor in STANDBY. Assumes that Instrument Air Compressor A (CIA02A) is running in AUTO.
AAAAIAC02B	IA Compressor CIA02B Is Running	TRUE	Assumes that Instrument Air Compressor B (CIA02B) is running in AUTO.
AAAAIAC02C	IS Compressor CIA02C Is Running	FALSE	Assumes that Instrument Air Compressor C (CIA02C) is running in STANDBY.
AAAAMCCG18	480 VAC Motor Control Center G Is Being Powered From 480 VAC Bus 18	TRUE	Motor Control Center G may be powered from either Bus 17 or Bus 18. Assumes that MCC G is being powered from Bus 18.
AAAAPUMP0A	Charging Pump A Is Running	FALSE	Normal configuration is two charging pumps running. Assumes that Charging Pump PCH01A is in standby.
AAAAPUMP0B	Charging Pump B Is Running	TRUE	Assumes that Charging Pump PCH01B is in operation.
AAAAPUMP0C	Charging Pump C Is Running	TRUE	Assumes that Charging Pump PCH01C is in operation.

Table 3.3.7-4
As Quantified Configuration Logic Flags (Page 2 of 2)

Logic Flag	*Description*	*Set To*	*Comments*
AAAASWP1AR	Service Water Pump PSW01A Is In Operation	TRUE	Typical configuration is two SW pumps running and two selected in standby. Assumes Service Water Pump PSW01A is in operation.
AAAASWP1AS	Service Water Pump PSW01A Is Selected In Standby	FALSE	Assumes Service Water Pump PSW01A is not selected in standby.
AAAASWP1BR	Service Water Pump PSW01B Is In Operation	FALSE	Assumes Service Water Pump PSW01B is not in operation.
AAAASWP1BS	Service Water Pump PSW01B Is Selected In Standby	TRUE	Assumes Service Water Pump PSW01B is selected in standby.
AAAASWP1CR	Service Water Pump PSW01C Is In Operation	FALSE	Assumes Service Water Pump PSW01C is not in operation.
AAAASWP1CS	Service Water Pump PSW01C Is Selected In Standby	TRUE	Assumes Service Water Pump PSW01C is selected in standby.
AAAASWP1DR	Service Water Pump PSW01D Is In Operation	TRUE	Assumes Service Water Pump PSW01D is in operation.
AAAASWP1DS	Service Water Pump PSW01D Is Selected In Standby	FALSE	Assumes Service Water Pump PSW01D is not selected in standby.

Table 3.3.7-5
Sequence Logic Flags (Page 1 of 6)

Sequence	*AAAA00ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAES0BAF*
Transient Sequences:				
T/B1/L1/P1	FALSE	FALSE	FALSE	TRUE
T/B1/L1/UH1	FALSE	FALSE	FALSE	TRUE
T/B1/L1/XL	FALSE	FALSE	FALSE	TRUE
T/B1/L1/FC/UCS	FALSE	FALSE	TRUE	TRUE
T/B1/L1/FC/XCS	FALSE	FALSE	TRUE	TRUE
Reactor Coolant Pump Seal LOCA Sequences:				
T/Q1/B1/L1/P2	FALSE	FALSE	FALSE	FALSE
T/Q1/B1/XH	FALSE	FALSE	TRUE	FALSE
T/Q1/XH	FALSE	FALSE	TRUE	FALSE
T/Q1/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q1/FC/XCS	FALSE	FALSE	TRUE	FALSE
T/Q1/B1/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q1/B1/FC/XCS	FALSE	FALSE	TRUE	FALSE
T/Q1/B1/L1/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q1/B1/L1/FC/XCS	FALSE	FALSE	TRUE	FALSE
T/Q1/B1/L1/XL	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/L1	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/FC/XCS	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/UA	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/UL	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/XL	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/FC/XCS	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/P3SS	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/UA	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/UL	FALSE	FALSE	TRUE	FALSE

Table 3.3.7-5
Sequence Logic Flags (Page 2 of 6)

Sequence	*AAAA00ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAESOBAF*
T/Q1/UH2/XL	FALSE	FALSE	TRUE	FALSE
T/Q1/UH2/B1/P3SS	FALSE	FALSE	TRUE	FALSE
PORV / RC Safety Valve LOCA Sequences:				
T/Q2/UH2	FALSE	FALSE	TRUE	FALSE
T/Q2/XL	FALSE	FALSE	TRUE	FALSE
T/Q2/FC/UCS	FALSE	FALSE	TRUE	FALSE
T/Q2/FC/XCS	FALSE	FALSE	TRUE	FALSE
Large Break LOCA Sequences:				
A/UA	FALSE	FALSE	FALSE	FALSE
A/UL	FALSE	FALSE	FALSE	FALSE
A/XL	FALSE	FALSE	TRUE	FALSE
A/FC/UCS	FALSE	FALSE	TRUE	FALSE
A/FC/XCS	FALSE	FALSE	TRUE	FALSE

Table 3.3.7-5
Sequence Logic Flags (Page 3 of 6)

Sequence	*AAAA00ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAES0BAF*
Medium Break LOCA Sequences:				
M/UH2	FALSE	FALSE	FALSE	FALSE
M/XL	FALSE	FALSE	TRUE	FALSE
M/FC/UCS	FALSE	FALSE	TRUE	FALSE
M/FC/XCS	FALSE	FALSE	TRUE	FALSE
Small Break LOCA Sequences:				
S/UH2	FALSE	FALSE	FALSE	FALSE
S/XH	FALSE	FALSE	TRUE	FALSE
S/FC/UCS	FALSE	FALSE	TRUE	FALSE
S/FC/XCS	FALSE	FALSE	TRUE	FALSE

Table 3.3.7-5 Sequence Logic Flags (Page 4 of 6)				
Sequence	*AAAA0ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAES0BAF*
Small - Small Break LOCA Sequences:				
SS/B1/L1/P2	FALSE	FALSE	FALSE	FALSE
SS/B1/XH	FALSE	FALSE	TRUE	FALSE
SS/B1/FC/UCS	FALSE	FALSE	TRUE	FALSE
SS/B1/FX/XCS	FALSE	FALSE	TRUE	FALSE
SS/B1/L1/FC/UCS	FALSE	FALSE	TRUE	FALSE
SS/B1/L1/FC/XCS	FALSE	FALSE	TRUE	FALSE
SS/B1/L1/XL	FALSE	FALSE	TRUE	FALSE
SS/FC/UCS	FALSE	FALSE	TRUE	FALSE
SS/FC/XCS	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/L1	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/FC/UCS	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/FC/XCS	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/UA	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/UL	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/XL	FALSE	FALSE	TRUE	FALSE
SS/UH2/FC/UCS	FALSE	FALSE	TRUE	FALSE
SS/UH2/FC/XCS	FALSE	FALSE	TRUE	FALSE
SS/UH2/P3SS	FALSE	FALSE	TRUE	FALSE
SS/UH2/UA	FALSE	FALSE	TRUE	FALSE
SS/UH2/UL	FALSE	FALSE	TRUE	FALSE
SS/UH2/XL	FALSE	FALSE	TRUE	FALSE
SS/UH2/B1/P3SS	FALSE	FALSE	TRUE	FALSE

Table 3.3.7-5
Sequence Logic Flags (Page 5 of 6)

Sequence	*AAAA00ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAES0BAF*
Anticipated Transients Without SCRAM (ATWS) Sequences:				
IE/KE/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/PF	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/PR1	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/FF/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/FF/PR2	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/FF/PF	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/AM	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/R1/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/R1/PR3	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/R1/FF/LT	TRUE	FALSE	FALSE	FALSE
IE/KE/MF/R1/FF/PR4	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/R1/FF/PF	TRUE	FALSE	FALSE	FALSE
IE/KE/PL/MF/R1/AM	TRUE	FALSE	FALSE	FALSE
IE/KM/LT	TRUE	FALSE	FALSE	FALSE
IE/KM/PF	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/LT	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/MF/LT	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/MF/PR3	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/MF/FF/LT	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/MF/FF/PR4	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/MF/FF/PF	TRUE	FALSE	FALSE	FALSE
IE/KM/PL/AM	TRUE	FALSE	FALSE	FALSE

Table 3.3.7-5
Sequence Logic Flags (Page 6 of 6)

Sequence	*AAAA00ATWS*	*AAAAAFISSG*	*AAAARECIRC*	*AAAAES0BAF*
Steam Generator Tube Rupture Sequences:				
R/I3S/SC	FALSE	FALSE	TRUE	FALSE
R/D	FALSE	FALSE	TRUE	FALSE
R/B1/I3S/SC	FALSE	FALSE	TRUE	FALSE
R/B1/D	FALSE	FALSE	TRUE	FALSE
R/B1/L1	FALSE	FALSE	TRUE	FALSE
R/UH2/SC	FALSE	FALSE	TRUE	FALSE
R/UH2/P3TR2	FALSE	FALSE	TRUE	FALSE
R/UH2/B1/SC	FALSE	FALSE	TRUE	FALSE
R/UH2/B1/P3TR2	FALSE	FALSE	TRUE	FALSE
R/UH2/B1/L1	FALSE	FALSE	TRUE	FALSE
R/I2/I3L/SC	FALSE	FALSE	TRUE	FALSE
R/I2/I3L/P3TR1	FALSE	FALSE	TRUE	FALSE
R/I2/D	FALSE	FALSE	TRUE	FALSE
R/I2/B1/I3L/SC	FALSE	FALSE	TRUE	FALSE
R/I2/B1/I3L/P3TR1	FALSE	FALSE	TRUE	FALSE
R/I2/B1/D	FALSE	FALSE	TRUE	FALSE
R/I2/B1/L1	FALSE	FALSE	TRUE	FALSE
R/I2/UH2/SC	FALSE	FALSE	TRUE	FALSE
R/I2/UH2/P3TR2	FALSE	FALSE	TRUE	FALSE
R/I2/UH2/B1/SC	FALSE	FALSE	TRUE	FALSE
R/I2/UH2/B1/P3TR2	FALSE	FALSE	TRUE	FALSE
R/I2/UH2/B1/L1	FALSE	FALSE	TRUE	FALSE
R/I1/SC	FALSE	FALSE	FALSE	FALSE
R/I1/P3TR1	FALSE	FALSE	FALSE	FALSE
R/I1/B1/SC	FALSE	FALSE	FALSE	FALSE
R/I1/B1/P3TR1	FALSE	FALSE	FALSE	FALSE

R/I1/B1/L1	FALSE	FALSE	FALSE	FALSE

Table 3.3.7-6
Quantification Batch And Macro Files

Batch File	*Macro File*	*Description*
QUANT.BAT	FTPMAC.MAC CUTLOAD.MAC	QUANT.BAT calls the CAFTA fault tree editor (CAF386.EXE) and runs the editor under the control of the macro file FTPMAC.MAC. This macro adds the configuration flags to the logic model from FLAGS.FRE, sets the sequence logic flags to either TRUE or FALSE as defined in the sequence driver file, redefines all logic flags as either TRUE or FALSE, and redefines the specified sequences as the top event in the fault tree. The model is then written to a .FTP file; this file is used as input to the cut set generator. The master integrated model logic file is exited without saving the reconfigured logic. This preserves the integrated logic model for subsequent analyses. Once the .FTP files have been created, QUANT.BAT calls the cut set editor (CSED386.EXE) and runs it under the control of the macro file CUTLOAD.MAC. This macro loads the generated cut sets from a .RAW file into the cut set editor and saves them in an appropriately named .CUT file.
CUTDEL.BAT	CUTDEL.MAC	CUTDEL.MAC runs the cut set editor (CSED386.EXE) under the control of the macro CUTDEL.MAC. This macro deletes cut sets containing mutually exclusive events and / or cut sets which do not satisfy the sequence logic specified in the event trees (i.e., to account for sequence success paths).

Table 3.3.7-7
Quantification Driver Files

Driver File	*Batch Files*	*Description*
MAKE_INT.BAT	None	Creates the master integrated logic model (GINNA.*)
ALL.BAT	RGETRANS.BAT RGESLOCA.BAT RGEMLOCA.BAT RGELLOCA.BAT RGESGTR.BAT RGEATWS.BAT	General driver file to generate minimal cut sets for all sequences.
RGETRANS.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all transient induced core damage sequences.
RGESLOCA.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all small break loss of coolant (SLOCA) induced core damage sequences.
RGEMLOCA.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all medium break loss of coolant (MLOCA) induced core damage sequences.
RGELLOCA.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all large break loss of coolant (LLOCA) induced core damage sequences.
RGESGTR.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all steam generator tube rupture (SGTR) induced core damage sequences.
RGEATWS.BAT	QUANT.BAT CUTDEL.BAT	Generate minimal cut sets for all anticipated transients without SCRAM (ATWS) induced core damage sequences.

Table 3.3.7-8 Success Path File Generation and Use		
Batch File	*Success Path Files Generated*	*External Success Path Files Used To Delete Success Paths*
RGETRANS.BAT	B1, HPR, L1, LPR, P1, P2, Q1, Q2, TNOTQ1, TNOTQ2, UCS, UH1, UH2	none
RGESLOCA.BAT	none	B1, HPR, L1, LPR, P2, UCS
RGEMLOCA.BAT	none	LPR, UCS
RGELLOCA.BAT	none	UCS
RGESGTR.BAT	D1, I1, I2, SD	B1, L1, UH2
RGEATWS.BAT	TLFF, TLPF, TLPR1, TLPR2, TLPR3, TLPR4	none

Table 3.3.7-9
CROSS-REFERENCE OF POST-TRIP HUMAN FAILURE EVENTS TO SEQUENCES

SEQUENCES	AFHFDPCD04	AFHFDSWX03	CTHFDISOLA	CTHFDISOLB	IAHFDCNTBK	RCHDF01BAF	RCHFD00RCP	RCHFDCD0SS	RCHFDCDDPR	RCHFDCDTR1	RCHFDCDTR2	RCHFDPLOCA	RHHFD0SGTR	RRHFDRCR0A	RRHFDRCR0M	RRHFDRCR0S	RRHFDRCRSS
T/B1/L1/UH1						X											
T/B1/L1/XL															X		
T/Q1/B1/XH							X										
T/Q1/XH							X										
T/Q1/B1/L1/XL							X										
T/Q2/XL												X			X		
A/XL														X			
M/XL															X		
S/XL																X	
SS/B1/XH	X	X															X
SS/UH2/P3SS								X									
SS/UH2/XL														X			
R/I3S/SC													X				
R/D					X				X								
R/B1/D	X	X			X				X								
R/UH2/SC													X				
R/UH2/P3TR2											X						
R/I1/SC			X	X									X				
R/I1/P3TR1			X	X						X							
R/I1/B1/SC	X	X	X	X									X				
R/I1/B1/P3TR1	X	X	X	X						X							

Table 3.3.7-10
CROSS-REFERENCE OF NONRECOVERY EVENTS TO SEQUENCES

SEQUENCES	NRHAFWCOOL	NRHCCWPUMP	NRHLETDOWN	NRHLRHRTHL	NRS011BDC	NRHS0ALTCD	NROGRID10H
T/B1/L1/P1	X				X		X
T/B1/L1/UH1							X
T/B1/L1/XL	X		X	X			X
T/Q2/XL		X	X	X			
A/XL			X				
M/XL			X				
R/D						X	
R/B1/D						X	
R/UH2/P3TR2						X	
R/I1/P3TR1						X	

Table 3.3.7-11
DETERMINATION OF THE NEED TO MODEL HARDWARE
CONTRIBUTIONS TO NONRECOVERY EVENTS

SEQUENCES		NRHAFWCOOL	NRHCCWPUMP	NRHLETDOWN	NRHLRHRTHL	NRS011BDC	NRHS0ALTCD
T/B1/L1/P1	CDF	3.97E-07				1.74E-07	
	prob	1.26E-01				2.88E-01	
T/B1/L1/UH1	CDF						
	prob						
T/B1/L1/XL	CDF	1.78E-06		1.58E-07	6.96E-08		
	prob	2.81E-02		3.16E-01	7.19E-01		
T/Q2/XL	CDF		6.70E-07	3.95E-05	8.18E-06		
	prob		7.46E-02	1.27E-03	6.11E-03		
A/XL	CDF			1.04E-05			
	prob			4.83E-03			
M/XL	CDF			2.30E-05			
	prob			2.17E-03			
R/D	CDF						1.22E-03
	prob						4.11E-05
R/B1/D	CDF						1.02E-06
	prob						4.88E-02
R/UH2/P3TR2	CDF						1.14E-05
	prob						4.40E-03
R/I1/P3TR1	CDF						6.62E-07
	prob						7.56E-02
maximum hardware-related nonrecovery event probability to ensure that all cut sets containing the nonrecovery are below the truncation limit of 5.00E-08/y		2.81E-02	7.46E-02	1.27E-03	6.11E-03	2.88E-01	4.11E-05
approximate hardware-related nonrecovery event probability		3.47E-04	2.16E-03	3.47E-04	3.12E-06	2.59E-08	3.21E-05
hardware model required		N	N	N	N	N	N

LEGEND

CDF: core-damage frequency of the most likely cut set in the sequence containing the nonrecovery event

prob: maximum probability of the hardware contribution to ensure that all cut sets containing the nonrecovery event are below the truncation limit (= 5.00E-08/CDF)

Table 3.3.7-12
MATRIX OF INFLUENCE INDICES

Location	in-CR 0		ex-CR 2
Available Time	long (several hours) 0	medium (up to one hour) 1	short (several minutes) 2
Human Engineering	simple, single action; no adverse conditions 0	difficult access; poor lighting; separated I&C 1	multiple actions or locations; physical protective clothing or tools required 2
Training	normal operations; frequent practice 0	some training or practice 1	no regular training or practice 2

Table 3.3.7-13 CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS							
		As Quantified		*After Recovery*			
Sequence	*Cut Set File*	*Number Of Cut Sets*	*Frequency (/y)*	*Refined HFD*	*NR*	*Number Of Cut Sets*	*Frequency (/y)*
TRANSIENT SEQUENCES							
T/B1/L1/P1	TB1L1P1	25	3.02E-06	N	Y	15	1.12E-06
T/B1/L1/UH1	TB1L1UH1	169	4.69E-05	Y	Y	4	8.37E-07
T/B1/L1/XL	TB1L1XL	20	3.94E-06	Y	Y	3	2.66E-07
T/B1/L1/FC/UCS	TBLFUS	0	-	-	-	-	-
T/B1/L1/FC/XCS	TBLFXC	0	-	-	-	-	-
				TRANSIENT SEQUENCES TOTAL			2.22E-06
REACTOR COOLANT PUMP SEAL LOCA SEQUENCES							
T/Q1/B1/L1/P2	TQ1B1L1P	0	-	-	-	-	-
T/Q1/B1/XH	TQ1B1XH	1	8.45E-08	N	Y	0	-
T/Q1/XH	TQ1XH	15	3.69E-06	Y	N	0	-
T/Q1/FC/UCS	TQ1FUS	0	-	-	-	-	-
T/Q1/FC/XCS	TQ1FXS	0	-	-	-	-	-
T/Q1/B1/FC/UCS	TQ1BFUS	0	-	-	-	-	-
T/Q1/B1/FC/XCS	TQ1BFXS	0	-	-	-	-	-
T/Q1/B1/L1/FC/UCS	TQ1BLFUS	0	-	-	-	-	-
T/Q1/B1/L1/FC/XCS	TQ1BLFXS	0	-	-	-	-	-
T/Q1/B1/L1/XL	TQ1BLXL	1	1.78E-07	N	N	0	-
T/Q1/UH2/B1/L1	TQ1U1	0	-	-	-	-	-
T/Q1/UH2/B1/FC/UCS	TQ1U2	0	-	-	-	-	-
T/Q1/UH2/B1/FC/XCS	TQ1U3	0	-	-	-	-	-
T/Q1/UH2/B1/UA	TQ1U4	0	-	-	-	-	-
T/Q1/UH2/B1/UL	TQ1U5	0	-	-	-	-	-
T/Q1/UH2/B1/XL	TQ1U6	0	-	-	-	-	-

Table 3.3.7-13
CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS

Sequence	Cut Set File	As Quantified: Number Of Cut Sets	As Quantified: Frequency (/y)	After Recovery: Refined HFD	After Recovery: NR	After Recovery: Number Of Cut Sets	After Recovery: Frequency (/y)
T/Q1/UH2/FC/UCS	TQ1U7	0	-	-	-	-	-
T/Q1/UH2/FC/XCS	TQ1U8	0	-	-	-	-	-
T/Q1/UH2/P3SS	TQ1U9	0	-	-	-	-	-
T/Q1/UH2/UA	TQ1U10	0	-	-	-	-	-
T/Q1/UH2/UL	TQ1U11	0	-	-	-	-	-
T/Q1/UH2/XL	TQ1U12	0	-	-	-	-	-
T/Q1/UH2/B1/P3SS	TQ1U13	0	-	-	-	-	-
REACTOR COOLANT PUMP SEAL LOCA SEQUENCES TOTAL							< 5.00E-08
PORV / RC SAFETY VALVE LOCA SEQUENCES							
T/Q2/UH2	TQ2UH2	12	3.37E-06	N	N	12	3.37E-06
T/Q2/XL	TQ2XL	220	3.14E-04	Y	Y	54	1.82E-05
T/Q2/FC/UCS	TQ2FUS	0	-	-	-	-	-
T/Q2/FC/XCS	TQ2FXS	0	-	-	-	-	-
PORV / RC SAFETY VALVE LOCA SEQUENCES TOTAL							2.16E-05
LARGE BREAK LOCA SEQUENCES							
A/UA	AUA	0	-	-	-	-	-
A/UL	AUL	4	1.44E-06	N	N	4	1.44E-06
A/XL	AXL	9	2.91E-05	Y	Y	9	1.65E-06
A/FC/UCS	AFUS	0	-	-	-	-	-
A/FC/XCS	AFXS	0	-	-	-	-	-
LARGE BREAK LOCA SEQUENCES TOTAL							3.09E-06

Table 3.3.7-13 CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS							
		As Quantified		*After Recovery*			
Sequence	*Cut Set File*	*Number Of Cut Sets*	*Frequency (/y)*	*Refined HFD*	*NR*	*Number Of Cut Sets*	*Frequency (/y)*
MEDIUM BREAK LOCA SEQUENCES							
M/UH2	MUH	4	9.22E-07	N	N	4	9.22E-07
M/XL	MXL	17	6.76E-05	Y	Y	15	4.83E-06
M/FC/UCS	MFUS	0	-	-	-	-	-
M/FC/XCS	MFXS	0	-	-	-	-	-
			MEDIUM BREAK LOCA SEQUENCES TOTAL				**5.75E-06**
SMALL BREAK LOCA SEQUENCES							
S/UH2	SUH	4	8.53E-07	N	N	4	8.53E-07
S/XH	SXH	25	4.11E-05	Y	N	24	4.11E-06
S/FC/UCS	SFUS	0	-	-	-	-	-
S/FC/XCS	SFXS	0	-	-	-	-	-
			SMALL BREAK LOCA SEQUENCES TOTAL				**4.96E-06**
SMALL-SMALL BREAK LOCA SEQUENCES							
SS/B1/L1/P2	SSB1L1P	0	-	-	-	-	-
SS/B1/XH	SSB1XH	2	1.61E-07	Y	N	0	-
SS/B1/FC/UCS	SSB1FUS	0	-	-	-	-	-
SS/B1/FX/XCS	SSB1FXS	0	-	-	-	-	-
SS/B1/L1/FC/UCS	SSBLFUS	0	-	-	-	-	-
SS/B1/L1/FC/XCS	SSBLFXS	0	-	-	-	-	-
SS/B1/L1/XL	SSBLXL	0	-	-	-	-	-
SS/FC/UCS	SSFUS	0	-	-	-	-	-
SS/FC/XCS	SSFXS	0	-	-	-	-	-
SS/XH	SSXH	44	8.23E-05	Y	N	44	9.40E-06
SS/UH2/B1/L1	SSU1	0	-	-	-	-	-

Table 3.3.7-13 CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS							
		As Quantified		*After Recovery*			
Sequence	*Cut Set File*	*Number Of Cut Sets*	*Frequency (/y)*	*Refined HFD*	*NR*	*Number Of Cut Sets*	*Frequency (/y)*
SS/UH2/B1/FC/UCS	SSU2	0	-	-	-	-	-
SS/UH2/B1/FC/XCS	SSU3	0	-	-	-	-	-
SS/UH2/B1/UA	SSU4	0	-	-	-	-	-
SS/UH2/B1/UL	SSU5	0	-	-	-	-	-
SS/UH2/B1/XL	SSU6	0	-	-	-	-	-
SS/UH2/FC/UCS	SSU7	0	-	-	-	-	-
SS/UH2/FC/XCS	SSU8	0	-	-	-	-	-
SS/UH2/P3SS	SSU9	1	6.12E-08	Y	N	0	-
SS/UH2/UA	SSU10	1	5.60E-08	N	N	1	5.60E-08
SS/UH2/UL	SSU11	1	1.88E-07	N	N	1	1.88E-07
SS/UH2/XL	SSU12	1	6.12E-08	Y	N	0	-
SS/UH2/B1/P3SS	SSU13	0	-	-	-	-	-
		SMALL-SMALL BREAK LOCA SEQUENCES TOTAL					9.64E-06
ANTICIPATED TRANSIENTS WITHOUT SCRAM SEQUENCES							
IE/KE/LT	ATWS3	0	-	-	-	-	-
IE/KE/PF	ATWS4	0	-	-	-	-	-
IE/KE/PL/LT	ATWS6	0	-	-	-	-	-
IE/KE/PL/MF/LT	ATWS8	0	-	-	-	-	-
IE/KE/PL/MF/PR1	ATWS9	0	-	-	-	-	-
IE/KE/PL/MF/FF/LT	ATWS11	0	-	-	-	-	-
IE/KE/PL/MF/FF/PR2	ATWS12	0	-	-	-	-	-
IE/KE/PL/MF/FF/PF	ATWS13	0	-	-	-	-	-
IE/KE/PL/MF/AM	ATWS14	0	-	-	-	-	-
IE/KE/PL/MF/R1/LT	ATWS16	0	-	-	-	-	-
IE/KE/PL/MF/R1/PR3	ATWS17	0	-	-	-	-	-

Table 3.3.7-13
CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS

Sequence	Cut Set File	As Quantified		After Recovery			
		Number Of Cut Sets	Frequency (/y)	Refined HFD	NR	Number Of Cut Sets	Frequency (/y)
IE/KE/PL/MF/R1/FF/LT	ATWS19	0	-	-	-	-	-
IE/KE/MF/R1/FF/PR4	ATWS20	0	-	-	-	-	-
IE/KE/PL/MF/R1/FF/PF	ATWS21	0	-	-	-	-	-
IE/KE/PL/MF/R1/AM	ATWS22	0	-	-	-	-	-
IE/KM/LT	ATWS24	1	5.13E-08	N	N	1	5.13E-08
IE/KM/PF	ATWS25	0	-	-	-	-	-
IE/KM/PL/LT	ATWS27	0	-	-	-	-	-
IE/KM/PL/MF/LT	ATWS29	1	1.14E-07	N	N	1	1.14E-07
IE/KM/PL/MF/PR3	ATWS30	0	-	-	-	-	-
IE/KM/PL/MF/FF/LT	ATWS32	0	-	-	-	-	-
IE/KM/PL/MF/FF/PR4	ATWS33	0	-	-	-	-	-
IE/KM/PL/MF/FF/PF	ATWS34	0	-	-	-	-	-
IE/KM/PL/AM	ATWS35	0	-	-	-	-	-
ANTICIPATED TRANSIENTS WITHOUT SCRAM SEQUENCES TOTAL							1.65E-07
STEAM GENERATOR TUBE RUPTURE SEQUENCES							
R/I3S/SC	SGTR03	2	1.03E-05	Y	N	0	-
R/D	SGTR04	127	3.40E-03	Y	Y	27	1.40E-05
R/B1/I3S/SC	SGTR07	0	-	-	-	-	-
R/B1/D	SGTR08	22	9.65E-06	Y	Y	1	1.34E-07
R/B1/L1	SGTR09	0	-	-	-	-	-
R/UH2/SC	SGTR11	13	2.96E-05	Y	N	0	-
R/UH2/P3TR2	SGTR12	23	7.44E-06	Y	Y	0	-
R/UH2/B1/SC	SGTR14	0	-	-	-	-	-
R/UH2/B1/P3TR2	SGTR15	0	-	-	-	-	-
R/UH2/B1/L1	SGTR16	0	-	-	-	-	-

Table 3.3.7-13
CORE-DAMAGE FREQUENCY RESULTS FOR INTERNAL INITIATING EVENTS

Sequence	Cut Set File	As Quantified		After Recovery			
		Number Of Cut Sets	Frequency (/y)	Refined HFD	NR	Number Of Cut Sets	Frequency (/y)
R/I2/I3L/SC	SGTR19	0	-	-	-	-	-
R/I2/I3L/P3TR1	SGTR20	0	-	-	-	-	-
R/I2/D	SGTR21	0	-	-	-	-	-
R/I2/B1/I3L/SC	SGTR24	0	-	-	-	-	-
R/I2/B1/I3L/P3TR1	SGTR25	0	-	-	-	-	-
R/I2/B1/D	SGTR26	0	-	-	-	-	-
R/I2/B1/L1	SGTR27	0	-	-	-	-	-
R/I2/UH2/SC	SGTR29	0	-	-	-	-	-
R/I2/UH2/P3TR2	SGTR30	0	-	-	-	-	-
R/I2UH2/B1/SC	SGTR32	0	-	-	-	-	-
R/I2/UH2/B1/P3TR2	SGTR33	0	-	-	-	-	-
R/I2/UH2/B1/L1	SGTR34	0	-	-	-	-	-
R/I1/SC	SGTR36	41	2.36E-03	Y	N	8	7.96E-07
R/I1/P3TR1	SGTR37	129	6.30E-04	Y	Y	29	1.20E-05
R/I1/B1/SC	SGTR39	28	6.01E-06	Y	N	0	-
R/I1/B1/P3TR1	SGTR40	7	6.39E-07	Y	N	0	-
R/I1/B1/L1	SGTR41	0	-	-	-	-	-
STEAM GENERATOR TUBE RUPTURE SEQUENCES TOTAL							2.69E-05
TOTAL FOR ALL INTERNAL SEQUENCES							7.43E-05

Figure 3.3.7-1
Model Integration Process

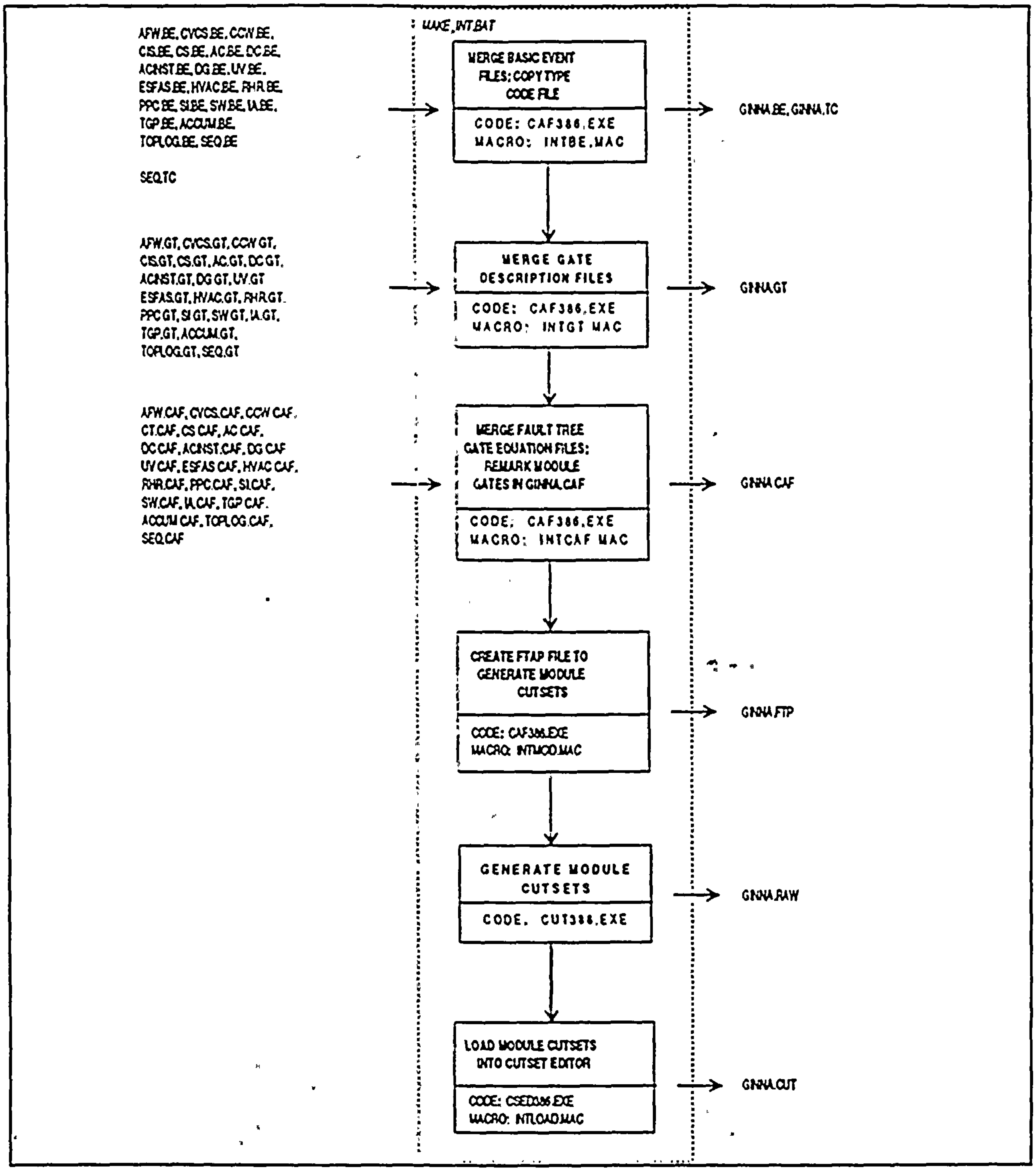


Figure 3.3.7-2
Software Implimentation of the Quantification Process

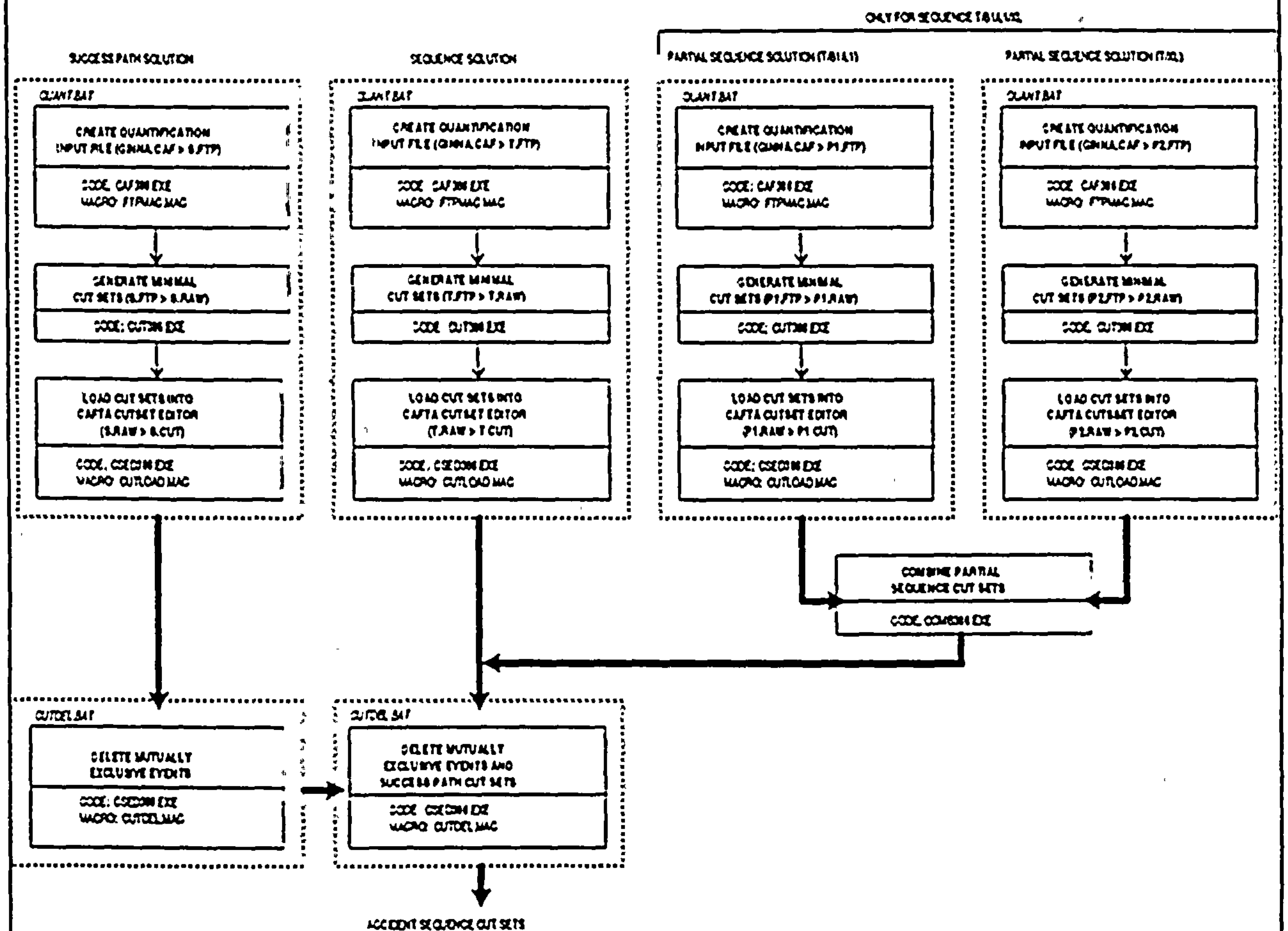
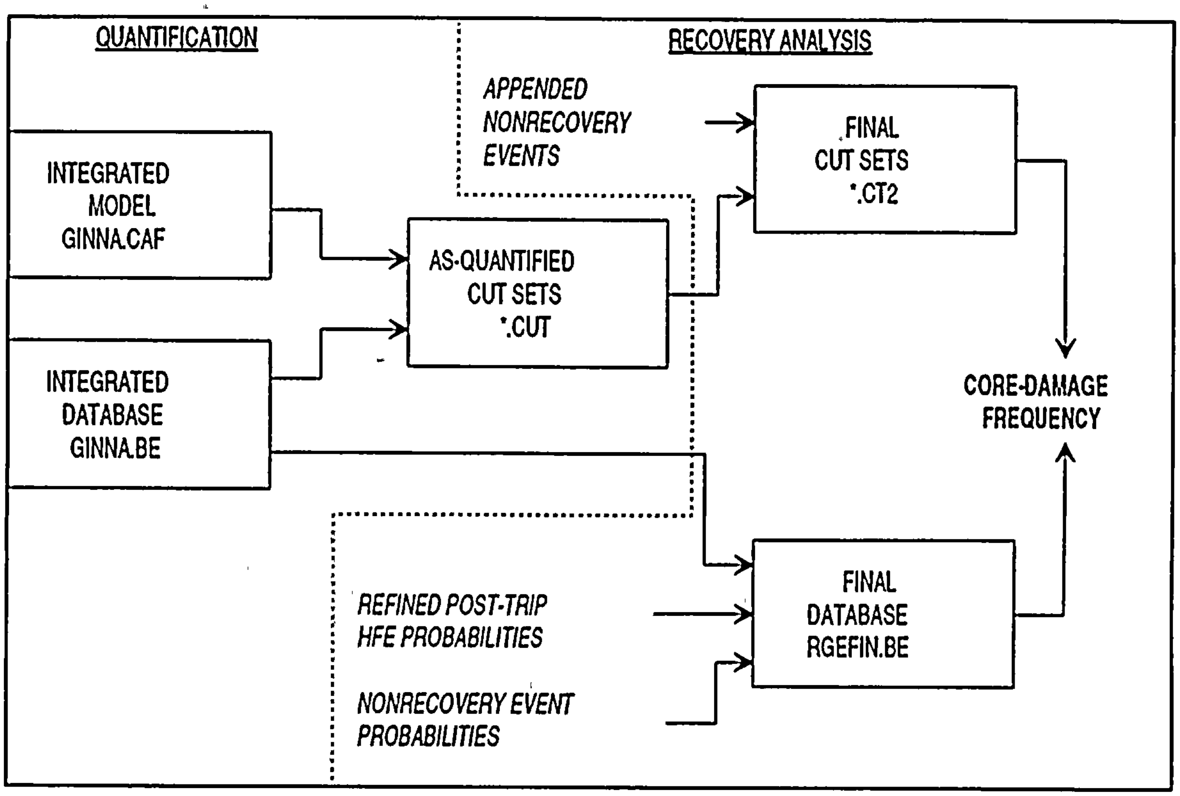


Figure 3.3.7-3
Computer File Development Process.



3.3.8 Internal Plant Flooding Analysis

3.3.8.1 Introduction

This section presents the methods, supporting information, and results of the assessment to plant risk from internal floods. The internal plant flooding analysis was conducted in accordance with the *Flood Analysis Task Procedure* [Ref. 3.3.8-1]. Only the risk of core damage due to internal floods (floods originating within the plant confines) has been assessed; the impact of such floods on containment performance systems has not been generally addressed.

Each plant location has been systematically reviewed for any possible threat to the plant equipment required to prevent core damage; no *a priori* assumptions have been made which eliminated certain areas of the plant. To keep the analysis tractable, a series of screening analyses were performed to focus attention on those plant locations which pose the greatest risk. Following an initial information gathering effort, the initial screening analysis eliminated plant locations which (1) did not contain any equipment related to a basic event in the integrated plant risk model, and (2) did not contain any equipment which, if flooded, would initiate a plant trip. The second screening analysis consisted of a computer search for dominant core-damage sequences caused by floods originating from specific sources and affected specific plant locations. A detailed analysis was performed on all dominant sequences remaining after the second screening analysis, consisting of (1) refinement of the flood occurrence frequency, (2) reassessment of flood vulnerabilities, and (3) recovery analysis. It should be noted that this approach expresses flood-induced core-damage risk in terms of the same sequences defined in Section 3.3.1.2 [Ref. 3.3.8-2].

3.3.8.2 Identification of Flood Vulnerabilities

Information was gathered to determine the vulnerability of equipment included within the integrated plant risk model (see Section 3.3.7 [Ref. 3.3.8-3]) to floods. First, a set of flood areas and flood zones were defined based on the plant layout (e.g., buildings, walls, etc.). Second, each basic event that would occur if associated plant equipment was sprayed or submerged by a flood was related to one or more equipment identification numbers (EINs), which were subsequently mapped into the previously defined flood zones. The following sections describe these steps in detail.

3.3.8.2.1 Specification of Flood Areas and Flood Zones

Flood areas and flood zones were defined [Ref. 3.3.8-4] through a review of plant layout drawings and walkdowns. For the purposes of this analysis, the following definitions were made:

Flood Area: Major structural areas of the plant which may be susceptible to internal flooding, or areas that contain fluid systems or stored fluid volumes which, if failed, could act as a source of internal flooding to an interconnected flood area or flood zone.

Flood Zone: A further division of a flood area, based on floor elevations and/or other structural features such as support columns, doors and/or passive flood barriers.

Table 3.3.8-1 lists the flood areas and flood zones. Figure 3.3.8-1 summarizes the major interconnections among flood zones as identified by RG&E. A tabulation of significant flood sources by flood zone, as reported by RG&E, is contained in Table 3.3.8-2.

3.3.8.2.2 Mapping PRA Basic Events to Flood Zones

In order to utilize the integrated plant risk model to assess flood-induced core-damage risk, it was necessary to determine which basic events would occur following a flood in a given zone (or combination of zones). In principle, this task is straightforward: (1) Eliminate basic events whose associated equipment is not vulnerable to floods (e.g., manual valves, etc.); (2) Relate the remaining basic events to plant EINs; and, (3) Determine the location of those previously identified EINs in terms of the defined flood zones. A computerized database was developed to organize the required information [Ref. 3.3.8-5]. The following sections summarize how this database was populated.

3.3.8.2.2.1 Identifying Basic Events Vulnerable to Floods

A complete list of basic events in the integrated plant risk model was obtained from the *Quantification Work Package* [Ref. 3.3.8-3] (in particular, from the CAFTA Basic Event File GINNA.BE). The following types of basic events were removed as either (1) they are not vulnerable to floods, or (2) they are not associated with specific plant locations:

1. Manual valves;

2. Piping;

3. Heat exchangers;

4. Check valves;

5. Tanks;

6. Test / maintenance unavailability events;

7. Human failure events;

8. Initiating events (initiating events induced by floods are discussed in Section 3.3.8.3.1.2);

9. Common-cause failure modules;

10. Modular events; and,

11. Logic flags.

All other basic events were assumed to be vulnerable to flood effects (spray and/or submergence). It was assumed that all failure modes of a vulnerable component were possible; basic events were not eliminated from the flood analysis database on the basis of component failure mode.

3.3.8.2.2.2 Relating Basic Events to EINs

The basic event descriptions were reviewed to associate each event with an EIN. In some cases, these descriptions were unclear or incomplete, and the associated fault tree models and referenced drawings used to develop them were reviewed.

3.3.8.2.2.3 Identifying Electrical Subcomponents

During the process of mapping basic events to EINs, it was noted that the component boundaries used to develop the fault tree models [Ref. 3.3.8-6] often included subcomponents which have unique plant locations. For example, motor-operated valve 4614 in the service water system (basic events SWMVC04614, SWMVK04614, AND SWMVN04614) is located in flood zone IBN; it also has subcomponents such as the load circuit breaker (flood zone ABO), hand controller (flood zone CR), thermal overload bypass relay (flood zone ABM), DC control power fuses (flood zone ABO), and the ESFAS / safety injection signal auxiliary relay (flood zone RR). The load circuit breaker and DC control power fuses are individually modeled in the PRA; hence, their EINs were identified through review of the basic event descriptions. The other subcomponents were noted during review of the associated electrical elementary drawings.

Another source of unmodeled electrical components is interconnecting cables (which were not modeled) containing splice boxes. Thus, a detailed drawing review was conducted to identify electrical subcomponents and their unique locations.

3.3.8.2.2.4 Relating EINS to Flood Zones

EINs were related to the defined flood zones through several methods: (1) review of plant layout drawings, (2) review of process and instrumentation drawings (P&IDs), (3) plant walkdowns, and (4) queries of various RG&E databases (e.g., GMEDB, CMIS, etc.). For electrical subcomponents, it was efficient to relate a specific subcomponent to a panel, cabinet, or relay rack and subsequently identify the flood zone of the associated panel, cabinet, or relay rack.

3.3.8.3 Initial Screening Analysis

Following the collection and organization of information, as described in Section 3.3.8.2, an initial screening analysis was performed to eliminate flood zones from further consideration using the following bases:

1. The flood zone does not contain any significant flood sources <u>and</u> cannot be flooded from any flood zone; or,

2. The flood zone does not contain any equipment whose failure causes the occurrence of <u>either</u> a PRA basic event <u>or</u> an internal initiating event.

The first criteria eliminates flood zones which may contain vulnerable equipment of interest, but cannot be flooded by any means. The second criteria eliminates flood zones which do not impact the integrated plant risk model events.

3.3.8.3.1 Definition of Flooding Scenarios

A *flooding scenario* is defined as the occurrence of a flood from a specific source in an originating flood zone which affects one or more adjacent flood zones. The initial screening analysis was performed by noting that flood zones may be eliminated from further consideration if they do not appear in any flooding scenario. Thus, flooding scenarios express how the integrated risk model interfaces with plant locations and equipment susceptible to flood effects.

Three elements must be considered when defining flood scenarios: (1) The possibility that plant equipment will be either sprayed or submerged given a flood in any flood zone; (2) The possibility that a plant trip will occur given a flood in a specific flood zone; and, (3) The possibility that flood water may flow into or out of a given flood zone from adjacent zones. The information collected in Section 3.3.8.2 has been used to address these elements, as discussed in the following sections.

3.3.8.3.1.1 Relating Flood Zones to Basic Events

The flood analysis database was queried to determine the set of basic events associated with each flood zone. In order to support other tasks in the flood analysis, results of these queries were expressed in the form of free-formatted fault tree gate equations suitable for importing into the integrated risk CAFTA model; these gate equations are contained in *flood flag files* (one per flood zone). No basic events were associated with the following flood zones: AVT, CT, IBB, SBM, and SHW.

The flood analysis database was populated under the assumption that basic events associated with electrically connected components (i.e., components which receive electrical motive or control power, or receive or transmit electrical signals) will occur if the underlying components or electrical subcomponents are sprayed or submerged. Each flood flag file generated through the interrogation of the flood analysis database was reviewed to check the validity of this assumption. In certain cases, manual adjustments were made:

1. **De-energized motor-operated valves**

   The containment spray, safety injection, and RHR systems contain several motor-operated valves which are electrically disconnected when the plant is in operation. In the integrated plant risk model, these valves were modeled as manual valves (the third and fourth characters in the ten-character basic event name are "XV"). Thus, a flood cannot impact these valves, and all XV-related basic events were removed from the flags files ABO.FRE and ABM.FRE.

2. **TSC Manual Throwover Switch** (DCPDPTB02)

   DCPDPTB02, located in Flood Zone TB/TBB, allows either battery (BRTYA or BRTYB) to be supplied from the TSC battery (BTRYTSC). It is normally deenergized since all of the fused disconnect links with which it interfaces (DCPDPCD01, DCPDPCB05A, and DCPDPCB05B) are open during plant operation. Thus, a flood in the turbine building basement cannot adversely affect either battery. Accordingly, basic event DCBDFFUSEB was removed from flag file TBB.FRE.

3. **Instrument Bus Maintenance Power Supply** (CVTAUX)

The flood analysis database indicates that the instrument bus maintenance power supply, CVTAUX, is a subcomponent to each 120 VAC instrument bus (IBPDPCBAR, IBPDPCBBW, IBPDPCBCB, and IBPDPCBDY). CVTAUX, powered from 480 VAC Motor Control Center A which is located in the turbine building basement, is not connected to any instrument bus when the plant is operating; subsequently, its failure due to a flood is of no consequence. Thus, events ACB4FBUS1A, ACB4FBUS1B, ACB4FBUS1C, and ACB4FBUS1D were removed from the flood flag file TBB.FRE.

3.3.8.3.1.2 Defining Flood Initiators

A flood may initiate a plant trip in two ways: (1) Spray or submergence of essential plant equipment; and / or, (2) Failure of the pressure boundary in operating systems. In the first case, the only characteristic of the flood source that is important is its proximity to essential equipment (e.g., spray from any water system located in the vicinity of switchgear, etc.). The second case relates directly to the defined internal initiators of the PRA (e.g., a pipe rupture in the CCW header is equivalent to initiator TI000CCW).

The flood sources located within each flood zone were assessed as to their ability to cause plant trips by one or both of the mechanisms identified above, using knowledge from the flood analysis database and discussions with RG&E. Flood initiators were developed for each flood zone according to the following guidelines:

1. Floods originating from sources directly analogous to one of the internal PRA initiators were assumed to cause the related initiator to occur (affects main feedwater, service water, and CCW systems);

2. Floods originating from source not directly represented by an internal PRA initiator which sprayed or submerged essential plant equipment were assumed to cause the generic plant trip initiator TIRXTRIP;

3. Floods from any source that could not spray or submerge any equipment related to PRA basic event were assumed to be subsumed within one of the existing internal initiators and, subsequently, were not further considered (this guideline requires the consideration of flood zone interconnections);

4. Flood sources originating from the reactor coolant system (interfacing system LOCAs) were not addressed since such events have been separately considered in

the PRA [Ref. 3.3.8-7];

5. Flood sources which could cause or increase the possibility of transient-induced LOCAs (e.g., reactor coolant pump seal LOCAs, etc.) were retained; and,

6. Since DC power is required to open the PORVs and the possibility of a "hot short" across conductors during a flood is remote, it was assumed that a flood could not result in a spurious actuation of the PORVs.

Table 3.3.8-3 relates the specific flood sources within a given flood zone to the occurrence of each internal initiator.

3.3.8.3.1.3 Considering Flood Zone Interconnections

A set of flooding scenarios (Table 3.3.8-4) was defined for floods located within a single flood zone; note that each flood zone may have more than one flood initiator and, thus, more than one related flooding scenario. Such an approach provided a conservative bounding estimate for spray effects since it was assumed that all PRA-related equipment within the flood zone would be failed (sprays tend to be highly localized and, thus, would not typically affect all equipment within a given flood zone).

Flooding scenarios affecting multiple flood zones were defined based on a review of the flood zone interconnection information [Ref. 3.3.8-4]. Within the turbine building, a flood originating in zone TBM from the main feedwater piping and propagating into zone TBB was defined to conservatively address steam floods. There is no other credible source of flooding in zone TBM which can also affect zone TBB. A second multiple flooding scenario originates in zone SBM from the CCW header and propagates into zone SBB. (Note that there is no PRA-related equipment in zone SBM; hence, a flood from the CCW header which is confined to zone SBM is bounded by initiator TI000CCW. Further, a plant trip cannot occur due to flooding in zone SBB. Thus, this flooding scenario is interesting in that both zone must be affected.)

Flooding scenarios involving multiple zones within the auxiliary building are not credible. A conservative calculation [Ref. 3.3.8-8] indicates that zone ABS holds about 50,000 gallons, and that zone ABB holds about 318,000 gallons. Thus, either a large-volume or long-duration flood is required to affect these zones. As indicated in Table 3.3.8-2, the only flood source within zone ABB whose occurrence could lead to a plant trip is a rupture of the CCW header (an RWST rupture will not cause an immediate plant trip); however, the CCW system volume is small as compared to the free volume of zone ABS. Thus, a flood originating within zone ABB from the CCW header cannot substantially affect zone ABS. Floods from the service water header originating in either zone ABM or ABO (which connect with zones ABB and ABS) would have to go unnoticed for a substantial period of time to create a problem involving multiple flood zones; there is no other source of flooding in zones ABM and ABO which has sufficient volume to adversely affect the other auxiliary building flood zones.

3.3.8.3.2 Results of the Initial Screening Analysis

The results of the initial screening analysis are shown in Table 3.3.8-5, which addresses the three elements discussed in Sections 3.3.8.3.1.1, 3.3.8.3.1.2, and 3.3.8.3.1.3 and compares these elements with the screening criteria given in the introduction to Section 3.3.8.3. As result of the initial screening analysis, fourteen of thirty flood zones were eliminated from further consideration.

Flood zone IBN has been eliminated from further consideration based on RG&E's and NRC's assessment of high-energy line breaks and floods in the intermediate building [Ref. 3.3.8-8, Section 3.6.2]. As a result of this assessment, various plant modifications were made to minimize the risk due to floods in zone IBN:

1. An augmented inservice inspection program was initiated to further reduce the probability of a main feedwater or steam line break;

2. The standby auxiliary feedwater system (SAFW) was added specifically to substitute for the auxiliary feedwater system (AFW) in the event that the AFW pumps are damaged due to nearby high-energy line breaks within the intermediate building;

3. Check valves were added to existing AFW lines near the connections to the main feedwater lines to minimize the AFW piping that is pressurized during normal operation;

4. Two parallel remotely operated valves were added to a crossover line between the motor-driven AFW pump discharge line to provide additional AFW makeup capability;

5. Jet impingement shields were added in the intermediate building to protect vital equipment including: (1) containment isolation valves, (2) motor generators, (3) transfer switches, (4) cable trays, (5) terminal boxes and wiring, (6) pressure transmitters, and (7) reactor trip breakers;

6. Instrument cabling was relocated to areas that would not be affected by postulated high-energy line breaks; and,

With the exception of the concrete block walls and the beams and decking of the high roof, all structural components in the intermediate building are capable of withstanding the internal pressures caused by high energy line breaks [Ref. 3.3.8-8, 3.6.2.5.1.2]. This dependency was recognized and modeled during development of the AFW [Ref. 3.3.8-9, Section 11.3.12] and RHR [Ref. 3.3.8-10, Section 11.3(8)] system fault tree models by adding initiating events related to high-energy line breaks at appropriate places in the fault tree structure. Thus, the effects of high-energy line breaks within the intermediate building have been addressed during the assessment of risk from internal initiators, and needs not be further assessed during the internal plant flooding analysis.

RG&E has also considered intermediate building floods from the service water system [Ref. 3.3.8-8, Section 3.6.2.4.8.1], noting that all flood water would drain to the subbasement (zone IBS) via floor drains and that such an event would be detected during the once-per-shift walk-through inspections before any essential equipment could be affected. Thus, the effects of a service water piping rupture within the intermediate building would be confined to loss of the affected header, which has been considered during the assessment of risk from internal initiators (initiators TI000SWA and TI000SWB).

3.3.8.4 Second Screening Analysis

The second screening analysis consisted of a computer search for significant core-damage sequences arising from each of the flooding scenarios defined in Section 3.3.8.3. Details of this search are provided in the following sections.

3.3.8.4.1 Identification of Flood-Induced Core-Damage Sequences

The event trees associated with the integrated plant risk model [Ref. 3.3.8-2] were used as the basis for identifying flood-related core-damage sequences. Only the transient event tree is relevant (sequences beginning with the designator "T/"), including transient-induced LOCAs (reactor coolant pump seal LOCAs - designated with "T/Q1", and PORV LOCAs following failure of pressurizer spray - designated with "T/Q2"). Thus, a total of thirty-two core-damage sequences were solved for each of the twenty-four flooding scenarios defined by Table 3.3.8-4 (along with sixteen "success path" top events per scenario; a total of 1,152 fault tree top events).

3.3.8.4.2 Computer Solution Method

In general, the process for generating flood-induced core-damage cut sets was analogous to the methods used to generate the internally initiated sequence cut sets. The following general assumptions were used:

1. The frequency of all flood initiators was taken to be 1.00E-03/y, which is generally consistent with the flood frequencies used in the NUREG-1150 PRA studies [Ref. 3.3.8-12]; and,

2. All sequence cut sets were truncated at a frequency of 5.00E-08/y, which was consistent with the truncation value used to quantify the internally initiated sequences [Ref 3.3.8-3].

3.3.8.4.2.1 Developing the Integrated Flooding Risk Model

An integrated flooding risk model was developed from the integrated plant risk model developed during the quantification task [Ref 3.3.8-3]. The following changes were made:

Integrated Plant Risk Model	*Flooding Integrated Risk Model*	*Changes Made*
GINNA.CAF	FLOOD.CAF	added RHR (shutdown cooling) fault tree
GINNA.BE	FLOODCOM.BE	added RHR (shutdown cooling) basic events added flood initiators
GINNA.TC	FLOODCOM.TC	added RHR (shutdown cooling) CAFTA type codes
GINNA.GT	FLOODCOM.GT	added RHR (shutdown cooling) gate descriptions

Table 3.3.8-6 lists the flood initiators.

3.3.8.4.2.2 Developing DOS Batch and CAFTA Macro Files

Figure 3.3.8-2 illustrates the process used to generate the second screening analysis cut sets in terms of the various DOS batch and CAFTA macro files developed during the analysis.

All cut set file names and cut set module names (the name given to the top event being solved) follow the naming scheme: FFFZZZZZ, where FFF denotes the specific top event (F01 to F32 for the core-damage sequences as specified in Table 1 of the *Flood Analysis Task Procedure* [Ref. 3.3.8-1]), and ZZZZ denotes the specific flooding scenario involved as specified on Table 3.

It should be noted that two flood-related free-formatted files are loaded into the integrated flooding risk model (FLOOD.CAF) in order to account for scenario-specific impacts: (1) The flood flag file; and, (2) The flood initiator flag file (further discussed in Section 3.3.8.4.2.3. All basic events and initiating events which occur as a result of a given flooding scenario are set equal to the dummy flood initiator FLOODIE, which is subsequently set equal to the scenario-specific flood initiator (from Table 3.3.8-6). Experimentation showed that this approach, as opposed to setting flood-failed events to Boolean TRUE, minimized the cut set generation time by several orders of magnitude.

3.3.8.4.2.3 Creating Flood Initiator Flag Files

A set of flood initiator flag files, which set each internal initiating event to either FLOODIE or Boolean FALSE, was developed from Table 3.3.8-3. Thus, the flood initiator flag files are specific to a given flooding scenario.

One additional problem with the event tree top logic was addressed in the flood initiator flag files. Namely, the Event Q2 top logic (which describes PORV/safety valve LOCAs) contains two opposing failure modes for the PORVs within the same fault tree structure. Gates TL_Q2CV430 and TL_Q2CV431 describe failure of the PORVs to reseat whereas gate TL_Q2_SRV contains logic which represents both PORVs' failure to open; all of these gates feed into gate TL_Q2_OPEN, which subsequently can produce cut sets that contain either type of PORV failure.

As previously noted in Section 3.3.8.3.2.1, Item 6, it has been assumed that the PORVs fail closed if any associated component is wetted by a flood. Thus, in any flooding scenario where PORV components are flooded, events RCRZT00430 ("PORV PCV-430 Fails to Reset After Steam Relief") and/or RCRZT0431C ("PORV PCV-431C Fails to Reset After Steam Relief") should be set to Boolean FALSE in the flood initiator flag file if the flood fails sufficient equipment to prevent the PORVs from opening. The impact of a flood on either PORV's ability to open was assessed on a zone-by-zone basis by merging the appropriate flood flag file for the flood zone in question into the integrated flood risk model (FLOOD.CAF) and generating cut sets for gates RC203 ("PRESSURIZER PORV PCV-430 FAILS TO AUTOMATICALLY OPEN") and RC233 ("PRESSURIZER PORV PCV-431C FAILS TO AUTOMATICALLY OPEN"); the existence of a single cut set indicates that the flood alone is sufficient to prevent PORV opening. Table 3.3.8-7 summarizes the results of this analysis.

3.3.8.4.3 Results of the Second Screening Analysis

Results of the second screening analysis are summarized in Table 3.3.8-8. Note that four scenarios were eliminated during this analysis (TSCG, TBOG, TBBG, and TBBSA).

3.3.8.5 Detailed Flooding Analysis

Each sequence generated by the second screening analysis was examined to assess the validity of the integrated flood risk model and associated flood analysis database, refine flood frequencies, reassess equipment vulnerability to flood effects, and to consider possible recovery actions. These work is discussed in the following sections.

3.3.8.5.1 Refinement of Flooding Event Frequencies

A method developed on behalf of EPRI [Ref. 3.3.8-13] was used to refine the frequencies of floods in zones CC/BR1A, CC/BR1B), EDG1A, and IB/IBS. This method parses pipe ruptures into three groups according to nominal pipe diameter, and accounts for partial breaks in large pipe (which create flow rates similar to those created by the full rupture of smaller diameter pipes). The basic equations are:

$$Z_l(>6'') = Z_{gc} \cdot C_3 \cdot P_{3/3} \cdot n_3$$

$$Z_m(2-6'') = Z_{gc}[C_2 \cdot P_{2/2} \cdot n_2 + C_3 \cdot P_{2/3} \cdot n_3]$$

$$Z_s(<2'') = Z_{gc}[C_1 \cdot n_1 + C_2 \cdot P_{1/2} \cdot n_2 + C_3 \cdot P_{1/3} \cdot n_3]$$

where:

$$Z_{gc} = 5E-10/section\text{-}hr$$

Size Attribute Value	*Pipe Diameter Range*
$C_1 = 1.2$	< 2"
$C_2 = 0.6$	2 - 6"
$C_3 = 1.4$	> 6"

$P_{i/j}$=Pr{flood size is group i given rupture in group size j}				
$P_{1/2}$	$P_{2/2}$	$P_{3/3}$	$P_{2/3}$	$P_{1/3}$
1/10	9/10	7/15	1/3	1/5

n_i = number of pipe sections in group i

Note that a *pipe section* is defined as a segment of pipe between major discontinuities such as valves, pumps, reducers, tees, etc. The frequency of rupture for such discontinuities was assumed to be 3.00E-09/h [Ref. 3.3.8-14]. Thus, this approach allows one to determine an estimate of flooding frequency by counting pipe sections and discontinuities from the relevant flow diagrams.

3.3.8.5.1.1 Refining Battery Room Flood Frequencies

There is a single section of one-inch pipe in each battery room (a non-safety service water line to the relay room HVAC units) which contains no major fittings (e.g., valves). Thus, the refined frequency was calculated as:

$$\begin{aligned} f &= 5E{-}10\left[1.2 \cdot 1 + 0 \cdot 0 \cdot 0 + 0 \cdot 0 \cdot 0\right] \\ &= 6E{-}10/h \\ &= 5.26E{-}6/y \end{aligned}$$

3.3.8.5.1.2 Refining the EDG1B Flood Frequency from Service Water Floods

There is a twenty-inch diameter section of service water pipe (safety-related header A) in flood zone EDG1B that constitutes the flood source. Thus, the refined frequency was calculated as:

$$\begin{aligned} f &= Z_l + Z_m + Z_s \\ &= Z_{gc}\ C_3\ n_3 \quad \text{if } n_1 = n_2 = 0 \\ &= 5E{-}10 \cdot 1.4 \cdot 1 \\ &= 7E{-}10/h \\ &= 6.13E{-}6/h \end{aligned}$$

3.3.8.5.1.3 Refining the IB / IBS Flood Frequency from CCW

Based on a review of the relevant flow diagram [Ref. 3.3.8-15], zone IB / IBS contains six sections of three-inch pipe and 23 valves. Thus, the refined frequency was calculated as:

$$\begin{aligned} f &= 5E{-}10\left[1.2 \cdot 6 + 0 \cdot 0 \cdot 0 + 0 \cdot 0 \cdot 0\right] + 3E{-}9 \cdot 23 \\ &= 7.26E{-}8/h \\ &= 6.36E{-}4/y \end{aligned}$$

3.3.8.5.2 Reassessment of Flooding Vulnerabilities

The vulnerability of certain plant equipment to floods has been reassessed based on the results of the screening analysis. Unlike the manual adjustments made to the computer-generated flood flag files (Section 3.3.8.3.1.1), the basic events related to certain flood zones have true dependencies upon various electrical subcomponents as identified in the flood analysis database; the degree of susceptibility to floods (either spray or submergence) of this equipment was questioned. Thus, the flood flag files were redefined by removing certain basic events judged to be invulnerable to floods and the corresponding sequences were requantified.

3.3.8.5.2.1 Reassessing Flood Zone AHR Vulnerabilities

Basic events ACCBR75112, ACCBR76702, ACT1FST12A, and ACT1FST12B removed from flood flag file AHR.FRE (thus creating a new flood flag file, AHR_D.FRE) since loss of the offsite power breaker operating air compressors (powered from ACPDPCB04, located in zone AHR) will not result in a spurious opening of the 115 kVAC circuit breakers (i.e., the breakers will fail "as-is" given loss of ACPDPCB04, and no loss of offsite power would occur). Flood scenarios AHRG and AHRSB were requantified, and no cut sets above the truncation limit were generated.

3.3.8.5.2.2 Reassessing Flood Zone SHE Vulnerabilities

In the second screening analysis, it was assumed that floods in zone SHE (Screen House - East) would fail all four service water pumps (either by directly spraying or submerging them, or by damaging their related switchgears - 480 VAC Buses 17 and 18). The most likely source of flooding would come from the expansion joints located on the SW pump discharge lines; an assessment [Ref. 3.3.8-16] indicates that it is unlikely more than two pumps would be affected. Note that BUS17 and BUS18 are sealed and provided with drip shields; the orientation of any credible flood source makes it unlikely these switchgears would receive any substantial spray. Further, water cannot pool within zone SHE.

Considering the configuration of the SW pumps within the flood zone, the following scenarios are possible:

Ruptured Expansion Joint	*Affected Adjacent SW Pump*	*Notes*
SWEJFSSW02 (SW pump A)	SW pump B	bounded by internal initiator TI000SWA (loss of service water header A)
SWEJFSSW03 (SW pump B)	SW pump A	bounded by internal initiator TI000SWA (loss of service water header A)
SWEJFSSW03 (SW pump B)	SW pump C	causes loss of one pump in each header
SWEJFSSW04 (SW pump C)	SW pump B	causes loss of one pump in each header
SWEJFSSW04 (SW pump C)	SW pump D	bounded by internal initiator TI000SWB (loss of service water header B)
SWEJFSSW05 (SW pump D)	SW pump C	bounded by internal initiator TI000SWB (loss of service water header B)

In the Ginna PRA model, it is assumed that service water pumps PSW01A and PSW01D are the normally operating pumps, and that pumps PSW01B and PSW01C are in standby (in accordance with the configuration logic settings in FLAGS.FRE [Ref. 3.3.8-3]). Thus, the middle two combinations do not result in a plant trip unless either pump PSW01A or PSW01D fails to continue running. Consequently, zone SHE was dismissed from further consideration.

3.3.8.5.2.3 Reassessing Flood Zones ABO, ABM, and ABB Vulnerabilities

The second screening analysis conservatively assumed that all electrical equipment was vulnerable to the effects of floods. Flood zones ABO and ABM contain much of the Class 1E equipment in the plant, which is housed in spray-proof enclosures and is, therefore, not vulnerable to floods within these zones. Two flood flag files were created (ABM_D.FRE from ABM.FRE, and ABO_D.FRE from ABO.FRE) which eliminated all basic events whose failure could be tied to the flooding of Class 1E equipment. The basic events eliminated were identified through queries of the flood analysis database. Flood scenarios ABMG, ABMSA, ABMSB, ABMC, ABOG, ABOSA, and ABOC were requantified using the new flood flag files (Table 3.3.8-9).

Further examination of the cut sets generated for the ABM-related sequences indicated an overly conservative assumption concerning the likelihood of a reactor coolant pump (RCP) seal LOCA (sequence T/Q1/XH). An RCP seal LOCA occurs if both the seal injection flow (from CVCS) and thermal barrier cooling (from CCW) are lost. In these scenarios, all supply to the CVCS pumps is failed due flooding of level transmitter LT-112, leading to a loss of seal injection. Also, motor operated valves 749A and 749B, which supply CCW to the RCP thermal barriers, are also failed by the flood. However, LT-112 is separated from 749A and 749B by various walls, equipment, and other obstructions; thus, it is not likely that both RCP seal injection and CCW to the thermal barriers would be lost due to spray originating from a single flood source. Further, floods in zone ABM cannot pool (instead, it drains to zone ABB). Consequently, ABM-related flooding scenarios involving T/Q1/XH were eliminated from further consideration.

A similar situation exists concerning floods in zone ABB originating from the CCW system (sequence T/Q1/UH2/UL). In this case, CCW to the thermal barriers is directly lost; the scenario also assumes that all CVCS pumps, SI pumps, and RHR pumps would be failed. However, there is not sufficient volume in the CCW system to simultaneously affect this equipment; consequently, ABB-related scenarios involving T/Q1/UH2/UL were eliminated from further consideration.

3.3.8.5.3 Recovery Analysis

The same techniques used to recover internally initiating sequences were used to recover flood-related sequences: (1) Refinement of human failure event (HFE) probabilities; and, (2) Adding nonrecovery events to cut sets as appropriate. A new CAFTA basic event file (FLOODFIN.BE) was created by merging FLOODCOM.BE with the final integrated risk basic event file (RGEFIN.BE), thereby incorporating HFE probabilities previously refined during the internal events recovery analysis process [Ref. 3.3.8-17]. This action also incorporated the previously defined nonrecovery events [Ref. 3.3.8-18].

Two additional HFEs were refined during the flooding recovery analysis:

1. Event MFHFDMF100 describes the failure to restore main feedwater flow to the steam generators. Per step 5 of FR-H.1 [Ref. 3.3.8-19], the operators are directed to restore main feedwater flow if at least 200 gpm AFW flow cannot be established to one steam generator. Per MAAP run FB13E [Ref. 3.3.8-20], the cue to start bleed-and-feed cooling (steam generator level less that three feet) is reached at 0.4 hours (24 m) assuming a complete loss of feedwater at the time of plant trip. From the SAIC Time Response Correlation for rule-based behavior without hesitation [Ref. 3.3.8-17, Table 1], the probability of failing to restore main feedwater within this 24 m window is 6.64E-04.

2. Event CCHFDSTART describes the failure to start a CCW pump following a concurrent loss-of-offsite-power and SI actuation. This event is similar to nonrecovery event NRHCCWPUMP, and was set to the same probability (2.4E-04).

3.3.8.5.4 Results of the Detailed Flooding Analysis

Table 3.3.8-10 presents the final list of flood-related core-damage sequences, incorporating all refined flood frequencies, vulnerability reassessments, and recovery analysis results.

3.3.8.6 Conclusions

The total core-damage frequency due to floods is estimated as 5.05E-06/y, with the major contributor being related to turbine building floods from the main feedwater system.

3.3.8.7 References

3.3.8-1 Science Applications International Corporation, *Internal Flooding Analysis Task Procedure*, TQAP-2118-8.1, Rev. 0, February 18, 1994.

3.3.8-2 Science Applications International Corporation, *Events Trees Work Package*, Project Document 749-01-14, Rev. 0, December 10, 1993.

3.3.8-3 Science Applications International Corporation, *Quantification Work Package*, Project Document 749-05-40, Rev. 0, December 17, 1993.

3.3.8-4 Rochester Gas & Electric Corporation, *Determination of Internal Flood Zones and Sources*, Design Analysis NSL-4976-DA002.

3.3.8-5 Science Application International Corporation, *Flood Analysis Database Work Package*, Project Document 749-08-100, Rev. 0, February 28, 1994.

3.3.8-6 Rochester Gas & Electric Corporation, *Ginna Station Probabilistic Risk Assessment Determination of Component Boundaries*, EWR 4976, Design Analysis NSL-4976-DA001, Revision 1, November 30, 1990.

3.3.8-7 Science Applications International Corporation, *ISLOCA Work Package*, Project Document 749-01-100, Rev. 0, January 29, 1993.

3.3.8-8 Memo from D. Wilson to M. Stutzke, *Auxiliary Building Basement and Sub-Basement Free Volumes*, NSL-PRALT-94.025, March 2, 1994.

3.3.8-9 Rochester Gas & Electric Corporation, *R. E. Ginna Nuclear Power Plant Updated Final Safety Analysis Report*, Rev. 6, 12/90.

3.3.8-10 Science Applications International Corporation, *Auxiliary Feedwater System Work Package*, Project Document 749-02-20.01, Rev. 0, September 15, 1992.

3.3.8-11 Science Applications International Corporation, *Residual Heat Removal (RHR) System Work Package*, Project Document 749-02-20.09, Rev. 0, October 9, 1992.

3.3.8-12 M. P. Bohn, et. al., *Analysis of Core Damage Frequency: Surry Power Station, Unit 1 External Events*, NUREG/CR-4550, Vol. 3, Rev. 1, Part 3, December 1990.

3.3.8-13 K. Jamali, *Pipe Failures in U.S. Commercial Nuclear Power Plants*, EPRI TR-100380, Interim Report, July 1992.

3.3.8-14 Joint Research Centre - ISPRA Site, *EIREDA - European Industry Reliability Data Handbook*, Technical Note No. I.91.131, ISEI/SER 2121/91, October 1991.

3.3.8-15 Rochester Gas & Electric Corporation, *Auxiliary Coolant - Component Cooling Water P&ID*, 33013-1245, Rev. 20.

3.3.8-16 Memo from D. Wilson to M. Stutzke, *Failures of Service Water Pump Discharge Expansion Joints*, NSL-PRALT-94.014, February 14, 1994.

3.3.8-17 Science Applications International Corporation, *Human Failure Events Analyzed in Detail*, Project Document 749-04-32, Rev. 0, December 28, 1993.

3.3.8-18 Science Applications International Corporation, *Recovery Analysis Work Package*, Project Document 749-06-36, Rev. 0, February 11, 1994.

3.3.8-19 Rochester Gas & Electric Corporation, *Response to Loss of Secondary Heat Sink*, FR-H.1, Rev. 9, September 4, 1990.

3.3.8-20 Rochester Gas & Electric Corporation, *Ginna PRA MAAP Run FB13E*, October 5, 1993.

Table 3.3.8-1
List of Flood Areas and Flood Zones

Flood Area	*Flood Zone*	*Description*	*Elevation*
AB - Auxiliary Building			
AB	ABS	Auxiliary Building Sub-Basement	219
AB	ABB	Auxiliary Building Basement	235
AB	ABM	Auxiliary Building Mid-Level	253
AB	ABO	Auxiliary Building Operating Floor	271
AB	N2	Nitrogen Storage	271
IB - Intermediate Building			
IB	IBB	Intermediate Building Sub-Basement	219
IB	IBN	Intermediate Building (Clean Side) North	all
IB	IBS	Intermediate Building (Controlled Side) South	all
CT - Cable Tunnel			
CT	CT	Cable Tunnel	253
CC - Control Complex			
CC	BR1A	Battery Room A	253
CC	BR1B	Battery Room B	253
CC	AHR	Air Handling Room	253
CC	RR	Relay Room	271
CC	RRA	Relay Room Annex	271
CC	CR	Control Room	289
EDG1A - Diesel Room A			
EDG1A	EDG1A	Diesel Room A	253
EDG1B - Diesel Room B			
EDG1B	EDG1B	Diesel Room B	253

Table 3.3.8-1 List of Flood Areas and Flood Zones			
Flood Area	*Flood Zone*	*Description*	*Elevation*
H2 - Hydrogen Storage			
H2	H2	Hydrogen Storage	253
RC - Containment			
RC	RC	Containment	all
SB - Service Building			
SB	SBB	Service Building Basement	253
SB	SBM	Service Building Mid-Level	271
SH - Screen House			
SH	SHE	Screen House East	253
SH	SHW	Screen House West	253
SAF - Standby Auxiliary Feedwater Building			
SAF	SAF	Standby Auxiliary Feedwater	all
TO - Turbine Oil Storage			
TO	TO	Turbine Oil Storage	253
TB - Turbine Building			
TB	TBB	Turbine Building Basement	253
TB	TBM	Turbine Building Mezzanine	271
TB	TBO	Turbine Building Operating Floor	289
AVT - All Volatile Treatment Building			
AVT	AVT	All Volatile Treatment Building	247
AVT	TSC	Technical Support Center	271

Table 3.3.8-2
Internal Plant Flooding Sources

Auxiliary Building Sub-Basement, Elevation 219 (AB / ABS)

10" Residual Heat Removal line
2" Liquid Waste Disposal line
3" Reactor Coolant Drain Tank (TWD01A) line
375 gallon Auxiliary Building Sump Tank (TWD09)

Auxiliary Building Basement, Elevation 235 (AB / ABB)

3" Service Water line
10" Containment Spray line
10" Safety Injection line
1" Liquid Waste Disposal line
10" Component Cooling Water line
2" Fire Service Water line
10" Residual Heat Removal line
6" Spent Fuel Pool Cooling line
2" Letdown line
4" Charging line
2" Boric Acid line
2" line from the Holdup Tank to the Gas Strippers
2" line from the Boric Acid Evaporator to the Monitor Tank
1" Reactor Makeup Water line
2" Liquid Waste Disposal line
3" Reactor Coolant Drain Tank line
3" Post Accident Sampling System (PASS) line
335,000 gallon Refueling Water Storage Tank (TSI01)
Three 31,200 gallon CVCS Holdup Tanks (TCH09A, TCH09B, TCH09C)
21,4444 gallon Waste Holdup Tank (TWD10)
5,100 gallon Sodium Hydroxide Tank (TSI02)
Two 1,122 gallon Spent Resin Storage Tank (TWD05A, TWD05B)

Table 3.3.8-2
Internal Plant Flooding Sources

Auxiliary Building Mid-Level, Elevation 253 (AB / ABM)

3" Component Cooling Water line
4" Spent Fuel Pool Cooling line
20" Safety-Related Service Water header
2" Pressurizer Spray line
10" Safety Injection line
2" Letdown line
1" Charging line
1" Boric Acid line
4" line from the holdup tanks to the gas strippers
2" line from the Boric Acid Evaporator to the Monitor Tank
3" line to the Liquid Waste Disposal Tank
2" line to the Reactor Coolant Drain Tank
2" line to the Polishing Demineralizes
1" Nuclear Sampling line
6" Fire Service Water line
2" Reactor Makeup Water line
1,500 gallon Volume Control Tank (TCH04)
700 gallon Concentrates Holding Tank (TCH13)

Table 3.3.8-2
Internal Plant Flooding Sources

Auxiliary Building Operating Floor, Elevation 271 (AB / ABO)

10" Component Cooling Water line
6" Spent Fuel Pool Cooling line
14" Safety-Related Service Water header
6" Containment Spray line from the RWST
3" Letdown line
2" Boric Acid Line
3" line from the holdup tank to the gas strippers
3" line from the Boric Acid Evaporator to the Monitor Tank
3" Reactor Makeup Water line
1" Liquid Waste Disposal line
2" line to the Waste Evaporator
3" line to the Polishing Demineralizes
6" Fire Service Water Line
75,000 gallon Reactor Makeup Water Tank (TCH15)
Two 3,600 gallon Boric Acid Storage Tanks (TCH07A, TCH07B)
Two 600 gallon Waster Evaporator Condensate Tanks (TWD11A, TWD11B)

Auxiliary Building Nitrogen Storage, Elevation 271 (AB/N2)

No flood sources

Table 3.3.8-2
Internal Plant Flooding Sources

Turbine Building Basement, Elevation 253 (TB / TBB)

80" Circulating Water
2" Main Steam line
4" Feedwater Heaters line
14" Condensate line
18" Main Feedwater line
1.5" Standby Auxiliary Feedwater line
10" Non-Safety Service Water Header A
10" Non-Safety Service Water Header B
1.5" Steam Generator Blowdown line to the Liquid Waste Disposal System
8" Steam Generator Blowdown line
10" Fire Service Water line
1.5" City & Domestic Water line
8" Steam Generator Blowdown line
10" Fire Service Water line
1.5" City & Domestic Water line
15,000 gallon Fire Service Water Tank (TFS01)
5,386 gallon Heater Drain Tank (TFW01)

Turbine Building Mezzanine, Elevation 271 (TB / TBM)

30" Main Steam line
14" line to the Low-Pressure Feedwater Heaters
14" Condensate line
18" Main Feedwater line
4" Fire Service Water line
1.5" City & Domestic Water line

Table 3.3.8-2
Internal Plant Flooding Sources

Turbine Building Operating Floor, Elevation 289 (TB / TBO)

High-Pressure Main Steam Lines
Low-Pressure Main Steam Lines
1" Condensate line
4" Non-Safety Service Water line
1.5" Fire Service Water line

Control Building, Elevation 289 - Control Room (CC / CR)

1" City Water line

Control Building, Elevation 271 - Relay Room (CC / RR)

1" Non-Safety Service Water line

Control Building, Elevation 271 - Relay Room Annex (CC / RRA)

No flood sources

Control Building, Elevation 253 - Battery Room A (CC / BR1A)

1" Non-Safety Service Water Line

Control Building, Elevation 253 - Battery Room B (CC / BR1B)

1" Non-Safety Service Water Line

Control Building, Elevation 253 - Air Handling Room (CC / AHR)

20" Safety-Related Service Water line
10" Fire Service Water line
1.5" City Water line

Table 3.3.8-2
Internal Plant Flooding Sources

Diesel Generator A Room, Elevation 253 (EDG1A)

4" Safety-Related Service Water line
8" Fire Service Water header

Diesel Generator B Room, Elevation 253 (EDG1B)

20" Safety-Related Service Water line
2.5" Fire Service Water line

Intermediate Building (Clean Side) - North (IB / IBN)

30" Main Steam header
20" Safety-Related Service Water headers
14" Main Feedwater lines
10" Fire Service Water header
5" Auxiliary Feedwater lines
635 gallon House Heating Boiler Return Tank (THS03)

Intermediate Building (Controlled Side) - South (IB / IBS)

3" Component Cooling Water line
3" Spent Fuel Pool Cooling line
3" Steam Generator Blowdown line
Two 600 gallon Laundry & Hot Shower Tanks (TWD02A, TWD02B)
375 gallon Radio-Chemistry Lab Drain Tank (TWD01)

Intermediate Building Sub-Basement, Elevation 235 (IB / IBB)

20" Safety-Related Service Water headers
10" Auxiliary Feedwater header

Table 3.3:8-2
Internal Plant Flooding Sources

Standby Auxiliary Feedwater Building, Elevation 271 (SAFW)

6" Standby Auxiliary Feedwater lines
4" Safety-Related Service Water lines
2.5" Fire Service Water line
10,000 gallon Condensate Test Tank (TCD01)

Service Building Basement, Elevation 253 (SB / SBB)

10" Condensate line
8" Fire Service Water header
4" City Water line
Two 30,000 gallon Condensate Storage Tanks (TCD02A, TCD02B)
24,000 gallon Primary Water Treatment Neutralizing tank (PWT02)
6,000 gallon Acid Storage Tank (TWT01)
6,000 gallon Caustic Storage Tank (TWT23)
200 gallon House Heating Steam Return Tank (THS01)

Service Building Mid-Level, Elevation 271 (SB / SBM)

4" Fire Service Water line
2" Component Cooling Water line

Screen House, East (SH / SHE)

20" Safety-Related Service Water lines
10" Fire Service Water headers

Screen House, West (SH / SHW)

90" Circulating Water headers

Table 3.3.8-2
Internal Plant Flooding Sources

All Volatile Treatment Building, Elevation 253 (AVT / AVT)

2" Fire Service Water line
45,000 gallon High Conductivity Waste Tank (TWT20)
22,600 gallon Low Conductivity Waste Tank (TWT19)
20,000 gallon Dilute Acid Reclaim Tank (TWT16)
6,000 gallon Acid Tank (TWT18)
6,000 gallon Caustic Tank (TWT21)
4,000 gallon Dilute Ammonia Reclaim Tank (TWT12)
1,500 gallon Dilute Caustic Reclaim Tank (TWT13)

Technical Support Center, Elevation 271 (AVT / TSC)

4" Fire Service Water header
1.5" Non-Safety Service Water line
1" City Water line

Cable Tunnel, Elevation 235 (CT)

No flood sources

Turbine Oil Storage Building, Elevation 253 (TO)

No flood sources

Hydrogen Storage, Elevation 253 (H2)

No flood sources

Table 3.3.8-2
Internal Plant Flooding Sources

Containment, All Elevations (RC)

No flood-vulnerable PRA-related equipment (qualified for post-LOCA environment); thus, flood sources were not tabulated

Table 3.3.8-3

Relationship of Internal Plant Flood Sources to Initiating Events

FLOOD ZONE	AHR	AHR	BRA	BRB	TSC	SHE	SHW	IBO	IBM	IBM	IBB	IBB	IBB	DGB	SBO	IBN	IBN	IBN	IBN	IBS	IBB	IBB	ABO	ABO	ABO	ABM	ABM	ABM	ABM	ABB
FLOOD SOURCE	generic	service water header B	generic	generic	generic	generic	generic	generic	generic	main feedwater header	generic	main feedwater header	service water header A	service water header A	CCW header	main feed header A	main feed header B	service water header A	service water header B	CCW header	service water header A	service water header B	generic	service water header A	CCW header	generic	service water header A	service water header B	CCW header	CCW header
TIRXTRIP	F	F	F	F	T	F	T	T	T	F	T	F	F	F	F	F	F	F	F	F	F	F	T	F	F	T	F	F	F	F
TIGRLOSP	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISWLOSP	T	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFWLOSS	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFWEXCS	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIIALOSS	F	F	F	F	F	T	F	F	F	F	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBACT	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBBCT	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLB0TB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBAIB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBBIB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TI0SLBSD	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBSVA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TISLBSVB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFLBACT	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFLBBCT	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFLB0TB	F	F	F	F	F	F	F	F	F	T	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFLBAIB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TIFLBBIB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F
LISSLOCA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LISBLOCA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LIMBLOCA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LILBLOCA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LIRVRUPT	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LI0SGTRA	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
LI0SGTRB	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TI000SWA	F	F	F	F	F	T	F	F	F	F	F	F	T	T	F	F	F	T	F	F	T	F	F	T	F	F	T	F	F	F
TI000SWB	F	T	F	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	T	F	F	T	F	F	F	F	F	T	F	F
TI000CCW	F	F	F	F	F	F	F	F	F	F	F	F	F	F	T	F	F	F	F	T	F	F	F	F	T	F	F	F	T	T
TI000DCA	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
TI000DCB	F	F	F	T	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F

Table 3.3.8-4 Flooding Scenrios			
Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Partial Cut Set File Name*
AHR	generic	none	AHRG
AHR	SW Header B	none	AHRSB
BR1A	generic	none	BRAG
BR1B	generic	none	BRBG
TSC	generic	none	TSCG
SHE	generic	none	SHEG
TBO	generic	none	TBOG
TBM	generic	none	TBMG
TBM	feedwater header	none	TBMF
TBB	generic	none	TBBG
TBB	feedwater header	none	TBBF
TBB	service water header A	none	TBBSA
EDG1B	service water header A	none	DGBSA
IBS	CCW header	none	IBSC
ABO	generic	none	ABOG
ABO	service water header A	none	ABOSA
ABO	CCW header	none	ABOC
ABM	generic	none	ABMG
ABM	service water header A	none	ABMSA
ABM	service water header B	none	ABMSB
ABM	CCW header	none	ABMC
ABB	CCW header	none	ABBC
TBM	feedwater header	TBB	TBF
SBM	CCW header	SBB	SBC

Table 3.3.8-5
Initial Screening Analysis

Flood Area	*Flood Zone*	*Significant Flood Sources?*	*Significant Interconnections?*	*Vulnerable PRA-Related Basic Events?*	*Flood Causes an Initiator?*	*Disposition*	*Remarks*
AB	ABS	yes	yes	yes	no	retained	only in combination with ABB scenarios
AB	ABB	yes	yes	yes	yes	retained	
AB	ABM	yes	yes	yes	yes	retained	
AB	ABO	yes	no	yes	yes	retained	
AB	N2	no	no	no	no	eliminated	
IB	IBB	yes	no	no	no	eliminated	
IB	IBN	yes	no	yes	yes	eliminated	see text for explanation
IB	IBS	yes	no	yes	yes	retained	
CT	CT	no	no	no	no	eliminated	
CC	BR1A	yes	no	yes	yes	retained	
CC	BR1B	yes	no	yes	yes	retained	
CC	AHR	yes	no	yes	yes	retained	
CC	RR	no	no	yes	yes	eliminated	adequate floor drains compared to 1" service water supply to room coolers; will not spray on cabinets
CC	RRA	no	no	yes	yes	eliminated	
CC	CR	no	no	yes	yes	eliminated	1" city water line not located near any panel or cabinet

Table 3.3.8-5
Initial Screening Analysis

Flood Area	*Flood Zone*	*Significant Flood Sources?*	*Significant Interconnections?*	*Vulnerable PRA-Related Basic Events?*	*Flood Causes an Initiator?*	*Disposition*	*Remarks*
EDG1A	EDG1A	no	no	yes	no	eliminated	4" service water break will not cause a loss of service initiator
EDG1B	EDG1B	yes	no	yes	yes	retained	
H2	H2	no	no	no	no	eliminated	
RC	RC	yes	no	no	yes	eliminated	all equipment inside containment important to PRA is qualified for post-LOCA environment
SB	SBB	yes	yes	yes	no	retained	only in combination with SBM scenarios
SB	SBM	yes	yes	no	yes	retained	only in combination with SBB scenarios
SH	SHE	yes	no	yes	yes	retained	
SH	SHW	yes	no	no	yes	eliminated	sump level instrumentation will trip circulating water pumps; will overflow to the traveling screen pits and into Lake Ontario; bounded by loss of feedwater initiator
SAF	SAF	yes	no	yes	no	eliminated	
TO	TO	no	no	no	no	eliminated	
TB	TBB	yes	yes	yes	yes	retained	
TB	TBM	yes	yes	yes	yes	retained	

Table 3.3.8-5 Initial Screening Analysis							
Flood Area	*Flood Zone*	*Significant Flood Sources?*	*Significant Interconnections?*	*Vulnerable PRA-Related Basic Events?*	*Flood Causes an Initiator?*	*Disposition*	*Remarks*
TB	TBO	yes	no	yes	yes	retained	
AVT	AVT	yes	no	no	no	eliminated	
AVT	TSC	yes	no	yes	yes	retained	

Table 3.3.8-6
Internal Plant Flooding Analysis Initiating Events

Initiator	Description
FI000ABM	Flood in Auxiliary Building 253' (AB/ABM) from Generic Source
FI000ABO	Flood in Auxiliary Building 271' (AB/ABO) from Generic Source
FI000AHR	Flood in Air Handling Room 253' (CC/AHR) from Generic Source
FI000BRA	Flood in Battery Room A 253' (CC/BR1A) from Generic Source
FI000BRB	Flood in Battery Room B 253' (CC/BR1B) from Generic Source
FI000SHE	Flood in Screen House East 253' (SH/SHE) from Generic Source
FI000TBB	Flood in Turbine Building Basement 253' (TB/TBB) from Generic Source
FI000TBM	Flood in Turbine Building Mezzanine 271' (TB/TBM) from Generic Source
FI000TBO	Flood on Turbine Building Operating Floor 289' (TB/TBO) from Generic Source
FI000TSC	Flood in Technical Support Center 271' (AVT/TSC) from Generic Source
FIABBCCW	Flood in Auxiliary Building 235' (AB/ABB) from the CCW Header
FIABMCCW	Flood in Auxiliary Building 253' (AB/ABM) from the CCW Header
FIABMSWA	Flood in Auxiliary Building 253' (AB/ABM) from SW Header A
FIABMSWB	Flood in Auxiliary Building 253' (AB/ABM) from SW Header B
FIABOCCW	Flood in Auxiliary Building 271' (AB/ABO) from the CCW Header
FIABOSWA	Flood in Auxiliary Building 271' (AB/ABO) from SW Header A
FIAHRSWB	Flood in Air Handling Room 253' (CC/AHR) from Service Water Header B
FIDGBSWA	Flood in Diesel Room B 253' (EDG1A) from Service Water Header A
FIIBNFAI	Flood in Intermediate Building (North/Clean) 253' (IB/IBN) from FW Header A
FIIBNFBI	Flood in Intermediate Building (North/Clean) 253' (IB/IBN) from FW Header B
FIIBNSWA	Flood in Intermediate Building (North/Clean) 253' (IB/IBN) from SW Header A
FIIBNSWB	Flood in Intermediate Building (North/Clean) 253' (IB/IBN) from SW Header B
FIIBSCCW	Flood in Intermediate Building (South/Hot) all' (IB/IBS) from the CCW Header
FISBMCCW	Flood in Service Building Mid-Level 271' (SBM) from the CCW Header
FITBBFTB	Flood in Turbine Building Basement 253' (TB/TBB) from the Feedwater Header
FITBBSWA	Flood in Turbine Building Basement 253' (TB/TBB) from Service Water Header A
FITBMFTB	Flood in Turbine Building Mezzanine 271' (TB/TBM) from the Feedwater Header

Table 3.3.8-7
Impact of Internal Plant Floods on PORVs Ability to Open

Flooding Scenario	*PCV-430*	*PCV-431C*
AHRG	no impact	failed closed
AHRSB	no impact	failed closed
BRAG	no impact	failed closed
BRBG	failed closed	failed closed
TSCG	no impact	no impact
SHEG	failed closed	failed closed
TBOG	no impact	failed closed
TBMG	no impact	failed closed
TBMF	failed closed	failed closed
TBBG	no impact	no impact
TBBF	no impact	no impact
TBBSA	no impact	no impact
DGBSA	no impact	no impact
IBNFA	failed closed	no impact
IBNFB	failed closed	no impact
IBNSA	failed closed	no impact
IBNSB	failed closed	no impact
IBSC	no impact	no impact
ABOG	failed closed	no impact
ABOSA	failed closed	no impact
ABOC	failed closed	no impact
ABMG	failed closed	failed closed
ABMSA	failed closed	failed closed
ABMSB	failed closed	failed closed
ABMC	failed closed	failed closed
ABBC	no impact	no impact

Table 3.3.8-8
Results of the Second Internal Flooding Screening Analysis

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*
CC/AHR	generic	none	T/B1/L1/UH1	F02AHRG.CUT	44	7.90E-06
			T/Q2/XL	F30AHRG.CUT	2	4.47E-07
CC/AHR	SW B	none	T/B1/L1/UH1	F02AHRSB.CUT	44	7.90E-06
			T/B1/L1/XL	F03AHRSB.CUT	21	2.07E-06
			T/Q2/XL	F30AHRSB.CUT	3	1.99E-05
CC/BR1A	generic	none	T/B1/L1/P1	F01BRAG.CUT	28	5.74E-05
			T/B1/L1/UH1	F02BRAG.CUT	17	1.06E-04
			T/Q2/UH2	F29BRAG.CUT	2	1.49E-06
			T/Q2/XL	F30BRAG.CUT	12	3.84E-06
CC/BR1B	generic	none	T/B1/L1/P1	F01BRBG.CUT	22	5.03E-05
			T/B1/L1/UH1	F02BRBG.CUT	13	4.87E-06
			T/Q2/XL	F30BRBG.CUT	12	3.84E-06
SH/SHE	generic	none	T/B1/L1/P1	F01SHEG.CUT	18	2.30E-04
			T/B1/L1/UH1	F02SHEG.CUT	10	1.03E-04
			T/B1/L1/XL	F03SHEG.CUT	1	1.00E-03
			T/Q1/B1/L1/P2	F06SHEG.CUT	14	3.30E-05
			T/Q1/B1/L1/XL	F15SHEG.CUT	1	1.00E-04
			T/Q1/UH2/B1/L1	F16SHEG.CUT	2	1.39E-07
			T/Q2/XL	F30SHEG.CUT	2	1.49E-05
TB/TBM	generic	none	T/B1/L1/UH1	F02TBMG.CUT	46	8.06E-06
			T/B1/L1/XL	F03TBMG.CUT	24	2.33E-06

Table 3.3.8-8
Results of the Second Internal Flooding Screening Analysis

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*
			T/Q2/XL	F30TBMG.CUT	2	4.47E-07
TB/TBM	FW	none	T/B1/L1/UH1	F02TBMF.CUT	56	9.21E-06
			T/B1/L1/XL	F03TBMF.CUT	61	5.75E-06
			T/Q2/XL	F30TBMF.CUT	16	5.80E-06
TB/TBB	FW	none	T/B1/L1/UH1	F02TBBF.CUT	2	1.53E-07
			T/B1/L1/XL	F03TBBF.CUT	3	2.11E-07
EDG1B	SW B	none	T/B1/L1/UH1	F02DGBSA.CUT	1	1.00E-06
IB/IBS	CCW	none	T/B1/L1/XL	F03IBSC.CUT	2	1.53E-07
			T/Q1/B1/XH	F07IBSC.CUT	1	1.50E-07
			T/Q1/XH	F08IBSC.CUT	1	1.50E-07
AB/ABO	generic	none	T/B1/L1/XL	F03ABOG.CUT	4	3.50E-07
			T/Q1/B1/XH	F07ABOG.CUT	4	3.50E-07
			T/Q1/XH	F08ABOG.CUT	1	1.00E-04
			T/Q1/UH2/P3SS	F24ABOG.CUT	1	5.59E-08
			T/Q1/UH2/XL	F27ABOG.CUT	12	2.11E-06
AB/ABO	SW A	none	T/B1/L1/XL	F03ABOSA.CUT	4	3.50E-07
			T/Q1/B1/XH	F07ABOSA.CUT	4	3.50E-07
			T/Q1/XH	F08ABOSA.CUT	1	1.00E-04
			T/Q1/UH2/P3SS	F24ABOSA.CUT	1	5.59E-08
			T/Q1/UH2/XL	F27ABOSA.CUT	12	2.11E-06

Table 3.3.8-8
Results of the Second Internal Flooding Screening Analysis

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*
AB/ABO	CCW	none	T/B1/L1/XL	F03ABOC.CUT	4	3.50E-07
			T/Q1/B1/XH	F07ABOC.CUT	4	3.50E-07
			T/Q1/XH	F08ABOC.CUT	1	1.00E-04
			T/Q1/UH2/P3SS	F24ABOC.CUT	1	5.59E-08
			T/Q1/UH2/XL	F27ABOC.CUT	1	2.11E-06
AB/ABM	generic	none	T/B1/L1/UH1	F02ABMG.CUT	31	5.95E-05
			T/Q1/UH2/B1/L1	F16ABMG.CUT	9	5.56E-06
			T/Q1/UH2/P3SS	F24ABMG.CUT	5	1.41E-05
			T/Q1/UH2/UL	F26ABMG.CUT	1	1.00E-04
AB/ABM	SW A	none	T/B1/L1/UH1	F02ABMSA.CUT	31	5.95E-05
			T/Q1/UH2/B1/L1	F16ABMSA.CUT	9	5.56E-06
			T/Q1/UH2/P3SS	F24ABMSA.CUT	5	1.41E-05
			T/Q1/UH2/UL	F26ABMSA.CUT	1	1.00E-04
AB/ABM	SW B	none	T/B1/L1/UH1	F02ABMSB.CUT	31	5.95E-05
			T/Q1/UH2/B1/L1	F16ABMSB.CUT	9	5.56E-06
			T/Q1/UH2/P3SS	F24ABMSB.CUT	5	1.41E-05
			T/Q1/UH2/UL	F26ABMSB.CUT	1	1.00E-04
AB/ABM	CCW	none	T/B1/L1/UH1	F02ABMC.CUT	31	5.95E-05
			T/Q1/UH2/B1/L1	F16ABMC.CUT	9	5.56E-06
			T/Q1/UH2/P3SS	F24ABMC.CUT	5	1.41E-05
			T/Q1/UH2/UL	F26ABMC.CUT	1	1.00E-04

Table 3.3.8-8
Results of the Second Internal Flooding Screening Analysis

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*
AB/ABB	CCW	none	T/Q1/UH2/B1/UL	F20ABBC.CUT	2	2.20E-07
			T/Q1/UH2/P3SS	F24ABBC.CUT	3	1.37E-05
			T/Q1/UH2/UL	F26ABBC.CUT	1	1.00E-04
TB/TBM	FW	TB/TBB	T/B1/L1/UH1	F02TBF.CUT	56	9.21E-06
			T/B1/L1/XL	F03TBF.CUT	61	5.75E-06
			T/Q2/XL	F30TBF.CUT	16	5.80E-06
SB/SBM	CCW	SB/SBB	T/Q1/XH	F08SBC.CUT	1	1.50E-07

Table 3.3.8-9 Sequence Results After Reassessment of Vulnerabilities						
Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*
ABM	generic	none	T/B1/L1/XL	F03ABMG.CT1	2	2.20E-07
			T/Q1/B1/XH	F07ABMG.CT1	2	2.20E-07
			T/Q1/XH	F08ABMG.CT1	1	1.00E-04
			T/Q1/UH2/XL	F27ABMG.CT1	2	1.39E-07
ABM	SA	none	T/B1/L1/XL	F03ABMSA.CT1	2	2.20E-07
			T/Q1/B1/XH	F07ABMSA.CT1	2	2.20E-07
			T/Q1/XH	F08ABMSA.CT1	1	1.00E-04
			T/Q1/UH2/XL	F27ABMSA.CT1	2	1.39E-07
ABM	SB	none	T/B1/L1/XL	F03ABMSB.CT1	2	2.20E-07
			T/Q1/B1/XH	F07ABMSB.CT1	2	2.20E-07
			T/Q1/XH	F08ABMSB.CT1	1	1.00E-04
			T/Q1/UH2/XL	F27ABMSB.CT1	2	1.39E-07
ABM	CCW	none	T/B1/L1/XL	F03ABMC.CT1	2	2.20E-07
			T/Q1/B1/XH	F07ABMC.CT1	2	2.20E-07
			T/Q1/XH	F08ABMC.CT1	1	1.00E-04
			T/Q1/UH2/XL	F27ABMC.CT1	2	1.39E-07
ABO	generic	none	T/Q1/XH	F08ABOG.CT1	7	5.57E-06
ABO	SW A	none	T/Q1/XH	F08ABOSA.CT1	7	5.57E-06
ABO	CCW	none	T/Q1/XH	F08ABOSA.CT1	7	5.57E-06

Table 3.3.8-10 Final Internal Plant Flooding-Induced Core-Damage Sequences												
					Second Screening (.CUT)*		*Detailed Analysis*					
								Vulnerability Reassessment (.CT1)*			*Final Results (*.CT2)*	
Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Cut Sets*	*CDF(/y)*	f_{FL}	*Cut Sets*	*CDF(/y)*	*HFE NR*	*Cut Sets*	*CDF(/y)*
CC/AHR	generic	none	T/B1/L1/UH1	F02AHRG	44	7.90E-06	N	0	-	NA	NA	NA
			T/Q2/XL	F30AHRG	2	4.47E-07	N	0	-	NA	NA	NA
CC/AHR	SW B	none	T/B1/L1/UH1	F02AHRSB	44	7.90E-06	N	0	-	NA	NA	NA
			T/B1/L1/XL	F03AHRSB	21	2.07E-06	N	0	-	NA	NA	NA
			T/Q2/XL	F30AHRSB	3	1.99E-05	N	0	-	NA	NA	NA
CC/BR1A	generic	none	T/B1/L1/P1	F01BRAG	28	5.74E-05	Y	N	N	N	1	7.70E-08
			T/B1/L1/UH1	F02BRAG	17	1.06E-04	Y	N	N	Y	0	-
			T/Q2/UH2	F29BRAG	2	1.49E-06	Y	N	N	N	0	-
			T/Q2/XL	F30BRAG	12	3.84E-06	Y	N	N	N	0	-
CC/BR1B	generic	none	T/B1/L1/P1	F01BRBG	22	5.03E-05	Y	N	N	N	1	7.70E-08
			T/B1/L1/UH1	F02BRBG	13	4.87E-06	Y	N	N	Y	0	-
			T/Q2/XL	F30BRBG	12	3.84E-06	Y	N	N	N	0	-

Table 3.3.8-10
Final Internal Plant Flooding-Induced Core-Damage Sequences

Originating Flood Zone	Flood Source	Connecting Flood Zone(s)	Sequence	Cut Set File	Second Screening (*.CUT)		Detailed Analysis					
								Vulnerability Reassessment (*.CT1)			Final Results (*.CT2)	
					Cut Sets	CDF(/y)	f_{FL}	Cut Sets	CDF(/y)	HFE NR	Cut Sets	CDF(/y)
SH/SHE	generic	none	T/B1/L1/P1	F01SHEG	18	2.30E-04	N	0	-	NA	NA	NA
			T/B1/L1/UH1	F02SHEG	10	1.03E-04	N	0	-	NA	NA	NA
			T/B1/L1/XL	F03SHEG	1	1.00E-03	N	0	-	NA	NA	NA
			T/Q1/B1/L1/P2	F06SHEG	14	3.30E-05	N	0	-	NA	NA	NA
			T/Q1/B1/L1/XL	F15SHEG	1	1.00E-04	N	0	-	NA	NA	NA
			T/Q1/UH2/B1/L1	F16SHEG	2	1.39E-07	N	0	-	NA	NA	NA
			T/Q2/XL	F30SHEG	2	1.49E-05	N	0	-	NA	NA	NA
TB/TBM	generic	none	T/B1/L1/UH1	F02TBMG	46	8.06E-06	N	N	N	Y	0	-
			T/B1/L1/XL	F03TBMG	24	2.33E-06	N	N	N	Y	0	-
			T/Q2/XL	F30TBMG	2	4.47E-07	N	N	N	N	2	4.47E-07
TB/TBM	FW	none	T/B1/L1/UH1	F02TBMF	56	9.21E-06	N	N	N	Y	0	-
			T/B1/L1/XL	F03TBMF	61	5.75E-06	N	N	N	Y	29	see TBM / TBB
			T/Q2/XL	F30TBMF	16	5.80E-06	N	N	N	Y	4	see TBM / TBB
TB/TBB	FW	none	T/B1/L1/UH1	F02TBBF	2	1.53E-07	N	N	N	Y	0	-
			T/B1/L1/XL	F03TBBF	3	2.11E-07	N	N	N	Y	1	see TBM / TBB
EDG1B	SW B	none	T/B1/L1/UH1	F02DGBSA	1	1.00E-06	Y	N	N	N	0	-

Table 3.3.8-10
Final Internal Plant Flooding-Induced Core-Damage Sequences

Originating Flood Zone	Flood Source	Connecting Flood Zone(s)	Sequence	Cut Set File	Second Screening (*.CUT) Cut Sets	Second Screening (*.CUT) CDF(/y)	Detailed Analysis f_{FL}	Vulnerability Reassessment (*.CT1) Cut Sets	Vulnerability Reassessment (*.CT1) CDF(/y)	HFE NR	Final Results (*.CT2) Cut Sets	Final Results (*.CT2) CDF(/y)
IB/IBS	CCW	none	T/B1/L1/XL	F03IBSC	2	1.53E-07	Y	N	N	N	1	6.47E-08
			T/Q1/B1/XH	F07IBSC	1	1.50E-07	Y	N	N	Y	0	-
			T/Q1/XH	F08IBSC	1	1.50E-07	Y	N	N	Y	0	-
AB/ABO	generic	none	T/B1/L1/XL	F03ABOG	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/B1/XH	F07ABOG	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/XH	F08ABOG	1	1.00E-04	N	7	5.57E-06	Y	2	1.04E-07
			T/Q1/UH2/P3SS	F24ABOG	1	5.59E-08	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABOG	12	2.11E-06	N	0	-	NA	NA	NA
AB/ABO	SW A	none	T/B1/L1/XL	F03ABOSA	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/B1/XH	F07ABOSA	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/XH	F08ABOSA	1	1.00E-04	N	7	5.57E-06	Y	2	1.04E-07
			T/Q1/UH2/P3SS	F24ABOSA	1	5.59E-08	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABOSA	12	2.11E-06	N	0	-	NA	NA	NA
AB/ABO	CCW	none	T/B1/L1/XL	F03ABOC	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/B1/XH	F07ABOC	4	3.50E-07	N	0	-	NA	NA	NA
			T/Q1/XH	F08ABOC	1	1.00E-04	N	7	5.57E-06	Y	2	1.04E-07
			T/Q1/UH2/P3SS	F24ABOC	1	5.59E-08	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABOC	1	2.11E-06	N	0	-	NA	NA	NA

Table 3.3.8-10
Final Internal Plant Flooding-Induced Core-Damage Sequences

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Second Screening (*.CUT)*		*Detailed Analysis*					
								Vulnerability Reassessment (.CT1)*			*Final Results (*.CT2)*	
					Cut Sets	*CDF(/y)*	f_{FL}	*Cut Sets*	*CDF(/y)*	*HFE NR*	*Cut Sets*	*CDF(/y)*
AB/ABM	generic	none	T/B1/L1/UH1	F02ABMG	31	5.95E-05	N	0	-	NA	NA	NA
			T/B1/L1/XL	F03ABMG	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/B1/XH	F07ABMG	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/XH	F08ABMG	0	-	N	1	1.00E-04	see text		
			T/Q1/UH2/B1/L1	F16ABMG	9	5.56E-06	N	0	-	NA	NA	NA
			T/Q1/UH2/P3SS	F24ABMG	5	1.41E-05	N	0	-	NA	NA	NA
			T/Q1/UH2/UL	F26ABMG	1	1.00E-04	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABMG	0	-	N	2	1.39E-07	Y	0	-
AB/ABM	SW A	none	T/B1/L1/UH1	F02ABMSA	31	5.95E-05	N	0	-	NA	NA	NA
			T/B1/L1/XL	F03ABMSA	0	-	N	2	2.20E-07	NA	NA	NA
			T/Q1/B1/XH	F07ABMSA	0	-	N	2	2.20E-07	NA	NA	NA
			T/Q1/XH	F08ABMSA	0	-	N	1	1.00E-04	see text		
			T/Q1/UH2/B1/L1	F16ABMSA	9	5.56E-06	N	0	-	NA	NA	NA
			T/Q1/UH2/P3SS	F24ABMSA	5	1.41E-05	N	0	-	NA	NA	NA
			T/Q1/UH2/UL	F26ABMSA	1	1.00E-04	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABMSA	0	-	N	2	1.39E-07	NA	NA	NA

Table 3.3.8-10
Final Internal Plant Flooding-Induced Core-Damage Sequences

Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Second Screening (*.CUT)*		*Detailed Analysis*					
								Vulnerability Reassessment (.CT1)*			*Final Results (*.CT2)*	
					Cut Sets	*CDF(/y)*	f_{FL}	*Cut Sets*	*CDF(/y)*	*HFE NR*	*Cut Sets*	*CDF(/y)*
AB/ABM	SW B	none	T/B1/L1/UH1	F02ABMSB	31	5.95E-05	N	0	-	NA	NA	NA
			T/B1/L1/XL	F03ABMSB	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/B1/XH	F07ABMSB	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/XH	F08ABMSB	0	-	N	1	1.00E-04	see text		
			T/Q1/UH2/B1/L1	F16ABMSB	9	5.56E-06	N	0	-	NA	NA	NA
			T/Q1/UH2/P3SS	F24ABMSB	5	1.41E-05	N	0	-	NA	NA	NA
			T/Q1/UH2/UL	F26ABMSB	1	1.00E-04	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABMSB	0	-	N	2	1.39E-07	Y	0	-
AB/ABM	CCW	none	T/B1/L1/UH1	F02ABMC	31	5.95E-05	N	0	-	Y	NA	NA
			T/B1/L1/XL	F03ABMC	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/B1/XH	F07ABMC	0	-	N	2	2.20E-07	Y	0	-
			T/Q1/XH	F08ABMC	0	-	N	1	1.00E-04	see text		
			T/Q1/UH2/B1/L1	F16ABMC	9	5.56E-06	N	0	-	NA	NA	NA
			T/Q1/UH2/P3SS	F24ABMC	5	1.41E-05	N	0	-	NA	NA	NA
			T/Q1/UH2/UL	F26ABMC	1	1.00E-04	N	0	-	NA	NA	NA
			T/Q1/UH2/XL	F27ABMC	0	-	N	2	1.39E-06	Y	0	-

Table 3.3.8-10 Final Internal Plant Flooding-Induced Core-Damage Sequences												
Originating Flood Zone	*Flood Source*	*Connecting Flood Zone(s)*	*Sequence*	*Cut Set File*	*Second Screening (*.CUT)*		*Detailed Analysis*					
								Vulnerability Reassessment (.CT1)*			*Final Results (*.CT2)*	
					Cut Sets	*CDF(/y)*	f_{FL}	*Cut Sets*	*CDF(/y)*	*HFE NR*	*Cut Sets*	*CDF(/y)*
AB/ABB	CCW	none	T/Q1/UH2/B1/UL	F20ABBC	2	2.20E-07	N	2	2.20E-07	Y	0	-
			T/Q1/UH2/P3SS	F24ABBC	3	1.37E-05	N	3	1.37E-05	Y	1	6.54E-08
			T/Q1/UH2/UL	F26ABBC	1	1.00E-04	N	1	1.00E-04	see text		
TB/TBM	FW	TB/TBB	T/B1/L1/UH1	F02TBF	56	9.21E-06	N	N	N	Y	0	-
			T/B1/L1/XL	F03TBF	61	5.75E-06	N	N	N	Y	29	2.85E-06
			T/Q2/XL	F30TBF	16	5.80E-06	N	N	N	Y	4	1.16E-06
SB/SBM	CCW	SB/SBB	T/Q1/XH	F08SBC	1	1.50E-07	N	N	N	Y	0	-

Figure 3.3.8-1
Flood Zones Interconnecting Diagram

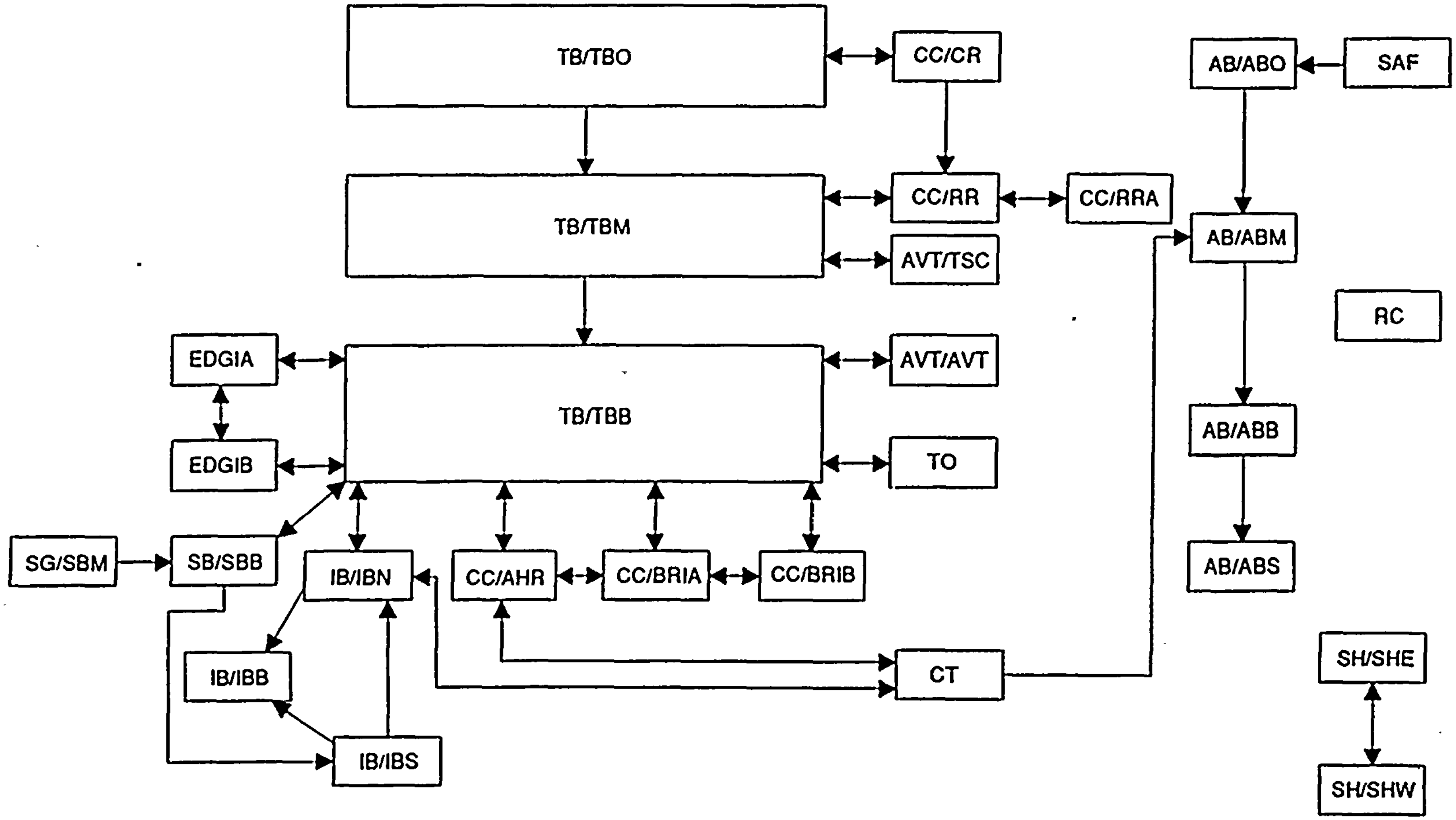
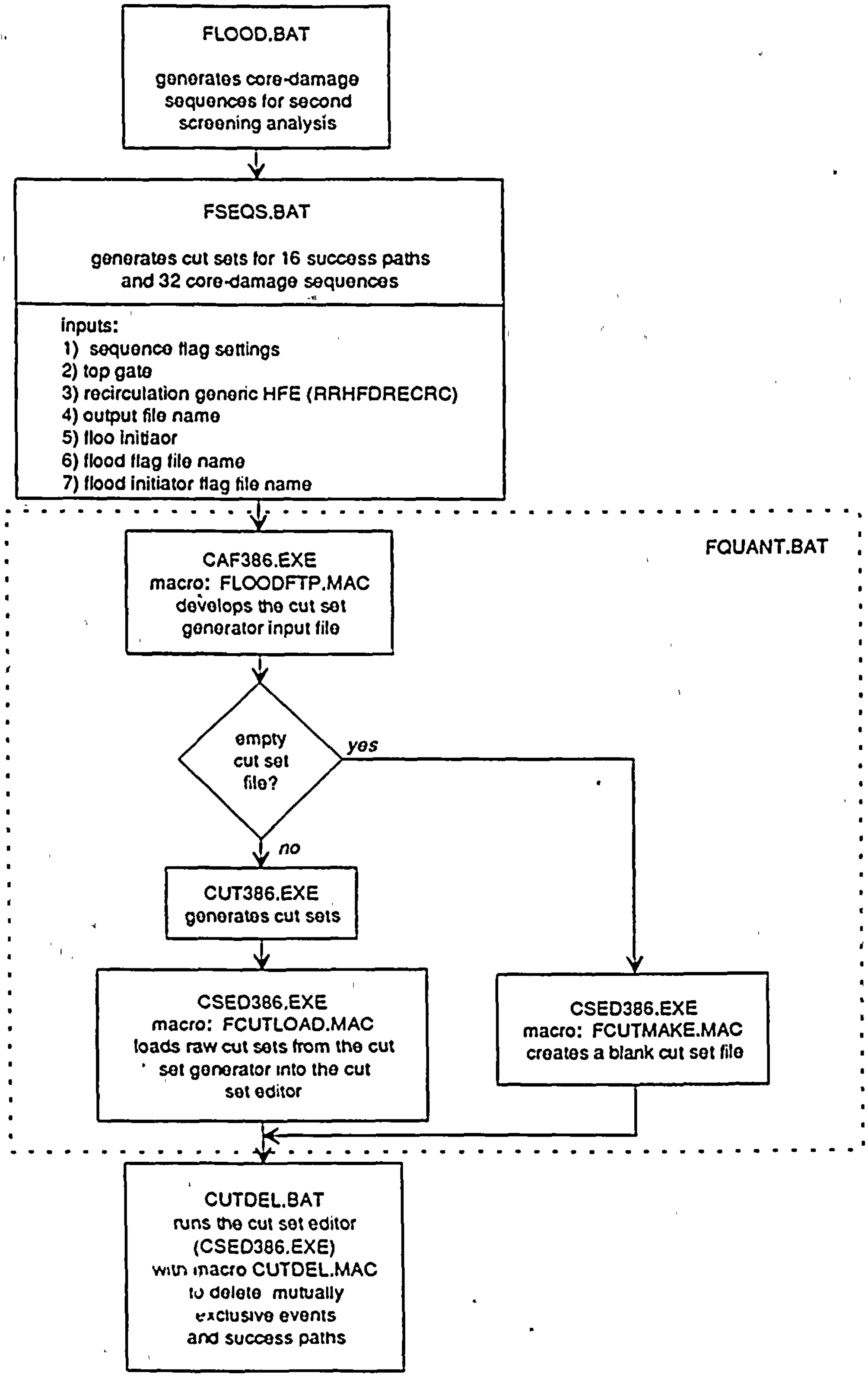


Figure 3.3.8-2
Internal Plant Flooding Analysis DOS Batch and Macro Files



3.4 Level 1 Results and Screening Process

3.4.1 Application of Generic Letter 88-20 / NUREG-1335 Screening Criteria

NUREG-1335 requests that sequences be reported that meet the following criteria:

1. Sequences contributing ≥ 1.00E-07 / year to the calculated core damage frequency;

2. All sequences in the upper 95 percent of the total calculated core damage frequency; and,

3. Sequennces contributing > 1.00E-08 / year to the calculated containment bypass frequency.

Sequences meeting these criteria are shown in Table 3.4-1.

3.4.2 Vulnerability Screening

No consensus definition is available for severe accident vulnerabilities. Therefore, for purposes of this report, RG&E has chosen the following definitions, based on the USNRC's mean safety goal targets for domestic nuclear power licensees published in SECY-89-102, *Implementation of Safety Goal Policy*:

> *Severe accident vulnerabilities are plant-specific design or operating characteristics that result in dominant contributors to core damage frequency or large fission product release frequencies significantly greater than the USNRC's mean safety goal targets stated in SECY-89-102. A significant dominant contributor to calculated core damage or release frequency meeting this definition would call for immediate corrective actions to address the vulnerability. These targets are 1.00E-04 / year for calculated core damage frequency, and 1.00E-06 / year for calculated frequency of large fission product release. Further, a large fission product release is defined as a release sequence which results in the release of more than one percent of the volatile radioactive fission product inventory of the reactor core, yielding off-site radiation exposures with the potential for at least one off-site, early radiation-induced fatality.*

As can be seen in Table 3.4-1, the total calculated core damage frequency for the Ginna PRA of 8.71E-05 / year meets the first of these criteria (being less than 1.00E-04 / year). See Section 4.7.4 and Section 6 for a discussion of how the Level 2 results compare to the second criteria (frequency of large release).

3.4.3 Uncertainty Analysis

A Monte Carlo uncertainty analysis was performed using the SAIC computer code UNCERT [Ref. 3.4-1] to assess the impact of statistical deviations in the underlying reliability data (e.g., failure rates, test/maintenance unavailabilities, etc.), common-cause failure parameters, human error rates, and initiating event frequencies. This analysis was conducted under the following guidelines:

1. All cut sets above the truncation limit (5.00E-08/y) were included; and,

2. Uncertainty was propagated in such a manner as to account for coupling among groups of components whose related basic events are based on a common failure rate (e.g., the failure rate for service water motor-operated valves was varied and the probabilities of all events in the integrated risk model based on this failure rate were recalculated).

A summary of the statistical results of the uncertainty analysis (e.g., moments and percentiles) are shown in Figure 3.4-1. Figures 3.4-2 and 3.4-3 present the sampling probability density and distribution functions. The overall core-damage frequency may be characterized as having an error factor (ratio of the 95th percentile to the median) of about 4.9.

3.4.4 Sensitivity Analysis

To assist in the determination of dominant risk contributors, importance measures for all basic events in the integrated risk model was calculated. These importance measures include: (1) The Vesely-Fussell (VF) measure; (2) The risk achievement worth (RAW); (3) The risk reduction worth (RRW); and, (4) The Birnbaum measure. Each type of importance measure has its strengths and weaknesses; thus, a combination of importance measures was used to assess sensitivities.

The SAIC Risk Management Query System (RMQS) computer code was used to calculate importance measures. The following definitions are from the *RMQS User's Manual* [Ref. 3.4-2]:

Vesley-Fussell Measure: Gives the risk associated with a given component; that is, how much the component is contributing to the total calculated core damage frequency.

Risk Achievement Worth: Expressed as a ratio, giving the factor by which calculated core damage frequency increases due to the component in question not being available.

Risk Reduction Worth: A measure of the calculated core damage frequency that would be reduced by reducing the unavailability of the component in question to zero (making the component in question always reliable / always available). Also expressed as a ratio.

Birnbaum Measure: Measures the difference in calculated total core damage frequency when the failure of the component in question occurs and when the failure in question does not occur, and therefore the increase in total calculated core damage frequency associated with the failure of the component in question.

Tables 3.4-2 through 3.4-5 lists the calculated importance measures sorted by Vesely-Fussell, RAW, RRW and Birnbaum, respectively. The top twenty basic events for each category are shown in bold-faced type in each of these tables for ease of identification and comparison.

3.4.4.1 Hardware-Related Events

A complete list of hardware-related failures contributing to the total calculated core damage frequency (sorted by the Vesely-Fussell measure) is given in Table 3.4-6. The following hardware-related events are of interest:

Failure of either pressurizer safety valve to reseat following steam relief;

Failure of various components associated with the residual heat removal function;

> Failure of 125 VDC power (Circuit E215 - RA Rack Train A, Circuit E212 - RA Rack Train B, Circuits E76 - Main DC Distribution Panel B, and Circuit E103 - MCB DC Distribution Panel 1B);
>
> Rupture of the component cooling water surge tank;
>
> Motor operated valves 896A or 896B transfer closed, blocking flow from the refueling water storage tank; and,
>
> Failure of main steam isolation valve 3516 to close. The VF measure for this event is high, but other importance measures are low. This suggests that this significance is due to the system configuration, and not to a valve maintenance / reliability problem.

3.4.4.2 Test / Maintenance Unavailabilities

A complete list of test / maintenance-related basic events contributing to the total calculated core damage frequency (sorted by the Vesely-Fussell measure) is given in Table 3.4-7. The following test / maintenance events are of interest:

Either RHR train is out of service; and,

Unavailability of diesel generator EDG1B.

Both of these events exhibit a high Vesely-Fussell importance; however, the other importance measures are low. This suggests that the problem is one of system configuration (i.e., B train AC power is more risk-significant than A train AC power, and both trains of RHR are important to risk), and not one of diesel generator or RHR pump reliability or maintenance.

3.4.4.3 Human Failure Events and Non-Recovery Events

A complete list of human failure events and non-recovery events that contribute to the total calculated core damage frequency (sorted by the Vesely-Fussell measure) is given in Table 3.4-8. Included are the following significant events:

Failure to close air operated valve 371 after the valve fails to close on a containment isolation signal;

Failure to throttle flow from the RHR pumps after failure of air operated valves 624 and 625; and,

Failure to cooldown and depressurize following a steam generator tube rupture (SGTR) event.

3.4.4.4 Common-Cause Failure Events

A complete list of common cause failure events that contribute to the total calculated core damage frequency (sorted by the Vesely-Fussell measure) is given in Table 3.4-9. The following top events are of interest:

Common cause failure of motor operated valves 852A and 852B to open for the residual heat removal injection mode;

Common cause failure of Refueling Water Storage Tank TSI01 level transmitters to respond to a decreasing tank level;

Common cause failure of motor operated valves 850A and 850B to open for the residual heat removal recirculation mode;

Common cause failure of motor operated valves 897 and 898 to close for the safety injection recirculation (high-head recirculation) mode; and,

Common cause failure of the safety injection pumps to run in the injection mode.

3.4.5 Decay Heat Removal Evaluation

USNRC Generic Letter 88-20 requires that the decay heat removal function be explicitly analyzed as part of this study. The Ginna PRA event trees and fault trees do contain detailed models of all systems required for decay heat removal including the Residual Heat Removal System, the Auxiliary Feedwater and Standby Auxiliary Feedwater Systems and the Primary Pressure Control Systems (pressurizer PORVs during bleed and feed operation).

3.4.6 Unresolved Safety Issue and Generic Safety Issue Screening

The following USNRC Unresolved Safety Issues (USIs) and Generic Safety Issues (GSIs) are considered resolved by RG&E based on the results of the R. E. Ginna PRA Project as summarized by this report:

USI A-17, *Systems Interactions in Nuclear Power Plants*, is considered resolved for water intrusion and flooding from internal sources as shown by the results discussed in Section 3.3.8 of this report;

USI A-45, *Shutdown Decay Heat Removal Requirements*, is considered resolved for internally initiated events from power operation and internal plant flooding events, as discussed in Section 3.4.5 above; and,

GSI 23, *Reactor Coolant Pump Seal Failures*, is considered resolved per the results shown in Table 3.4-1, whereas these sequences do not contribute at all above the truncation value of 5.0E-08 / year to the total calculated core damage frequency.

3.4.7 References

3.4-1 Science Applications International Corporation, *UNCERT User's Manual*, Version 2.0c, June, 1993.

3.4-2 Science Applications International Corporation, *Risk Management Query System (RMQS) User's Manual*, Version 2.4f, November, 1992.

Table 3.4-1
Final Results of the R. E. Ginna PRA Project Level 1 Analyses

Sequence	Number of Quantified Cut Sets	Quantified Frequency	Number of Recovered Cut Sets	Recovered Frequency	% of Total CDF
T/Q2/XL	220	3.14E-04	54	1.82E-05	21%
R/D	127	3.40E-03	27	1.40E-05	16%
R/I1/P3TR1	129	6.30E-04	29	1.20E-05	14%
SS/XH	44	8.23E-05	44	9.40E-06	11%
ISLOCA LI000111				5.79E-06	7%
M/XL	17	6.76E-05	15	4.83E-06	6%
S/XH	25	4.11E-05	24	4.11E-06	5%
T/Q2/UH2	12	3.37E-06	12	3.37E-06	4%
Flood: TBM/TBB/FW/T/B1/L1/XL				2.85E-06	3%
A/XL	9	2.91E-05	9	1.65E-06	2%
A/UL	4	1.44E-06	4	1.44E-06	2%
ISLOCA LI000140				1.37E-06	2%
Flood: TBM/TBB/FW/T/Q2/XL				1.16E-06	1%
T/B1/L1/P1	25	3.02E-06	15	1.12E-06	1%
M/UH2	4	9.22E-07	4	9.22E-07	1%
S/UH2	4	8.53E-07	4	8.53E-07	1%
T/B1/L1/UH1	169	4.69E-05	4	8.37E-07	1%
R/I1/SC	41	2.36E-03	8	7.96E-07	1%
Flood: TBM/G/T/Q2/XL				4.47E-07	1%
T/B1/L1/XL	20	3.94E-06	3	2.66E-07	0%
ISLOCA LI000101				2.66E-07	0%
ISLOCA LI000113				2.66E-07	0%
SS/UH2/UL	1	1.88E-07	1	1.88E-07	0%
R/B1/D	22	9.65E-06	1	1.34E-07	0%
IE/KM/PL/MF/LT	1	1.14E-07	1	1.14E-07	0%
Flood: ABO/G/T/Q1/XH				1.04E-07	0%
Flood: ABO/SWA/T/Q1/XH				1.04E-07	0%
Flood: ABO/CCW/T/Q1/XH				1.04E-07	0%
Flood: BR1A/G/T/B1/L1/P1				7.70E-08	0%
Flood: BR1B/G/T/B1/L1/P1				7.70E-08	0%
Flood: ABB/CCW/T/Q1/UH2/P3SS				6.54E-08	0%
Flood: IBS/CCW/T/B1/L1/XL				6.47E-08	0%
SS/UH2/UA	1	5.60E-08	1	5.60E-08	0%
IE/KM/LT	1	5.13E-08	1	5.13E-08	0%
T/Q1/B1/L1/XL	1	1.78E-07	0	0.00E+00	0%
SS/B1/XH	2	1.61E-07	0	0.00E+00	0%
SS/UH2/P3SS	1	6.12E-08	0	0.00E+00	0%
SS/UH2/XL	1	6.12E-08	0	0.00E+00	0%
R/13S/SC	2	1.03E-05	0	0.00E+00	0%
R/UH2/SC	13	2.96E-05	0	0.00E+00	0%
R/UH2/P3TR2	23	7.44E-06	0	0.00E+00	0%
R/I1/B1/SC	28	6.01E-06	0	0.00E+00	0%
R/I1/B1/P3TR1	7	6.39E-07	0	0.00E+00	0%

Table 3.4-2

Importance Measures Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation	1.38E-01	1.16	139	1.20E-02
RCHFDCDTR1	Failure to Cooldown to RHR After Ruptured S/G Isolation Fails	1.38E-01	1.16	14.1	1.15E-03
RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <common cause event>	8.58E-02	1.09	23.4	1.95E-03
RRMMHXBFLW	Failure of components for RHR Heat Exchanger B	5.60E-02	1.06	2.92	1.71E-04
RHMM00852B	852B Fails to Open	5.54E-02	1.06	2.1	1.01E-04
RRHXFAC02A	HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]	5.35E-02	1.06	2.83	1.64E-04
RHMM00852A	852a Fails to Open	5.34E-02	1.06	2.07	9.72E-05
MSAVX03516	MSIV 3516 Fails to Close	3.74E-02	1.04	2.05	9.41E-05
CSCCMLDRWT	Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters	3.30E-02	1.03	36.1	3.05E-03
RRCC850A/B	MOVS 850A/B FAIL TO OPEN <common cause event>	3.24E-02	1.03	36.1	3.05E-03
DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.48E-02	1.03	1.8	7.19E-05
CVAVX00371	AOV 371 FAILS TO CLOSE	2.47E-02	1.03	1.4	3.73E-05
NRHLETDOWN	FAILURE TO LOCALLY ISOLATE LETDOWN VALVE AOV-371 USING 204A	2.33E-02	1.02	2.27	1.12E-04
SICCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run during injection due to common cause	2.07E-02	1.02	25.6	2.14E-03
RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)	2.05E-02	1.02	2.7	1.49E-04
NRHLRHRTHL	FAILURE TO THROTTLE RHR FLOW USING 715 AND 717	1.98E-02	1.02	1.45	4.10E-05
SRCCM897/8	MOVs 897 and 898 fail to close due to common cause	1.95E-02	1.02	13.6	1.10E-03
RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)	1.94E-02	1.02	2.6	1.41E-04
SWMVP9629A	Motor operated valve 9629A fails to open	1.75E-02	1.02	2.18	1.04E-04
MSAVX03517	MSIV 3517 Fails to Close	1.71E-02	1.02	1.48	4.30E-05
CSMM896A/B	MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)	1.63E-02	1.02	25.6	2.14E-03
RHCCPUMPAB	PUMPS A AND B FAIL TO START <common cause event>	1.43E-02	1.01	36.1	3.05E-03
SICCMPSI1X	PSI01A, PSI01B & PSI01C fail to start for injection due to common cause	1.35E-02	1.01	25.6	2.14E-03
NRHSOALTCD	FAILURE TO COOLDOWN AFTER SGTR USING STEAM DUMP OR RUPTURED S/G	1.22E-02	1.01	22.8	1.90E-03
CCCC738A/B	MOVS 738A/B FAIL TO OPEN <common cause event>	1.21E-02	1.01	36.1	3.05E-03
RRCCM0857M	MOVs 857A, 857B and 857C fail to open due to common cause	1.17E-02	1.01	13.6	1.10E-03
CRCCM0896X	Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)	1.17E-02	1.01	13.6	1.10E-03
SRCCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause	1.06E-02	1.01	13.6	1.10E-03
CTAVX05736	AOV 5736 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
CTAVX05737	AOV 5737 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
RRMVP0857B	MOV 857B fails to open	9.66E-03	1.01	1.8	7.05E-05
NROGRID10H	FAILURE TO RESTORE OFFSITE POWER FROM GRID WITHIN 10H	9.63E-03	1.01	1.17	1.55E-05
RHHFD0SGTR	Failure to Establish or Maintain RHR Cooling Following SGTR	9.16E-03	1.01	10.1	7.96E-04
MSAVP03411	AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)	8.60E-03	1.01	1.05	5.06E-06

Table 3.4-2
Importance Measures Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RRMVP0857A	MOV 857A fails to open	8.53E-03	1.01	1.71	6.22E-05
RRMVP0857C	MOV 857C fails to open	8.53E-03	1.01	1.71	6.22E-05
CSMM00RWST	Insufficient Flow Available From TS101 (RWST)	8.49E-03	1.01	34	2.87E-03
RRHFDRCR0A	Failure to Switch to Recirculation After LLOCA	8.29E-03	1.01	3.06	1.80E-04
RHMVP0852B	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]	8.19E-03	1.01	1.16	1.49E-05
SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open	7.86E-03	1.01	8.72	6.71E-04
DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	7.82E-03	1.01	1.25	2.26E-05
MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	6.96E-03	1.01	3.96	2.58E-04
RCMMTRC04A	FAILURE OF NITROGEN SUPPLY TO PCV-430	6.77E-03	1.01	1.1	8.92E-06
RCMMTRC04B	FAILURE OF NITROGEN SUPPLY TO PCV-431C	6.77E-03	1.01	1.1	8.92E-06
SWMVN04616	Service Water Header Isolation MOV 4616 Fails To Open On Demand	5.82E-03	1.01	2.32	1.16E-04
CRMVX00897	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
CRMVX00898	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
AFMMSAFWPC	Failure of SAFW Pump 1C train	5.24E-03	1.01	1.22	1.96E-05
AFMMSAFWPD	Failure of SAFW Pump 1D Train	5.24E-03	1.01	1.22	1.96E-05
ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip	4.74E-03	1	5.73	4.12E-04
CCMM00738A	MOV 738A FAILS TO OPEN	4.47E-03	1	1.93	8.15E-05
RCHFD00RCP	Operators Fail to Trip RCPs After Loss of CCW Support	4.36E-03	1	2.45	1.26E-04
MSAVP03410	AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)	4.34E-03	1	1.03	2.55E-06
RRPTHPC629	Pressure transmitter PIC-629 fails high	4.32E-03	1	1.66	5.73E-05
CTAVX05735	AOV 5735 Fails to Close	4.20E-03	1	1.45	3.92E-05
CCMM00738B	MOV 738B FAILS TO OPEN	3.89E-03	1	1.81	7.10E-05
IAHFDCNTBK	Operators fail to restore IA to the containment (AOV 5392, SW to IA Compressors	3.83E-03	1	2.27	1.11E-04
SWMVNCCF$$	Beta Factor For Common Cause Failure Events SWCCFBMOVN & SWCCFGMOVN	3.57E-03	1	1.05	4.38E-06
DCMMCB04AN	Failure of Circuit E215 (To RA Racks Train A)	3.38E-03	1	95.9	8.25E-03
MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]	3.09E-03	1	3.07	1.80E-04
CTHFDISOLB	Operators Fail to Isolate S/G B	2.96E-03	1	1.98	8.58E-05
CCTKJSURGE	CCW SURGE TANK RUPTURE	2.95E-03	1	25.2	2.10E-03

Table 3.4-2
Importance Measures Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
AFCCPRECLB	Common cause failure of AOVs 9710A and 9710B to open	2.84E-03	1	6.58	4.85E-04
RRHFL0850A	LATENT HUMAN FAILURE OF MOV 850A	2.70E-03	1	1.9	7.83E-05
RRHFL0850B	LATENT HUMAN FAILURE OF MOV 850B	2.70E-03	1	1.9	7.83E-05
CTCCCSGBLO	Common Cause Failure of Steam Generator Blowdown AOVs to Close	2.56E-03	1	2.44	1.25E-04
HVMFSAFF1A	MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START	2.47E-03	1	1.34	3.00E-05
RCMM0430N2	SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
RCMM431CN2	SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
MSCCCMSIVX	Common Cause Failure Of MSIVs To Close	2.28E-03	1	1.45	3.92E-05
MSMVC3504A	MOV 3504A Fails to Close	2.25E-03	1	1.99	8.58E-05
MSXVX03412	Manual Valve 3412A Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03520	Manual Valve 3520 Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03668	Manual Valve 3668 Fails to Close	2.22E-03	1	1.99	8.58E-05
CSLTDLT920	RWST Level Transmitter LT-920 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CSLTDLT921	RWST Levle Transmitter LT-921 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	2.06E-03	1	1.68	5.97E-05
RHHFLAC01A	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)	2.06E-03	1	1.68	5.97E-05
CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	2.06E-03	1	1.68	5.96E-05
RHHFLAC01B	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)	2.06E-03	1	1.68	5.96E-05
CRMVZ0896A	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
CRMVZ0896B	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
AFHFDXSAFW	Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G	2.02E-03	1	1	1.76E-07
RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	1.99E-03	1	1.68	5.97E-05
RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	1.99E-03	1	1.68	5.96E-05
AFTMSAFWPC	SAFW Pump Train 1C out-of-service for maintenance	1.92E-03	1	1.34	3.00E-05
TLCCFMATWS	Mechanical Scram Failure Probability (WOG Data)	1.91E-03	1	1060	9.20E-02
SICCM0867X	Common Cause Failure To Open Of Check Valves 867A & 867B	1.85E-03	1	25.2	2.10E-03
IASVP14206	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVP14307	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVX05736	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
IASVX05737	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
SWMVP9629B	Motor operated valve 9629B fails to open	1.62E-03	1	1.11	9.64E-06
RRHFDRCR0M	Failure to Switch to Recirculation After MLOCA	1.58E-03	1	16.8	1.37E-03
DCMMCB04BK	Failure of Circuit E212 (To RA Racks Train B)	1.54E-03	1	44.4	3.77E-03
DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	1.54E-03	1	44.4	3.77E-03
DCMMMCB01B	Failure of Circuit E103 (To MCB DC Distribution Panel 1B)	1.54E-03	1	44.4	3.77E-03
RCMVX00515	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE	1.42E-03	1	1.05	4.87E-06

Table 3.4-2
Importance Measures Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief	1.42E-03	1	1.28	2.47E-05
RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
CTHFDISOLA	Operators Fail to Isolate S/G A	1.35E-03	1	1.45	3.92E-05
HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.31E-03	1	1.34	3.00E-05
SICCM0878X	Check valves 878G and 878J fail to open due to common cause	1.21E-03	1	16.8	1.37E-03
RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE	1.14E-03	1	1.22	1.91E-05
AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint	1.04E-03	1	1.34	3.00E-05
HVHFLSAFWA	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION	1.04E-03	1	1.34	3.00E-05
MSMVC3505A	MOV 3505A Fails to Close	1.03E-03	1	1.45	3.92E-05
MSXVX03521	Manual Valve 3521 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX03669	Manual Valve 3669 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX3413A	Manual Valve 3413A Fails to Close	1.01E-03	1	1.45	3.92E-05
DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE	9.87E-04	1	1.17	1.46E-05
AFTMSAFWIA	SAFW injection line to S/G A out-of-service for maintenance	9.84E-04	1	1.34	3.00E-05
AFAVP9710A	Air operated valve 9710A fails to open	9.83E-04	1	1.34	3.00E-05
IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE	8.90E-04	1	3.07	1.80E-04
RRPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE	8.57E-04	1	1.22	1.91E-05
RRHFDRCRSS	Failure to Switch to Recirculation After SSLOCA	8.40E-04	1	9.4	7.30E-04
DGDGA0001B	DIESEL GENERATOR KDG01B FAILS TO START	8.22E-04	1	1.17	1.46E-05
MSCCARVAIR	COMMON CAUSE FAILURE OF AIR OPERATED ARVS	7.85E-04	1	1.05	4.62E-06
IASVX05735	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize	7.42E-04	1	1.45	3.92E-05
SIHFL857AC	Latent Human Failure of MOV 857A OR 857C	7.16E-04	1	1.24	2.07E-05
SIHFL0857B	Latent Human Failure of MOV 857B	7.15E-04	1	1.24	2.07E-05
ACCBD2BTBB	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate	7.10E-04	1	1.18	1.60E-05
ACCBD5211B	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand	7.10E-04	1	1.18	1.60E-05
AFFTD04084	Flow transmitter FT-4084 fails to respond	6.98E-04	1	1.34	3.00E-05
ACCBD1611B	AC BREAKER BUS16/11B FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBD1611C	AC BREAKER BUS16/11C FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBDJ/01K	AC BREAKER MCCJ/01K FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBN1612A	AC BREAKER BUS16/12A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1613C	AC BREAKER BUS16/13C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614A	AC BREAKER BUS16/14A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614C	AC BREAKER BUS16/14C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615A	AC BREAKER BUS16/15A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615B	AC BREAKER BUS16/15B FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05

Table 3.4-2

Importance Measures Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
ACCBN1615C	AC BREAKER BUS16/15C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1616A	AC BREAKER BUS16/16A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1617A	AC BREAKER BUS16/17A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727C	AC BREAKER BUS17/27C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727D	AC BREAKER BUS17/27D FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBNMCD5K	AC BREAKER MCCD/5K FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
RCMM0430IA	SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RCMM431CIA	SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RHMMAC01AA	PAC01A fails to start	6.04E-04	1	1.24	2.07E-05
RHMMAC01BA	AC01B Fails to Start	6.03E-04	1	1.24	2.07E-05
CCHFDSTART	OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI	2.02E-06	1	1.01	7.28E-07
ACCBRC2648	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN	7.19E-08	1	1.01	6.84E-07
RCHFLPC451	ALARM PC-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPC452	ALARM PC-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT451	PRESSURE TRANSMITTER PT-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT452	PRESSURE TRANSMITTER PT-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCMM0PT451	PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
RCMM0PT452	PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
ACCBR012AY	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open	9.68E-10	1	1	0.00E+00
ACCBR75112	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails	9.68E-10	1	1	0.00E+00

Table 3.4-3
Importance Measures Sorted by Risk Reduction Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation	1.38E-01	1.16	139	1.20E-02
RCHFDCDTR1	Failure to Cooldown to RHR After Ruptured S/G Isolation Fails	1.38E-01	1.16	14.1	1.15E-03
RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <common cause event>	8.58E-02	1.09	23.4	1.95E-03
RRMMHXBFLW	Failure of components for RHR Heat Exchanger B	5.60E-02	1.06	2.92	1.71E-04
RHMM00852B	852B Fails to Open	5.54E-02	1.06	2.1	1.01E-04
RRHXFAC02A	HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]	5.35E-02	1.06	2.83	1.64E-04
RHMM00852A	852a Fails to Open	5.34E-02	1.06	2.07	9.72E-05
MSAVX03516	MSIV 3516 Fails to Close	3.74E-02	1.04	2.05	9.41E-05
CSCCMLDRWT	Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters	3.30E-02	1.03	36.1	3.05E-03
RRCC850A/B	MOVS 850A/B FAIL TO OPEN <common cause event>	3.24E-02	1.03	36.1	3.05E-03
DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.48E-02	1.03	1.8	7.19E-05
CVAVX00371	AOV 371 FAILS TO CLOSE	2.47E-02	1.03	1.4	3.73E-05
NRHLETDOWN	FAILURE TO LOCALLY ISOLATE LETDOWN VALVE AOV-371 USING 204A	2.33E-02	1.02	2.27	1.12E-04
SICCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run during injection due to common cause	2.07E-02	1.02	25.6	2.14E-03
RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)	2.05E-02	1.02	2.7	1.49E-04
NRHLRHRTHL	FAILURE TO THROTTLE RHR FLOW USING 715 AND 717	1.98E-02	1.02	1.45	4.10E-05
SRCCM897/8	MOVs 897 and 898 fail to close due to common cause	1.95E-02	1.02	13.6	1.10E-03
RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)	1.94E-02	1.02	2.6	1.41E-04
SWMVP9629A	Motor operated valve 9629A fails to open	1.75E-02	1.02	2.18	1.04E-04
MSAVX03517	MSIV 3517 Fails to Close	1.71E-02	1.02	1.48	4.30E-05
CSMM896A/B	MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)	1.63E-02	1.02	25.6	2.14E-03
RHCCPUMPAB	PUMPS A AND B FAIL TO START <common cause event>	1.43E-02	1.01	36.1	3.05E-03
SICCMPSI1X	PSI01A, PSI01B & PSI01C fail to start for injection due to common cause	1.35E-02	1.01	25.6	2.14E-03
NRHS0ALTCD	FAILURE TO COOLDOWN AFTER SGTR USING STEAM DUMP OR RUPTURED S/G	1.22E-02	1.01	22.8	1.90E-03
CCCC738A/B	MOVS 738A/B FAIL TO OPEN <common cause event>	1.21E-02	1.01	36.1	3.05E-03
RRCCM0857M	MOVs 857A, 857B and 857C fail to open due to common cause	1.17E-02	1.01	13.6	1.10E-03
CRCCM0896X	Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)	1.17E-02	1.01	13.6	1.10E-03
SRCCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause	1.06E-02	1.01	13.6	1.10E-03
CTAVX05736	AOV 5736 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
CTAVX05737	AOV 5737 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
RRMVP0857B	MOV 857B fails to open	9.66E-03	1.01	1.8	7.05E-05
NROGRID10H	FAILURE TO RESTORE OFFSITE POWER FROM GRID WITHIN 10H	9.63E-03	1.01	1.17	1.55E-05
RHHFD0SGTR	Failure to Establish or Maintain RHR Cooling Following SGTR	9.16E-03	1.01	10.1	7.96E-04
MSAVP03411	AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)	8.60E-03	1.01	1.05	5.06E-06

Table 3.4-3
Importance Measures Sorted by Risk Reduction Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RRMVP0857A	MOV 857A fails to open	8.53E-03	1.01	1.71	6.22E-05
RRMVP0857C	MOV 857C fails to open	8.53E-03	1.01	1.71	6.22E-05
CSMM00RWST	Insufficient Flow Available From TSI01 (RWST)	8.49E-03	1.01	34	2.87E-03
RRHFDRCR0A	Failure to Switch to Recirculation After LLOCA	8.29E-03	1.01	3.06	1.80E-04
RHMVP0852B	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]	8.19E-03	1.01	1.16	1.49E-05
SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open	7.86E-03	1.01	8.72	6.71E-04
DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	7.82E-03	1.01	1.25	2.26E-05
MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	6.96E-03	1.01	3.96	2.58E-04
RCMMTRC04A	FAILURE OF NITROGEN SUPPLY TO PCV-430	6.77E-03	1.01	1.1	8.92E-06
RCMMTRC04B	FAILURE OF NITROGEN SUPPLY TO PCV-431C	6.77E-03	1.01	1.1	8.92E-06
SWMVN04616	Service Water Header Isolation MOV 4616 Fails To Open On Demand	5.82E-03	1.01	2.32	1.16E-04
CRMVX00897	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
CRMVX00898	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
AFMMSAFWPC	Failure of SAFW Pump 1C train	5.24E-03	1.01	1.22	1.96E-05
AFMMSAFWPD	Failure of SAFW Pump 1D Train	5.24E-03	1.01	1.22	1.96E-05
ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip	4.74E-03	1	5.73	4.12E-04
CCMM00738A	MOV 738A FAILS TO OPEN	4.47E-03	1	1.93	8.15E-05
RCHFD00RCP	Operators Fail to Trip RCPs After Loss of CCW Support	4.36E-03	1	2.45	1.26E-04
MSAVP03410	AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)	4.34E-03	1	1.03	2.55E-06
RRPTHPC629	Pressure transmitter PIC-629 fails high	4.32E-03	1	1.66	5.73E-05
CTAVX05735	AOV 5735 Fails to Close	4.20E-03	1	1.45	3.92E-05
CCMM00738B	MOV 738B FAILS TO OPEN	3.89E-03	1	1.81	7.10E-05
IAHFDCNTBK	Operators fail to restore IA to the containment (AOV 5392, SW to IA Compressors	3.83E-03	1	2.27	1.11E-04
SWMVNCCF$$	Beta Factor For Common Cause Failure Events SWCCFBMOVN & SWCCFGMOVN	3.57E-03	1	1.05	4.38E-06
DCMMCB04AN	Failure of Circuit E215 (To RA Racks Train A)	3.38E-03	1	95.9	8.25E-03
MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]	3.09E-03	1	3.07	1.80E-04
CTHFDISOLB	Operators Fail to Isolate S/G B	2.96E-03	1	1.98	8.58E-05
CCTKJSURGE	CCW SURGE TANK RUPTURE	2.95E-03	1	25.2	2.10E-03

Table 3.4-3
Importance Measures Sorted by Risk Reduction Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
AFCCPRECLB	Common cause failure of AOVs 9710A and 9710B to open	2.84E-03	1	6.58	4.85E-04
RRHFL0850A	LATENT HUMAN FAILURE OF MOV 850A	2.70E-03	1	1.9	7.83E-05
RRHFL0850B	LATENT HUMAN FAILURE OF MOV 850B	2.70E-03	1	1.9	7.83E-05
CTCCCSGBLO	Common Cause Failure of Steam Generator Blowdown AOVs to Close	2.56E-03	1	2.44	1.25E-04
HVMFSAFF1A	MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START	2.47E-03	1	1.34	3.00E-05
RCMM0430N2	SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
RCMM431CN2	SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
MSCCCMSIVX	Common Cause Failure Of MSIVs To Close	2.28E-03	1	1.45	3.92E-05
MSMVC3504A	MOV 3504A Fails to Close	2.25E-03	1	1.99	8.58E-05
MSXVX03412	Manual Valve 3412A Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03520	Manual Valve 3520 Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03668	Manual Valve 3668 Fails to Close	2.22E-03	1	1.99	8.58E-05
CSLTDLT920	RWST Level Transmitter LT-920 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CSLTDLT921	RWST Levle Transmitter LT-921 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	2.06E-03	1	1.68	5.97E-05
RHHFLAC01A	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)	2.06E-03	1	1.68	5.97E-05
CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	2.06E-03	1	1.68	5.96E-05
RHHFLAC01B	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)	2.06E-03	1	1.68	5.96E-05
CRMVZ0896A	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
CRMVZ0896B	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
AFHFDXSAFW	Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G	2.02E-03	1	1	1.76E-07
RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	1.99E-03	1	1.68	5.97E-05
RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	1.99E-03	1	1.68	5.96E-05
AFTMSAFWPC	SAFW Pump Train 1C out-of-service for maintenance	1.92E-03	1	1.34	3.00E-05
TLCCFMATWS	Mechanical Scram Failure Probability (WOG Data)	1.91E-03	1	1060	9.20E-02
SICCM0867X	Common Cause Failure To Open Of Check Valves 867A & 867B	1.85E-03	1	25.2	2.10E-03
IASVP14206	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVP14307	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVX05736	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
IASVX05737	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
SWMVP9629B	Motor operated valve 9629B fails to open	1.62E-03	1	1.11	9.64E-06
RRHFDRCR0M	Failure to Switch to Recirculation After MLOCA	1.58E-03	1	16.8	1.37E-03
DCMMCB04BK	Failure of Circuit E212 (To RA Racks Train B)	1.54E-03	1	44.4	3.77E-03
DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	1.54E-03	1	44.4	3.77E-03
DCMMMCB01B	Failure of Circuit E103 (To MCB DC Distribution Panel 1B)	1.54E-03	1	44.4	3.77E-03
RCMVX00515	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE	1.42E-03	1	1.05	4.87E-06

Table 3.4-3
Importance Measures Sorted by Risk Reduction Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief	1.42E-03	1	1.28	2.47E-05
RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
CTHFDISOLA	Operators Fail to Isolate S/G A	1.35E-03	1	1.45	3.92E-05
HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.31E-03	1	1.34	3.00E-05
SICCM0878X	Check valves 878G and 878J fail to open due to common cause	1.21E-03	1	16.8	1.37E-03
RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE	1.14E-03	1	1.22	1.91E-05
AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint	1.04E-03	1	1.34	3.00E-05
HVHFLSAFWA	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION	1.04E-03	1	1.34	3.00E-05
MSMVC3505A	MOV 3505A Fails to Close	1.03E-03	1	1.45	3.92E-05
MSXVX03521	Manual Valve 3521 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX03669	Manual Valve 3669 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX3413A	Manual Valve 3413A Fails to Close	1.01E-03	1	1.45	3.92E-05
DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE	9.87E-04	1	1.17	1.46E-05
AFTMSAFW1A	SAFW injection line to S/G A out-of-service for maintenance	9.84E-04	1	1.34	3.00E-05
AFAVP9710A	Air operated valve 9710A fails to open	9.83E-04	1	1.34	3.00E-05
IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE	8.90E-04	1	3.07	1.80E-04
RRPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE	8.57E-04	1	1.22	1.91E-05
RRHFDRCRSS	Failure to Switch to Recirculation After SSLOCA	8.40E-04	1	9.4	7.30E-04
DGDGA0001B	DIESEL GENERATOR KDG01B FAILS TO START	8.22E-04	1	1.17	1.46E-05
MSCCARVAIR	COMMON CAUSE FAILURE OF AIR OPERATED ARVS	7.85E-04	1	1.05	4.62E-06
IASVX05735	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize	7.42E-04	1	1.45	3.92E-05
SIHFL857AC	Latent Human Failure of MOV 857A OR 857C	7.16E-04	1	1.24	2.07E-05
SIHFL0857B	Latent Human Failure of MOV 857B	7.15E-04	1	1.24	2.07E-05
ACCBD2BTBB	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate	7.10E-04	1	1.18	1.60E-05
ACCBD5211B	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand	7.10E-04	1	1.18	1.60E-05
AFFTD04084	Flow transmitter FT-4084 fails to respond	6.98E-04	1	1.34	3.00E-05
ACCBD1611B	AC BREAKER BUS16/11B FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBD1611C	AC BREAKER BUS16/11C FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBDJ/01K	AC BREAKER MCCJ/01K FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBN1612A	AC BREAKER BUS16/12A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1613C	AC BREAKER BUS16/13C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614A	AC BREAKER BUS16/14A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614C	AC BREAKER BUS16/14C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615A	AC BREAKER BUS16/15A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615B	AC BREAKER BUS16/15B FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05

Table 3.4-3
Importance Measures Sorted by Risk Reduction Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
ACCBN1615C	AC BREAKER BUS16/15C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1616A	AC BREAKER BUS16/16A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1617A	AC BREAKER BUS16/17A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727C	AC BREAKER BUS17/27C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727D	AC BREAKER BUS17/27D FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBNMCD5K	AC BREAKER MCCD/5K FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
RCMM0430IA	SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RCMM431CIA	SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RHMMAC01AA	PAC01A fails to start	6.04E-04	1	1.24	2.07E-05
RHMMAC01BA	AC01B Fails to Start	6.03E-04	1	1.24	2.07E-05
CCHFDSTART	OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI	2.02E-06	1	1.01	7.28E-07
ACCBRC2648	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN	7.19E-08	1	1.01	6.84E-07
RCHFLPC451	ALARM PC-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPC452	ALARM PC-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPL451	PRESSURE TRANSMITTER PT-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT452	PRESSURE TRANSMITTER PT-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCMM0PT451	PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
RCMM0PT452	PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
ACCBR012AY	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open	9.68E-10	1	1	0.00E+00
ACCBR75112	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails	9.68E-10	1	1	0.00E+00

Table 3.4-4
Importance Measures Sorted by Risk Achievement Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
TLCCFMATWS	Mechanical Scram Failure Probability (WOG Data)	1.91E-03	1	1060	9.20E-02
RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation	1.38E-01	1.16	139	1.20E-02
DCMMCB04AN	Failure of Circuit E215 (To RA Racks Train A)	3.38E-03	1	95.9	8.25E-03
DCMMCB04BK	Failure of Circuit E212 (To RA Racks Train B)	1.54E-03	1	44.4	3.77E-03
DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	1.54E-03	1	44.4	3.77E-03
DCMMMCB01B	Failure of Circuit E103 (To MCB DC Distribution Panel 1B)	1.54E-03	1	44.4	3.77E-03
CSCCMLDRWT	Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters	3.30E-02	1.03	36.1	3.05E-03
RRCC850A/B	MOVS 850A/B FAIL TO OPEN <common cause event>	3.24E-02	1.03	36.1	3.05E-03
RHCCPUMPAB	PUMPS A AND B FAIL TO START <common cause event>	1.43E-02	1.01	36.1	3.05E-03
CCCC738A/B	MOVS 738A/B FAIL TO OPEN <common cause event>	1.21E-02	1.01	36.1	3.05E-03
CSMM00RWST	Insufficient Flow Available From TSI01 (RWST)	8.49E-03	1.01	34	2.87E-03
SICCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run during injection due to common cause	2.07E-02	1.02	25.6	2.14E-03
CSMM896A/B	MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)	1.63E-02	1.02	25.6	2.14E-03
SICCMPSI1X	PSI01A, PSI01B & PSI01C fail to start for injection due to common cause	1.35E-02	1.01	25.6	2.14E-03
CCTKJSURGE	CCW SURGE TANK RUPTURE	2.95E-03	1	25.2	2.10E-03
SICCM0867X	Common Cause Failure To Open Of Check Valves 867A & 867B	1.85E-03	1	25.2	2.10E-03
RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <common cause event>	8.58E-02	1.09	23.4	1.95E-03
NRHS0ALTCD	FAILURE TO COOLDOWN AFTER SGTR USING STEAM DUMP OR RUPTURED S/G	1.22E-02	1.01	22.8	1.90E-03
RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RRHFDRCR0M	Failure to Switch to Recirculation After MLOCA	1.58E-03	1	16.8	1.37E-03
RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
SICCM0878X	Check valves 878G and 878J fail to open due to common cause	1.21E-03	1	16.8	1.37E-03
RCHFDCDTR1	Failure to Cooldown to RHR After Ruptured S/G Isolation Fails	1.38E-01	1.16	14.1	1.15E-03
SRCCM897/8	MOVs 897 and 898 fail to close due to common cause	1.95E-02	1.02	13.6	1.10E-03
RRCCM0857M	MOVs 857A, 857B and 857C fail to open due to common cause	1.17E-02	1.01	13.6	1.10E-03
CRCCM0896X	Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)	1.17E-02	1.01	13.6	1.10E-03
SRCCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause	1.06E-02	1.01	13.6	1.10E-03
RHHFD0SGTR	Failure to Establish or Maintain RHR Cooling Following SGTR	9.16E-03	1.01	10.1	7.96E-04
RRHFDRCRSS	Failure to Switch to Recirculation After SSLOCA	8.40E-04	1	9.4	7.30E-04
SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open	7.86E-03	1.01	8.72	6.71E-04
AFCCPRECLB	Common cause failure of AOVs 9710A and 9710B to open	2.84E-03	1	6.58	4.85E-04
ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip	4.74E-03	1	5.73	4.12E-04
DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	6.96E-03	1.01	3.96	2.58E-04
RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]	3.09E-03	1	3.07	1.80E-04

Table 3.4-4

Importance Measures Sorted by Risk Achievement Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE	8.90E-04	1	3.07	1.80E-04
RRHFDRCR0A	Failure to Switch to Recirculation After LLOCA	8.29E-03	1.01	3.06	1.80E-04
RRMMHXBFLW	Failure of components for RHR Heat Exchanger B	5.60E-02	1.06	2.92	1.71E-04
RRHXFAC02A	HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]	5.35E-02	1.06	2.83	1.64E-04
RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)	2.05E-02	1.02	2.7	1.49E-04
RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)	1.94E-02	1.02	2.6	1.41E-04
RCHFD00RCP	Operators Fail to Trip RCPs After Loss of CCW Support	4.36E-03	1	2.45	1.26E-04
CTCCCSGBLO	Common Cause Failure of Steam Generator Blowdown AOVs to Close	2.56E-03	1	2.44	1.25E-04
SWMVN04616	Service Water Header Isolation MOV 4616 Fails To Open On Demand	5.82E-03	1.01	2.32	1.16E-04
NRHLETDOWN	FAILURE TO LOCALLY ISOLATE LETDOWN VALVE AOV-371 USING 204A	2.33E-02	1.02	2.27	1.12E-04
IAHFDCNTBK	Operators fail to restore IA to the containment (AOV 5392, SW to IA Compressors	3.83E-03	1	2.27	1.11E-04
SWMVP9629A	Motor operated valve 9629A fails to open	1.75E-02	1.02	2.18	1.04E-04
RHMM00852B	852B Fails to Open	5.54E-02	1.06	2.1	1.01E-04
MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
RHMM00852A	852a Fails to Open	5.34E-02	1.06	2.07	9.72E-05
CTAVX05736	AOV 5736 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
CTAVX05737	AOV 5737 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
MSAVX03516	MSIV 3516 Fails to Close	3.74E-02	1.04	2.05	9.41E-05
MSMVC3504A	MOV 3504A Fails to Close	2.25E-03	1	1.99	8.58E-05
MSXVX03412	Manual Valve 3412A Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03520	Manual Valve 3520 Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03668	Manual Valve 3668 Fails to Close	2.22E-03	1	1.99	8.58E-05
IASVX05736	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
IASVX05737	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
CTHFDISOLB	Operators Fail to Isolate S/G B	2.96E-03	1	1.98	8.58E-05
CCMM00738A	MOV 738A FAILS TO OPEN	4.47E-03	1	1.93	8.15E-05
RRHFL0850A	LATENT HUMAN FAILURE OF MOV 850A	2.70E-03	1	1.9	7.83E-05
RRHFL0850B	LATENT HUMAN FAILURE OF MOV 850B	2.70E-03	1	1.9	7.83E-05
CCMM00738B	MOV 738B FAILS TO OPEN	3.89E-03	1	1.81	7.10E-05
DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.48E-02	1.03	1.8	7.19E-05
RRMVP0857B	MOV 857B fails to open	9.66E-03	1.01	1.8	7.05E-05
RRMVP0857A	MOV 857A fails to open	8.53E-03	1.01	1.71	6.22E-05
RRMVP0857C	MOV 857C fails to open	8.53E-03	1.01	1.71	6.22E-05

Table 3.4-4
Importance Measures Sorted by Risk Achievement Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	2.06E-03	1	1.68	5.97E-05
RHHFLAC01A	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)	2.06E-03	1	1.68	5.97E-05
CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	2.06E-03	1	1.68	5.96E-05
RHHFLAC01B	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)	2.06E-03	1	1.68	5.96E-05
RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	1.99E-03	1	1.68	5.97E-05
RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	1.99E-03	1	1.68	5.96E-05
RRPTHPC629	Pressure transmitter PIC-629 fails high	4.32E-03	1	1.66	5.73E-05
MSAVX03517	MSIV 3517 Fails to Close	1.71E-02	1.02	1.48	4.30E-05
NRHLRHRTHL	FAILURE TO THROTTLE RHR FLOW USING 715 AND 717	1.98E-02	1.02	1.45	4.10E-05
CTAVX05735	AOV 5735 Fails to Close	4.20E-03	1	1.45	3.92E-05
MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSCCCMSIVX	Common Cause Failure Of MSIVs To Close	2.28E-03	1	1.45	3.92E-05
CTHFDISOLA	Operators Fail to Isolate S/G A	1.35E-03	1	1.45	3.92E-05
MSMVC3505A	MOV 3505A Fails to Close	1.03E-03	1	1.45	3.92E-05
MSXVX03521	Manual Valve 3521 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX03669	Manual Valve 3669 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX3413A	Manual Valve 3413A Fails to Close	1.01E-03	1	1.45	3.92E-05
IASVX05735	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize	7.42E-04	1	1.45	3.92E-05
CVAVX00371	AOV 371 FAILS TO CLOSE	2.47E-02	1.03	1.4	3.73E-05
HVMFSAFF1A	MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START	2.47E-03	1	1.34	3.00E-05
AFTMSAFWPC	SAFW Pump Train 1C out-of-service for maintenance	1.92E-03	1	1.34	3.00E-05
HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.31E-03	1	1.34	3.00E-05
AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint	1.04E-03	1	1.34	3.00E-05
HVHFLSAFWA	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION	1.04E-03	1	1.34	3.00E-05
AFTMSAFWIA	SAFW injection line to S/G A out-of-service for maintenance	9.84E-04	1	1.34	3.00E-05
AFAVP9710A	Air operated valve 9710A fails to open	9.83E-04	1	1.34	3.00E-05
AFFTD04084	Flow transmitter FT-4084 fails to respond	6.98E-04	1	1.34	3.00E-05
RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief	1.42E-03	1	1.28	2.47E-05
CRMVX00897	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
CRMVX00898	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	7.82E-03	1.01	1.25	2.26E-05
SIHFL857AC	Latent Human Failure of MOV 857A OR 857C	7.16E-04	1	1.24	2.07E-05
SIHFL0857B	Latent Human Failure of MOV 857B	7.15E-04	1	1.24	2.07E-05

Table 3.4-4
Importance Measures Sorted by Risk Achievement Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RHMMAC01AA	PAC01A fails to start	6.04E-04	1	1.24	2.07E-05
RHMMAC01BA	AC01B Fails to Start	6.03E-04	1	1.24	2.07E-05
CSLTDLT920	RWST Level Transmitter LT-920 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CSLTDLT921	RWST Levle Transmitter LT-921 Fails To Respond	2.14E-03	1	1.23	1.97E-05
AFMMSAFWPC	Failure of SAFW Pump 1C train	5.24E-03	1.01	1.22	1.96E-05
AFMMSAFWPD	Failure of SAFW Pump 1D Train	5.24E-03	1.01	1.22	1.96E-05
RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE	1.14E-03	1	1.22	1.91E-05
RRPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE	8.57E-04	1	1.22	1.91E-05
ACCBD2BTBB	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate	7.10E-04	1	1.18	1.60E-05
ACCBD5211B	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand	7.10E-04	1	1.18	1.60E-05
NROGRID10H	FAILURE TO RESTORE OFFSITE POWER FROM GRID WITHIN 10H	9.63E-03	1.01	1.17	1.55E-05
DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE	9.87E-04	1	1.17	1.46E-05
DGDGA0001B	DIESEL GENERATOR KDG01B FAILS TO START	8.22E-04	1	1.17	1.46E-05
ACCBD1611B	AC BREAKER BUS16/11B FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBD1611C	AC BREAKER BUS16/11C FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBDJ/01K	AC BREAKER MCCJ/01K FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBN1612A	AC BREAKER BUS16/12A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1613C	AC BREAKER BUS16/13C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614A	AC BREAKER BUS16/14A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614C	AC BREAKER BUS16/14C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615A	AC BREAKER BUS16/15A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615B	AC BREAKER BUS16/15B FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615C	AC BREAKER BUS16/15C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1616A	AC BREAKER BUS16/16A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1617A	AC BREAKER BUS16/17A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727C	AC BREAKER BUS17/27C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727D	AC BREAKER BUS17/27D FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBNMCD5K	AC BREAKER MCCD/5K FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
RHMVP0852B	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]	8.19E-03	1.01	1.16	1.49E-05
CRMVZ0896A	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
CRMVZ0896B	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
SWMVP9629B	Motor operated valve 9629B fails to open	1.62E-03	1	1.11	9.64E-06
RCMMTRC04A	FAILURE OF NITROGEN SUPPLY TO PCV-430	6.77E-03	1.01	1.1	8.92E-06
RCMMTRC04B	FAILURE OF NITROGEN SUPPLY TO PCV-431C	6.77E-03	1.01	1.1	8.92E-06
IASVP14206	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVP14307	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06

Table 3.4-4
Importance Measures Sorted by Risk Achievement Worth

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCMM0430N2	SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
RCMM431CN2	SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
MSAVP03411	AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)	8.60E-03	1.01	1.05	5.06E-06
SWMVNCCFSS	Beta Factor For Common Cause Failure Events SWCCFBMOVN & SWCCFGMOVN	3.57E-03	1	1.05	4.38E-06
RCMVX00515	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE	1.42E-03	1	1.05	4.87E-06
MSCCARVAIR	COMMON CAUSE FAILURE OF AIR OPERATED ARVS	7.85E-04	1	1.05	4.62E-06
MSAVP03410	AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)	4.34E-03	1	1.03	2.55E-06
RCMM0430IA	SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RCMM431CIA	SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
CCHFDSTART	OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI	2.02E-06	1	1.01	7.28E-07
ACCBRC2648	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN	7.19E-08	1	1.01	6.84E-07
AFHFDXSAFW	Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G	2.02E-03	1	1	1.76E-07
RCHFLPC451	ALARM PC-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPC452	ALARM PC-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPL451	PRESSURE TRANSMITTER PT-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT452	PRESSURE TRANSMITTER PT-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCMM0PT451	PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
RCMM0PT452	PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
ACCBR012AY	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open	9.68E-10	1	1	0.00E+00
ACCBR75112	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails	9.68E-10	1	1	0.00E+00

Table 3.4-5
Importance Measures Sorted by the Birnbaum Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
TLCCFMATWS	Mechanical Scram Failure Probability (WOG Data)	1.91E-03	1	1060	9.20E-02
RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation	1.38E-01	1.16	139	1.20E-02
DCMMCB04AN	Failure of Circuit E215 (To RA Racks Train A)	3.38E-03	1	95.9	8.25E-03
DCMMCB04BK	Failure of Circuit E212 (To RA Racks Train B)	1.54E-03	1	44.4	3.77E-03
DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	1.54E-03	1	44.4	3.77E-03
DCMMMCB01B	Failure of Circuit E103 (To MCB DC Distribution Panel 1B)	1.54E-03	1	44.4	3.77E-03
CSCCMLDRWT	Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters	3.30E-02	1.03	36.1	3.05E-03
RRCC850A/B	MOVS 850A/B FAIL TO OPEN <common cause event>	3.24E-02	1.03	36.1	3.05E-03
RHCCPUMPAB	PUMPS A AND B FAIL TO START <common cause event>	1.43E-02	1.01	36.1	3.05E-03
CCCC738A/B	MOVS 738A/B FAIL TO OPEN <common cause event>	1.21E-02	1.01	36.1	3.05E-03
CSMM00RWST	Insufficient Flow Available From TSI01 (RWST)	8.49E-03	1.01	34	2.87E-03
SICCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run during injection due to common cause	2.07E-02	1.02	25.6	2.14E-03
CSMM896A/B	MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)	1.63E-02	1.02	25.6	2.14E-03
SICCMPSI1X	PSI01A, PSI01B & PSI01C fail to start for injection due to common cause	1.35E-02	1.01	25.6	2.14E-03
CCTKJSURGE	CCW SURGE TANK RUPTURE	2.95E-03	1	25.2	2.10E-03
SICCM0867X	Common Cause Failure To Open Of Check Valves 867A & 867B	1.85E-03	1	25.2	2.10E-03
RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <common cause event>	8.58E-02	1.09	23.4	1.95E-03
NRHS0ALTCD	FAILURE TO COOLDOWN AFTER SGTR USING STEAM DUMP OR RUPTURED S/G	1.22E-02	1.01	22.8	1.90E-03
RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RRHFDRCR0M	Failure to Switch to Recirculation After MLOCA	1.58E-03	1	16.8	1.37E-03
RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
SICCM0878X	Check valves 878G and 878J fail to open due to common cause	1.21E-03	1	16.8	1.37E-03
RCHFDCDTR1	Failure to Cooldown to RHR After Ruptured S/G Isolation Fails	1.38E-01	1.16	14.1	1.15E-03
SRCCM897/8	MOVs 897 and 898 fail to close due to common cause	1.95E-02	1.02	13.6	1.10E-03
RRCCM0857M	MOVs 857A, 857B and 857C fail to open due to common cause	1.17E-02	1.01	13.6	1.10E-03
CRCCM0896X	Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)	1.17E-02	1.01	13.6	1.10E-03
SRCCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause	1.06E-02	1.01	13.6	1.10E-03
RHHFD0SGTR	Failure to Establish or Maintain RHR Cooling Following SGTR	9.16E-03	1.01	10.1	7.96E-04
RRHFDRCRSS	Failure to Switch to Recirculation After SSLOCA	8.40E-04	1	9.4	7.30E-04
SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open	7.86E-03	1.01	8.72	6.71E-04
AFCCPRECLB	Common cause failure of AOVs 9710A and 9710B to open	2.84E-03	1	6.58	4.85E-04
ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip	4.74E-03	1	5.73	4.12E-04
DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	6.96E-03	1.01	3.96	2.58E-04
RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]	3.09E-03	1	3.07	1.80E-04

Table 3.4-5

Importance Measures Sorted by the Birnbaum Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE	8.90E-04	1	3.07	1.80E-04
RRHFDRCR0A	Failure to Switch to Recirculation After LLOCA	8.29E-03	1.01	3.06	1.80E-04
RRMMHXBFLW	Failure of components for RHR Heat Exchanger B	5.60E-02	1.06	2.92	1.71E-04
RRHXFAC02A	HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]	5.35E-02	1.06	2.83	1.64E-04
RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)	2.05E-02	1.02	2.7	1.49E-04
RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)	1.94E-02	1.02	2.6	1.41E-04
RCHFD00RCP	Operators Fail to Trip RCPs After Loss of CCW Support	4.36E-03	1	2.45	1.26E-04
CTCCCSGBLO	Common Cause Failure of Steam Generator Blowdown AOVs to Close	2.56E-03	1	2.44	1.25E-04
SWMVN04616	Service Water Header Isolation MOV 4616 Fails To Open On Demand	5.82E-03	1.01	2.32	1.16E-04
NRHLETDOWN	FAILURE TO LOCALLY ISOLATE LETDOWN VALVE AOV-371 USING 204A	2.33E-02	1.02	2.27	1.12E-04
IAHFDCNTBK	Operators fail to restore IA to the containment (AOV 5392, SW to IA Compressors	3.83E-03	1	2.27	1.11E-04
SWMVP9629A	Motor operated valve 9629A fails to open	1.75E-02	1.02	2.18	1.04E-04
RHMM00852B	852B Fails to Open	5.54E-02	1.06	2.1	1.01E-04
RHMM00852A	852a Fails to Open	5.34E-02	1.06	2.07	9.72E-05
MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
CTAVX05736	AOV 5736 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
CTAVX05737	AOV 5737 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
MSAVX03516	MSIV 3516 Fails to Close	3.74E-02	1.04	2.05	9.41E-05
MSMVC3504A	MOV 3504A Fails to Close	2.25E-03	1	1.99	8.58E-05
MSXVX03412	Manual Valve 3412A Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03520	Manual Valve 3520 Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03668	Manual Valve 3668 Fails to Close	2.22E-03	1	1.99	8.58E-05
IASVX05736	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
IASVX05737	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
CTHFDISOLB	Operators Fail to Isolate S/G B	2.96E-03	1	1.98	8.58E-05
CCMM00738A	MOV 738A FAILS TO OPEN	4.47E-03	1	1.93	8.15E-05
RRHFL0850A	LATENT HUMAN FAILURE OF MOV 850A	2.70E-03	1	1.9	7.83E-05
RRHFL0850B	LATENT HUMAN FAILURE OF MOV 850B	2.70E-03	1	1.9	7.83E-05
DGDGF0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.48E-02	1.03	1.8	7.19E-05
CCMM00738B	MOV 738B FAILS TO OPEN	3.89E-03	1	1.81	7.10E-05
RRMVP0857B	MOV 857B fails to open	9.66E-03	1.01	1.8	7.05E-05
RRMVP0857A	MOV 857A fails to open	8.53E-03	1.01	1.71	6.22E-05
RRMVP0857C	MOV 857C fails to open	8.53E-03	1.01	1.71	6.22E-05

Table 3.4-5
Importance Measures Sorted by the Birnbaum Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	2.06E-03	1	1.68	5.97E-05
RHHFLAC01A	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)	2.06E-03	1	1.68	5.97E-05
RHTM00000A	TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	1.99E-03	1	1.68	5.97E-05
RHTM00000B	TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	1.99E-03	1	1.68	5.96E-05
CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	2.06E-03	1	1.68	5.96E-05
RHHFLAC01B	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)	2.06E-03	1	1.68	5.96E-05
RRPTHPC629	Pressure transmitter PIC-629 fails high	4.32E-03	1	1.66	5.73E-05
MSAVX03517	MSIV 3517 Fails to Close	1.71E-02	1.02	1.48	4.30E-05
NRHLRHRTHL	FAILURE TO THROTTLE RHR FLOW USING 715 AND 717	1.98E-02	1.02	1.45	4.10E-05
CTAVX05735	AOV 5735 Fails to Close	4.20E-03	1	1.45	3.92E-05
MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSCCCMSIVX	Common Cause Failure Of MSIVs To Close	2.28E-03	1	1.45	3.92E-05
CTHFDISOLA	Operators Fail to Isolate S/G A	1.35E-03	1	1.45	3.92E-05
MSMVC3505A	MOV 3505A Fails to Close	1.03E-03	1	1.45	3.92E-05
MSXVX03521	Manual Valve 3521 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX03669	Manual Valve 3669 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX3413A	Manual Valve 3413A Fails to Close	1.01E-03	1	1.45	3.92E-05
IASVX05735	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize	7.42E-04	1	1.45	3.92E-05
CVAVX00371	AOV 371 FAILS TO CLOSE	2.47E-02	1.03	1.4	3.73E-05
HVMFSAFF1A	MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START	2.47E-03	1	1.34	3.00E-05
AFTMSAFWPC	SAFW Pump Train 1C out-of-service for maintenance	1.92E-03	1	1.34	3.00E-05
HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.31E-03	1	1.34	3.00E-05
AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint	1.04E-03	1	1.34	3.00E-05
HVHFLSAFWA	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION	1.04E-03	1	1.34	3.00E-05
AFTMSAFWIA	SAFW injection line to S/G A out-of-service for maintenance	9.84E-04	1	1.34	3.00E-05
AFAVP9710A	Air operated valve 9710A fails to open	9.83E-04	1	1.34	3.00E-05
AFFTD04084	Flow transmitter FT-4084 fails to respond	6.98E-04	1	1.34	3.00E-05
RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief	1.42E-03	1	1.28	2.47E-05
CRMVX00897	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
CRMVX00898	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	7.82E-03	1.01	1.25	2.26E-05
SIHFL857AC	Latent Human Failure of MOV 857A OR 857C	7.16E-04	1	1.24	2.07E-05
RHMMAC01AA	PAC01A fails to start	6.04E-04	1	1.24	2.07E-05

Table 3.4-5
Importance Measures Sorted by the Birnbaum Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
SIHFL0857B	Latent Human Failure of MOV 857B	7.15E-04	1	1.24	2.07E-05
RHMMAC01BA	AC01B Fails to Start	6.03E-04	1	1.24	2.07E-05
CSLTDLT920	RWST Level Transmitter LT-920 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CSLTDLT921	RWST Levle Transmitter LT-921 Fails To Respond	2.14E-03	1	1.23	1.97E-05
AFMMSAFWPC	Failure of SAFW Pump 1C train	5.24E-03	1.01	1.22	1.96E-05
AFMMSAFWPD	Failure of SAFW Pump 1D Train	5.24E-03	1.01	1.22	1.96E-05
RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE	1.14E-03	1	1.22	1.91E-05
RRPPJMBL0B	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE	8.57E-04	1	1.22	1.91E-05
ACCBD2BTBB	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate	7.10E-04	1	1.18	1.60E-05
ACCBD5211B	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand	7.10E-04	1	1.18	1.60E-05
NROGRID10H	FAILURE TO RESTORE OFFSITE POWER FROM GRID WITHIN 10H	9.63E-03	1.01	1.17	1.55E-05
RHMVP0852B	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]	8.19E-03	1.01	1.16	1.49E-05
DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE	9.87E-04	1	1.17	1.46E-05
DGDGA0001B	DIESEL GENERATOR KDG01B FAILS TO START	8.22E-04	1	1.17	1.46E-05
ACCBD1611B	AC BREAKER BUS16/11B FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBD1611C	AC BREAKER BUS16/11C FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBDJ/01K	AC BREAKER MCCJ/01K FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBN1612A	AC BREAKER BUS16/12A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1613C	AC BREAKER BUS16/13C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614A	AC BREAKER BUS16/14A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614C	AC BREAKER BUS16/14C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615A	AC BREAKER BUS16/15A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615B	AC BREAKER BUS16/15B FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615C	AC BREAKER BUS16/15C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1616A	AC BREAKER BUS16/16A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1617A	AC BREAKER BUS16/17A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727C	AC BREAKER BUS17/27C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727D	AC BREAKER BUS17/27D FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBNMCD5K	AC BREAKER MCCD/5K FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
CRMVZ0896A	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
CRMVZ0896B	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
SWMVP9629B	Motor operated valve 9629B fails to open	1.62E-03	1	1.11	9.64E-06
IASVP14206	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVP14307	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
RCMMTRC04A	FAILURE OF NITROGEN SUPPLY TO PCV-430	6.77E-03	1.01	1.1	8.92E-06
RCMMTRC04B	FAILURE OF NITROGEN SUPPLY TO PCV-431C	6.77E-03	1.01	1.1	8.92E-06

Table 3.4-5
Importance Measures Sorted by the Birnbaum Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCMM0430N2	SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
RCMM431CN2	SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
MSAVP03411	AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)	8.60E-03	1.01	1.05	5.06E-06
RCMVX00515	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE	1.42E-03	1	1.05	4.87E-06
MSCCARVAIR	COMMON CAUSE FAILURE OF AIR OPERATED ARVS	7.85E-04	1	1.05	4.62E-06
SWMVNCCFSS	Beta Factor For Common Cause Failure Events SWCCFBMOVN & SWCCFGMOVN	3.57E-03	1	1.05	4.38E-06
MSAVP03410	AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)	4.34E-03	1	1.03	2.55E-06
RCMM0430IA	SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RCMM431CIA	SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
CCHFDSTART	OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI	2.02E-06	1	1.01	7.28E-07
ACCBRC2648	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN	7.19E-08	1	1.01	6.84E-07
AFHFDXSAFW	Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G	2.02E-03	1	1	1.76E-07
RCHFLPC451	ALARM PC-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPC452	ALARM PC-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPL451	PRESSURE TRANSMITTER PT-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT452	PRESSURE TRANSMITTER PT-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCMM0PT451	PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
RCMM0PT452	PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
ACCBR012AY	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open	9.68E-10	1	1	0.00E+00
ACCBR75112	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails	9.68E-10	1	1	0.00E+00

Table 3.4-6
Importance Measures for Hardware-Related Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCRYT00434	Pressurizer Safety Valve PCV-434 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RCRYT00435	Pressurizer Safety Valve PCV-435 Fails To Reclose Following Steam Relief	1.32E-01	1.15	18.7	1.55E-03
RRMMHXBFLW	Failure of components for RHR Heat Exchanger B	5.60E-02	1.06	2.92	1.71E-04
RHMM00852B	852B Fails to Open	5.54E-02	1.06	2.1	1.01E-04
RRHXFAC02A	HEAT EXCHANGER EAC02A COOLING CAP. FAILS [RECIRC]	5.35E-02	1.06	2.83	1.64E-04
RHMM00852A	852a Fails to Open	5.34E-02	1.06	2.07	9.72E-05
MSAVX03516	MSIV 3516 Fails to Close	3.74E-02	1.04	2.05	9.41E-05
DGDGR0001B	DIESEL GENERATOR KDG01B FAILS TO RUN	2.48E-02	1.03	1.8	7.19E-05
CVAVX00371	AOV 371 FAILS TO CLOSE	2.47E-02	1.03	1.4	3.73E-05
RRMM00850B	MOV 850B FAILS TO OPEN (RECIRCULATION)	2.05E-02	1.02	2.7	1.49E-04
RRMM00850A	MOV 850A FAILS TO OPEN (RECIRCULATION)	1.94E-02	1.02	2.6	1.41E-04
SWMVP9629A	Motor operated valve 9629A fails to open	1.75E-02	1.02	2.18	1.04E-04
MSAVX03517	MSIV 3517 Fails to Close	1.71E-02	1.02	1.48	4.30E-05
CSMM896A/B	MOV 896A Or 896B Transfers Closed (Fails CS And SI From RWST)	1.63E-02	1.02	25.6	2.14E-03
CTAVX05736	AOV 5736 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
CTAVX05737	AOV 5737 Fails to Close	1.01E-02	1.01	2.07	9.41E-05
RRMVP0857B	MOV 857B fails to open	9.66E-03	1.01	1.8	7.05E-05
MSAVP03411	AIR-OPERATED VALVE 3411 FAILS TO OPEN (ARV A)	8.60E-03	1.01	1.05	5.06E-06
RRMVP0857A	MOV 857A fails to open	8.53E-03	1.01	1.71	6.22E-05
RRMVP0857C	MOV 857C fails to open	8.53E-03	1.01	1.71	6.22E-05
CSMM00RWST	Insufficient Flow Available From TSI01 (RWST)	8.49E-03	1.01	34	2.87E-03
RHMVP0852B	MOTOR-OP VALVE 852B FAILS TO OPEN [INJECTION]	8.19E-03	1.01	1.16	1.49E-05
DGDGF0001A	DIESEL GENERATOR KDG01A FAILS TO RUN	7.82E-03	1.01	1.25	2.26E-05
MSRYT03508	Steam Generator Relief Valve 3508 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03510	Steam Generator Relief Valve 3510 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03512	Steam Generator Relief Valve 3512 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
MSRYT03514	Steam Generator Relief Valve 3514 Fails to Close After Steam Release	7.45E-03	1.01	2.08	9.41E-05
RCMMTRC04A	FAILURE OF NITROGEN SUPPLY TO PCV-430	6.77E-03	1.01	1.1	8.92E-06
RCMMTRC04B	FAILURE OF NITROGEN SUPPLY TO PCV-431C	6.77E-03	1.01	1.1	8.92E-06
SWMVN04616	Service Water Header Isolation MOV 4616 Fails To Open On Demand	5.82E-03	1.01	2.32	1.16E-04
CRMVX00897	MOTOR-OPERATED VALVE 897 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
CRMVX00898	MOTOR-OPERATED VALVE 898 FAILS TO CLOSE	5.69E-03	1.01	1.26	2.33E-05
AFMMSAFWPC	Failure of SAFW Pump 1C train	5.24E-03	1.01	1.22	1.96E-05
AFMMSAFWPD	Failure of SAFW Pump 1D Train	5.24E-03	1.01	1.22	1.96E-05
ACLOPRTALL	Loss of All Off-Site Power Following Reactor Trip	4.74E-03	1	5.73	4.12E-04

Table 3.4-6

Importance Measures for Hardware-Related Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
CCMM00738A	MOV 738A FAILS TO OPEN	4.47E-03	1	1.93	8.15E-05
MSAVP03410	AIR-OPERATED VALVE 3410 FAILS TO OPEN (ARV B)	4.34E-03	1	1.03	2.55E-06
RRPTHPC629	Pressure transmitter PIC-629 fails high	4.32E-03	1	1.66	5.73E-05
CTAVX05735	AOV 5735 Fails to Close	4.20E-03	1	1.45	3.92E-05
CCMM00738B	MOV 738B FAILS TO OPEN	3.89E-03	1	1.81	7.10E-05
DCMMCB04AN-	Failure of Circuit E215 (To RA Racks Train A)	3.38E-03	1	95.9	8.25E-03
MSRYT03509	Steam Generator Relief Valve 3509 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03511	Steam Generator Relief Valve 3511 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03513	Steam Generator Relief Valve 3513 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
MSRYT03515	Steam Generator Relief Valve 3515 Fails to Close After Steam Release	3.11E-03	1	1.45	3.92E-05
RHCVP00854	CHECK VALVE 854 FAILS TO OPEN [INJECTION]	3.09E-03	1	3.07	1.80E-04
CCTKJSURGE	CCW SURGE TANK RUPTURE	2.95E-03	1	25.2	2.10E-03
HVMFSAFF1A	MOTOR-DRIVEN FAN AFF1A (SAFW-A) FAILS TO START	2.47E-03	1	1.34	3.00E-05
RCMM0430N2	SOLENOID VALVE 8619A FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
RCMM431CN2	SOLENOID VALVE 8619B FAILS TO OPEN ON DEMAND	2.32E-03	1	1.06	5.84E-06
MSMVC3504A	MOV 3504A Fails to Close	2.25E-03	1	1.99	8.58E-05
MSXVX03412	Manual Valve 3412A Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03520	Manual Valve 3520 Fails to Close	2.22E-03	1	1.99	8.58E-05
MSXVX03668	Manual Valve 3668 Fails to Close	2.22E-03	1	1.99	8.58E-05
CSLTDLT920	RWST Level Transmitter LT-920 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CSLTDLT921	RWST Levle Transmitter LT-921 Fails To Respond	2.14E-03	1	1.23	1.97E-05
CRMVZ0896A	Motor Operated Valve 896A Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
CRMVZ0896B	Motor Operated Valve 896B Fails To Close On Demand (Recirculation)	2.04E-03	1	1.16	1.40E-05
IASVP14206	SOLENOID VALVE 14206S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVP14307	SOLENOID VALVE 14307S FAILS TO OPEN (STANDBY)	1.80E-03	1	1.1	9.00E-06
IASVX05736	Solenoid Valve 5736S for AOV 5736 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
IASVX05737	Solenoid Valve 5737S for AOV 5737 Fails to Deenergize	1.62E-03	1	1.99	8.58E-05
SWMVP9629B	Motor operated valve 9629B fails to open	1.62E-03	1	1.11	9.64E-06
DCMMCB04BK	Failure of Circuit E212 (To RA Racks Train B)	1.54E-03	1	44.4	3.77E-03
DCMMMAIN1B	Failure of Circuit E76 (To Main DC Distribution Panel B)	1.54E-03	1	44.4	3.77E-03
DCMMMCB01B	Failure of Circuit E103 (To MCB DC Distribution Panel 1B)	1.54E-03	1	44.4	3.77E-03
RCMVX00515	MOTOR-OPERATED VALVE 515 FAIL TO CLOSE	1.42E-03	1	1.05	4.87E-06
RCRZT0431C	PORV PCV-431C Fails To Reseat After Steam Relief	1.42E-03	1	1.28	2.47E-05
RRPPJMBL0A	CONDITIONAL PROBABILITY OF MBLOCA IN "A" RHR LINE	1.14E-03	1	1.22	1.91E-05
MSMVC3505A	MOV 3505A Fails to Close	1.03E-03	1	1.45	3.92E-05

Table 3.4-6
Importance Measures for Hardware-Related Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
MSXVX03521	Manual Valve 3521 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX03669	Manual Valve 3669 Fails to Close	1.01E-03	1	1.45	3.92E-05
MSXVX3413A	Manual Valve 3413A Fails to Close	1.01E-03	1	1.45	3.92E-05
AFAVP9710A	Air operated valve 9710A fails to open	9.83E-04	1	1.34	3.00E-05
IAXVK00371	SOLENOID VALVE 14204S FOR AOV 371 FAILS TO DEENERGIZE	8.90E-04	1	3.07	1.80E-04
RRPPJMBLOB	CONDITIONAL PROBABILITY OF MBLOCA IN "B" RHR LINE	8.57E-04	1	1.22	1.91E-05
DGDGA0001B	DIESEL GENERATOR KDG01B FAILS TO START	8.22E-04	1	1.17	1.46E-05
IASVX05735	Solenoid Valve 5735S for AOV 5735 Fails to Deenergize	7.42E-04	1	1.45	3.92E-05
ACCBD2BTBB	4160 VAC Bus 11B Bus 12B Tie Breaker 52/BTB-B (BUS11B/21) Fails To Operate	7.10E-04	1	1.18	1.60E-05
ACCBD5211B	4160 VAC Bus 11B Feeder Circuit Breaker 52/11B (BUS11B/22) Fails On Demand	7.10E-04	1	1.18	1.60E-05
AFFTD04084	Flow transmitter FT-4084 fails to respond	6.98E-04	1	1.34	3.00E-05
ACCBD1611B	AC BREAKER BUS16/11B FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBD1611C	AC BREAKER BUS16/11C FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBDJ/01K	AC BREAKER MCCJ/01K FAILS TO OPERATE	6.48E-04	1	1.17	1.46E-05
ACCBN1612A	AC BREAKER BUS16/12A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1613C	AC BREAKER BUS16/13C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614A	AC BREAKER BUS16/14A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1614C	AC BREAKER BUS16/14C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615A	AC BREAKER BUS16/15A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615B	AC BREAKER BUS16/15B FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1615C	AC BREAKER BUS16/15C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1616A	AC BREAKER BUS16/16A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1617A	AC BREAKER BUS16/17A FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727C	AC BREAKER BUS17/27C FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBN1727D	AC BREAKER BUS17/27D FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
ACCBNMCD5K	AC BREAKER MCCD/5K FAILS TO OPEN	6.48E-04	1	1.17	1.46E-05
RCMM0430IA	SOLENOID VALVE 8620A FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RCMM431CIA	SOLENOID VALVE 8620B FAILS TO OPEN ON DEMAND	6.47E-04	1	1.02	1.63E-06
RHMMAC01AA	PAC01A fails to start	6.04E-04	1	1.24	2.07E-05
RHMMAC01BA	AC01B Fails to Start	6.03E-04	1	1.24	2.07E-05
ACCBRC2648	AC BREAKER IBPDPCBC/01 (CIRCUIT C2648) TRANSFERS OPEN	7.19E-08	1	1.01	6.84E-07
RCMM0PT451	PRESSURE TRANSMITTER PT-451 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
RCMM0PT452	PRESSURE TRANSMITTER PT-452 FAILS TO RESPOND TO HIGH PRESSURE CONDITION	6.45E-09	1	1	0.00E+00
ACCBR012AY	4160 VAC Breaker 52/12AY (4160 VAC Bus 12A Normal Supply) Transfers Open	9.68E-10	1	1	0.00E+00
ACCBR75112	34.5 kVAC Circuit Breaker 52/75112 (RG&E Circuit 751 From Substa. 204) Fails	9.68E-10	1	1	0.00E+00

Table 3.4-7

Importance Measures for Test / Maintenance Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RHTM00000A	RHR TRAIN "A" OUT OF SERVICE FOR MAINTENANCE OR TESTING [INJECTION]	1.99E-03	1	1.68	5.97E-05
RHTM00000B	RHR TRAIN "B" OUT OF SERVICE FOR TEST OR MAINTENANCE [INJECTION]	1.99E-03	1	1.68	5.96E-05
AFTMSAFWPC	SAFW Pump Train 1C out-of-service for maintenance	1.92E-03	1	1.34	3.00E-05
HVTMSAFW_A	A SAFW ROOM HVAC STRING IN MAINTENANCE	1.31E-03	1	1.34	3.00E-05
DGTM00001B	DIESEL GENERATOR KDG01B UNAVAILABLE DUE TO TESTING OR MAINTENANCE	9.87E-04	1	1.17	1.46E-05
AFTMSAFWIA	SAFW injection line to S/G A out-of-service for maintenance	9.84E-04	1	1.34	3.00E-05

Table 3.4-8

Importance Measures for Human Failure Events and Non-Recovery Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RCHFDCDDPR	Operators Fail To Cooldown and Depressurize RCS During SGTR Given SI Operation	1.38E-01	1.16	139	1.20E-02
RCHFDCDTR1	Failure to Cooldown to RHR After Ruptured S/G Isolation Fails	1.38E-01	1.16	14.1	1.15E-03
NRHLETDOWN	FAILURE TO LOCALLY ISOLATE LETDOWN VALVE AOV-371 USING 204A	2.33E-02	1.02	2.27	1.12E-04
NRHLRHRTHL	FAILURE TO THROTTLE RHR FLOW USING 715 AND 717	1.98E-02	1.02	1.45	4.10E-05
NRHSOALTCD	FAILURE TO COOLDOWN AFTER SGTR USING STEAM DUMP OR RUPTURED S/G	1.22E-02	1.01	22.8	1.90E-03
NROGRID10H	FAILURE TO RESTORE OFFSITE POWER FROM GRID WITHIN 10H	9.63E-03	1.01	1.17	1.55E-05
RHHFD0SGTR	Failure to Establish or Maintain RHR Cooling Following SGTR	9.16E-03	1.01	10.1	7.96E-04
RRHFDRCR0A	Failure to Switch to Recirculation After LLOCA	8.29E-03	1.01	3.06	1.80E-04
RCHFD00RCP	Operators Fail to Trip RCPs After Loss of CCW Support	4.36E-03	1	2.45	1.26E-04
IAHFDCNTBK	Operators fail to restore IA to the containment (AOV 5392, SW to IA Compressors	3.83E-03	1	2.27	1.11E-04
CTHFDISOLB	Operators Fail to Isolate S/G B	2.96E-03	1	1.98	8.58E-05
RRHFL0850A	LATENT HUMAN FAILURE OF MOV 850A	2.70E-03	1	1.9	7.83E-05
RRHFL0850B	LATENT HUMAN FAILURE OF MOV 850B	2.70E-03	1	1.9	7.83E-05
CCHFL0780A	CCW THROTTLING VALVE 780A MISPOSITIONED	2.06E-03	1	1.68	5.97E-05
RHHFLAC01A	LATENT HUMAN FAILURE OF RHR PUMP "A" (PAC01A)	2.06E-03	1	1.68	5.97E-05
CCHFL0780B	CCW THROTTLING VALVE 780B MISPOSITIONED	2.06E-03	1	1.68	5.96E-05
RHHFLAC01B	LATENT HUMAN FAILURE OF RHR PUMP "B" (PAC01B)	2.06E-03	1	1.68	5.96E-05
AFHFDXSAFW	Operators fail to open cross-tie valves between SAFW trains and/or isolate S/G	2.02E-03	1	1	1.76E-07
RRHFDRCR0M	Failure to Switch to Recirculation After MLOCA	1.58E-03	1	16.8	1.37E-03
CTHFDISOLA	Operators Fail to Isolate S/G A	1.35E-03	1	1.45	3.92E-05
AFHFLSAFWA	Failure to restore SAFW Pump Train 1C to service post test/maint	1.04E-03	1	1.34	3.00E-05
HVHFLSAFWA	LATENT HUMAN ERRORS IN SAFW-A COOLING INCL. SWITCH-A POSITION	1.04E-03	1	1.34	3.00E-05
RRHFDRCRSS	Failure to Switch to Recirculation After SSLOCA	8.40E-04	1	9.4	7.30E-04
SIHFL857AC	Latent Human Failure of MOV 857A OR 857C	7.16E-04	1	1.24	2.07E-05
SIHFL0857B	Latent Human Failure of MOV 857B	7.15E-04	1	1.24	2.07E-05
CCHFDSTART	OPERATOR FAILS TO START A CCW PUMP FOLLOWING AN EVENT WITH BOTH A LOOP AND SI	2.02E-06	1	1.01	7.28E-07
RCHFLPC451	ALARM PC-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPC452	ALARM PC-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPL451	PRESSURE TRANSMITTER PT-451 MISCALIBRATED	1.43E-08	1	1	0.00E+00
RCHFLPT452	PRESSURE TRANSMITTER PT-452 MISCALIBRATED	1.43E-08	1	1	0.00E+00

Table 3.4-9

Importance Measures for Common Cause Failure Events Sorted by the Vesely-Fussell Measure

Basic Event	Description	VF	RRW	RAW	BIRNBAUM
RHCC852A/B	MOVS 852A, 852B FAIL TO OPEN <common cause event>	8.58E-02	1.09	23.4	1.95E-03
CSCCMLDRWT	Common Cause Failure To Respond Of TSI01 (RWST) Level Transmitters	3.30E-02	1.03	36.1	3.05E-03
RRCC850A/B	MOVS 850A/B FAIL TO OPEN <common cause event>	3.24E-02	1.03	36.1	3.05E-03
SICCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run during injection due to common cause	2.07E-02	1.02	25.6	2.14E-03
SRCCM897/8	MOVs 897 and 898 fail to close due to common cause	1.95E-02	1.02	13.6	1.10E-03
RHCCPUMPAB	PUMPS A AND B FAIL TO START <common cause event>	1.43E-02	1.01	36.1	3.05E-03
SICCMPSI1X	PSI01A, PSI01B & PSI01C fail to start for injection due to common cause	1.35E-02	1.01	25.6	2.14E-03
CCCC738A/B	MOVS 738A/B FAIL TO OPEN <common cause event>	1.21E-02	1.01	36.1	3.05E-03
RRCCM0857M	MOVs 857A, 857B and 857C fail to open due to common cause	1.17E-02	1.01	13.6	1.10E-03
CRCCM0896X	Common Cause Failure Of MOVs 896A And 896B To Close (Recirculation)	1.17E-02	1.01	13.6	1.10E-03
SRCCMPSI1Y	PSI01A, PSI01B & PSI01C fail to run for recirc. due to common cause	1.06E-02	1.01	13.6	1.10E-03
SWCCPSWMVB	Common cause failure of MOVs 9629A and 9629B to open	7.86E-03	1.01	8.72	6.71E-04
DGCC000RUN	DIESEL GENERATORS FAIL TO RUN (COMMON CAUSE)	6.96E-03	1.01	3.96	2.58E-04
AFCCPRECLB	Common cause failure of AOVs 9710A and 9710B to open	2.84E-03	1	6.58	4.85E-04
CTCCCSGBLO	Common Cause Failure of Steam Generator Blowdown AOVs to Close	2.56E-03	1	2.44	1.25E-04
MSCCCMSIVX	Common Cause Failure Of MSIVs To Close	2.28E-03	1	1.45	3.92E-05
TLCCFMATWS	Mechanical Scram Failure Probability (WOG Data)	1.91E-03	1	1060	9.20E-02
SICCM0867X	Common Cause Failure To Open Of Check Valves 867A & 867B	1.85E-03	1	25.2	2.10E-03
RHCC697A/B	CHECK VALVES 697A, 697B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
RHCC853A/B	CHECK VALVES 853A, 853B FAIL TO OPEN <common cause event>	1.41E-03	1	16.8	1.37E-03
SICCM0878X	Check valves 878G and 878J fail to open due to common cause	1.21E-03	1	16.8	1.37E-03
MSCCARVAIR	COMMON CAUSE FAILURE OF AIR OPERATED ARVS	7.85E-04	1	1.05	4.62E-06

Figure 3.4-1

Uncertainty Analysis Summary

Input Options

Filename	: C:\RMQS\RGEUNC.TXT
Module Name	: [TOP]
Sample Size	: 5000
Seed	: 4042637
Point Estimate	: 8.69E-05
Number of Modules	: 47
Total Cutsets In All Modules	: 446
Number of Basic Events	: 280
Number of Type Codes	: 62
Inputs Missing Distribution	: 15

Moments
(With 95% Confidence)

	Low	Estimate	High
Mean	8.93E-05	9.37E-05	9.80E-05
Standard Deviation	1.60E-04	1.57E-04	1.54E-04
Skewness	-	1.13E+01	-
Kurtosis	-	2.49E+02	-

Percentiles
(With 95% Confidence)

	Low	Estimate	High
Minimum	-	5.64E-06	-
2.5	1.30E-05	1.37E-05	1.45E-05
5.0	1.60E-05	1.67E-05	1.72E-05
10.0	2.07E-05	2.14E-05	2.22E-05
20.0	2.84E-05	2.93E-05	3.00E-05
25.0	3.22E-05	3.32E-05	3.40E-05
30.0	3.60E-05	3.70E-05	3.80E-05
40.0	4.43E-05	4.55E-05	4.65E-05
50.0	5.39E-05	5.53E-05	5.74E-05
60.0	6.67E-05	6.86E-05	7.03E-05
70.0	8.34E-05	8.62E-05	8.97E-05
75.0	9.56E-05	9.90E-05	1.03E-04
80.0	1.12E-04	1.16E-04	1.20E-04
90.0	1.71E-04	1.80E-04	1.87E-04
95.0	2.55E-04	2.71E-04	2.92E-04
97.5	3.84E-04	4.12E-04	4.68E-04
Maximum	-	5.11E-03	-

Errors

Number of Observations Sampled Where a:

Cutset was less than zero	: 0
Cutset was greater than one	: 34
Basic Event was less than zero	: 0
Basic Event was greater than one	: 0

Figure 3.4-2
Sampling Probability Density

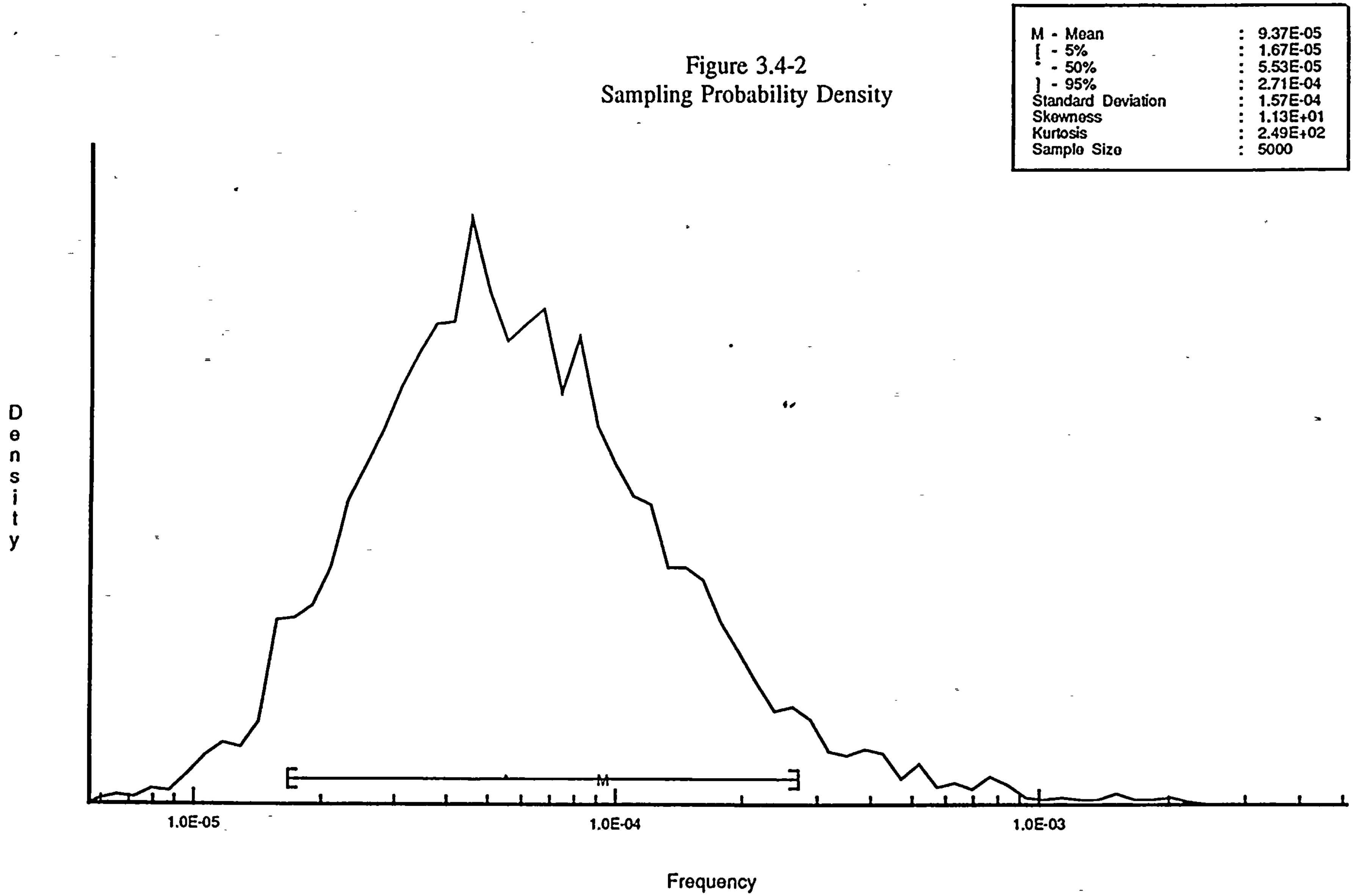
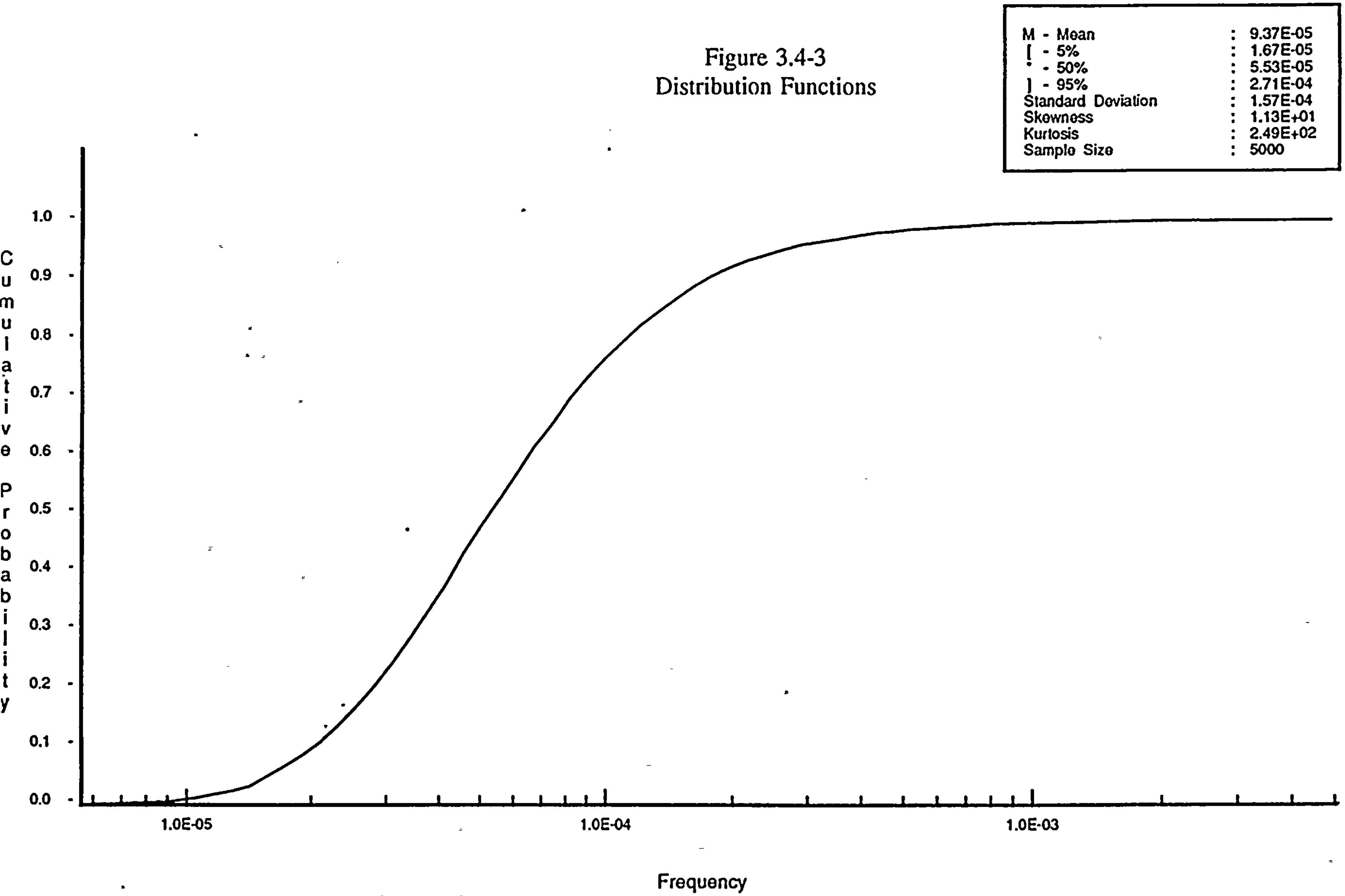


Figure 3.4-3
Distribution Functions



4.0 Level 2 Analysis

The objectives of the Level 2 Containment Analysis are to develop an understanding of the potential containment challenges, and the impact of physical phenomena, plant design features and operator actions on prevention and mitigation of the containment challenges under severe accident conditions. Another objective is to develop basic insights on severe accident behavior that will assist in the development of an accident management program.

The Level 2 Containment Analysis includes both deterministic and probabilistic aspects. The deterministic aspects are:

- Use of the MAAP code to simulate the progression of severe accidents which were identified as dominant contributors to core damage.

  The MAAP code was used to assess the timing of key events such as core uncovery, vessel failure, and containment failure, to determine the containment pressure history and to estimate the magnitude of source term releases

The probabilistic aspect of the analysis includes:

- Development of an intermediate event tree to assess the performance of systems that impact containment accident progression and quantification of these containment system event trees (CSETs) by linking the Level 1 core damage cutset results to the CSET. The use of core damage sequence cutsets as the initiating events for the CSETs assured that the status of key systems was treated consistently in both the Level 1 and 2 analysis.

- Assessment of the impacts of uncertainties in the severe accident progression due to lack of knowledge regarding critical physical phenomena. These phenomenological uncertainties were modelled in the containment event tree. The probabilities assigned for the possible outcomes for various physical processes and phenomena were largely based on MAAP code analysis, engineering calculations, published data in the literature, and engineering judgement.

The first seven sections are generally organized as requested in NUREG-1335. An additional section (4.8) presents sensitivity analyses result.

Section 4.1 identifies and highlights the containment design characteristics that are of significance in assessing severe accident progression.

Section 4.2 discusses the MAAP plant model and the selection of key input data.

Section 4.3 describes the interface of the front-end (Level 1) analysis to the back-end (Level 2) analysis, the analysis of systems important to containment accident progression and the binning of accident sequences into plant damage states.

Section 4.4 describes the containment ultimate strength assessment, the failure modes of containment and the overall containment probabilistic fragility curve.

Section 4.5 discusses the containment event tree which characterizes the possible paths that an accident sequence may progress along, given the sets of initial conditions defined by the various plant damage states. The methods and the results of the containment event tree probabilistic analyses (quantification) are also in this section.

Section 4.6 describes the deterministic containment accident progression analyses performed with the MAAP code to support the containment event tree development and quantification and to provide insights and information on the plant response.

Section 4.7 discusses the radionuclide release source term development, analyses, and numerical results.

Section 4.8 presents the results of the sensitivity analysis performed on the probabilistic containment event tree model and with the MAAP code.

4.1 Plant Data and Plant Description

Ginna is a Westinghouse PWR with a large, dry containment. A video taped walkdown of the Ginna containment was performed on April 25, 1991 to provide an integrated three-dimensional understanding of the Ginna containment and to collect information for use in the develpoment of the Modular Accident Analysis Program (MAAP) parameter file. Results of a Seismic Qualification Utility Group (SQUG) project photographic walkdown were also used in order to develop a better understanding of the layout of the cavity region, which was difficult to develop from a review of the drawings alone.

4.1.1 General Containment Building Structure

The Ginna containment is a steel lined concrete containment with pre-stressed reinforcement in the cylindrical wall meridional direction and mild steel reinforcement in the cylindrical wall circumferential direction and in the dome. It has the shape of a vertical cylinder with a flat base and topped by a hemispherical dome. The containment is founded on bedrock and the meridional reinforcing tendons are coupled to 160 prestressed rock anchor tendons which are grouted into the rock foundation of containment. The containment basemat is 4 ft. thick with the liner imbedded two feet below the surface. The wall of the cylinder has a thickness of 3.5 ft., an internal diameter of 105 ft. and a height from the floor to the springline of 99 ft. The dome is 2.5 ft. thick. The thickness of the liner in the cyliner and the dome is 3/8 inch and in the base it is 1/4 inch. The containment vessel provides a minimum free volume of approximately 972,000 ft^3. The containment design pressure is 60 psig. Table 4.1-1 contains Ginna design information and Figure 4.1-1 shows a section through the Ginna containment.

Reinforced concrete walls are located around the major reactor coolant system components and serve as missile barriers to prevent damage to the containment wall and to components of the safety injection system should a failure occur to one of the reactor coolant system components located inside the walls.

A 1.25 inch thick liner insulation is provided for the side walls to a point 15 ft above the spring line. The liner insulation is a closed-cell polyvinyl chloride foam insulation with low conductivity, low water absorption and high strength and is covered with a metal sheeting.

All penetrations through the containment pressure barrier for pipe, electrical conductors, ducts and access hatches are of the double barrier type. In general, a penetration consists of a sleeve embedded in the reiforced concrete wall and welded to the containment liner. Piping penetrations have a bellows type expansion joint mounted on the exterior end of the embedded sleeve where required to compensate for differential motions. An equipment hatch with a diameter of 14 ft., constructed of welded steel and having a double gasketed flange and bolted dished door, is located near grade. Two personnel accesses are provided; one penetrates the dished door of the equipment hatch and the other is directly opposite the equipment hatch. Each personnel hatch is a hydraulically-latched double door, welded steel assembly. All penetrations, with the exception of the equipment access hatch, permit testing of leaktightness.

4.1.2 Reactor Cavity Design

The reactor cavity in the Ginna plant is isolated from the remainder of the lower containment compartment. Figures 4.1-2 and 4.1-3 show the reactor cavity. The reactor cavity has the shape of a "keyhole" with a cylindrical section under the reactor vessel and a rectangular tunnel for passage of the instrument tubes. The radius of the cylindrical portion of the cavity is 6.54 ft and the height from the cavity floor to the bottom of the reactor vessel lower head is approximately 11.5 ft. [Ref. 4.9-1]. The distance to the end of the cavity tunnel from the centerline of the reactor vessel is 30.25 ft [Ref. 4.9-1]. The total floor area of the reactor cavity is 312 ft^2 of which 134.4 ft^2 is in the cylindrical region under the reactor vessel. At the far end of the cavity tunnel is a 5 ft. deep sump. The concrete thickness in the cavity away from the sump is 2.0 ft above the imbedded liner and 2.0 ft below the liner [Ref. 4.9-1]. Below the cavity sump the total thickness of the basemat concrete is 1.5 ft [Ref. 4.9-1].

The floor of the reactor cavity is located 25.7 ft below the floor of the main containment region. A six inch curbing [Ref. 4.9-1] exists above the floor of the main containment compartment at the top of the instrument tunnel (where the instrument tubes exit the roof of the cavity). Hence, whenever the contents of the RWST are injected into the containment the cavity will be completely filled and will remained filled (unless water inventory leaks from containment due to a containment breach).

The outer end of the instrument tunnel away from the reactor vessel is not sloped as in some designs (e.g. Zion). This design should result in a geometry somewhat less favorable to debris dispersion out of the cavity following vessel failure. At the outer end of the instrument tunnel the instrument tubes are directed vertically upward and exit through the ceiling of the cavity. The ceiling of the cavity tunnel includes an opening above the cavity sump (covered by a removable metal plate) and an opening for air ducting. The combined area of these two openings is 21.3 ft^2 [Ref. 4.9-1]. This is a likely pathway for debris (and water and gases) to be expelled from the cavity under high reactor vessel pressure failure conditions. Two other possible pathways for debris to be dispersed from the cavity involve transport through the annulus between the reactor vessel and biological shield to either the refueling pool or to the main coolant piping penetrations through the biological shield wall.

4.1.3 Containment Systems

4.1.3.1 Containment Spray System

Active containment heat removal during design basis accident conditions is accomplished by the Containment Spray System and the Containment Recirculating Fan Coolers. Each of these systems is capable of maintaining and reducing containment temperature and pressure within the 60 psig design limit following a LOCA or a main steam line break. The Containment Spray System utilizes two pumps, a spray additive tank, two spray headers in the dome of the containment, spray nozzles and the necessary piping and valves to provide a spray of cool, borated water to the containment atmosphere. The system initially draws water from the Refueling Water Storage Tank until a low level is reached. If spray is required in the recirculation mode, the pumps are fed from the discharge of the Residual Heat Removal pumps. The system is designed to spray at least 2400 gpm into the containment whenever the coincidence of two of three high containment pressure (28 psig) signals occurs. The Containment Spray System is covered in detail in section 3.2.1.4.

4.1.3.2 Containment Isolation System

The Containment Isolation System is designed to isolate non-essential process lines that penetrate the containment in order to maintain the total leakage of radioactivity within design limits in the event of an accident. In addition, the system ensures that essential process lines and penetrations remain capable of maintaining containment integrity both during and following the performance of their safety related activities. The Containment Isolation System utilizes both automatic and normally closed isolation valves, and the physical design of piping systems and penetrations to perform its function. Automatic isolation is initiated by a containment isolation signal from the Engineered Safety Features Actuation System or by manual actuation from the control room. The Containment Isolation System is covered in detail in section 3.2.1.3.

4.1.3.3 Containment Recirculating Fan Coolers

The Containment Recirculating Fan Coolers provide a dynamic heat sink to cool the containment atmosphere and filter the containment atmosphere to remove airborne particulate and halogen fission products that form the source for potential public exposure. There are four air handling units, each including 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 systems are equipped with activated charcoal filter units through which the air-steam mixture is passed to remove volatile iodine following an accident. The Containment Recirculating Fan Coolers are covered in detail in the Heating, Ventilation and Air Conditioning System discussion in section 3.2.1.8.

4.1.3.4 Residual Heat Removal System

The Residual Heat Removal (RHR) System recirculates and cools water drawn from the containment sump and delivers it back to the Reactor Coolant System via the RHR pumps or the Safety Injection pumps and/or the containment via the Containment Spray pumps. The RHR system flow is cooled by two heat exchanges cooled by the Component Cooling Water System. The Residual Heat Removal System is covered in detail in section 3.2.1.11.

4.2 Plant Models and Methods for Physical Processes

The Modular Accident Analysis Program (MAAP) was used in the Ginna PRA containment evaluation of the accident progression analysis, to assist in quantifying the containment event tree (CET), and for estimating source terms. Information from prior analyses (principally NUREG-1150) was also utilized.

A slightly modified version of MAAP3.0B-PWR, Revision 19.0 was the basis for the Ginna analysis. Minor changes to four subroutines were made to correct errors that were in the base 19.0 version of the code that had not been corrected in a released version of the code at the time the analyses for Ginna began. These modifications were incorporated into the working version of the code prior to initiating any Ginna specific MAAP runs as described in Reference 4.9-2. Sample problem testing and checkout of the code were performed with the modifications included [Ref. 4.9-3].

Section 4.2.1 briefly summarizes important MAAP input modelling assumptions which were used in the Ginna study. The plant model description (parameter file) used in the Ginna MAAP analyses is described and documented in Reference 4.9-1.

4.2.1 MAAP Analysis Assumptions (Model Parameters)

The MAAP model parameters generally represent inputs to phenomenological models in which significant uncertainties exist. Variations in the values of these parameters can be used to assess the impact of uncertainties in important physical models. The nominal, or default, values of these parameters used in the Ginna analyses were based on the recommendations found in the EPRI MAAP Guidance Document [Ref. 4.9-4].

For most of the model parameters, the default values have been used for base case analysis in the Ginna PRA. The following MAAP model parameter inputs were varied from the default values.

FCMDA - This model parameter dictates the fraction of entrained corium and water that goes from the cavity to the upper compartment with the remainder going to the lower compartment. For Ginna, this variable was calculated based on the area ratio of the openings from the cavity to each of these regions. Thus, a conservative maximum value considering area ratio alone of 0.284 was used in the base cases. Several cases were run to explore the sensitivity to this assumption as described in Section 4.6.2.

FCDDC - This parameter was previously only used for B&W units in the MAAP code. However, recent changes to the code made the choice of this parameter necessary for Westinghouse units as well. A value of 1.0 was chosen to limit the amount of condensation in the cold leg to the smaller of that computed by a simple Reynold's analogy model and that which would saturate the film of water flowing through the cold leg. A value of 1.0 gave the best agreement with RELAP data as described in Reference 4.9-5.

Several other MAAP sensitivity analyses were performed as part of this effort in which variations were made in parameters to assess the impact of uncertainties in important physical models. Results from these analyses are discussed in Section 4.8.2.

4.3 Bins and Plant Damage States

The interface between the Level 1 core damage analysis and the Level 2 containment analysis consists of a set of plant damage states. The plant damage states (PDSs) are defined by a set of functional characteristics for system operation which are important to accident progression, containment failure and source term definition. Each PDS contains core damage sequences with sufficient similarity in system functional characteristics that the containment accident progression for all sequences in the group can be considered to be essentially the same. Each PDS defines a unique set of conditions regarding the state of the plant and containment systems, and the physical state of the core, primary coolant system and the containment boundary at (approximately) the time of core damage/vessel failure.

The important functional characteristics for each PDS are determined by identifying the critical parameters (system functions) which impact the key results. The sequence characteristics which are important are defined by the requirements of the containment accident progression analysis. They include the type of accident initiator, the operability/non-operability of important systems, the value of important state variables (e.g., primary system pressure) which are defined by system operation, and timing of key events.

The Level 1 accident sequence event trees (ASETs) generally considered systems operation and operator actions only to the extent that those actions impacted the determination of core damage. Systems which impact containment integrity, radionuclide behavior, source term determination and containment accident progression were not explicitly considered in the Level 1 ASETs unless they also impacted core damage. Furthermore, even for those systems and operator actions which impact both core damage and containment performance, the Level 1 analysis only considered those functional aspects which impact core damage. Consequently, it was necessary to perform additional systems analysis to define the status of all systems important to the containment accident progression. This analysis was performed through the use of a containment systems event tree (CSET).

The important plant and containment systems that need to be modelled to support the definition of the plant damage states were identified and the containment systems event tree was developed to assess the availability of these systems for each important Level 1 core damage sequence cutset. The CSET quantification task provided the frequency and system functional status of all core damage sequences above the established frequency cutoff threshold.

The core damage accident sequence event trees and CSET contain all the necessary information to allow sequences to be unambiguously assigned to specific plant damage states. The plant damage states contain all the system status information necessary to evaluate the containment accident progression (evaluate the containment event tree - CET) with the possible exceptions of systems failures which result from the occurrence of specific physical phenomena and operator, recovery or mitigation actions which occur subsequent to core damage. Since systems important to the containment analysis are being considered in conjunction with systems important to core damage in the Level 1 event trees and CSET, dependencies between containment systems and all other systems were handled in a rigorous and consistent manner.

The PDS grouping task provided the PDS frequency, PDS characteristics and dominant sequences for each PDS to the containment event tree task (Section 4.5) and to the deterministic accident progression modelling task (Section 4.6).

4.3.1 Level 1 / Level 2 Interface

4.3.1.1 CSET Description

A review of the systems modeled in the Level 1 analysis was conducted in order to assure that the systems analyses included considerations of those systems and operator actions which are important to the containment analyses and are required for plant damage state definition.

The accident initiators, plant systems and various possible states of the primary system and containment, (at the time of the core damage) were reviewed to determine their potential impact on containment accident progression. The most important features were identified and the PDSs defined to assure that these features were considered. The systems and the important states of the containment and primary system are listed in Table 4.3-1.

The Level 1/Level 2 interface task involved the development of the containment systems event tree (CSET). The CSET assesses the availability of systems important to containment accident progression, containment failure and the radionuclide source term for the core damage sequences (cutsets) identified in the Level 1 core damage analysis. This task also included the definition of the event headings and the success criteria for the system functions evaluated in the CSET.

The CSET is needed to assess those systems which impact containment performance which have not been evaluated in the Level 1 event trees. The events considered in the CSET include systems/processes which were not considered in the Level 1 event trees for any sequence (e.g. failure to isolate containment) and events which were considered for some sequences, but because these systems were not important to core damage for specific sequence conditions (e.g. low pressure injection systems for sequences at elevated RCS pressure) they were not evaluated in the Level 1 trees.

Figure 4.3-1 shows the containment systems event tree which has been developed for the Ginna PRA. (For clarity, the branching following to the right of the upper branch of event PRV is not shown. The tree structure following this branch is identical to that shown in the tree structure leading to endpoints 1 through 46. Rather than expand the tree, these endpoints will be delineated SBOV1-SBOV46. Similarly, the tree structure following to the right of the upper branch of event PRC is the same as for the tree structure leading to endpoints 1-8. These endpoints will be delineated SBOC1-SBOC8. Note that branching is not required for events UL,XL,UH, and XH for these latter sequence pathways.) It was solved for each core damage sequence that has a frequency greater than the truncation limit imposed on the Level 1 analysis.

The containment system event tree includes the following event headings:

4.3.1.1.1 No Station Blackout - SBO

This event heading is used to distinguish transient sequences with total loss of AC power (and failure to recover power prior to core damage initiation) from all other transient sequences. SBO sequences have been uniquely identified in the Level 1 core damage analysis and the inclusion of SBO as a heading in the CSET is to clarify the logic for the next two events in the tree which consider offsite AC power recovery after core damage.

4.3.1.1.2 Power Recovery Prior Vessel Failure - PRV

This event is used to identify station blackout sequences with recovery of offsite AC power (subsequent to core damage) within a time period judged to be prior to core support plate and reactor vessel failure. Note that recovery of the diesel generators is not considered in the Level 1 core damage event trees or in the CSETs and that power recovery is defined solely as offsite power recovery.

MAAP calculations [Ref. 4.9-8] for several station blackout sequences (which considered operation/non-operation of the steam turbine-driven auxiliary feedwater system) indicate a time period of approximately 1.4 to 2.0 hours between core damage initiation and core support plate failure (if core support plate failure occurs then it is assumed that the probability of cooling the debris in-vessel is small and vessel failure is assumed to occur).

Based on these MAAP calculations, a time period from the start of core damage to core plate failure of 1.4 hours for sequences with early failure of AFW (at accident initiation) and 2.0 hours for late failure of AFW (following battery depletion) will be used to estimate the power recovery probability.

4.3.1.1.3 . Power Recovery Prior to Containment Failure - PRC

This event is used to identify station blackout sequences with recovery of offsite AC power (subsequent to vessel failure) within a time period judged to be prior to containment overpressure failure from long term production of steam and noncondensible gases.

MAAP calculations indicate that there will be many hours between vessel failure and the time when the containment integrity is first threatened from long term pressurization. The Ginna containment fragility curve has a median containment failure pressure of 144 psia [Ref. 4.9-9].

We have conservatively chosen to use the 5th percentile failure pressure (133 psia) to assess time available for power recovery prior to containment failure. The MAAP calculations indicate a time period of between 8.1 to 9.8 hours from the time of core support plate failure to the time the containment pressure reaches 133 psia [Ref. 4.9-8].

4.3.1.1.4 Status of In-Vessel Injection

The four event headings which are included in the CSET for in-vessel injection are:

Low Pressure Injection - UL
Low Pressure Recirculation - XL
High Pressure Injection - UH
High Pressure Recirculation - XH

For most sequences the availability of these systems has already been determined in the Level 1 core damage trees. However, for those sequences where the availability of one or more of these systems has not been determined, then the CSET will evaluate their status. Note that the functional success criteria for these systems in the CSET is the same as in the Level 1 core damage analysis. Note also that the success criteria for low pressure recirculation is operation of one RHR pump taking suction from the sump, successful heat removal with one RHR heat exchanger and water delivery to the reactor vessel. Simplifications made in the consideration of in-vessel injection in the CSET are discussed in section 4.3.1.2.1.

4.3.1.1.5 Containment Fan Coolers - FC

Analyses [Refs. 4.9-11 and 4.9-45] indicate that one train of fan coolers is sufficient to prevent overpressurization of the containment resulting from gradual steam production. Hence, the success criteria for fan cooler operation is one train of fan coolers (with or without the charcoal filter train). Simplifications made in the consideration of containment heat removal in the CSET are discussed in section 4.3.1.2.1.

4.3.1.1.6 Containment Spray Injection - UCS

The success criteria for containment spray injection is spray delivery from the RWST to the containment by one spray train.

4.3.1.1.7 Containment Spray Recirculation - XCS

The success criteria for containment spray recirculation is spray delivery from the sump to the containment by one spray train with successfull containment heat removal from one RHR heat exchanger. The success criteria for the RHR heat exchangers is operation of one heat exchanger (with one RHR pump supplying flow to the heat exchanger and one containment spray pump taking suction from the discharge of the RHR pump).

4.3.1.1.8 No Loss of Containment Isolation - IS

This event heading evaluates whether the containment is isolated following the start of core damage. Loss of isolation is defined as a leakage pathway from the containment atmosphere to outside the containment boundary with a minimum equivalent diameter of 1.5 inches or greater. MAAP code analysis [Ref. 4.9-6] for a spectrum of loss of isolation cases indicates that for containment leak sizes of 1.5 inches or less the volatile fission product (CsI) release fraction will be less than 10^{-2}. Furthermore, these MAAP calculations indicate that a leak size equal to, or greater than, 1.5 in. will generally prevent gradual overpressurization of containment in the absence of containment heat removal.

4.3.1.2 CSET Solution

The solution is built one node at a time, starting from the CUTSETs from a core damage sequence, by logically ANDing the CUTSETs for a top heading to the terms from the previous node. Mutually exclusive events and success terms identified in both the Level 1 Event Tree and the CSET are then deleted. This process ensures that no information from the Level 1 solution is lost in the quantification of the CSET. Split fractions are then computed for each CSET node, which are then used to determine the frequencies of the end states.

Special care is taken to preserve the results of the Level 1 recovery analysis without incorrectly applying recovery terms to systems that are not involved in the core damage scenario. The exceptions to this are certain containment isolation recoveries that are explicitly described in the Emergency Operating Procedures.

The end state frequencies are computed from split fractions rather than CUTSETS because all of the CSET end states are significant, and CUTSET solutions tend to over estimate the frequencies of success paths. (The reason for this is that independent success terms are not explicitly represented in this type of solution.) The split fraction solution preserves the core damage frequency from the Level 1, while allowing the sequences to be binned into Plant Damage States (PDS) based on Level 2 system performance considerations.

4.3.1.2.1 Evaluate Level 1 Sequences

The first step in solving the CSET for a core damage sequence is to determine what is already known about the availability of the containment systems explicitly modeled in the sequence. Since the success criteria for the CSET headings has been defined to be identical to the Level 1 success criteria, there are only three possibilities for a system state:

1) Available

2) Failed

3) Not Modeled

The exception to this rule is that a system that has been failed due to a loss of offsite power may become available after core damage occurs because of power recovery.

If a system falls into the "Not Modeled" category, its availability state may still be inferred by the states of the other explicitly known systems. The rules that apply in this situation are:

1) If low pressure injection (UL) is failed, then low pressure recirculation (XL) is assumed to be failed.

2) If high pressure injection (UH) is failed, then high pressure recirculation (XH) is assumed to be failed.

3) If low pressure recirculation (XL) is failed, then high pressure recirculation (XH) and containment spray recirculation (XCS) are assumed failed since high pressure recirculation and containment spray recirculation take suction from the discharge of the low pressure pumps.

4) If the containment fan coolers (FC) are available, then the availability of containment sprays in both injection and recirculation mode (UCS and XCS) are assumed failed. The containment pressure setpoint for actuation of the fan coolers (4 psig) is much lower than the sprays (28 psig), and for most sequences, with the possible exception of large and medium LOCAs, operable fan coolers will prevent the containment pressure from exceeding the pressure setpoint of the sprays prior to vessel failure.

   There is one exception to this rule. If both low and high pressure injection into the reactor vessel has failed, containment spray is a valid mode of injecting water into containment. In these cases, UCS is asked to determine if the RWST has been injected into containment rather than for containment cooling purposes.

Note that the following corollaries also apply:

1) If low pressure recirculation (XL) is available, then low pressure injection (UL) is also available.

2) If high pressure recirculation (XH) is available, then high pressure injection (UH) is also available.

3) If high pressure recirculation (XH) or containment spray recirculation (XCS) are available, then low pressure recirculation (XL) is available.

In addition to the system status, the logic flags that were used in the Level 1 analysis for each sequence must be preserved in the solution of the CSET.

Finally, the frequency of each of the Level 1 core damage sequences must be known. If a core damage sequence was below the truncation level, or if recovery reduces the frequency below the truncation level, the sequence will not be analyzed in the Level 2, and therefore does not need to have a CSET solution.

4.3.1.2.2 AC Power Recovery

There are four possible states of offsite AC power considered in the Level 2 analysis. AC power can be available at all times, unavailable prior to core damage and recovered before vessel failure, unavailable prior to vessel failure and recovered before containment failure, or unavailable throughout the scenario. The core damage CUTSETs must be sorted into these configurations.

The first heading in the CSET, "No Station Blackout" (SBO), determines whether or not power was available prior to core damage. The sequence CUTSETs are divided into SBO and non-SBO. Note that even though recovery of AC power is considered in the Level 1, the only terms that show up in the core damage sequences are those that have not been recovered prior to core damage.

The next two CSET headings, "Power Recovery Prior Vessel Failure" (PRV) and "Power Recovery Prior Containment Failure" (PRC), are based on the offsite power recovery curves. The probability of recovery is determined by the time available to restore power before the given undesired event occurs. In this analysis, only one scenarios is necessary:

1) AFW fails due to loss of ventilation, Vessel Failure at 12 hours, Containment Failure at 21 hours

If the state of AFW is unknown, it is assumed to be failed. For Level 1 sequences that include power non-recovery at 4 or 10 hours, it is assumed that AFW is available since the core would have been damaged much earlier if AFW was failed.

A review of the recovered Level 1 CUTSETs shows that all of the SBO terms above the truncation limit involve loss of the grid. This makes the calculation of the CSET recovery split fractions simple since the CUTSETs do not have to be further broken down into grid related and switchyard related loss of power events. A split fraction for each of the CSET headings is calculated based on the time required to recover power and any known time period of non-recovery. The probability of non-recovery by a given time is estimated by

$$P_{NR}(t) = e^{-0.327\, t^{0.907}}$$

and the probability of non-recovery between two times is given by

$$P_{NR}(t_2 - t_1) = \frac{P_{NR}(t_2)}{P_{NR}(t_1)}$$

The CSET split fraction is defined as the probability of non-recovery between two times. Table 4.3-2 summarizes the split fractions used.

4.3.1.2.3 Generate the CSET Top Events

This section deals with the quantification of the injection, recirculation, and containment cooling systems modeled in the CSET. The containment isolation system is treated differently, and is described in the next section.

The top events in the CSET are defined such that they are the same as those used in the Level 1 analysis. Therefore, the Level 1 fault tree models can be used without modification. The major difference is the treatment of offsite AC power. All of the CSET branches that consider the system availability have offsite power either available or recovered at the time in question.

4.3.1.2.4 Containment Isolation Tree Solution

The Containment Isolation fault tree contains logic that is highly dependant on the core damage sequences being evaluated. Many of the systems considered in the Level 1 analyses have components that also perform a containment isolation function, while others have parts that preclude the failure of the containment isolation function. Great care was taken to ensure that all dependencies between the Level 1 solution and the Containment Isolation tree quantification were handled in a rigorous and consistent manner. The Containment Isolation tree treats dependencies to the other models via logic flags. There are two types of flags used; those that are associated with a containment isolation signal to a valve, and those associated with special events.

The first type of flags are used to identify Level 1 failures that would generate a containment isolation signal for a particular valve. The gate logic identified in the flag description must be DELETED from the associated "No Containment Isolation Signal from ESFAS" gate. This is because failure of the items identified in the flag description will generate a signal for the valve to close whether an actual containment isolation signal is present or not. Note that the valve can still mechanically fail to close even if it gets a signal to close. These flags are handled in the solution by deleting the flagged terms prior to combining the Containment Isolation CUTSETs with the rest of the CSET.

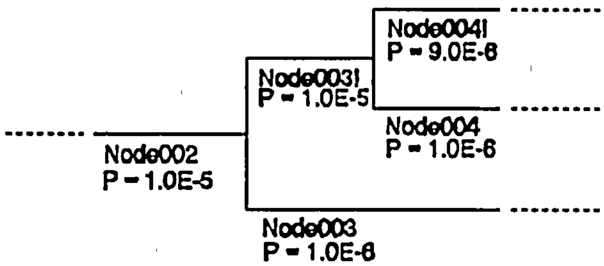
The second type of flags are used to identify special circumstances that may occur in a core damage sequence that may invalidate a given containment penetration as a potential release path. A typical scenario of this type is a valve that is required to be open to perform its Level 1 function, but its failure leads to the core damage event. In this case, the valve failure ensures that it is in its proper (closed) state for the containment isolation function. These flags are handled in the solution by deleting the flagged terms after combining the Containment Isolation CUTSETs with the rest of the CSET.

As in the other system tops, the Level 1 flags need to be preserved for the solution of the Containment Isolation fault tree. However, AC power is treated differently for containment isolation than it is for the other systems. It is possible that the containment isolation function could fail due to power failure for PRC success sequences. For these sequences, the tree is solved with the AC power terms in their Level 1 quantification state, and the combination of the logic determines whether or not the isolation function is failed by power.

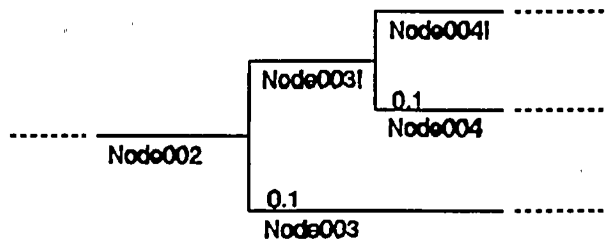
Initial quantification of the CSET showed failure to isolate AOV-371 to be a significant contributor to the failure of containment isolation. Procedure E-0, step 12b calls for the local isolation of AOV-371 via manual valve 204A. A recovery action was applied to these isolation failures to provide a more realistic estimation of the containment isolation failure probability. All Level 1 recovery rules were followed when including this recovery to the CUTSETs.

4.3.1.2.5 CSET End State Solution

The system tops are combined with the Level 1 core damage solutions by a CUTSET linking process. A failure branch is computed by ANDing the terms from the system top to the terms from the upstream node. Then the mutually exclusive terms and previous success branch terms are deleted from the result. A success branch is computed by copying the upstream node, and deleting the terms from the system top. A split fraction for the node is then calculated by dividing the probability of the failure branch by the probability of the upstream node.



Probabilities from CUTSET Solution



Calculated Split Fractions

Several special cases may be encountered during the CSET solution. Some nodes may have been pre-determined by the Level 1 analyses, while others may be truncated or found impossible due to exclusive events or system successes. The following paragraphs describe the way that exceptions to the CUTSET linking process are handled.

<u>SBO</u>

Rather than ANDing terms for this split fraction, the solution of this node splits the Level 1 sequence CUTSETs into terms involving AC power failure and those that do not. The process for performing this split is described in Section 4.3.1.2.2. The split fraction is computed by dividing the probability of the Loss of Power portion by the probability of the core damage sequence.

<u>Power Recovery</u>

The nodes for PRV and PRC are split fractions computed from Table 4.3-2. No CUTSETs are involved. Because of this, the terms from the failure branch of Node 1 will be the upstream node for each of the power recovery branches. The split fractions used on these nodes are presented in Section 4.3.1.2.2.

Pre-Determined Branches

Since many of the systems in the CSET have already been considered in the Level 1 analysis, the state of many of the nodes has been pre-determined. If a system was determined to be unavailable, the split fraction for the node is assigned to unity (1.0) and the CUTSETs from the upstream branch are copied into the failure branch. The success branch is set to FALSE (0.0). If the system was determined to be available, the failure branch is set to FALSE, the split fraction is set to 0.0, and the upstream CUTSETs are copied to the success branch. In this case, the system CUTSETs are still deleted from the success branch for completeness.

Upstream Success or Failure

As the solution of the CSET progresses, some branches may be determined to have a zero probability. There is no reason to proceed with the solution along such a branch. If the success path of a node is zero, the solution continues along the failure path. If the failure path is zero, the success path solution is completed and then the quantification skips the failure branch. The solution is resumed at the next node below the FALSE failure branch.

4.3.1.3 Results

Table 4.3-3 lists the frequencies for each of the non-truncated CSET end states. These frequencies are used directly in the determination of Plant Damage State probabilities.

4.3.2 Plant Damage State Grouping Parameters

Twelve parameters were selected for use in defining the Ginna plant damage states (however, two parameters apply only to SGTR sequences). A description of these parameters and the bases for their selection are discussed in detail below.

4.3.2.1 Containment Bypass

This parameter is used to divide the Level 1 core damage sequences into bypass and non-bypass groups. Furthermore, the containment bypass sequences are subdivided into interfacing system LOCA (ISLOCA) and steam generator tube rupture (SGTR) groups. The containment bypass sequences are distinctly different from non-bypass sequences in that there exists a direct flow pathway from the primary system to outside the containment boundary which bypasses the main containment region. Hence, holdup and attenuation of radionuclides (released from the core/primary system prior to vessel failure) are not affected by the natural processes and engineered safety systems in containment. Consequently, bypass sequences can result in relatively large source term releases early in time. The interfacing system LOCA and SGTR bypass sequences are separated into different groups because the radionuclide release pathways for these two groups of sequences are unique.

For the SGTR sequences the pathway includes, for example, the reactor coolant system (RCS), steam generator (SG) secondary side, secondary steam line and safety/relief valves. For interfacing system LOCA sequences a typical pathway is RCS, low pressure injection (LPI) system piping and the auxiliary building (where the break location may be submerged). Strictly speaking a containment event tree is not required for these sequences since containment phenomena are largely irrelevant or unimportant.

4.3.2.2 Containment Isolation Status

This parameter segregates the core damage sequences into sequence groups based on the status of containment isolation at the time of core damage. With the containment not isolated, early and relatively large releases of radionuclides from the plant are possible. If the containment is not isolated the most important additional system consideration from the standpoint of the radionuclide source term is whether the containment sprays and/or containment fan coolers function. With operation of the sprays or fan coolers, leakage from the containment will be reduced and effective mitigation of radionuclides in the containment atmosphere will occur. Consequently, for sequences which are not isolated these are the only other grouping parameters which are considered.

MAAP calculations [Ref. 4.9-6] indicate that the minimum leak diameter that need be evaluated (from consideration of the off-site source term and the impact of the leak on containment pressurization and failure) is 1.5 inches.

4.3.2.3 Transient or LOCA Type

This parameter is used to separate transient sequences from LOCA sequences and to further subdivide large/intermediate LOCAs sequences from small LOCAs. The major reasons for the use of this parameter for grouping are: 1) to aid in the subsequent classification of sequences by RCS pressure, 2) to distinguish sequences with distinctly different key event timing, and 3) for radionuclide release and transport behavior differences. Large and intermediate LOCAs have been combined since their containment accident progression is expected to be similar.

4.3.2.4 Reactor Shutdown

This parameter segregates ATWS sequences from all other transient sequences. For ATWS sequences it is assumed that the damaged core is not coolable in-vessel because of the potential for elevated power levels when the debris is flooded with water.

4.3.2.5 Station Blackout

This parameter is used to distinguish transient sequences with total loss of AC power (and failure to recover power prior to core damage initiation) from all other transient sequences. This distinction is not made for LOCA initiated sequences since a LOCA initiated sequence with total loss of AC power has a very low frequency. Station blackout is selected as a grouping parameter for several reasons. First, total loss of AC power results in a sequence without any containment safeguards (sprays or containment fan coolers). Second, past studies of similar plants [Ref. 4.9-7] indicate that station blackout sequences may be important contributors to core damage and offsite risks.

4.3.2.6 Power Recovery

This parameter is used to identify station blackout sequences with recovery of offsite AC power (subsequent to core damage) within a time period judged to be prior to vessel failure and/or containment failure. Three possible branch pathways are evaluated; 1) "PRIOR Vessel Failure", 2)"PRIOR Containment Failure" and 3) "NO power RECOVery". Power recovery subsequent to core damage allows for the possible restoration of in-vessel injection which may terminate the accident and prevent vessel failure. Power recovery prior to containment failure allows for restoration of containment sprays and/or containment fan coolers in sufficient time to prevent containment failure or mitigate the source term.

4.3.2.7 RCS Pressure During Core Damage/At Vessel Failure

The reactor coolant system pressure during core damage and at the time of vessel failure can have a major impact on several potentially important containment events. High RCS pressures during core heatup and core damage facilitate natural circulation heat transfer from the core to the hot leg which increases the potential for high temperature induced hot leg, surge line or steam generator tube failure. Elevated pressures at the time of vessel rupture may result in entrainment of the core debris out of the reactor cavity and increase the potential for debris fragmentation and dispersal into the main containment gas volume thus increasing the potential for direct containment heating (DCH). Four pressure regimes have been identified as being significant. These are:

Pressure Regime	Pressure Range (psig)
LO-LO	< 140
LO-HI	140 - 1400
HIGH	1400 - 2335
HI-HI	> 2335

The reasons for this selection of pressure regimes for use as PDS characteristics are discussed below. The shutoff head for the Residual Heat Removal (RHR) System is approximately 140 psig [Ref. 4.9-1]. Energetic dispersal of the debris out of the reactor cavity following vessel failure is not expected for RCS pressures less than 150 psi [Refs. 4.9-10, 4.9-33 and 4.9-34], whereas for pressure differentials above 150 psi debris entrainment and dispersal out of the cavity and DCH are potentially important processes. Based on the RHR shutoff pressure and the debris entrainment threshold pressure the upper pressure limit for LO-LO pressures was selected as 140 psig.

The shutoff head for the Safety Injection (SI) System is approximately 1400 psig [Ref. 4.9-1]. In addition, 2000 psi was judged by the NUREG-1150 In-Vessel Expert Panel as the lowest pressure where induced hot leg or surge line creep rupture failure was credible (though unlikely). Since the threshold pressure for induced RCS failure is above the shutoff pressure for SI, 1400 psig was selected as the upper pressure limit for the LO-HI regime.

At very high RCS pressures in the range of the pressurizer relief/safety value setpoints (2335-2485 psig) [Ref. 4.9-1] the NUREG-1150 experts panel judged that induced hot leg or surge line failure was likely and that induced steam generator rupture was possible (though highly unlikely).

4.3.2.8 Status of In-vessel Injection

The status of in-vessel cooling at the time of core damage is important for several reasons. If in-vessel cooling is available during the period of core damage, core damage may be limited and vessel failure prevented. This situation would be the case for a large break LOCA sequence with operable RHR cooling but with all accumulators failed. For this sequence the Level 1 success criteria indicate core damage occurs [Ref. 4.9-22]. If the RCS pressure is elevated above the RHR system shutoff pressure (140 psig) or above the SI system shutoff pressure (1400 psig) but these systems are available (deadheaded) they could provide in-vessel injection if the RCS is depressurized prior to RV failure (such as by an induced hot-leg rupture). In addition, with the in-vessel cooling systems available an additional source of cooling water is available to the cavity debris following vessel failure. The in-vessel cooling systems may also be available following off-site power recovery for station blackout sequences. The seven possible branches for this heading are:

REC ON	(in-vessel cooling on early - both injection and recirculation modes available)
INJ ON	(in-vessel cooling on early - only injection mode available)
REC DEADHEAD	(in-vessel cooling available but cannot inject because of high RCS pressure - both injection and recirculation modes available)
INJ DEADHEAD	(in-vessel cooling available but cannot inject because of high RCS pressure - only injection mode available)

REC RECOV	(in-vessel cooling recovered subsequent to core damage but prior to the anticipated time of core support plate and RV failure - both injection and recirculation modes available)
INJ RECOV	(in-vessel cooling recovered subsequent to core damage but prior to the anticipated time of core support plate and RV failure - only injection mode available)
INJ FAIL	(in-vessel cooling never available)

Note that failure in the recirculation mode is assumed to occur if long term containment heat removal (fan coolers and containment sprays) is failed, even when in-vessel cooling in the recirculation mode is initially available.

4.3.2.9 Containment Fan Coolers

Operation of containment fan coolers (i.e. operation of at least one train of fan coolers) or operation of one train of the containment sprays with a functional RHR heat exchanger is considered necessary to prevent long term containment over-pressure failure from steam generation and high containment temperature [Ref. 4.9-11]. Successful operation of containment heat removal requires that heat removal be established prior to the containment reaching a pressure where containment integrity is first threatened (taken to be 133 psia). This requirement generally affects SBO sequences where success of offsite power recovery (prior to containment failure) is based on the time period from onset of core damage to the time when the containment integrity is initially threatened.

Operation of the fan coolers also provides for mitigation of the radionuclides in the containment atmosphere. Even without the filter trains in service, effective deposition of radionuclides on the fan coolers is expected due to steam condensation on the cooling coils.

4.3.2.10 Containment Sprays

Operation of the containment sprays provides several important functions which impact containment accident progression, containment loading and the radionuclide source term. First, operation of the sprays in the recirculation mode (with an operational RHR heat exchanger) is considered necessary for long term containment heat removal if the fan coolers are failed [Ref. 4.9-11]. Second, operation of the sprays will attenuate fission products released to the containment atmosphere and greatly reduce the source term. To be considered successful for this purpose the sprays must operate during periods of time when fission product release is occurring and when containment heat removal is required. However, with the fan coolers available the containment sprays are unlikely to be operated in the long term.

The sprays also provide a means of injecting the contents of the RWST into containment and thus provide a source of water to cover the debris in the reactor cavity or on the lower containment floor for cooling the debris. Cooling the debris ex-vessel prevents debris concrete attack and the release of radionuclides and non-condensible and combustible gases.

4.3.2.11 Steam Generator Isolated

Given that a SGTR has occurred, the source term to the environment will be significantly larger if there is an open release pathway from the broken steam generator to the environment (such as a stuck open atmospheric relief valve), compared to the case where there is no open pathway and the only significant releases occur through relief valves cycling at their setpoint pressure.

4.3.2.12 Steam Generator Break Covered

If the broken steam generator is flooded to a level which covers the steam generator tubes during the time period of core damage and fission product release, then significant attenuation of the fission product source term can be expected by scrubbing in the steam generator. The steam generator would remain flooded if AFW was not isolated to the broken steam generator.

4.3.3 PDS Logic Diagram and Characteristics

A logic diagram was constructed with these twelve parameters as decision branches to aid in the assembly of specific plant damage state characteristics from the matrix of all possible combinations allowed by the twelve grouping parameters.

The logic diagram for the Ginna plant damage states is shown in Figure 4.3-2. The endpoints of the logic diagram represent individual plant damage states and the pathway through the diagram (i.e. the set of decision paths taken at each decision branch) define the attributes for each plant damage state.

The logic diagram is a tool used to combine the various grouping parameters into unique plant damage states. The goal of the grouping process is to reduce the number of required containment analyses to a tractable number while continuing to distinguish the more important differences among the sequences which are likely to influence the containment accident progression.

Using twelve parameters in a grouping logic structure with (only) binary choices at each decision point would result in 2^{12} (4096) groups which is clearly intractable. However, by arranging the logic diagram in such a way that the most important parameters are considered before parameters of lesser importance, and eliminating decision points by allowing only one decision branch results in the collapse of the number of plant damage states to a reasonable number while still preserving the most important differences among the various sequences.

The reasons for suppressing branching on a decision branch are highly judgmental and involve the following considerations: (1) Is this branch necessary to distinguish an important difference among the sequences? (2) Is the frequency of sequences following this pathway likely to be sufficiently large to warrant additional plant damage states?, and (3) Can a conservative choice be made which allows for branch suppression which is not likely to significantly impact the overall results. For example, on the Ginna PDS Logic Diagram shown on Figure 4.3-2 branching is suppressed under the Station Blackout heading for LOCA sequences based on the relative frequency of LOCAs with and without AC power.

Figure 4.3-2 has been reduced to eliminate plant damage states containing no sequences (i.e. all sequences in these groups had frequencies below the cutoff threshold - see section 4.3.1). Twenty four plant damage states were defined for the Ginna plant.

The timing of key events such as system failure/recovery, and operator actions were assessed. The PDS logic diagram was structured to assure that the key event timing information was appropriately considered. The major time periods of interest are:

- Prior Core Damage
- Core Damage to Vessel Failure
- At Vessel Failure
- Between Vessel Failure and Gradual Containment Overpressure Failure
- After Containment Failure

4.3.4 Plant Damage State Frequencies and Dominant Sequences

The core damage sequences evaluated through the Level 1 accident sequence event trees (ASET) and containment system event tree (CSET) were assigned to plant damage states using the PDS logic diagram (Figure 4.3-2).

The total core damage frequency (CDF) is 8.24E-5. Table 4.3-4 presents the Ginna PDS frequencies. The dominant plant damage states are 12, 22, 24, 20, 15, 17, 11 and 1. These PDSs represent 96.3% of the total core damage frequency. Three of the top four frequency ranked PDSs contain containment bypass sequences. PDSs 22 and 24 represent steam generator tube rupture (SGTR) initiated core damage sequences. SGTR sequences represent 32.7% of the total CDF. Interfacing system loss of coolant accident (ISLOCA) sequences are contained in PDS 20. ISLOCA initiated core damage sequences account for 9.7% of the total CDF.

The PDS with the highest frequency is PDS 12 (29.7% of total CDF). This PDS contains large and intermediate LOCA sequences with the in-vessel emergency cooling systems available in the injection phase but failed in the recirculation phase. PDS 11 is similar to PDS 12 except that for PDS 11 the in-vessel cooling systems are available in both the injection and recirculation modes.

PDSs 15 and 17 (9.6% and 7.5% of CDF, respectively) contain small break LOCA sequences. For PDS 15 in-vessel injection is available in both the injection and recirculation modes, however the reactor coolant system has not been depressurized sufficiently to allow injection into the vessel. For PDS 17 in-vessel cooling is provided during the injection phase, however failure of in-vessel cooling occurs in the recirculation phase.

PDS 1 contains all sequences with failure of containment isolation. Loss of isolation sequences represent 3.0% of the total CDF and 5.2% of the frequency for non-containment-bypass core damage sequences.

Containment heat removal is available for all PDSs except for the PDS containing SBO sequences with offsite power never recovered (PDS 8). This result indicates that the containment heat removal systems are reliable (particularly the containment fan cooler system).

Inspection of Ginna individual plant damage state attributes yields the following additional insights. Of the non-bypass, non-loss of isolation sequences, transient sequences[1] represent 2.7%, small break LOCAs 17.6%, and large/intermediate break LOCAs 34.5%, of the total core damage frequency. Station blackout (SBO) sequences account for only about 1% of the total core damage frequency (and 38% of the transient CDF). For SBO sequences, 38% have power recovery subsequent to core damage but prior to the estimated time for vessel failure, 54% have power recovery after vessel failure but prior to the estimated time when long term containment overpressure failure might first occur, and for 8% of the SBO sequences, power is not recovered.

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[1]Transient sequences assigned to Transient PDSs do not contain all the transient initiated sequence CDF. Transient initiated sequences which are transferred to LOCA event trees (for example, as a result of a stuck open pressurizer PORV) are assigned to the corresponding LOCA PDSs.

RCS pressure during core damage is an important parameter for assessing containment accident progression. The overall breakdown for fraction of all plant damage state sequences in each pressure regime is shown below (neglecting bypass and loss of isolation sequences):

Very High	(P > 2335 psig)	5 %
High	(1400 < P < 2335)	0 %
Intermediate	(140 < P < 1400)	32 %
Low	(P < 140)	63 %

Table 4.3-5 lists the core damage sequences that contribute to the frequency of each plant damage state.

4.4 Containment Failure Characterization

4.4.1 Containment Ultimate Strength

A finite element analysis was performed by Ebasco Services [Ref. 4.9-12] to assess the ultimate strength and failure modes of the Ginna containment under the pressure and temperature loads associated with a severe accident. Bounding pressure and temperature loads for the finite element analysis were selected from a set of MAAP code calculations for a spectrum of severe accident sequences.

Global structural failure was found to be initiated in the circumferential reinforcement steel in the cylindrical wall at its midheight. The containment internal pressure at the inception of global failure was 155 psia. Local liner tearing at discontinuities (penetrations) was estimated to occur at a pressure of 145 psia. These failure pressures were assessed to have an uncertainty of (+/- 5%) estimated from the general accuracy of the finite element modelling approach.

Due to conservatism in design and construction, most estimates of the failure pressure for PWR containments are between two and three times the design pressure. Based on a design pressure of 60 psig (75 psia) and a global failure pressure of 155 psia the ratio of failure pressure to design pressure for the Ginna containment is 2:1.

4.4.2 Containment Building Failure Mechanisms

The containment failure mechanisms considered in the Ginna PRA are based on NUREG-1150 [Ref. 4.9-7] results. NUREG-1335 [Ref. 4.9-13] provides a list of potential containment failure modes and mechanisms and states that all of these failure modes and mechanisms were considered in the NUREG-1150 analysis. This section discusses each of these items.

4.4.2.1 Direct Bypass

Direct bypass of the containment is considered in the NUREG-1150 analysis and in the Ginna PRA. In each analysis the bypass sequences include both interfacing system loss of coolant accident (ISLOCA) and steam generator tube rupture (SGTR) sequences.

4.4.2.2 Failure to Isolate

Failure to isolate containment can lead to an early release of radioactivity. A leak in containment, either pre-existing at the time of the accident, or resulting from the failure of the isolation paths to close, may result in a significant radionuclide release especially if the release pathway is in direct contact with the containment atmosphere. In the Ginna PRA, loss of isolation is treated as an event heading in the containment system event tree. A detailed fault tree model has been developed to assess loss of isolation failures.

4.4.2.3 Vapor Explosions

NUREG-1150 considered steam explosions originating in-vessel (the classic alpha-mode failure) or ex-vessel in the reactor cavity. Alpha-mode failures were considered by the Steam Explosion Review Group [Ref. 4.9-14]. Ex-vessel steam explosions were dismissed for the Surry plant in NUREG-1150 because steam explosions in the cavity would not directly contact structures that are both vulnerable and essential to the containment function. The Ginna reactor cavity is located below the level of the containment floor and is isolated from the containment walls. Consequently, based on the NUREG-1150 results, containment failure resulting directly from ex-vessel steam explosions was not considered credible in the Ginna PRA.

Estimates for probability of alpha mode containment failures used in the Ginna PRA were based on insights from the Steam Explosion Review Group.

4.4.2.4 Combustion Processes

Hydrogen combustion was considered in the Surry NUREG-1150 accident progression analysis. Both early and late combustion were considered.

Hydrogen combustion at the time of vessel failure in the absence of high pressure melt ejection (HPME) and direct containment heating (DCH) result in pressure transients which do not threaten containment integrity [Ref. 4.9-15]. Combustion of hydrogen late in the sequence (many hours after vessel failure) is only of concern for sequences where the containment atmosphere is rapidly de-inerted following a long period with extensive debris concrete interactions in an inerted containment. Based on the results from NUREG-1150 and a review of the Ginna interior design, hydrogen detonations were considered of negligible importance.

4.4.2.5 Steam Overpressurization

In the absence of effective containment heat removal, gradual pressurization of the containment would result from the generation of steam and non-condensible gases from the interaction of core debris with water on the containment floor or with the concrete basemat. This pressurization process could last from several hours to several days, depending upon accident-specific factors such as the availability of water in the containment and the operability of engineered safety features.

Gradual containment pressurization by steam production and from the non-condensible gases generated during debris concrete attack was considered in the Ginna PRA.

4.4.2.6 Core-Concrete Interaction (Basemat Meltthrough)

The Ginna design is such that water fills the reactor cavity if the contents of the refueling water storage tank (RWST) are injected into containment. In addition, the containment floor will be covered with water when the RWST empties. However, if the RWST is not injected or the debris is not in a coolable configuration, then basemat meltthrough may occur at Ginna.

Basemat meltthrough was considered in the Ginna PRA containment analysis.

4.4.2.7 Blowdown Forces (Vessel Thrust Force)

Failure of the containment as a result of gross displacement of the reactor vessel (above the shield wall) was considered in the NUREG/CR-4551 accident progression analysis. However, the assigned probability for this event was sufficiently small that it made a negligible contribution to the probability of early containment failure. This mode of containment failure was not considered in the Ginna PRA containment analysis.

4.4.2.8 Liner MeltThrough (Direct Contact of Containment Shell with Fuel Debris)

The principal pathway for release of gases, water and debris dispersed from the Ginna cavity is near the end of instrument tunnel. The containment compartment outside the cavity in this area is not separated from the containment wall by any major structures. Consequently, there exists the potential for significant quantities of debris to come into contact with the containment wall.

This mode of failure was considered in the Ginna PRA.

4.4.2.9 Failure of Containment Penetrations

Failure of containment penetrations (electrical, fluid, equipment hatch, personnel hatch, etc.) was evaluated in the NUREG-1150 analysis and was judged to be significantly less important than over-pressure failure of the cylinder wall. Based on the NUREG-1150 results and the Ebasco study [Ref. 4.9-12] this failure mode was not explicitly included in the Ginna PRA.

4.4.3 Containment Building Overpressure Fragility

The Level 2 analysis considers the possibility of the containment failing under various accident scenarios. In order to be comprehensive, failures resulting over the range of possible pressures and pressurization rates must be considered. The objective of this task was to develop the fragility curve for containment failure (i.e. the probability of containment failure as a function of containment pressure) and to assess the probability of each possible mode of containment failure.

Construction of the Ginna containment fragility curve was based on the containment structural analysis from Ref. 4.9-12 and summarized in Section 4.4.1 above. The procedure for construction of the fragility curve is described in detail in Ref. 4.9-9. A general sketch of the containment is shown in Figure 4.4-1.

In the Level 2 containment analysis, it is necessary to assess the probability of containment failure for a spectrum of accident sequences. A principal threat to the integrity of containment is overpressurization associated with the severe accident. Overpressurization results from steam production from the decay heat in the debris; from noncondensible gases generated from debris concrete attack and from oxidation of the metals in the debris; and from direct heating of the containment atmosphere. The pressurization rate can be slow, as from gradual steam production, or rapid, as from a hydrogen burn or from direct containment heating (DCH).

The containment fragility curve represents the probability of containment failure as a function of containment pressure. The fragility curve is generally based on a structural analysis of containment which identifies the potential modes of containment failure (limiting components of the containment pressure boundary) and provides an estimate of the expected failure pressure for each mode. In addition, the containment structural analysis generally provides an estimate of the uncertainties associated with the failure pressure estimate for each mode. This information is used to construct the containment fragility curve.

A detailed structural analysis of the Ginna containment shell was performed by Ebasco Services [Ref. 4.9-12]. This analysis identified two dominant modes of containment failure: global failure of the reinforcing in the containment wall at an estimated pressure of 155 psia, and local liner failure in the vicinity of large penetrations at an estimated pressure of 145 psia. Each of these failure estimates was assessed to have an associated uncertainty of (+/-) 5%.

In order to develop the containment fragility curve, an assumption must be made on the manner in which the uncertainties are distributed. Typically, either a normal or log-normal distribution is assumed. The stated uncertainty from Ref. 4.9-12 (+/- 5%) is symmetric about the best estimate failure pressure. Since a normal distribution has this property, it has been assumed that the uncertainties in the Ginna containment failure pressure for each mode can be represented by a normal distribution. Furthermore, it is assumed that the stated uncertainty of +/- 5% represents one standard deviation from the mean failure pressure.

It was assumed that local liner failure and global failure will both prevent further containment pressurization under gradual overpressurization conditions. For rapid pressurization conditions, however, local liner failure was assumed to provide insufficient pressure relief to prevent continued containment pressurization.

The uncertainties in estimating the local liner failure pressure and the global failure pressure were conservatively assumed to be independent in constructing the composite containment fragility curve.

The normally distributed probability density functions for local liner and global containment failure are:

$$p_{dens-i}(p)=\frac{1}{\sqrt{2\pi\sigma_i^2}}e^{\left[-\frac{(p-p_{m-i})^2}{2\sigma_i^2}\right]}$$

where:

p	= the absolute pressure
$P_{dens\text{-}i}$	= the probability density for failure mode i
σ_i	= the standard deviation for failure mode i
$p_{m\text{-}i}$	= the median/mean failure pressure for failure mode i
$p_{m\text{-}l}$	= 145 psia
$p_{m\text{-}g}$	= 155 psia
i	= local liner failure (l) or global failure (g)

The cumulative distribution function is given by:

$$p_{cum-i}(p)=\int_0^p p_{dens-i}(p')dp'$$

Based on the stated accuracy of the ultimate failure pressure calculation +/- 5% it is assumed that the standard deviation is 5% of the mean failure pressures for each failure mode. Hence:

σ_l	= 7.25 psi
σ_g	= 7.75 psi

Using these parameters the probability density functions and the cumulative density function for each failure mode were determined and are shown on Figures 4.4-2 and 4.4-3 respectively.

The overall containment fragility curve is calculated using the equation to combine the probabilities for two independent failure modes:

$$p_{cum}(p)=p_{cum-l}+p_{cum-g}-p_{cum-l}p_{cum-g}$$

The assumption of independence (i.e., uncertainties in the analysis for the failure pressure for each mode are not correlated) is reasonable since the material for the liner and the concrete reinforcing are not the same and different models would be used to assess the ultimate strength for each of these modes. Furthermore, the assumption of independence is conservative (i.e, results in the lowest value for the overall ultimate strength). This curve is also shown on Figure 4.4-3. The median pressure for containment failure (by any mode) from the combined curve is 144 psia and the 5th percentile failure pressure is 133 psia.

Given that containment failure has occurred, it is also necessary to know the mode of failure. Two possible conditions may exist: firstly, for slow pressurization events containment pressurization will cease whenever either a local liner failure or a global containment failure occurs (it is assumed that the leakage area for a liner failure is sufficient to prevent continued pressurization of containment) and secondly, for rapid pressurization events (such as from hydrogen burns or direct containment heating) the leak rate from containment is unlikely to be sufficiently large to prevent the containment from continuing to pressurize for a local liner failure.

Consequently, for slow pressurization events it can be assumed that only one failure mode will occur and whichever failure mode occurs first will preclude failure by the other mode. On the other hand for fast pressurization events local liner failure will not necessarily preclude containment failure by global failure also.

For cases of slow pressurization, where the failure of containment in one mode precludes failure in the other mode, local liner failure and global containment failure are mutually exclusive. The equation for the probability of a specific failure mode, conditional on containment failure, at a pressure p, under these conditions is:

$$p_{cf-i}=\frac{p_{cum-i}}{p_{cum-l}+p_{cum-g}}$$

These conditional probabilities as a function of the containment failure pressure are shown on Figure 4.4-4.

For cases of fast pressurization, where the failure of containment in one mode does not precludes failure in the other mode either, or both, local liner failure or global failure may occur. The equation for the probability (conditional on containment failure) of local liner failure only, or global failure only, is:

$$p_{cf-l} = \frac{p_{cum-l} - p_{cum-l}\, p_{cum-g}}{p_{cum-l} + p_{cum-g} - p_{cum-l}\, p_{cum-g}}$$

and for both global failure and local liner failure is:

$$p_{cf-l+g} = \frac{p_{cum-l}\, p_{cum-g}}{p_{cum-l} + p_{cum-g} - p_{cum-l}\, p_{cum-g}}$$

These conditional probabilities are shown on Figure 4.4-5.

For slow pressurization events, containment failure will be dominated by local liner failure for failure pressures, at or below the median containment failure pressure. At failure pressures above the median failure pressure, the global failure mode becomes of increasing importance with the conditional probabilities of local liner failure and global failure asymptotically approaching 0.5 at high failure pressures. For fast pressurization events, local liner failure will again dominate for pressures at or below the median failure pressure. At higher pressures both global and local liner failures are expected.

4.5 Containment Event Trees

A containment event tree (CET) is a logic model to delineate the possible paths that an accident sequence may progress along, given an initial set of conditions defined by a plant damage state. The CET models the key uncertainties in the possible outcomes from various physical phenomena and processes which impact severe accident progression, containment integrity and the radionuclide source term.

The Ginna CET analysis was conducted as follows:

A simplified CET diagram was developed which contained headings for only the most significant events impacting severe accident progression. The CET is shown in Figure 4.5-1. For each of the event headings in the CET, Decomposition Event Trees (DETs) were constructed to assist in the quantification of each CET heading. Finally, an overall logic model was developed using the EVNTRE code [Ref. 4.9-16] based on the CET and DET diagrams.

The number of event headings incorporated into the main CET diagram was limited in order to preserve the lucidity of the CET and to delineate the most significant accident progression pathways. Additional event details required for the quantification of CET events were relegated to decomposition event trees (DETs) and incorporated into the EVNTRE model. The details of the Level 2 model development and quantification are discussed below.

It should be noted that the first 12 events in the EVNTRE input represent the plant damage state headings as shown in Figure 4.3-2. Incorporation of the PDS heading into the EVNTRE model allowed the direct modelling of dependencies between the CET/DET events and the PDS attributes.

4.5.1 Containment Event Tree Development

The events considered in the CET analysis generally represent phenomenological events or physical processes which are considered to be important to the definition of the source term and the time, mode, and location of containment failure. The severe accident phenomena and containment events specified in Generic Letter 88-20 [Ref. 4.9-17], the IPE Submittal Guidance Document-NUREG-1335 [Ref. 4.9-13] and the PRA Procedures Guide [Ref. 4.9-18] have been evaluated for inclusion in the CET. Also considered were the detailed set of events developed for NUREG-1150 [Ref. 4.9-7] and for NUREG/CR-4551 [Ref. 4.9-19]. A review of past PRAs and IDCOR results was also performed to identify events which should be included in the CET.

A general list of events considered for inclusion in the CET (and DETs) is shown in Table 4.5-1. The list of potentially important containment events shown in Table 4.5-1 indicate the type of events considered. Additional events were identified based on a review of the specific design and operational characteristics of the Ginna plant.

Event timing was a key factor in organizing the events on the CET. The accident progression was divided into distinct time periods for which different phenomenological processes are important and for which different recovery and mitigation actions may be effective. The general time periods considered were:

1. prior to RV failure
2. at or within a few hours of the time of RV failure
3. many hours after RV failure

The applicable time periods for each event are shown on Table 4.5-1.

A general containment event tree structure was used to assess containment accident progression for nearly all plant damage states except for those PDS associated with containment bypass sequences (SGTR or ISLOCA). For containment bypass sequences a CET was not required. Although the general CET structure was the same for most PDS, the quantification of the CET was different as a result of differing PDS characteristics. The following event headings were selected for incorporation into the main Ginna CET diagram. These events are judged to be the most important for assessing containment accident progression, containment failure and the source term. These events are grouped on the tree into the three principal time periods of interest for the analysis shown above.

The following discussion summarizes the events included in the main Ginna CET diagram.

4.5.1.1 Mode of Induced Primary System Failure

This event determines whether the elevated temperatures and pressures within the reactor coolant system (RCS) following core uncovery can result in failure of the RCS pressure boundary prior to reactor vessel lower head failure. Three branch possibilities are considered:

1. no induced RCS failure
2. rupture of a hot leg (or the pressurizer surge line)
3. steam generator tube rupture(s) (SGTRs)

Induced RCS pressure boundary failure is only likely to be important for sequences where the RCS pressure remains elevated during core uncovery and core heatup, since the high pressure conditions enhance natural convection heat redistribution from the core to the hot leg and steam generators [Ref. 4.9-17] and the high pressure conditions may lead to failure of these components at elevated temperatures. Each of the possible branch pathways for this event has an important impact on accident progression. Hot leg failures are likely to be of sufficient size (large break LOCA) [Ref. 4.9-17] to cause depressurization of the RCS prior to vessel failure, and consequently to greatly reduce the probability that energetic events at vessel failure (e.g., DCH or H_2 burning) will cause containment failure. Failure of one or more steam generator tubes can result in a bypass of containment if a secondary relief/safety valve opens. Unless the number of induced steam generator tube failures is large (> 10) and the secondary side of the steam generator is depressurized, the primary system would not be expected to depressurize prior to reactor vessel failure.

4.5.1.2 Debris Cooled In-Vessel

Given that core uncovery and some core damage has occurred, this question considers whether the damaged core can be cooled in-vessel and vessel failure prevented. For there to be any possibility that the core be cooled in-vessel, then a supply of water to the vessel in excess of that required to remove decay heat must be supplied. This requires an absolute minimum of several hundred gpm injection flow. At this minimum flow level, the probability of successfully cooling the damaged core in-vessel will be low, even given a core debris configuration favorable to cooling. At substantially higher injection flow rates, the probability of cooling the debris under less favorable debris configurations (e.g. at later times with greater amounts of core damage, core slumping and/or core melting) is enhanced.

The plant damage state entry conditions define whether low pressure (or high pressure) coolant flow is (or can be) provided in both the injection and recirculation phases. The types of core damage sequences with in-vessel cooling following core damage initiation can be divided into two major classes. The first class of sequences are those where the in-vessel cooling flows are insufficient to prevent core damage as defined by the Level 1 analysis success criteria. An example of this type of sequence is a large break LOCA with successful low pressure coolant injection (and recirculation) but with failure of the accumulators to inject.

The second class of sequences are those where there is no coolant injection prior to core uncovery and incipient core damage, but where some form of in-vessel cooling is recovered prior to vessel failure. This second class of sequences would include:

1) station blackout with late recovery of power and

2) high pressure sequences with failure of the high pressure system, or with failure to depressurize the RCS to the high (or low) pressure injection thresholds prior to core uncovery, followed by late depressurization (either intentionally or as a result of induced hot leg or surge line rupture) and with in-vessel cooling available.

The possible branch pathways for this event are:

1) debris cooled in-vessel (no vessel failure), and
2) debris not cooled in-vessel.

If the debris is cooled in-vessel, containment failure is extremely unlikely since only limited hydrogen production would be expected, steam generation will be limited, and DCH is not a possible threat. Furthermore, radionuclide release from the debris will be limited and longer-term revaporization of radionuclides deposited on RCS surfaces will be largely avoided. Hence, because the containment does not fail and because of the limited radionuclide release, the environmental source terms for core damage sequences successfully terminated in-vessel are expected to be very small. The sequences of this type are very similar to the TMI-2 accident. Note that successful in-vessel core cooling is assumed possible only if containment heat removal is available, the containment is isolated and the containment is not bypassed.

4.5.1.3 Mode of Early Containment Failure

This event assesses the probability that the containment will fail at, or soon after, vessel failure as a result of the containment loads generated by processes which may occur at vessel failure. The potential containment loading mechanisms which have been considered include:

- Direct Containment Heating (DCH)
- In-vessel Steam Explosions
- Hydrogen Combustion
- Ex-vessel Steam Explosions/Spikes
- Blowdown of The Reactor Vessel From Elevated Pressure

The rapid steam generation which may occur at vessel failure as the molten debris is ejected into water in the lower cavity and is quenched will result in peak containment pressures which are well below pressure levels which would threaten containment integrity. Furthermore, the dynamic loads associated with steam explosions which may occur in the lower cavity are not considered to pose a threat to containment integrity since there is no pathway for the pressure wave to be transmitted to the containment walls or dome either in water or gas. These results are similar to the conclusions presented on NUREG/CR-4551 for the Surry reactor [Ref. 4.9-19].

Bounding calculations indicate that hydrogen combustion at vessel failure alone will not result in a peak pressure which would threaten containment integrity. This calculation is summarized in Ref. 4.9-15. These bounding calculations assumed 75% of the core inventory of zirconium was reacted in-vessel and that a complete adiabatic burn occurs. The maximum calculated peak pressure from a hydrogen burn at vessel failure is less than 130 psia ($8.9(10)^5$ MPa) which is 14 psi below the median containment failure pressure (144 psia) for the Ginna plant. Considering that these calculations are very conservative (75% in-vessel metal water reaction and an adiabatic complete burn), it can be concluded that a hydrogen burn alone will not threaten containment integrity prior to vessel failure.

The only credible threat to containment integrity from potential failure mechanisms at vessel failure is associated with vessel blowdown, high pressure melt ejection (HPME) from the cavity, and direct containment heating (DCH) for high pressure sequences. Associated with the DCH event, hydrogen combustion might also ocur and is considered in the analysis.

4.5.1.4 Containment Liner Meltthrough

This event assesses the probability of containment liner failure due to thermal attack by debris deposited near the liner. Under high pressure melt ejection (HPME) conditions debris expelled from the reactor vessel at the time of vessel failure may be dispersed from the reactor cavity as a result of the blowdown of the reactor vessel.

If water covers the containment floor at, or soon after the time of vessel failure, then the debris may be quenched and debris thermal attack on the liner will not result in liner failure. For sequences where the water inventory injected into containment is insufficient to cover the debris on the containment floor, heat removal from the debris then will be by radiation and convection to the containment atmosphere and conduction into the containment floor and adjacent structures. Under these conditions liner thermal failure may be more probable than for cases where the debris is covered by a water pool.

The probability of liner thermal failure is considered to be a function of the depth of the debris in the vicinity of the liner, and hence on the mass of debris dispersed from the cavity and the spread area of the debris.

4.5.1.5 Type of Ex-Vessel CCI

This event heading assesses the probability that the debris released from the reactor vessel is in a coolable configuration in the reactor cavity, and if not coolable, determines the type of core-concrete interactions (CCI) which would occur.

The analysis of ex-vessel debris cooling included consideration of plant physical states (e.g. reactor vessel pressure at vessel failure), and the uncertainties associated with the occurrence of critical physical phenomena (e.g. debris configuration in the reactor cavity) determined to be important in assessing whether the debris was coolable ex-vessel.

The important plant state variables which were considered were:

Reactor Vessel Pressure at RV Failure;
Whether the Reactor Cavity is Flooded Prior to Vessel Failure; and,
Whether the Reactor Cavity is Flooded After Vessel Failure.

To assess the coolability of the debris it was considered necessary to determine the debris configuration, both in the short term, and in the longer term. Two debris configurations were considered in the analysis including continuous liquid pools and fully developed debris beds.

For each of these debris configurations, values for the maximum and minimum potential upward heat fluxes are estimated and a probability distribution is constructed based on the available experimental results and analysis. The actual heat fluxes that must be removed under steady state conditions are then estimated based on the decay heat in the debris, the debris mass released from the vessel at the time of vessel failure (and not dispersed from the cavity) and the debris spread area in the cavity. The actual heat fluxes are then compared with the potential heat flux probability distributions for each debris configuration to estimate the probability that the debris is coolable for each potential debris configuration for both the early and late time periods.

The sump in the reactor cavity tunnel was considered to be the critical design feature with regard to coolability of the debris ex-vessel. The 5 foot deep sump, if filled (or partially filled) with debris, represents a less favorable geometry for cooling the debris than if the debris is spread over a larger area in the cavity. In addition, the thickness of the concrete under the sump is only 1.5 ft compared with 4 ft elsewhere in the cavity.

4.5.1.6 Mode of Late Containment Failure

This event assesses whether late containment failure occurs and the mode of late containment failure. The mechanisms considered for late containment failure include gradual overpressurization resulting from failure of containment heat removal, late hydrogen combustion and basemat meltthrough.

For sequences with failure of containment heat removal, gradual containment overpressure failure is expected. Two overpressure failure modes have been identified for the Ginna containment: global containment failure and liner tearing.

This event also considers whether a late hydrogen burn occurs (upon rapid deinerting of the containment) of sufficient magnitude to fail containment. This event is only considered for SBO sequences with power recovery after vessel failure and with ex-vessel CCI occurring. Prolonged debris concrete interactions can produce very high flammable gas concentrations in the containment atmosphere. Upon deinerting combustion of these gases can produce pressures that threaten containment integrity if the burn is global and efficient.

MAAP code calculations and the NUREG/CR-4551 [Ref. 4.9-19] results suggest that hydrogen combustion during rapid deinerting events late in the accident following a substantial period of debris concrete interaction, could pose a serious challenge to containment integrity. If containment failure occurs due to a large hydrogen burn it is assumed that the containment failure mode is global (i.e. a large failure area).

For sequences where containment heat removal has been successful in preventing late overpressure failure and a late hydrogen burn has not failed containment then the remaining threat to containment integrity is from basemat meltthrough if the debris is not cooled in the cavity. As discussed previously, the design feature which is expected to control debris coolability is the sump in the reactor cavity. The analysis of debris coolability consequently, has been focused on coolability of the debris transported into the cavity sump. In addition to being the limiting design feature for cavity debris coolability, the basemat thickness under the cavity sump is very thin (1.5 ft). Consequently, if long term CCI does occur in the region of the cavity sump then basemat penetration can be expected with a high probability. In this analysis it is assumed that if ex-vessel CCI in the reactor cavity occurs (either with an overlying water layer or dry) then basemat failure is certain.

4.5.2 Methodology for Containment Event Tree Quantification

The purpose of the CET quantification is to assess the relative likelihood or probability of each distinct containment end state conditional on the plant damage state associated with the CET. This is accomplished by assigning a probability to each branch in each event in the CET (and associated DETs) and propagating the probabilities for each pathway leading to a distinct containment end state.

After construction of the CET and supporting DETs an overall containment event tree model was constructed for quantification using the EVNTRE code. The sections below summarize the decomposition event tree analysis process, including the assignment of event branch probabilities. The DETs are shown on Figures 4.5-2 through 4.5-7. On these trees are shown the EVNTRE question numbers corresponding to the event headings on the trees.

The sources of "data" for quantification of the event branch probabilities include:

A. Results of Past Studies

B. Plant Specific Calculations with Deterministic Models (e.g. MAAP)

C. Separate Effects Calculations

D. Engineering Assessment/Judgment

The main containment event tree has six headings which are quantified using decomposition event trees (DETs). This section discusses each Ginna DET in order to provide an indication of how the quantification is accomplished.

4.5.2.1 Mode of Induced Primary System Failure

This event was decomposed as shown in Figure 4.5-2. The major events in the decomposition event tree are discussed below.

Event 1: RCS Pressure During Core Damage (RCSPRESS)
EVNTRE Event 7

Five Branches

Lo Lo Pressure (< 140 psig)
Lo Hi Pressure (140 - 1400 psig)
High Pressure (1400 - 2335 psig)
Hi Hi Pressure (> 2335 psig)
PRES OTH

The branch taken under this event heading is determined based on the plant damage state characteristics.

Event 2: Mode of Induced Primary System Failure (RCSFAIL)
EVNTRE Event 13

Four Branches

No RCS Failure
Hot Leg Failure (Surge Line Failure)
SGTR (Steam Generator Tube Rupture)
BP/nISOL

Discussion:

This phenomenological event was specifically addressed by the in-vessel experts in the NUREG/CR-4551 study [Ref. 4.9-19]. In addition, Ginna specific hot leg and steam generator tube temperatures (and temperature histories) were determined from MAAP code calculations for SBO and other high RCS pressure sequences. These temperature histories were then input into a Larson Miller Parameter (LMP) Creep Rupture model to estimate the time of failure for the hot leg and steam generator tubes. The Larson Miller Parameter analysis is summarized in Refs. 4.9-20 and 4.9-21. These results basically confirm the probability estimates found in NUREG/CR-4551. The LMP analysis indicates that there is a high probability of induced hot leg failure if the RCS pressure remains elevated, at or above, the pressurizer PORV setpoint (2335 psig) during core damage. There is only a remote possibility of induced SGTRs under these conditions unless the secondary side of the steam generators is depressurized (such as by a stuck open safety or atmospheric relief valve) and there is severe wastage (> 50% wall thinning) of one of more steam generator tubes in the high temperature zone (i.e. hot leg side of the tubes near the tube sheet).

Based on the supporting results of the Ginna specific LMP analysis and considering the large uncertainties in estimating induced RCS failures it was judged that the NUREG/CR-4551 results for the Surry plant could be used to estimate induced RCS failure for Ginna. The following discussion summarizes the NUREG/CR-4551 estimates for induced hot leg failure.

Case A: Lo Lo and Lo Hi Pressure Sequences (< 1400 psig)

The NUREG-1150 In-vessel Expert's Panel did not consider temperature induced SGTR or hot-leg failure to be credible events for sequences with pressures below about 2000 psi [Ref. 4.9-19].

	Probability
No RCS Failure	1.
Hot Leg Failure	0.
SGTR	0.

Case B: Hi Hi Pressure Sequences (> 2335 psig)

For very high RCS pressures (equal to or greater than the pressurizer PORV setpoint pressure - 2335 psig) the NUREG-1150 In-vessel Expert's Panel estimated that temperature induced SGTR would be highly unlikely if there were no defective tubes in the steam generators. Since there are likely to be a number of defective tubes, however, the probability of temperature induced SGTR would be increased. The expert panel estimated that under these conditions induced SGTRs would still be very unlikely (probability of SGTR = .018)[Ref. 4.9-19]. However, they also estimated that hot leg or surge line failure would be likely (probability of hot leg failure = .72). Making the simplifying assumption that induced SGTR and hot leg failure are mutually exclusive results in the branch probabilities shown below.

	Probability
No RCS Failure	.262
Hot Leg Failure	.720
SGTR	.018

Case C: High Pressure Sequences (< 2335 and > 1400 psig)

For high pressure sequences (but with the RCS pressure less than pressurizer PORV setpoint pressure - 2335 psig) the NUREG-1150 In-vessel Expert's Panel estimated that temperature induced hot leg or surge line failure would be unlikely (probability of hot leg failure = .034)[Ref. 4.9-19]. The In-vessel Expert's Panel estimated that temperature induced SGTRs were not credible at pressures below the pressurizer PORV setpoint pressure.

	Probability
No RCS Failure	0.966
Hot Leg Failure	0.034
SGTR	0.000

Case D: Other Sequences

For containment bypass sequences and for sequences with loss of isolation, loss of containment integrity has already occurred and subsequent events which impact on containment failure are not considered relevant. Hence, the "BP/nISOL" branch is taken for all bypass and loss of isolation sequences.

4.5.2.2 Debris Cooled In-Vessel

Figure 4.5-3 shows the decomposition event tree for this event. The following describes the events associated with this decomposition.

Event 1: Status of In-vessel Injection (INVESSINJ)
EVNTRE Event 8

Seven Branches

REC ON
INJ ON
REC DEADHEAD
INJ DEADHEAD
REC RECOV
INJ RECOV
INJ FAIL

"REC ON" indicates that in-vessel cooling is on at the time of core damage and that both the injection and recirculation modes of cooling are available. "INJ ON" indicates that in-vessel cooling is on at the time of core damage and that only the injection mode of cooling is available. "REC DEADHEAD" indicates that in-vessel cooling is available in both injection and recirculation modes but the RCS pressure is above the threshold for coolant injection at core damage initiation. "INJ DEADHEAD" indicates that in-vessel cooling is available in the injection mode (only) and the RCS pressure is above the threshold for coolant injection at core damage initiation. "REC RECOV" indicates that in-vessel cooling is available in both injection and recirculation modes following offsite power recovery for SBO sequences. "INJ RECOV" indicates in-vessel cooling is available in the injection mode only following offsite power recovery for SBO sequences. "INJ FAIL" indicates in-vessel cooling is failed in the injection and recirculation modes. Note that in-vessel cooling recovery is only considered for SBO sequences.

Event 2: Mode of Induced Primary System Failure (RCSFAIL)
EVNTRE Event 13 (Discussed in Section 4.5.2.1)

Three Branches

Hot Leg Failure
No RCS Failure
STGR

For cases where an in-vessel core cooling system is available but the primary system pressure is elevated above the shutoff head of the high pressure (HP) or low pressure (LP) systems (Deadheaded) initiation of cooling can occur if the RCS pressure is reduced to below the shutoff head of the HP or LP systems. Induced hot leg or surge line failure will result in a large break in the RCS which will rapidly reduce the RCS pressure to below 140 psig allowing for LP or HP cooling. Rupture of one or two steam generator tubes late in time would not be expected to depressurize the RCS prior to core slump.

Event 3: Debris Cooled In-vessel (INVCOOL)
EVNTRE Event 16

Two Branches

Not Cooled
Cooled

This event assess the probability that the debris is cooled in-vessel and vessel rupture prevented. Note that in this analysis the in-vessel cooling systems must be available in both the injection and recirculation phases to assure long term in-vessel debris cooling.

Case A: In-vessel Cooling On

The success criteria for large break LOCA sequences requires the LP cooling system and the accumulators to operate to avoid core damage [Ref. 4.9-22]. For intermediate LOCAs. both HP and LP cooling must operate to prevent core damage [Ref. 4.9-22]. With only LP cooling available core damage is assumed but the potential for cooling the core and preventing gross core damage and vessel failure is significant. Breeding [Ref. 4.9-19] estimated that for these cases successful in-vessel cooling is likely (probability of in-vessel cooling = .95). This case applies to branch "REC ON" under Event Heading "Status of In-vessel Injection".

	Probability
Cooled	.95
Not Cooled	.05

Case B: In-vessel Cooling Available (but Deadheaded)

If the RCS pressure remains above the shutoff head of the LP system during the transient. the LP system may be available but not able to inject. Later in the transient an induced hot leg (or surge line) failure may cause the pressure to decrease low enough to allow injection. Successful initiation of the LP system may provide enough core cooling to prevent vessel failure. Breeding [Ref. 4.9-19] 1990 estimated that successful in-vessel cooling is less probable for this case than for cases where the LP cooling is available early (probability of in-vessel cooling = .90). This case applies to branch "REC DEADHEAD" under Event Heading "Status of In-vessel Injection".

	Probability
Cooled	.9
Not Cooled	.1

Case C: AC Power Recovery After Core Damage

For loss of AC power sequences, the potential exists for recovery of AC power prior to reactor vessel failure. If power is restored in sufficient time and the in-vessel cooling systems are available, then in-vessel debris cooling and prevention of reactor vessel failure are possible. Since the Level 1 analysis considered power recovery in the time period prior to core uncovery, the recovery period considered here is from the end of the power recovery period considered in the Level 1 analysis to core support plate failure and core slump. For the recovery cases considered in NUREG/CR-4551 [Ref. 4.9-19], the mean values for the probability of successful in-vessel debris cooling ranged from indeterminant to likely (0.5 < probability of in-vessel cooling ≤ 0.9]. A value midway between these two values has been selected for our point estimate value (0.7). This case applies to branch "REC RECOV" under Event Heading "Status of In-vessel Injection".

	Probability
Cooled	.7
Not Cooled	.3

Case D: In-vessel Injection Failed

For the case where in-vessel cooling is lost (either in the injection or recirculation modes) and not recovered, then vessel failure is certain. This case applies to branches "INJ ON", "INJ DEAHHEAD", "INJ RECOV" and "INJ FAIL" under Event Heading "Status of In-vessel Injection".

	Probability
Cooled	0.0
Not Cooled	1.0

Note that if the RWST is injected into containment, the cavity will be flooded and the reactor vessel will be partially submerged. No credit for the influence of heat transfer to the water covering the lower portion of the reactor vessel has been considered in the Ginna PRA.

4.5.2.3 Mode of Early Containment Failure

The DET discussed below (and shown in Figure 4.5-4) focuses on assessing the threat to containment integrity associated with DCH and related phenomena.

Event 1: RCS Pressure at Time of RPV Failure (PRES_VB)
EVNTRE Event 15

Five Branches

Lo Lo Pressure (< 140 psig)
Lo Hi Pressure (140 - 1400 psig)
High Pressure (1400 - 2335 psig)
Hi Hi Pressure (> 2335 psig)
PRES OTH

This event assesses whether the RPV pressure is elevated at vessel failure. If the RPV pressure is above about 150 psig, then removal of debris from the reactor cavity would be expected and the potential for DCH exists. If the pressure is below 150 psig then there were no identified credible processes which would challenge containment integrity at the time of vessel failure and early containment failure resulting from in-vessel steam explosions is the only mechanism considered for early containment failure.

For sequences in the HI HI, HIGH and LO HI pressure categories (NOT LO LO branch in Figure 4.5-4) HPME and DCH are considered to potentially represent a threat to containment integrity. Bypass sequences are assigned to the "PRES OTH" category and early containment failure is not considered for these sequences.

This event is dependent on EVNTRE PDS Event 7 - RCS Pressure at Core Damage and EVNTRE Event 13 - Mode of Induced RCS Failure. If induced hot leg failure occurs then it is assumed that the RCS depressurizes to the LO LO pressure regime.

Event 2: In-vessel Steam Explosion Fails Containment (ALPHA)
EVNTRE Event 19

Two Branches

No Alpha CF
Alpha CF

This event is dependent on EVNTRE Event 15 - RCS Pressure at Time of RPV Failure (PRES_VB)

Case A: Low Pressure Sequences

Steam explosions have been observed to occur much more readily at low pressures than at elevated pressures. The mean value for the probability of an in-vessel steam explosion failing containment reported in NUREG-4551 [Ref. 4.9-19] is .008. The consensus of the Steam Explosion Review Group (SERG) experts was that the occurrence of a steam explosion of sufficient energy to lead to alpha mode containment failures was of low probability [Ref. 4.9-14]. The best estimate subjective probabilities of 7 of the 10 SERG experts (who provided numerical estimates) were less than 10^{-3} for the occurrence of an ALPHA mode failure. Based on the SERG results, it judged that 10^{-3} is appropriate as a best estimate probability for ALPHA mode failures under low pressure conditions.

	Probability
No Alpha CF	.999
Alpha CF	.001

Case B: High Pressure Sequences

For high RCS pressure sequences, the Alpha mode containment failure probability was decreased by one order of magnitude below the low pressure estimate. The SERG experts indicated that Alpha mode failures were much less likely under high pressure conditions. Consequently, 10^{-4} is judged to be the best estimate probability for Alpha mode failures under high pressure conditions.

	Probability
No Alpha CF	.9999
Alpha CF	.0001

Event 3: Containment Atmosphere Inert (INERT)
EVNTRE Event 21

This event assesses whether the containment atmosphere is inert to hydrogen burns at the time of vessel failure. The containment steam concentration will only be sufficiently high to inert the containment atmosphere to hydrogen burns if containment heat removal is unavailable. Hence, only sequences with failure of the containment fan coolers and containment sprays or SBO sequences with failure to recover AC power prior to vessel failure will be inerted.

This event is dependent on the following EVNTRE PDS Events: 9 - Containment Fan Coolers, 10 - Containment Spray Status, 5 - Station Blackout and 6 - Power Recovery.

Event 4: Mass Debris Expelled Early (M_DEBRIS)
EVNTRE Event 22

This event determines the mass of molten debris (fraction of total core debris mass) which is expelled from the reactor vessel at vessel failure.

This issue was addressed by the In-vessel Issues experts panel [Ref. 4.9-23]. The probability distributions for core fraction ejected at vessel failure (for PWRs) provided by each of the experts and the aggregate distribution are shown in Figure 4.5-8. For the Ginna PRA the aggregate distribution was discretized resulting in the following branch probabilities:

	Probability
0 - 20% Core Mass	.25
20 - 40%	.50
40 - 60%	.25

Event 5: Fraction Debris Involved in DCH (DCH_FRACT)
EVNTRE Event 23

Two distinct mechanisms are believed to be involved in debris dispersal from the cavity. The debris may be dispersed by a wave-like film displacement mechanism, or may be entrained by the shearing off of debris from the debris surface and the formation of liquid debris particles which are transported by the gas flow. Debris which is dispersed from the cavity by a wave-like film mechanism would not be expected to participate in DCH heating of the containment atmosphere.

Observations of test results conducted at Argonne National Laboratory indicate the dispersal process involves "a progression of hydrodynamic phenomena including crater formation due to jet impingement, radial wave motion and growth, sputtering and transport of liquid droplets, liquid layer formation on the far end of the inclined tunnel shaft as a result of droplet impaction and recombination (for a Zion like tunnel configuration with an inclined shaft at the end of the instrument tunnel), fluidization of liquid remaining in the cavity, removal of fluidized liquid droplets remaining in the cavity, and removal of the remaining liquid layer in the shaft" [Ref. 4.9-24].

The Ginna cavity design does not have an inclined shaft at the end of the instrument tunnel. The principle release pathways for debris from the Ginna cavity are the cavity sump access and ventilation penetrations in the ceiling of the cavity near the far end of the tunnel and the annulus between the reactor vessel and the biological shield wall. The design of the Ginna cavity is shown in Figures 4.1-2 and 4.1-3. For this geometry the initial dispersal process would be expected to involve wave-like film movement and entrained particles initially transported from the cylindrical portion of the cavity into the tunnel which would impact against the wall on the far end of the cavity. Subsequently, the debris would be transported out of the openings in the tunnel ceiling into the lower containment compartment above of the cavity.

The sweepout threshold pressure is a function of the failure area at vessel breach and the cavity configuration. For typical cavity configurations, a pressure below about 150-300 psi [Refs. 4.9-10, 4.9-33 and 4.9-34] will generally preclude entrainment of significant quantities of core debris out of the reactor cavity.

The Ginna cavity is generally similar in geometrical details to the Ringhals 2 design. For the Ringhals cavity design, scale model entrainment tests (Figure 4.5-9) were conducted using corium simulants [Ref. 4.9-25]. For the Ringhals 2 configuration the following dispersal behavior was observed:

1. Liquid was pushed away from the floor area beneath the reactor vessel.

2. A standing wave was formed where the hydrodynamic pressure head of the gas was balanced by the hydrostatic head of the liquid.

3. Breakup of the liquid occurs mainly in the region of the standing wave.

4. Liquid particles, which have a large, vertical upward velocity component, leave the cavity via the ceiling opening.

Extrapolating these results to full size conditions using simple considerations based on the local Kutateladze criterion and findings from other debris dispersion studies Frid [Ref. 4.9-25] drew the following conclusions:

1. Significant debris dispersion from the cavity ceiling opening is possible in Ringhals 2 for primary system pressures on the order of 2 to 3 MPa (150 to 300 psia).

2. Complete core dispersion from the cavity is to be expected at primary system pressures on the order of 5 MPa (750 psia).

Based on these results the following assumption has been made regarding entrainment from the Ginna cavity:

> For high pressure sequences (RCS pressure > 140 psig) complete debris removal from the reactor cavity is assumed.

Results from the Sandia Integral Effects Tests (IET) [Ref. 4.9-26] indicate that a large fraction of the metals in the simulant debris in these tests were oxidized during expulsion from the cavity. Generally, debris metal oxidation was 70 to 80% complete. These results suggest that debris fragmentation was extensive during the dispersal process (resulting in a large increase in the interfacial surface area between debris and gas).

Based on these results the branch probabilities for fraction of the debris released from the vessel at vessel failure which is fragmented and entrained out of the cavity as particles are:

	Probability
HI - 100%	:5
LO - 50%	.5

Because of the uncertainties in the fraction of the dispersed debris entrained as particles or removed by a wave-like film dispersed mechanism and since these branch values bound the IET test results equal probabilities are assigned to each branch.

Event 6: Fraction of Debris Entrained Outside Lower Compartment - (DIS_FRACT)
EVNTRE Event 24

This event assesses the fraction of the debris (which has been entrained from the cavity as particles) which is transported by the gas flows into regions outside the lower compartment. If little particulated debris is transported into the main containment gas volume above the operating deck then the potential pressure rise from DCH will be limited to values well below that required to threaten containment integrity. It is only when a significant quantity of debris is transported into the main containment gas regions that DCH pressures pose a threat to containment integrity.

Particulated debris that is entrained from the cavity can be transported to the main containment regions by gas convection. Debris removal from the gas will occur due to gravitational settling and impaction of the debris particles on surfaces during transport. Hence, the ability to transport large amounts of particulate debris into the main containment regions will be determined largely by the characteristics of the flow pathways between the cavity and the main containment gas volumes. Generally speaking, limited flow areas between compartments and complicated, convoluted pathways enhance debris removal and limit the mass of debris transported into the main containment regions.

Detailed scale model integral effects experiments of the Zion containment have been conducted at 1/10 and 1/40 scale at Sandia and Argonne National Laboratories, respectively, to assess the fraction of core debris that is transported into the main containment region above the operating deck under high pressure conditions. In these tests 4 to 18% of the debris has been observed to transport to the main containment region in the ANL 1/40 scale tests and from 9 to 14% in the Sandia 1/10 scale experiments [Ref. 4.9-27].

As a result of the compartmentalization of the lower containment in the vicinity of the openings in the ceiling of the cavity tunnel in the Ginna containment, it is expected that very little of the debris entrained from the cavity through these openings will be transported to the containment regions above the operating deck. The principal pathway for debris transport into the upper containment regions is judged to be through the annular gap between the reactor vessel and the biological shield walls.

The following discussion describes how the magnitude and probabilities were estimated for transport of debris into the upper containment. The fraction of the debris that is entrained from the cavity which is transported as particles into the upper containment gas region (F_{uc}) is estimated using the following four factor formula:

$$F_{uc}=F_1F_2[F_3+(1-F_3)F_4]$$

where:

F_1 = The fraction of debris entrained from the cavity that enters the RV annulus

F_2 = The fraction of the debris in the flow entering the annulus which exits upwards past the RV flange as opposed to flowing out through the hot leg/cold leg cutouts in the biological shield walls

F_3 = The fraction of the debris which flows out of the annulus past the flange which does not impact upon the lower side of the missile shield

F_4 = The fraction of the debris which impacts upon the missile shield which is re-entrained into the gas stream

For terms F_2, F_3 and F_4 best estimate and upper and lower estimates were developed. For term F_1 only a best estimate was made. F_1 was estimated based on the minimum flow areas out the tunnel pathway and out the annulus pathway. The minimum flow area out the tunnel is 21.25 ft^2 [Ref. 4.9-1]. The minimum flow area through the annulus is 8.427 ft^2 [Ref. 4.9-1]. Hence, the fraction of the cavity gas (and entrained debris) flow going up the annulus can be estimated as:

$$F_1=\frac{8.427}{8.427+21.25}=.28$$

The fraction of the debris which enters the annulus which is transported past the RV flange into the refueling pool region is estimated as follows:

It can be expected that some fraction of the debris particles which enter the annulus will be removed from the gas stream exiting past the annulus as a result of the gas flow splitting (between the flow exiting past the RV flange and exiting out the coolant loop cutouts) and as a result of the debris impacting upon the coolant loop piping or vessel nozzles. The upper limit ($F_{2\text{-}max}$ = 1.) is estimated assuming that none of the debris impacts upon the piping or nozzles and none of the debris is able to make the 90 degree turn with the gas flow and enter the piping cutouts. Hence, all of the debris which enters the annulus is assumed to exit the top of the annulus past the flange.

The lower limit ($F_{2\text{-min}}$) assumes that the debris particles can completely follow the gas flow (i.e. the debris particles are able to make the 90 degree turn with the gas which flows out the cutouts in the biological shield). The lower limit for F_2 is estimated based on the relative gas flow area (past the flange and out the cutouts). The flow area past the RV flange is 7.54 ft^2 and the flow area out the cutouts is 13.98 ft^2 [Ref. 4.9-1].

$$F_{2\text{-min}} = \frac{7.54}{7.54+13.98} = .35$$

The best estimate value for F_2 is estimated based on the fraction of the annulus flow area which is blocked by the coolant loop piping and vessel nozzles. At the elevation of the nozzles approximately 50% of the flow area is blocked by the piping/nozzles [Ref. 4.9-15]. Assuming that the debris in the gas flow stream which must divert around these obstructions would either impact upon the piping or, once diverted, would flow out the cutouts with the majority of the gas flow suggests the best estimate value ($F_{2\text{-be}}$) of .5.

The debris which exits past the vessel flange may impact upon the missile shield above the RV control rod drive assembly. The missile shield is located approximately 26 feet above the floor of the refueling pool and spans the narrow dimension of the refueling pool cavity (approximately 21' 6 " x 13' 6 ") [Ref. 4.9-15]. The smallest dimension of the missile shield (13' 6") is approximately the same as the diameter of the RV. As the gas/debris stream flows past the flange the jet would be expected to expand outward in a conical fashion. Depending on the spread of the jet the fraction of the debris stream which impacts on the missile shield will vary. The maximum impaction fraction would occur for a very narrow jet. Under these conditions upwards of 100% of the debris could impact upon the missile shield. With more dispersive jets (i.e. greater angle of dispersion) the impaction fraction would drop to a minimum of about 50%. Based on these considerations the best estimate and upper and lower bounds for F_3 are shown below.

$F_{3\text{-min}} = .1$
$F_{3\text{-be}} = .3$
$F_{3\text{-max}} = .5$

For the debris which impacts the missile shield it can be expected that some fraction of this debris will rebound or be re-entrained as droplets into the gas stream. This is a very difficult parameter to estimate; consequently, a wide span between the upper and lower bounds has been assumed. The estimated values for F_4 are shown below.

$F_{4\text{-min}} = .25$
$F_{4\text{-be}} = .5$
$F_{4\text{-max}} = .75$

Values for parameter F_{uc} are estimated using the upper bound, best estimate and lower bound values for F_1 - F_4 using the equation above. The calculated values for F_{uc} are shown below along with the estimated probability for each estimate (the upper and lower bounds are each assigned a probability of 0.1).

	Probability
$F_{uc\text{-}min} = .03$	0.1
$F_{uc\text{-}be} = .09$	0.8
$F_{uc\text{-}max} = .25$	0.1

These estimates are consistent with the IET test results discussed above for the Zion cavity configuration.

Event 7 Fraction Debris Metal Reacted (MET_REAC)

There are no branches under this event. The extent of metal oxidation is considered to be strongly dependent on the fraction of debris which is dispersed from the cavity as fragmented particles which is considered under event "Fraction Debris Involved in DCH" above. The fraction of metal oxidized is set equal to the value of "Fraction Debris Involved in DCH".

Event 8 Hydrogen Burn (H2_BURN)
EVNTRE Event 26

The molten debris particles associated with a large DCH event can provide a widely distributed ignition source and can greatly increase the containment gas temperature such that widespread burning or recombination of hydrogen may result. The HPME event also can result in the production of additional hydrogen by extensive metal water reaction between the high velocity steam and the core debris in the cavity during the entrainment and fragmentation process. The metal water reaction also produces additional energy which is available to heat the containment atmosphere.

To evaluate the impact of hydrogen combustion on the containment pressurization associated with a DCH event, two cases are considered in the event tree. In one case hydrogen combustion is allowed to occur as predicted by the hydrogen burn model contained in the MAAP code (which will generally initiate a hydrogen burn in a region when the hydrogen concentration is near the global flammability limit of 8% or, if the region gas temperatures exceeds the auto-ignition threshold of 983○K). This is termed the "STANDARD" burn in the tree. The other case considered is to assume that the DCH event results in essentially complete combustion of all the hydrogen in the containment when a DCH event occurs. This branch on the tree is labeled the Unconditional Hydrogen Burn (UCHB). These two cases are judged to represent lower and upper bounds on the amount of hydrogen combustion that would occur in association with a DCH event.

A review of the Sandia Integral Effects Experiments [Ref. 4.9-26] indicates the following hydrogen combustion behavior:

Combustion of essentially all the hydrogen produced by metal oxidation during the blowdown was observed to occur for all tests where the "containment" atmosphere was "reactive". A reactive atmosphere in these tests was characterized by an oxygen mole fraction greater than 5% and where the atmosphere was not inerted by a diluent gas (in IET Test 5 the containment atmosphere was inerted with a 76% mole fraction of CO_2). For tests where the containment was not reactive, very little hydrogen combustion was observed.

For all of the IET tests, very little of the hydrogen which was released into the containment vessel prior to the test was observed to burn during the DCH event. These observations lead to the following approach for the treatment of hydrogen combustion during DCH:

For sequences where the containment atmosphere is inerted at the time of vessel failure (steam concentration above about 55%), there is little likelihood of significant hydrogen combustion. MAAP will generally not predict a hydrogen burn unless the auto-ignition temperature is exceeded under these conditions.

The atmosphere in the containment will generally be steam inerted only for those sequences where containment heat removal has failed. Hence, SBO sequences and sequences with failure of containment heat removal are probably steam inerted.

For sequences where the containment atmosphere is not inerted, burning of the hydrogen produced during the blowdown (as it enters the main containment region as a jet) is likely, however little burning of the pre-existing hydrogen in the containment atmosphere would be expected. The MAAP code does not contain a model for burning of hydrogen as a diffusion flame as it enters the main containment compartment as a jet. Under these conditions the MAAP standard hydrogen burn model will probably underpredict hydrogen burning, while forcing a global burn (UCHB) will probably overpredict hydrogen combustion. Consequently, under conditions where the containment atmosphere is not inerted it is judged that a complete global burn is possible, but not likely, and a probability of 0.1 was assumed for the UCHB branch.

Event 9 Peak Containment Pressure (PEK_PRES)

This event determines the peak containment pressure associated with a DCH event based on the conditions defined on the sequence pathway leading to this event. This event has no branches and simply summarizes the calculated pressures resulting from MAAP code analysis [Ref. 4.9-28]. The process for defining these pressures is summarized below.

The MAAP code allows DCH pressurization to be modelled in a parametric fashion. The MAAP code DCH model treats heat transfer from the debris particles to the gas in a containment region as an equilibrium process (i.e. heat transfer from the debris to the region atmosphere is allowed to occur until the atmosphere comes into temperature equilibrium with the debris particles). This assumption, which neglects the rate limiting mechanisms in the heat transfer process is conservative. Unoxidized metals in the debris are assumed to completely oxidize (assuming a sufficient supply of steam and oxygen in the region atmosphere) and the chemical reaction energy is added to the debris.

The mass of debris which participates in the DCH heating is determined by the mass of debris dispersed from the cavity times an input fragmentation parameter (FCMDCH) which defines the fraction of the dispersed debris which is fragmented to small particles during the entrainment process. Finally, an input parameter (FCMDA) allows the user to specify the fraction of the entrained debris which is transported to the main containment region above the operating deck with the remaining fraction (1 - FCMDA) being transported to the lower containment region near the exit of the cavity tunnel.

A series of parametric DCH sensitivity calculations were performed for the Ginna PRA [Ref. 4.9-28]. These are summarized in Table 4.5-2. These runs varied a number of parameters considered important for assessing the DCH peak pressure including:

The Debris Fragmentation Fraction (FCMDCH)

The Debris Transport Parameter (FCMDA)

The Type of Hydrogen Burn at Vessel Failure

To assess the impact of differing hydrogen burn assumptions two parametric variations were considered. For one set of runs the MAAP code default hydrogen burn model was allowed to define the conditions of when burns would occur and the extent of the burns. For the other set of runs a complete global burn (UCHB) was forced to occur in conjunction with the DCH event.

The range of peak pressures shown on the DET (for each pathway) represent the uncertainty associated with the entrainment time. As shown on Table 4.5-2 an 8 to 11 psi difference in the peak pressures results from different assumptions regarding the entrainment time parameter (compare MAAP case SBO08 with SBO17 and SBO09 with SBO14 on Table 4.5-2).

Event 10 Early Containment Failure (CF_EARLY)
EVNTRE Event 28

This event assesses whether early containment failure occurs and the mode of containment failure. Containment failure resulting from in-vessel steam explosions is assessed in a prior event. Sequences with RCS pressures below the threshold pressure for significant entrainment from the reactor cavity (LO LO) are not expected to result in containment failure since hydrogen burns alone will not exceed the containment internal pressure capacity [Ref. 4.9-15]. Similarly, peak containment pressures for sequences with the containment atmosphere inert are not expected to exceed the containment capacity since the DCH thermal loads (without hydrogen combustion) are insufficient to threaten containment integrity. Sequences with peak pressures below 128 psia (1st percentile pressure on the containment fragility curve) are also assumed not to threaten containment integrity and subsequent branching in the DET is suppressed for these sequence pathways.

For sequences pathways with peak pressures in excess of 128 psia this event assesses the probability of containment failure given the peak DCH pressures shown in the prior event. The peak DCH pressures shown on the DET (high and low bounds) were compared with the containment fragility curve (Figure 4.4-3) to assess the probability of containment failure (the failure probabilities for the high and low bounds were equally weighted). Given that containment failure is predicted, the mode of containment failure (liner or global structural failure) was determined from Figure 4.4-5. Figure 4.4-5 shows the conditional probabilities of liner failure and global structural failure as a function of peak containment pressure for a fast containment pressurization event.

4.5.2.4 Containment Liner Meltthrough

The DET for Containment Liner Meltthrough is shown in Figure 4.5-5. The event headings evaluated in this tree are discussed below.

Event 1: RCS Pressure at Time of RPV Failure (PRES_VB)
EVNTRE Event 15

Five Branches

- Lo Lo Pressure (< 140 psig)
- Lo Hi Pressure (140 - 1400 psig)
- High Pressure (1400 - 2335 psig)
- Hi Hi Pressure (> 2335 psig)
- PRES OTH

This event assesses whether the RPV pressure is elevated at vessel failure. If the RPV pressure is above about 150 psig then removal of debris from the reactor cavity would be expected and the potential for liner meltthrough exists. If the pressure is below about 150 psig then little debris would be expected to be dispersed from the reactor cavity.

Sequences in the HI HI, HIGH and LO HI (NOT LO LO) categories may potentially have significant dispersal of debris from the cavity at vessel failure and liner meltthrough may be a possible threat to containment integrity. Bypass sequences are assigned to the "PRES OTH" category and liner meltthrough is not considered.

This event is dependent on EVNTRE PDS Event 7 - RCS Pressure at Core Damage and EVNTRE Event 13 - Mode of Induced RCS Failure. If induced hot leg failure occurs then it is assumed that the RCS depressurizes to the LO LO pressure regime.

Event 2: RWST Injected Early (E_RWST)
EVNTRE Event 20

This event assess whether the RWST is injected into containment prior to reactor vessel failure. The conditions under which the RWST is injected prior to RV failure are summarized below:

Case A: Large and Intermediate LOCAs with Containment Sprays

For large or intermediate LOCAs the pressure rise in containment will be sufficiently large to initiate the containment spray system (setpoint pressure = 28 psig) soon after accident initiation. Consequently, if the sprays are available they will initiate and deliver the contents of the RWST into containment.

Case B: Sequences with Failed Containment Fan Coolers (CFCs)

For sequences with the failure of the CFCs the pressure rise in containment will also exceed the pressure setpoint for spray actuation.

Case C: In-vessel Injection On

For sequences with in-vessel injection on during core damage the RWST will be injected prior to reactor vessel failure.

Case D: Injection Deadheaded and Induced Hot Leg Failure

For sequences with in-vessel injection available but deadheaded an induced hot leg failure will rapidly reduce RCS pressure and allow in-vessel injection prior to vessel failure.

Case E: SBO with Power Recovery After Core Damage But Prior to RV Failure

For SBO sequences with power recovery prior to vessel failure the RWST can be injected into containment by the in-vessel injection systems or by containment sprays if available.

This event is dependent on EVNTRE PDS Events 3 - Transient or LOCA Type, 5 - SBO, 6 - Power Recovery, 8 - Status of In-vessel Injection, 9 - Containment Fan Coolers, and 10 - Containment Spray Status.

Event 3: RWST Injected Late (L_RWST)
EVNTRE Event 30

This event assesses whether the RWST is injected into containment (soon) after reactor vessel failure. The conditions under which the RWST is injected after RV failure are summarized below.

Case A: Injection Deadheaded

For sequences with the in-vessel cooling systems available but deadheaded, RCS depressurization upon vessel lower head failure will allow the in-vessel cooling systems to inject the contents of the RWST into containment.

Case B: High Pressure Vessel Failure with Sprays Available

For sequences at elevated pressure at vessel failure and with containment spray injection available the containment pressure rise at vessel failure will result in actuation of the spray system.

This event is dependent on EVNTRE PDS Events 8 - Status of In-vessel Injection and 10 - Containment Spray Status.

Event 4: Containment Fan Coolers (CFC)
EVNTRE Event 9

This event assesses whether the fan coolers are available. If the fan coolers are available sufficient condensation of steam in the containment atmosphere will occur that the cavity will remain filled with water (water inventory released from the RCS and accumulators) and overflow onto the containment floor (even without injection of the RWST) thus providing cooling for the debris entrained from the reactor cavity [Ref. 4.9-15]. This event is PDS Parameter 9.

Event 5: Mass Debris Expelled Early (M_DEBRIS)
EVNTRE Event 22

This event determines the mass of molten debris (fraction of total core debris mass) which is expelled from the reactor vessel at vessel failure.

This issue was addressed by the In-vessel Issues experts panel [Ref. 4.9-23]. The probability distributions for core fraction ejected at vessel failure (for PWRs) provided by each of the experts and the aggregate distribution are shown in Figure 4.5-8. For the Ginna PRA the aggregate distribution was discretized resulting in the following branch probabilities:

	Probability
0 - 20% Core Mass	.25
20 - 40%	.50
40 - 60%	.25

Event 6: Fraction Debris Involved in DCH (DCH_FRACT)
EVNTRE Event 23

The branch probabilities for fraction of the debris released from the vessel at vessel failure which is fragmented and entrained out of the cavity as particles are:

	Probability
HI - 100%	.5
LO - 50%	.5

This event is discussed in detail in Section 4.5.2.3 (Mode of Early Containment Failure).

Event 7: Debris Depth Against Liner (D_DEPTH)
EVNTRE Event 32

This event assesses the possible depth of the debris in the vicinity of the containment wall in the area near the location of debris discharge from the reactor cavity.

No debris will be discharged from the reactor cavity unless the RCS pressure at vessel failure is above the threshold pressure for entrainment and dispersal (LO HI pressure regime or above). Given that the pressure is sufficiently high to disperse debris from the cavity then the depth of the debris near the liner will be determined by the mass of debris released from the vessel at vessel failure, the extent of debris fragmentation and dispersal from the cavity and the spread area of the debris on the floor of the basement of containment. Note that debris dispersal to the upper compartment is conservatively neglected in this analysis and that all debris dispersed from the reactor cavity is assumed to transport into the lower compartment outside of the cavity.

It is assumed that the debris that is dispersed from the reactor cavity will predominantly settle on the quadrant of the containment basement floor near the exit of the cavity instrument tunnel. With an inside radius of 52.5 ft [Ref. 4.9-1] the total geometrical area of the containment basement floor is 8659 ft^2 and of one quadrant of the floor 2165 ft^2. In the quadrant of the containment basement floor near the penetrations in the cavity tunnel ceiling are several major structures including:

- Refueling canal transfer tube/penetration - floor area ~ 400 ft^2
- Accumulator 1B - floor area ~ 80 ft^2
- Cavity/biological shield wall - floor area ~ 130 ft^2
- Miscellaneous structures - floor area ~ 100 ft^2

Hence the total free floor area in this quadrant is approximately 1455 ft^2. For calculating the debris depth, this is taken to be the best estimate spread area. However, the debris may not distribute uniformly across the floor in this quadrant and to estimate an upper bound on the debris depth it is assumed that the debris spreads to cover only one half of this area (i.e. 728 ft^2) with a probability of 0.5.

Table 4.5-3 summarizes the debris depths for various values for mass released from the vessel, fraction debris dispersed from the cavity and debris spread area. Note that the debris depth is a "collapsed depth" (i.e. no porosity) and the debris density was taken as 8678 kg/m^3 (See discussion in Section 4.5.2.5 - Ex-Vessel CCI).

Event 8: Containment Liner Meltthrough (LMT)
EVNTRE Event 33

This event assesses the probability of containment liner failure due to thermal attack by debris deposited near the liner. As Table 4.5-3 shows, the maximum depth of debris expected in the vicinity of the liner is approximately 5 cm and the maximum upwards heat flux required to cool the debris is less than 100 kw/m^2. Under these conditions, if water covers the debris then it is almost certain that the debris will be quenched and debris thermal attack on the liner will not result in liner failure. Consequently, for all cases where the RWST is injected into containment (either prior to, or at, vessel failure) liner integrity will not be threatened.

For sequences without RWST injection, there are sufficient inventories of water in the RCS (and accumulators) to fill the cavity and sumps and cover the floor of containment to a depth of approximately six inches [Ref. 4.9-15] as long as the containment fan coolers are operating to condense steam from the containment atmosphere. Hence, if the containment fan coolers are operating then the debris on the containment floor will be covered with water and liner integrity will not be threatened.

For sequences without RWST injection and with failure of the containment fan coolers, the water inventory on the containment floor will eventually boil away resulting in dryout of the debris on the containment floor. Heat removal from the debris then will be by radiation and convection to the containment atmosphere and conduction into the containment floor and adjacent structures.

The melting temperature of the steel liner is 1537 C (1810 K). However, as the temperature nears the steel melting temperature significant loss in liner strength will occur. Theofanous [Ref. 4.9-29] assumed liner thermal failure would occur at a temperature of 1500°C for a MARK-I containment. A more limiting temperature may be the ablation temperature of the concrete. The concrete melting point assumed for the Ginna basemat is 1313 C (1586 K) [Ref. 4.9-1]. Since the concrete melting temperature is significantly less than the steel melting temperature it was taken as the limiting temperature for defining liner thermal failure.

The core debris masses, volumes and conductivities are shown in Table 4.5-4. In this table the debris masses are from the MAAP input file [Ref. 4.9-1] and the densities and thermal conductivities are from the MAAP code [Ref. 4.9-30]. Note that 50% metal water reaction of the zirconium is assumed.

The temperature distribution in steady state, assuming a homogeneous one-dimensional debris mixture, is given by:

$$k\frac{\delta^2 T}{\delta x^2}+q_v=0$$

where:

k = debris thermal conductivity
q_v = volumetric heat generation rate

Assuming 1% decay power and assuming 15% of the decay heat are from volatile species which have been released from the debris in-vessel results in a total debris decay heat power of 13 MW. For a total debris volume of 7.5 m^3, this implies an average volumetric heat generation rate:

q_v = 1.73 MW/m^3

In a one-dimensional, flat geometry, integrating the above equation twice yields:

$$T=-\frac{q_v x^2}{2k}+C_1 x+C_2$$

If we conservatively assume that the bottom of the debris in contact with concrete is adiabatic, and impose the condition that the debris maximum temperature (at the bottom of the slab) be less than the concrete ablation temperature, we have as boundary conditions:

(Let X = 0 be the lower interface of the debris with the containment basement floor and X = X_s be the upper interface of the debris with a water pool or with the containment atmosphere)

T(X=0) = T_0 - Hence C_2 = T_0 °K

T'(X=0) = 0. (adiabatic surface) - Hence C_1 = 0

T(X=X_s) = T_s

The heat flux at the upper surface is:

$$q=q_v x_c=\frac{2k(T_o-T_s)}{X_c}$$

The volume fraction weighted debris conductivity calculated in Table 4.5-4 is 7.8 W/m-K (the control rod material conductivities are conservatively assumed to be the same as steel).

The debris conductivity calculated above is for a 100% theoretical density debris pool. With the incorporation of some porosity into the debris layer the effective conductivity would be reduced. The possible reduction in effective debris thermal conductivity is assessed parametrically by reducing the conductivity by 50% in the lower bound conductivity case described below.

Table 4.5-5 below shows the calculated debris upper surface temperature for various debris depths assuming the lower surface temperature is fixed at 1586 K for two values of the debris conductivity. This table indicates that the maximum ΔT across the debris is about 700°F for the maximum debris depth and minimum conductivity. This table indicates that debris internal conductivity is sufficient to remove decay heat without exceeding the limiting temperature of 1586 K.

The next step in the analysis is to determine if radiation and convection from the upper surface can remove the required heat fluxes.

Holman [Ref. 4.9-31] provides the following correlation for the Nusselt number under natural convection conditions for a heated upwards facing horizontal surface.

$$Nu = 0.14(PrGr)^{\frac{1}{3}}$$

Station Blackout (SBO) sequences are typical of sequences with both the RWST not injected into containment and with the fan coolers unavailable. MAAP calculations performed for SBO sequences indicate that the containment pressure following vessel failure is approximately 80 psi (MAAP calc. SBO00)[Ref. 4.9-32]. At this time the containment atmosphere temperature is 310 F and the steam mole fraction is 0.72. Using these conditions the following atmospheric properties were calculated (treating the containment atmosphere as 100% steam). Property data was calculated from correlations in the MAAP code [Ref. 4.9-30].

k	= thermal conductivity	= 0.031 W/m-K
μ	= dynamic viscosity	= 0.15E-04 kg/m-s
C_p	= specific heat	= 2325. J/kg-K
x	= characteristic length taken to be 1 m (note that the Nusselt number is not sensitive to the value chosen for x since x is taken to the 3rd power in the Grasholf number and the 1/3rd power in the Nusselt number correlation)	
β	= the volume coef. of expansion (ideal gas behavior assumed - $\beta = 1/T_g$)	
ρ	= density	= 2.9 kg/m^3

$$\alpha = thermal\ difussivity = \frac{\kappa}{\rho C_p} = 0.46E{-}05\ \frac{m}{s}$$

$$Pr = Prandtl\ Number = \frac{\mu}{\rho\alpha} = 1.11$$

$$Gr = Grashof\ Number = \frac{g\beta(T_s - T_o)x^3}{(\frac{\mu}{\rho})^2}$$

$$Nu = Nusselt\ Number = \frac{hx}{k}$$

Where,

h = convective heat transfer coefficient
T_o = containment atmosphere temperature = 310°F (427°K)

The radiation heat flux from the debris surface was calculated using the following expression for two parallel infinite plates:

$$q_{rad} = \frac{\sigma(T_s^4 - T_w^4)}{\frac{1}{\epsilon_d} + \frac{1}{\epsilon_w} - 1}$$

where:

σ = stephan boltzman constant = 5.669 $(10)^{-8}$ W/m^2-K

ε_d, ε_w = the emissivities of the debris surface and lower compartment walls = 0.85 [Ref. 4.9-1].

T_w = the lower compartment wall temperatures (assumed to be at the same temperature as the lower compartment gas)

Using the calculated surface temperature for the 5.5 cm deep debris layer with the nominal and lower bound debris thermal conductivities shown in Table 4.5-5 and calculating the convective and radiative heat fluxes results in:

For $T_s = 902.$ K (k = 3.9)

$h = 33$ w/m²-k
$q_{conv} = 16.$ KW/m²
$q_{rad} = 26.$ KW/m²
$q_{tot} = 42.$ KW/m²

For $T_s = 1244.$ (k = 7.8)

$h = 40$ w/m²-k
$q_{conv} = 32.$ KW/m²
$q_{rad} = 99.$ KW/m²
$q_{tot} = 131.$ KW/m²

Comparing the above results with the heat flux values in Table 4.5-5, it can be concluded that debris beds with depths of less than 2 cm do not represent a credible threat of liner thermal failure. Debris beds of between 2 and 4 cm are unlikely to result in containment failure and a probability of liner failure of 0.1 is judged to be appropriate for this range. Liner thermal failure in the 4 to 6 cm range is judged to be as likely as non-failure and a probability of 0.5 is assigned.

4.5.2.5 Type of Ex-Vessel CCI

This DET (shown in Figure 4.5-6) assesses the probability that the debris released from the reactor vessel is in a coolable configuration in the reactor cavity, and if not coolable, determines the type of core-concrete interactions (CCI) which would occur.

4.5.2.5.1 General Considerations

4.5.2.5.1.1 Volumetric Heat Generation Rate

The Ginna design power is 1520 MWt [Ref. 4.9-1]. At a decay heating level of 1% (decay heating at approximately 3 hours after shutdown) the total decay power is approximately 15. MW. Assuming that 15% of the decay heat is produced by noble gases and volatile fission products which would be released from the debris prior to reactor pressure vessel (RPV) failure results in 13. MW maximum decay heating in the core debris (assuming 100% of core mass is released into the reactor cavity and not dispersed out of the cavity).

The masses of the major structural materials in the Ginna core are shown in Table 4.5-4. The total debris volume (neglecting porosity) is 265 ft³ (7.5 m³) and the volumetric heating rate in the debris is therefore 1.73 MW/m³.

4.5.2.5.1.2 Debris Spread Areas

The total cavity floor area is 312 ft^2 (29. m^2). The floor areas outside the reactor cavity are sufficiently large that debris entrained out of the reactor cavity would be expected to solidify as a thin layer on the containment floor. Hence, debris concrete attack outside of the reactor cavity is not expected in the Ginna design except possibly under conditions when the RWST is not injected into containment and the containment fan coolers have failed (see discussion above under liner meltthrough failure).

4.5.2.5.1.3 Debris Depths

Assuming 100% of core debris (7.5 m^3) is spread over the total floor area of the reactor cavity (29 m^2) the depth of the debris, assuming 0% porosity, is 26 cm.

4.5.2.5.1.4 Debris Heat Fluxes

The upward heat flux required to remove the decay power (13 MW) is .45 MW/m^2 assuming the total core debris mass spreads to cover the entire reactor cavity floor area.

4.5.2.5.1.5 Reactor Cavity Sump

The 4.5 x 4.5 x 5 ft deep sump at the end of the instrument tunnel in the cavity has a volume of 101.3 ft^3 (2.87 m^3) and consequently can accommodate approximately 40% of the core debris volume (with no porosity) and approximately 20% of the total core volume (with a 50% void fraction). The total upward heat flux required to cool the debris with the sump completely filled with debris (no porosity) is:

$$5 \text{ ft} \times (.3048 \text{ m/ft}) \times 1.73 \text{ MW/m}^3 = 2.6 \text{ MW/m}^2$$

With a 50% porosity the heat flux is 1.3 MW/m^2.

4.5.2.5.2 Decomposition Event Tree for CCI

The Decomposition Event Tree developed to assess ex-vessel debris cooling for the Ginna PRA is shown in Figure 4.5-6. The events considered in this tree are discussed below.

Event 1 RCS Pressure at Time of RPV Failure (PRES_VB)
EVNTRE Event 15

The pressure in the reactor vessel (RV) at the time of vessel failure determines whether a high pressure melt ejection can occur. Prior studies [Refs. 4.9-10, 4.9-33, 4.9-34] suggest that for pressures in excess of about 150 to 300 psi the velocity of gases in the reactor cavity are sufficiently large to result in dispersal of core debris from the reactor cavity floor (either as a wave-like film or as fragmented particles).

This event was assessed previously and is described in Section 4.5.2.3 (Early Containment Failure).

Event 2 RWST Injected Early (E_RWST)
EVNTRE Event 20

This event separates sequences with little, or no, water in the reactor cavity at vessel failure from those with the reactor cavity flooded at vessel failure. A large depth of water in the cavity at vessel failure has the potential to fragment and quench the debris when it falls into the cavity either by hydrodynamic breakup of the debris stream or by the occurrence of steam explosions. A water pool in the reactor cavity is also necessary to assure that long term cooling of the debris can be maintained.

If the RWST has been injected (fully or partially) into containment prior to vessel failure then the reactor cavity will be flooded. Sequences with RWST injection include LOCAs with successful in-vessel injection and sequences with spray injection initiated prior to RPV failure.

This event was assessed previously and is described in Section 4.5.2.4 (Containment Liner Meltthrough).

Event 3 Mass Debris Expelled From RPV at RPV Failure (M_DEBRIS)
EVNTRE Event 22

This event assesses the mass of molten debris which is released from the RPV soon after RPV failure. For elevated pressures in the vessel at vessel failure some fraction of this debris would be expected to be dispersed out of the reactor cavity. For low pressure sequences it is expected that the debris would largely remain within the reactor cavity.

The debris mass ranges which are considered under this heading are:

	Mass Range
High	(40- 60% of core mass)
Int.	(20- 40%)
Low	(0 - 20%)

This event was assessed previously and is described in Section 4.5.2.3 (Early Containment Failure).

Event 4 Fraction Debris Involved in DCH (DCHFRACT)
EVNTRE Event 23

This event assesses the fraction of the debris expelled from the reactor vessel which is dispersed from the reactor cavity at the time of vessel failure. Hence, this event is important to the determination of the mass of debris released into the cavity at vessel failure.

This event was assessed previously and is described in Section 4.5.2.3 (Early Containment Failure).

Event 5 Steam Explosion Disperses Debris (SE)
EVNTRE Event 34

For situation where the core debris falls into water in the reactor cavity there is the potential for steam explosions to occur and for the debris to be fragmented and dispersed.

Given that a "significant" steam explosion occurs, it is expected that the debris would be fragmented and dispersed throughout the reactor cavity. For situations where steam explosions do not occur, the possibility of debris fragmentation is considered to be less likely.

The debris particle size is a critical parameter in assessing the coolability of debris beds (see discussion below). For debris sizes in excess of about 1 mm, the debris beds are most probably coolable over a wide range of debris depths. Debris particle sizes have been measured in numerous steam explosion experiments. Generally, for highly energetic steam explosions the mean particle size is 1 mm or less [Ref. 4.9-35]. For energetic steam explosions the characteristic particle size appears to be a function of the coolant to debris mass ratio. For mild steam explosions (low measurable work output) the mean debris size is greater than 1 mm.

In NUREG/CR-4551 [Ref. 4.9-19], Sandia estimated the likelihood that steam explosions would occur under low pressure conditions to be 0.86 based on results of numerous experiments which have been conducted. However, not all of these steam explosions are expected to be "significant". A "significant" steam explosion was defined in NUREG/CR-4551 (as regards ex-vessel debris coolability) as one which would fragment the debris and lead to a coolable debris bed, or which would determine the amount of debris involved in CCI. NUREG/CR-4551 estimated, based on the current state of knowledge, that a probability of about 0.5 was appropriate for the occurrence of a significant steam explosion given the occurrence of any steam explosion.

Given that a significant ex-vessel steam explosion occurred NUREG/CR-4551 estimated (for the Surry cavity) that there was a probability of 0.5 that a significant quantity of the core debris was ejected from the reactor cavity by the steam explosion. NUREG/CR-4551 estimated that an ex-vessel steam explosion could also eject a significant portion of the core debris from the pedestal cavity for the MARK III BWR. In the analysis for Ginna it was conservatively assumed that none of the debris involved in a steam explosion is ejected from the reactor cavity for the purpose of estimating the debris bed heat loads.

Based on the considerations presented above and analysis performed for the Ginna plant [Ref. 4.9-15] the probability that a significant steam explosion occurs which spreads the debris throughout the reactor cavity and results in the formation of a debris bed configuration which is favorable to cooling is estimated to be 0.43 (0.86 x 0.5) for sequences with the cavity flooded prior to reactor vessel failure.

Event 6 Depth of Debris in Sump (D_SUMP)
EVNTRE Event 36

The sump in the reactor cavity tunnel is considered to be the critical design feature with regard to coolability of the debris ex-vessel. Without the sump the average depth of the debris in the cavity would be 26 cm (assuming no porosity) and the required upward heat flux to remove decay heat would be 450 kw/m^2 (assuming 100% of the core has slumped into the cavity). Under these conditions coolability of the debris would be reasonably likely.

The 5 ft deep sump, if filled (or partially filled) with debris, represents a less favorable geometry for cooling the debris. In addition, the thickness of the concrete basemat under the sump is only 1.5 ft compared with 4 ft elsewhere in the cavity.

This event assesses the extent of spreading of the debris (away from the reactor vessel), the mass of debris which might be expected to enter the sump and ultimately the depth of the debris in the sump.

Three branches are considered for this event:

Sump Full - This branch implies that the sump has been filled (or nearly filled) with debris. The debris is assumed to have a porosity fraction ranging from 0% to 50%. Hence, the mass of debris in the sump can range from 27369 lbm (12440 kg) to 54737 lbm (24881 kg) and the upward heat flux necessary to remove decay heat ranges from 1.3 to 2.6 MW/m^2.

Part. Full - This branch implies that the sump has been partially filled (approximately one-quarter to one-half filled) with debris. As above, the debris may have a porosity ranging from 0% to 50%. Hence, the mass of debris in the sump can range from 6842 lbm (3110 kg) to 27369 lbm (12440 kg) and the upward heat flux necessary to remove decay heat ranges from 0.33 MW/m^2 to 1.3 MW /m^2.

Nominal - This branch implies that the debris depth in the sump is approximately the same as the depth of debris elsewhere in the reactor cavity. That is, there has been little or no preferential movement of debris into the sump (sump less than one quarter filled).

LO LO Pressure Sequences

CAVITY DRY

For low pressure sequences with the lower cavity dry at vessel failure the debris would be expected to spread out and cover the entire floor of the cavity. Under these conditions it would be expected that the sump would be filled to a substantial depth as the liquid debris flows into the sump. Even for a small initial release of debris from the reactor vessel (20% of total core mass) and assuming 50% of this debris enters the sump the depth of debris in the sump would be 1.3 ft (40 cm) and the required heat flux to cool the debris would be 700 KW/m^2.

As discussed later this heat load is well above the upward heat flux considered credible for cooling the debris initially in a liquid pool configuration. Hence for all low pressure sequences where the cavity is dry (or nearly dry) at the time of reactor vessel failure the debris is considered to not be coolable (even if water is added to the cavity soon after vessel failure).

CAVITY FLOODED - STEAM EXPLOSION(S)

For sequences with the cavity flooded at RPV failure the following behavior could be expected. If significant steam explosions occur during the initial debris pour (at vessel failure) then it can be expected that the debris participating in the steam explosion will be dispersed throughout the reactor cavity. Under these conditions more or less uniform dispersion of the debris particles throughout the reactor cavity could be expected. Hence, for cases where significant steam explosions occur the following branch probabilities are estimated:

40-60% Debris Released From RV at Vessel Failure

	Probability
SUMP FULL -	.01
PART FULL -	.09
NOMINAL -	.90

20-40% Debris Released From RV at Vessel Failure

	Probability
SUMP FULL -	.005
PART FULL -	.045
NOMINAL -	.95

0-20% Debris Released From RV at Vessel Failure

	Probability
SUMP FULL -	0.
PART FULL -	.015
NOMINAL -	.985

CAVITY FLOODED - NO STEAM EXPLOSION(S)

For sequences where steam explosions do not occur in the reactor cavity then the fraction of the initial debris stream which does not fragment and quench would likely form a coherent liquid layer under the water pool which would flow outward from the cylindrical portion of the cavity into the cavity tunnel. Freezing and crust formation on the upper debris pool surface and at the leading edge would act to inhibit free flow of the debris.

An empirical dimensional correlation of simulant material (lead - water) spreading experiments [Ref. 4.9-36] correlates the debris depth to the debris volume released, the water pool depth, the water subcooling and the debris initial superheat.

$$t=0.03V^{\frac{1}{6}}\left[\frac{H\,h_{fg}}{h_{fs}}\right]^{\frac{1}{2}}$$

where: t = the debris thickness
V = the debris volume
H = the water depth
h_{fs}= the effective heat of solidification of the debris (heat of fusion plus superheat enthalpy)
h_{fg}= the effective heat of vaporization of the water (latent heat of vaporization plus subcooling enthalpy)

The above correlation can be rearranged to solve for spread area using

$$A=\frac{V}{t}$$

$$A=\frac{V^{\frac{5}{6}}}{0.03}\left[\frac{h_{fs}}{H\,h_{fg}}\right]^{\frac{1}{2}}$$

For a debris superheat of 100 K and saturated water this correlation reduces to:

$$A=12.1\left[\frac{V^{\frac{5}{6}}}{H^{\frac{1}{2}}}\right]$$

This correlation yields the spread areas for Ginna as a function of debris mass for a water depth of 11.5 ft (3.5 m) (the distance from the bottom of the reactor vessel lower head to the cavity floor) shown in Table 4.5-6.

F. Moody has developed a simple model to estimate debris spreading in the presence of a water pool [Ref. 4.9-37]. This model calculates the debris spread radius as a function of the debris pour rate, debris superheat, water subcooling and heat transfer coefficient at the debris water interface.

$$r_f=\left[\frac{Q_0\rho C_v}{\pi H}\frac{(T_i-T_f)}{(T_f-T_w)}\right]^{\frac{1}{2}}$$

where:

r_f = final debris spread radius
Q_o = debris volumetric pour rate
ρ = debris density
C_v = debris specific heat
T_i = initial debris temperature
T_f = debris freezing temperature (2500 K)
H = enhanced film boiling coefficient (400 W/m^2-K)
T_w = water temperature

The debris heat capacities (at 2501 °K) from the MAAP code (USOLID Routine) are:

UO_2	491	J/kg-°K
Zr	356	
ZrO_2	645	
Steel	797	

Using the debris composition listed in Table 4.5-4 and neglecting the control materials the debris mixture heat capacity is:

$$C_{v-ave}=\frac{(47955)(491)+(5892)(356)+(7959)(645)+(2027)(797)}{63832}=507\frac{J}{kg-K}$$

Assuming gravity driven flow, the velocity of debris exiting the reactor vessel can be calculated assuming Bernoulli flow:

$$\frac{1}{2}v_1^2=g(h_1+t)$$

$$v_1=\sqrt{2g(h_1+t)}$$

where h_1 = the debris depth in the reactor vessel
t = the vessel lower head thickness

The mass flow through breach is then:

$$W=\rho A_1 v_1$$

where the area of the vessel breach

$$A_1=\pi\frac{d^2}{4}$$

increases during the debris pour due to ablation. Using the vessel penetration ablation model incorporated into the MAAP code the vessel breach diameter was calculated to increase from 4 cm at the start of the gravity pour to 18, 26 and 31 cm at the completion of the pour for pours of 10%, 30% and 50% of the total core mass.

In these three calculations the average debris mass flow rate was calculated and is shown in Table 4.5-7.

Table 4.5-7 shows the predicted spread radii for an initial debris temperature of 2600 K (100 K superheat) and a water temperature of 373 K using the Moody model.

Note the following dimensional features of the reactor cavity. The cylindrical portion of the reactor cavity has a radius of 6.54 ft (2 m) and area of 134.4 ft^2 (12.5 m^2). The distance from the centerline of the reactor vessel to the nearest edge of the cavity sump is 25.7 ft (7.8 m). The total area of the cavity is 312 ft^2 (29 m^2). Comparing the predictions of the two spreading models with the above dimensions suggests the following:

1) - For initial debris pours less than about 20% of the core mass the debris is unlikely to spread much beyond the cylindrical part of cavity. Consequently, a very low probability (.01) is assigned to the PART FULL branch. The SUMP FULL condition is not possible for this case due to an inadequate amount of debris to "fill" the sump when only 0-20% of the debris is initially released.

2) - For intermediate debris masses (20-40%) the results suggest spreading to cover the cylindrical portion of the cavity is likely, but debris spreading far down the cavity tunnel is unlikely. Hence, a low probability of .05 is assigned to the SUMP FULL branch and a somewhat higher probability (0.1) is assigned to the PART FULL branch.

3) - For high debris masses (40-60%) the results suggest that spreading to cover the entire cavity may be possible, but is not likely. Hence, a probability of 0.1 is assigned to the SUMP FULL branch and a probability 0.2 is assigned to the PART FULL branch.

HIGH (NOT LO-LO) PRESSURE SEQUENCES

For sequence with elevated pressure in the RCS at the time of vessel failure the forceful expulsion of the debris from the vessel and the blowdown of the gases in the RCS will act to spread the debris throughout the cavity and potentially disperse debris out of the cavity.

COMPLETE ENTRAINMENT FROM CAVITY

For sequences with essentially complete debris dispersal from the cavity ("HIGH" branch taken under prior event heading "FRACTION DEBRIS INVOLVED IN DCH") little debris would remain in the cavity and early debris cooling is not an issue.

PARTIAL DISPERSAL

For sequences with partial dispersal from the cavity ("LOW" branch taken under prior event heading "FRACTION DEBRIS INVOLVED IN DCH") approximately 50% of the debris released from the reactor vessel at vessel failure is assumed to remain in the cavity. The debris configurations for these partial dispersal cases are discussed below:

Partial Dispersal - No water in Cavity Prior to Vessel Breach

Under these conditions the residual debris remaining in the cavity would be expected to be driven away from the cylindrical part of the cavity into the cavity tunnel due to the flow of gases from the reactor vessel. Under these conditions a relatively large quantity of debris would be expected to enter the cavity sump and form a liquid pool. As noted above, if only 10% of the core debris enters the sump the required upwards heat flux to cool the debris would be on the order of 700 KW/m^2 which is well above the estimated heat flux capabilities for cooling an initially liquid pool debris configuration. Consequently, it is assumed that the debris in the sump is only potentially coolable under these conditions for the case of a small initial debris mass release from the vessel (EVNTRE Event 22 - branch "LOW (0-20%).

Partial Dispersal - Water in Cavity Prior to Vessel Breach - Steam Explosion Occurs

As discussed above a steam explosion would act to fragment the debris, quench the debris particles and disperse the debris. However, due to the blowdown of the reactor vessel it is possible that more of the debris (fragmented and dispersed by the steam explosion) would be driven toward the end of the cavity tunnel (and into the sump). Consequently, for the case of a steam explosion occurring following vessel failure at high pressure the probabilities for enhanced debris in the sump have been increased above their corresponding low pressure values by a factor of 3.

Partial Dispersal - Water in Cavity Prior to Vessel Breach - No Steam Explosion Occurs

The elevated pressures in the reactor vessel would result in higher debris flow rates from the reactor vessel and enhanced debris spreading. Application of the Moody model for an RCS pressure of 16.2 MPa (2335 psia) results in the predicted debris spread radius shown in Table 4.5-8. Comparing Tables 4.5-7 and 4.5-8 it can be seen that elevated pressures could result in significantly greater debris spreading. Consequently, for high pressure sequences with the cavity flooded and without a significant steam explosion the probabilities for enhanced debris masses in the sump have also been increased above their corresponding low pressure values by a factor of 3.

Event 7 Initial Debris Configuration in Reactor cavity (DEB_COB_I)

This event defines the initial debris configuration and hence the possible upward heat transfer rates which can occur immediately following the initial debris pour from the vessel following vessel failure. Two configurations are considered:

Debris Bed Configuration
Continuous Layer (Pool)

These heat transfer configurations are discussed below.

A debris bed configuration can be formed by fragmentation of the debris by hydrodynamic forces as it flows from the reactor vessel into the water pool in the reactor cavity or by the occurrence of an energetic molten debris coolant interaction (i.e. a steam explosion). Recent work by Chu [Ref. 4.9-38] at Argonne National Laboratory indicates that the ratio of the water pool depth to the debris stream diameter (L/D) is a critical parameter in assessing fragmentation and quenching of the debris stream. For L/D ratios in excess of about 50, substantial fragmentation of the debris stream can be expected and for (L/D) ratios in excess of about 75 essentially complete fragmentation could be expected. The implications for ex-vessel debris coolability in the Ginna reactor cavity are discussed below.

The expected failure of the Ginna lower vessel head is an instrument line penetration which has a diameter of 4 cm. As the debris flows out of the vessel breach the flowing debris will cause ablation of the surrounding steel causing the initial breach size to increase.

Calculations performed by Chu using the THIRMAL code for gravity pours of 130,000 kg of debris (initial vessel breach size of 5.0 cm) indicate that 10%, 25% and 70% of the debris was fragmented and quenched during the pour for water depths of 3, 6, and 9 meters, respectively. For the smaller initial debris pours for Ginna discussed above, under the heading M_DEBRIS, the extent of fragmentation would be larger (due to a smaller terminal debris stream diameter resulting from less extensive hole ablation at the end of the pour). For these size pours Table 4.5-9 summarizes the expected L/D ratio (for a 3 m deep water pool and at the midpoint in the debris pour).

These results indicate that (in the absence of a steam explosion) most of the initial debris pour would contact the reactor cavity floor as a liquid stream for a 3 m deep pool.

The above discussion is for low pressure sequences. For high pressure sequences at RPV failure somewhat different behavior would be expected. If the cavity is flooded with water the high pressure melt ejection and/or steam explosions would be expected to disrupt and intermix the debris and water pool leading to debris fragmentation and quenching. Under these conditions a debris bed configuration could be expected. However, for high pressure sequences with the reactor cavity dry, debris which is not dispersed from the reactor cavity would be expected to eventually form a continuous liquid layer on the reactor cavity floor.

Note that there is no branching under this event heading. The attributes of the sequence pathway prior to this event uniquely define which debris configuration will occur.

Event 8 Initial Upward Heat Flux to Cool Debris (HT_FLUX_I)

This event assesses the upward heat flux required to remove all the decay heat from the debris that is initially introduced into reactor cavity at the time of vessel failure. There are no branches under this event. The range of upward heat fluxes is determined by the mass of debris released at vessel failure, the initial spread area of the debris and the volumetric heat generation rate in the debris. As indicated above, the critical consideration for debris cooling in the Ginna cavity is the depth and mass of debris in the cavity sump.

The determination of the upward heat flux required to cool the sump debris is illustrated below. Consider the top "branch" under this heading with an assessed range of values from 1.3 to 2.6 MW/m^2. These values were determined as follows:

For this sequence pathway the sump is filled with debris. The depth of the sump is 5 ft (1.52 m) and it is assumed the void fraction (porosity) in the debris is between 0 and 50%. Hence, the estimated range of upward heat fluxes required to cool the debris is from 1.3 MW/m^2 (0.5 * 1.73 MW/m^3 * 1.52 m) to 2.6 MW/m^2 (1.73 MW/m^3 * 1.52 m).

For a partially filled sump (one-quarter to one-half full) the range of heat fluxes is .33 MW/m^2 (0.25 * 0.5 * 1.73 MW/m^3 * 1.52 m) to 1.3 MW/m^2 (0.5 * 1.0 * 1.73 MW/m^3 * 1.52 m).

For the "NOMINAL" branch it is assumed that the debris does not preferentially enter the sump and that the debris depth is more or less uniform throughout the cavity. The lower bound heat flux assumes that the debris spreads uniformly across the entire cavity floor. The upper bound heat flux assumes that the sump is 1/8 filled with debris (the lower bound for a partially filled sump.)

Event 9 Water Injection to Reactor Cavity After Vessel Failure (CAV_WAT_F)
EVNTRE Event 30

This event assesses whether the reactor cavity is flooded with water soon after vessel failure, given that the reactor cavity was dry at RPV failure. If the reactor cavity is not flooded, then long term debris concrete attack in a dry reactor cavity will occur. This is a sorting type event determined by the PDS characteristics for the status of systems which can add water into the reactor cavity after RPV failure. Systems which can add water into the reactor cavity after vessel failure include the in-vessel injection systems and the containment spray system.

This event has been discussed previously in Section 4.5.2.4 (Containment Liner Meltthrough).

Event 10 Type of Ex-Vessel Core/Concrete Interactions (TYPE_CCI)
EVNTRE Event 39

This event assesses whether the debris is coolable in the reactor cavity, or if not coolable, the type of core concrete interaction (CCI) that occurs. The branches for this event are:

NO CCI
WET CCI
DRY CCI

The "NO CCI" branch indicates that the debris was cooled fairly rapidly and no long term debris concrete attack occurred. The "WET CCI" branch indicates significant CCI occurs in the presence of an overlying water pool. The dry CCI branch represents CCI in a dry cavity.

The coolability of the debris in the reactor cavity is determined by the configuration of the debris and the internal heat generation rate of the debris. The configuration types and their possible upward heat removal capabilities are discussed below.

DEBRIS BED

A debris bed is the debris configuration with the maximum potential for cooling. A debris bed configuration allows water entry into the debris and greatly enhances the debris/water interfacial heat transfer area. The limitations on the coolability of debris beds are generally hydrodynamic in nature and are controlled by the ability of the liquid to penetrate into the bed against the upwards flow of steam generated within the bed.

The coolability of a debris bed is a strong function of the characteristic size of the debris particles. The coolability of debris beds is generally characterized by the dryout heat flux which is the maximum upward heat flux the bed can maintain without dryout inside the bed. Figure 4.5-10 shows the results of debris bed experiments and model predictions for the dryout heat flux as a function of the debris diameter [Ref. 4.9-39].

Generally, for debris particles sizes in excess of several millimeters the dryout heat flux is greater than 900 kW/m^2. As discussed previously the debris size for the debris beds formed either by a steam explosion or by hydrodynamic fragmentation of the debris stream as it enters the water pool in the Ginna reactor cavity are such that the characteristic debris size would be expected to be greater than 1 mm and the minimum upward heat flux capability for a debris bed configuration is expected to be in excess of 900 kW/m^2. The maximum heat flux capability for a debris bed configuration is assumed to be twice the minimum value (1800 kw/m^2). This value is approximately the dryout heat flux for a debris bed with 1 cm debris particles.

CONTINUOUS DEBRIS LAYER (POOL)

If the debris stream from the reactor vessel spreads out in a continuous pool under the water layer and the debris is not fragmented and water does not ingress into the debris pool then the limiting condition for solidification of the debris pool is by conduction through an overlying solid debris crust. For complete coolability the debris pool would need to freeze completely through and have an interfacial temperature with the underlying concrete less than the concrete melting temperature. Calculations which were performed for the Ginna PRA project indicate a limiting upward heat flux due to conduction of about 100 kW/m^2 for a solid crust with internal heat generation and with the boundary condition that the concrete surface temperature remain below the concrete melting temperature. Thus, if the debris pool has a heat generation rate less than 100 kW/m^2 then it can be considered to always be coolable with an overlying water layer.

Pool configurations with heat generation rates in excess of 100 kW/m^2 may also be coolable if the interfacial heat transfer area between the debris and the pool is enhanced by formation of irregularities in the upper crust surface or by cracking of the upper debris crust (by the freezing process - upon freezing there is about a 10% reduction in debris density, or by gas generation from the initial debris concrete reaction) and debris eruption into the water layer or water ingression into the debris pool. Consequently, the limiting heat flux capability for a pool type configuration is assumed to lie between 100 and 500 kW/m^2.

Experiments such as the MACE series being conducted at Argonne National Laboratory suggest that the upward heat transfer may be significantly enhanced above conduction through a solid debris crust. The overall results from the MACE tests [Refs. 4.9-40, 4.9-41] appear to generally fall into mid-to-upper end of the heat flux ranges defined above for a pool.

SUMMARY

In summary the upward heat flux capabilities of each of the debris configurations considered are:

Debris Bed	900 - 1800 kW/m^2
Continuous Layer (Pool)	100 - 500 kW/m^2

In order to determine the debris coolability for each branch in the tree the following procedure was adopted. The heat fluxes required to cool the debris as shown on the tree (Event HT_FLUX_I) were compared with the range of possible heat fluxes (shown above) for the debris configurations shown on the tree. Since both the required heat flux to cool the debris and the possible upward heat fluxes for each configuration span a range of values, uniform probability distributions within the indicated ranges were assumed and the two probability distributions were combined to assess the overall coolability of the debris in its initial and final state. The following discussion provides an example of this process.

Example:

For the pathway through the DET leading to endpoint number 3 the initial debris configuration was a debris bed in the cavity sump. The initial debris heat flux that must be removed is between 0.33 and 1.3 MW/m^2. The range of heat fluxes that can be removed for a pool configuration is between 0.9 and 1.8 MW/m^2. Combining the probability distributions for the range of heat fluxes that must be removed with the range of heat fluxes capable of being removed in a debris bed configuration results in a probability of cooling the debris initially released of 0.91. This probability is assigned to the "NO CCI" branch under event heading "TYPE_CCI".

COOLABILITY OF LATE DEBRIS POURS

After the initial debris pour following vessel failure, the remaining debris will heat up and gradually flow out of the reactor vessel. An upper bound estimate of the flow rate from the vessel at longer times after vessel failure can be made assuming:

- All residual debris in the vessel is at it solidus temperature

- All decay heat goes into melting of the residual debris

- Debris flows out of the vessel as it melts

With these assumptions the debris flow rates can be estimated and the debris stream characteristics upon entry into the reactor cavity water pool can be determined. The water pool depth to debris stream diameter (L/D) ratios are such that complete fragmentation of the late debris pours can be expected. If complete fragmentation and quenching of the late pour occurs, a debris bed configuration for the residual debris will result.

Due to the depth of water in the reactor cavity, all or nearly all of the residual debris which enters the reactor cavity after vessel failure will be fragmented by hydrodynamic forces and will form a debris bed in the cylindrical portion of the reactor cavity. The maximum depth of the debris in the cylindrical portion of the cavity and the corresponding heat flux from the debris are approximately 54 cm and 900 kW/m^2, respectively (assuming 90% of the total core debris mass is in the cylindrical portion of the cavity). Since the minimum heat flux from a debris bed is assumed to be 900 kw/m^2 it is concluded that the coolability of the residual debris which gradually drains out of the reactor vessel following vessel failure is not limiting.

4.5.2.6 Mode of Late Containment Failure

The DET for Mode of Late Containment Failure is shown in Figure 4.5-7. The mechanisms considered for late containment failure include gradual overpressurization resulting from failure of containment heat removal, late hydrogen combustion and basemat meltthrough.

The events considered in the DET are discussed below.

Event 1 Power Available Prior to Reactor Vessel Failure (POW_VF)
EVNTRE Event 42

With electric power available from the time period prior to reactor vessel failure onwards it is highly unlikely that a sufficiently high concentration of hydrogen would accumulate in the containment atmosphere (prior to a hydrogen burn occurring) that the containment integrity would be threatened by a hydrogen burn. It could be expected that with the numerous ignition sources that are available when electric power is available that hydrogen concentrations would not greatly exceed the global flammability concentration (approximately 8%) prior to ignition of a burn. Furthermore, the containment pressure would likely be at a relatively low level at the time the burn is ignited since if the containment pressure were elevated (such as would be the case when containment heat removal is unavailable) the steam concentration would be sufficiently high to render the containment atmosphere inert.

The major threat from a hydrogen burn would occur under the conditions where the containment has been inert for a long period of time and is rapidly deinerted. This situation might arise under station blackout conditions with late recovery of power (and actuation of the containment spray system or possibly fan coolers).

This event is dependent on EVENTRE PDS events 5 - Station Blackout and 6 - Power Recovery.

Event 2 Power Recovery Late (POW_REC_L)
EVNTRE Event 43

This event assesses the possibility of late recovery of AC power for sequences where AC power was not available prior to reactor vessel failure.

This event is dependent on EVENTRE PDS event 6 - Power Recovery.

Event 3 Type of Ex-Vessel CCI (TYPE_CCI)
EVNTRE Event 39

The type of ex-vessel CCI is important to assessing whether a late hydrogen burn can fail containment. The peak containment pressures resulting from burns of the hydrogen produced by in-vessel metal-water reactions are not sufficiently large to threaten containment integrity without the additional hydrogen (and carbon monoxide) produced during ex-vessel CCI. This event has been discussed previously in section 4.5.2.5.

Event 4 Containment Heat Removal (CNHEATREM)
EVNTRE Event 44

Failure of long term containment heat removal (fan coolers and sprays) will result in gradual overpressure failure of containment.

This event is dependent on EVENTRE PDS events 9 - Containment Fan Coolers and 10 - Containment Spray Status.

Event 5 Late H_2 Burn Fails Containment (LATEH2)
EVNTRE Event 46

This event assesses whether a late hydrogen burn occurs upon rapid deinerting of the containment (of sufficient magnitude to fail containment). This event is only considered for SBO sequences with power recovery after vessel failure and with ex-vessel CCI occurring.

Prolonged debris concrete interactions can produce very high flammable gas concentrations in the containment atmosphere. Upon deinterting, combustion of these gases can produce pressures that threaten containment integrity if the burn is complete. Under rapid deinterting conditions the MAAP code will generally predict efficient global combustion with peak pressures that approach that of an adiabatic complete burn.

On the other hand the NUREG/CR-4551 [Ref. 4.9-19] analysts judged that following the restoration of electric power (and the initiation of containment sprays) that hydrogen combustion would be initiated soon after the containment atmosphere transitioned from an inert state to a flammable state and while the steam concentration were still elevated. They concluded that under these conditions large deflagrations were possible but detonations were not possible. The NUREG/CR-4551 experts estimated that under these conditions the burn efficiency would be relatively high with a mean scale factor of .72 (the scale factor is defined as the actual pressure rise divided by the adiabatic pressure rise).

The MAAP code calculations and the NUREG/CR-4551 results suggest that hydrogen combustion during rapid deinerting events late in the accident following a substantial period of debris concrete interaction could pose a serious challenge to containment integrity. Consequently, a value of 0.5 is assigned for the probability of containment failure under these conditions.

Event 6 Mode of Late Containment Failure (CF_LATE)
EVNTRE Event 47

This event assesses whether late containment failure occurs and the mode of late containment failure. For sequences with failure of containment heat removal, gradual containment overpressure failure is expected. Two overpressure failure modes have been identified for the Ginna containment; global containment failure and liner tearing. Figure 4.4-3 shows the fragility curves for these two failure modes. In order to assess the probability of each mode given that containment failure is certain the conditional probabilities shown on Figure 4.4-4 were used.

This evaluation resulted in the following probabilities for liner leakage and global containment structural failure under gradual overpressurization conditions:

	Probability
Global	0.3
Liner Leakage	0.7

Note that this analysis is different than the containment failure modes analysis previously described for early containment failure. The failure mechanism for containment failure at the time of reactor vessel failure was a rapid containment pressurization event resulting from DCH related phenomena. Under rapid pressurization conditions the limited leakage resulting from liner tearing would not be expected to influence the peak containment pressure and consequently, global failure could follow liner tearing. However, for slow overpressurization conditions limited liner tearing would be expected to terminate the pressure rise and preclude global failure.

For sequences where containment heat removal has been successful in preventing late overpressure failure then the remaining threat to containment integrity is from basemat meltthrough if the debris is not cooled in the cavity. As discussed previously, the design feature which is expected to control debris coolability is the sump in the reactor cavity. Consequently, the analysis of debris coolability focused on coolability of the debris transported into the cavity sump. In addition to being the limiting design feature for cavity debris coolability, the basemat thickness under the cavity sump is very thin (1.5 ft). Consequently, if long term CCI does occur in the region of the cavity sump then basemat penetration can be expected with a high probability. In this analysis it is assumed that if ex-vessel CCI is predicted (either with an overlying water layer or dry) then basemat failure is certain.

Finally, if containment failure was predicted (in the previous event) due to a large hydrogen burn it is conservatively assumed that the containment failure mode is global (i.e. a large failure area).

4.6 Accident Progression Analysis

4.6.1 Summary of Sequences Analyzed

This section contains a description of the deterministic containment accident progression analyses. To support the development and quantification of the containment event tree an assessment of the physical progression of a spectrum of accident sequences was performed. This effort provided critical information and insights into:

- timing of key events
- containment loads
  - pressure
  - temperature
  - pressure rise rates
- debris relocation and cooling
- mitigation effectiveness of ESFs
- generation, and combustion of hydrogen

Plant-specific analysis of accident progression with the deterministic code MAAP (Section 4.2) were closely coupled to development of the CET. Accident progression analyses were also utilized in the quantification of the CETs. Results from prior studies, sensitivity studies with deterministic models (MAAP), and separate effects analysis and judgment are all used in assessing the relative probabilities of the various possible accident progression pathways modeled in the CET discussed in Section 4.5.

A number of MAAP calculations were performed to determine the range and variation in containment response to be expected for a variety of accident scenarios. A brief description of each of these accident progression cases is given in Table 4.6-1. Subsets of the accident progression studies were utilized for various specific aspects of the CET development and quantification. These are discussed in Section 4.6.2. The other calculations were performed primarily to gain general insights and are not discussed further here beyond their inclusion in the tables. (It should be noted that these runs were generally terminated when the item of interest had been determined. Also, in some cases, arbitrary modeling assumptions were imposed to achieve specific sequence circumstances. These factors should be kept in mind when interpreting the results.).

MAAP calculations were also performed to derive release fractions for various source term categories (Section 4.7). These source term cases were run well past containment failure and as such represent the entire accident progression from initiating event to release completion. The source term MAAP cases are summarized in Tables 4.7-1, 4.7-2, and 4.7-3. Three of these cases were selected, based upon their expected importance to the source term and/or the contribution of the initiating event to core damage, for detailed discussion of the accident progression. The cases selected are a medium break LOCA with no injection and late containment failure, an interfacing systems LOCA with no injection available, and a steam generator tube rupture scenarios with and without a stuck open secondary side relief valve. The discussion for these sequences is given in Section 4.6.3.

4.6.2 Accident Progression Analysis Results

As noted previously (above and Section 4.5.1), MAAP runs were performed to gain further understanding of the accident processes as they relate to the Ginna plant. Three specific topics are discussed below, based on selected sets of the cases of Table 4.6-1.

4.6.2.1 Containment Isolation Failure

Several MAAP cases were run to investigate the fission product releases associated with various loss of isolation failure areas. This was done to support the choice of the cutoff criterion for containment isolation failures. The results from these analyses helped to support the conclusion that 1½" diameter isolation failures represent an appropriate choice for the loss of isolation cutoff criterion at Ginna as is described below.

The full set of MAAP cases for this issue considered variations of the sequence initiator, the assumptions for the availability of fan coolers, and on the size of the isolation failures. The availability of containment sprays was not considered since it would provide for smaller releases to the environment compared to cases with fan coolers only available or with no containment heat removal at all. In addition, for these analyses, the nominal leak area representing the isolation failure area was multiplied by 0.6 from the full area based on diameter alone. This is justifiable by accounting for a minimum of loss coefficients. From reference 4.9-46, the entrance and exit effects will lead to K values of 0.5 and 1.0, respectively. Additionally, for example, assuming a nominal friction coefficient of 0.02 for a 1½" I.D. pipe, only 10 feet of pipe would lead to an additional K value of

$$K = f\frac{L}{D} = 0.02\frac{10'}{(1½/12)'} = 1.6$$

Since the flow rate through a hole will be proportional to $A_{ACTUAL}/(\Sigma K)^{1/2}$, one can compute an effective flow area for the MAAP calculations as follows:

$$A_{EFFECTIVE} = A_{ACTUAL}/(\Sigma K)^{1/2}$$

So taking only minimal credit for the length of pipe (10'), and without accounting for the myriad of bends and other valves which will normally exist in the isolation line, the actual area can be reduced by

$$1/(0.5 + 1.0 + 1.6)^{1/2} = 0.57$$

This was rounded to 0.6 A_{ACTUAL} for all of the cases summarized in Table 4.6-2.

CsI was chosen as the species of interest for these analyses since this species is a dominant contributor to early whole-body population dose. All of the cesium is assumed to combine with iodine (CsI) or to form hydroxide (CsOH) in the MAAP fission product models. However, CsI is used as a measure of the source term magnitude since the fractional CsOH release is typically very similar.

The wide range of uncertainties in the evaluation of public risk makes it difficult to draw rigid conclusions. However, the most significant finding in a review of consequence analysis is that once the CsI release fraction falls below about 0.05, there would be a low likelihood of early fatalities. As the CsI release fraction falls to below 0.02, early injuries are less probable, and latent health effects and land contamination become the dominant consequences. Therefore, CsI releases below the 10^{-2} to 10^{-3} range should not significantly contribute to the overall early health effects consequences [Ref. 4.9-47].

All but one of the 1½" isolation failure cases resulted in CsI release fractions in the range of 0.002 to 0.003 at the end of the run. The only 1½" case with a slightly higher release was LLOCA13 (0.0086) which represents the unlikely scenario of a large break LOCA with no containment heat removal available or recovered. Case LLOCA12 is the only 1½" case where a loss of isolation did not preclude containment structural failure due to containment overpressurization. The vast majority of the CsI release in this case occurred subsequent to containment structural failure so this case does not contradict the criterion. Smaller isolation failures will also not preclude containment failure (LLOCA09, for example). Larger isolation failures will allow for the possibility of CsI releases greater than 0.01 (LLOCA10). The 0.002 to 0.003 CsI releases reported here for the 1½" cases do not account for any fission product retention within the pipe itself nor do they account for any substantial line losses represented by bends or valves in the line. These would both tend to diminish the releases even further. Consequently, 1½" diameter isolation failures appear to be an appropriate choice for the cutoff criterion.

4.6.2.2 Induced Ruptures of the RCS

Another issue that was partially addressed using MAAP analysis for Ginna was the likelihood of induced hot leg or steam generator tube ruptures in high pressure scenarios. Section 4.5.2.1 describes the use of the NUREG/CR-4551 results for the Surry plant to estimate induced RCS failures for Ginna. These results were supported by the Larson-Miller Parameter (LMP) methodology described below which also indicated that induced hot leg ruptures would likely be similar to the Surry analysis.

Creep rupture of ductile materials is a function of time, temperature, and stress. An empirical formula relating the expected time to rupture with temperature and stress was developed by Larson and Miller [Ref. 4.9-48]. The form of this relationship and curve fits developed for different material types is described in Reference 4.9-49. With the curve fits available and a stress-temperature history for a given component, the time to creep rupture, t_r, may be estimated from

$$\int_o^{t_r} \frac{dt}{t_r(T,\sigma)} = 1$$

where T is the temperature and σ is the hoop stress associated with the component of interest. This formula assumes that the fraction of the total time to fail at a given stress-temperature condition is additive. Consequently, the pressure and temperature histories can be used to estimate when creep rupture may occur. The cumulative damage, δ, as expressed below can be used to estimate when rupture might occur. When δ reaches 1.0, creep rupture is likely. As δ becomes larger, creep rupture can be considered even more likely. The cumulative damage, δ, as given by the summation,

$$\delta = \sum_i \frac{\Delta t_i}{t_r(T_i,\sigma_i)},$$

was implemented into a stand-alone FORTRAN program which incorporated the MAAP temperature and stress histories for various scenarios. The results from the implementation of the LMP program on the selected MAAP cases are summarized in Table 4.6-3 [Ref. 4.9-21].

It is worth noting that simplifications in the MAAP core melt progression model are believed to reduce the calculated hot leg temperatures and thus under-predict the likelihood of induced hot leg failure. In MAAP 3.0B, all core constituents (i.e. zirconium, uranium, dioxide, and zirconium dioxide) are assumed to melt at a single "eutectic" melting temperature. This has the effect of causing rapid gross melting of the core once the eutectic temperature has been reached, and the disruption of core-upper plenum natural circulation follows immediately thereafter. Such a treatment is not considered particularly realistic. Based on small scale experiments, it is expected instead that the zirconium, along with some dissolved uranium, will relocate first, leaving behind the oxidic materials in a relatively rod-like geometry. This would lead to an extended but slower rate of heatup of the hot legs, which should lead to higher hot leg temperatures than MAAP normally predicts. This is the motivation for cases SBO05 and SBO11 which increased the assumed eutectic melting temperature in an attempt to somewhat mimic the behavior described above. The larger creep summation values reported in Table 4.6-3 in these cases compared to the comparable base case (SBO03) results show an even higher likelihood of induced hot leg rupture occurring prior to vessel failure.

The full set of results indicate that induced hot leg ruptures can be considered likely prior to vessel failure for cases above the PORV setpoint pressure. Cases with two 3/4" or larger LOCAs (as in SBO07 with 3/4" seal LOCAs) are highly unlikely to induce other ruptures. Secondary depressurization must occur for induced tube ruptures to be of concern. SBO18 and SBO19 indicate almost equally likely probabilities for tube ruptures to occur as hot leg ruptures if 50% wall thinning is assumed in the tubes. If more than 50% wall thinning is assumed in these cases, then tube ruptures are much more likely to occur than hot leg ruptures. If secondary depressurization does not occur (all cases but SBO18 and SBO19), then induced steam generator tube ruptures are not predicted even if 75% tube wall thinning is assumed. These conclusions are consistent with the results from NUREG/CR-4551 for Surry. Thus, the probabilities of induced ruptures for Ginna are taken directly from the Surry analysis as described in Section 4.5.2.1.

4.6.2.3 Direct Containment Heating

MAAP analyses were conducted with variations in several parameters to mimic the DCH-specific headings in the Early Containment Failure Decomposition Event Tree (ECF DET) shown in Figure 4.5-4. These included variations in 1) the mass of debris expelled early (M_DEBRIS), 2) the fraction of debris involved in DCH (DCH_FRACT), 3) the fraction of debris dispersed outside of the lower compartment (DIS_FRACT), and 4) the mode of hydrogen burns after vessel failure (H2_BURN). The mass of debris expelled early was controlled with input deck changes after vessel failure to limit the entrained mass to the desired amount. The fraction of debris involved in DCH was controlled by MAAP input parameter FCMDCH. The fraction of debris dispersed outside of the lower compartment was controlled by MAAP input parameter FCMDA. Either the standard burn model was employed (STD) or all hydrogen was forced to burn coincident with the DCH event (UCHB). Variations also considered the entrainment time constant (TTENTR) and whether or not the RWST inventory had been injected prior to vessel failure (i.e. yes in SLOCA cases, no in SBO sequence designator cases). The SLOCA cases also had primary system pressures of less than 500 psia at the time of vessel failure compared to greater than 2350 psia in the SBO cases.

The result of interest is the peak containment pressure following vessel failure for each run. These peak pressure results were then compared with the containment fragility curve [Ref. 4.9-9] to assess the probability of early containment failure for each sequence pathway through the Decomposition Event Tree. Table 4.6-4 summarizes the DCH parametric cases.

4.6.3 Discussion of Selected Accident Sequence Progressions

The sequences discussed below were analyzed for the purpose of determining representative sets of radionuclide release fractions for specific source term categories (those results are presented in Section 4.7.3). A discussion of the containment accident progression is presented here to provide insight into the phenomena and mechanisms that are occurring for representative severe accident sequences. The plant modeling utilized for MAAP has been presented in Section 4.2 and the plant damage state and containment event modeling have been discussed in Sections 4.4 and 4.5.

4.6.3.1 Medium Break LOCA with No Injection and Late Containment Failure

This case was run for Source Term Category (STC) 12 which represents a late containment failure by basemat meltthrough representing 14.2% of the total core damage frequency for Ginna. The unique configuration of only 1.5 ft of concrete below the cavity sump at Ginna make this mode of containment failure more prevalent than at most other plants. The representative case was chosen as a medium break LOCA without injection or containment spray available, but with AFW, the accumulators, and fan coolers available. Key MAAP results from this case are described below.

A 5.5" diameter break in the cold leg is assumed to initiate the accident. The system rapidly depressurizes to below the accumulator pressure setpoint so that the core is initially prevented from uncovering. However, the accumulators are depleted by about 15 minutes, and a gradual boil-off of the remaining RCS inventory begins. Initial core uncovery is predicted prior to 45 minutes upon which heatup and core degradation ensue. Vessel failure is predicted to occur at about 1.55 hours. Shortly after vessel failure, approximately 60% of the volatile fission products have been released to containment with most of the remainder deposited on RCS structures.

With vessel failure at low pressure, all of the molten core material stays in the cavity. The debris is not coolable in the cavity and core-concrete interactions initiate. Between the time of vessel failure (~1.6 hrs) and the time of basemat meltthrough (~13.6 hrs), an additional 10% of volatile fission products revaporize from the RCS structures and enter containment. However, over this same time period, natural fission product removal mechanisms (i.e. gravitational sedimentation, thermophoresis, etc.) and that afforded by condensation in the fan coolers result in the large majority of airborne fission products being deposited on heat sinks by the time containment failure is assumed to occur.

A small containment failure area of 0.025 ft^2 was chosen in an attempt to represent the torturous release pathway through the failed basemat and underlying soil, which would enhance the retention of fission products, which is not explicitly modelled in MAAP. With continued operation of fan coolers assumed in the sequence, the amount of revaporization that occurs is minimal. Concrete attack is assumed to continue in the cavity which provides a source of non-volatile fission products to containment. In any event, by 48 hours the majority of the noble gases are released from containment, but less than 1% of the volatiles and non-volatiles are calculated to be released. These source term results have been included in characteristic fission product releases for STC12 presented in Section 4.7.3.

4.6.3.2 Interfacing System LOCA

This source term category comprises 9.7% of the total core damage frequency. The representative sequence for this category (STC #16) was chosen to be very similar to the previous case except the LOCA is assumed to occur outside of containment rather than inside of containment. Thus, the scenario is given by a LOCA outside of containment with no injection available, but with accumulators, AFW, and containment fan coolers available. In the MAAP analysis, the conservative assumption was made to not take credit for any fission product retention which may occur in the auxiliary building. The reported releases are simply given as the releases from containment.

The early sequence of events in this case are fairly similar to the previous case up to the time of core uncovery. Upon core degradation, the subsequent fission product releases are now sent directly outside of containment rather than to containment. Therefore, the 60-70% release of volatiles which had previously gone to containment shortly after vessel failure is now a direct release from containment. Following vessel failure, core debris enters the cavity and core-concrete interactions contribute to the release of non-volatiles for this scenario.

Since there is a large uncertainty associated with exactly where the ISLOCA break may occur for these types of scenarios, it is difficult to accurately characterize the type of fission product retention which may occur in the auxiliary building. The reported releases given here and in Section 4.7.3 for this STC represent the upper bound of potential releases. Naturally occurring fission product removal mechanisms in the auxiliary building could substantially reduce the radionuclides released to the environment, and whether or not the ISLOCA break becomes submerged with water could have a dramatic influence on the actual releases which occur to the environment. This is a notable conservatism in the reported source terms in this analysis.

4.6.3.3 Steam Generator Tube Rupture

Steam generator tube ruptures comprise about 32.7% of the core damage frequency at Ginna: 17.1% of the core damage frequency is from isolated steam generator tube ruptures (i.e. secondary relief valve does not stick open - STC #18) and 15.6% is from not-isolated SGTRs (STC #20). Reestablishing AFW to the affected steam generator is not considered for either STC. Key results from the MAAP analyses are described below.

The representative scenario was chosen as a double-ended single tube rupture with an effective area of 0.0049 ft^2 with no high pressure injection available. In both cases, AFW is terminated to the affected steam generator within one half hour. In the unisolated case, a secondary relief valve is assumed to stick open at about 20 minutes (the time during a similar MAAP run when flow through the valve became liquid). This allows for depressurization below the accumulator setpoint so that accumulator injection occurs. In the isolated case (STC #18), secondary depressurization is not considered, the primary and secondary pressures remain near the SG relief valve setpoint and accumulator injection does not occur. Thus, vessel failure is calculated to occur earlier (~5.3 hrs) in the isolated case compared to the unisolated case (~7.3 hrs).

The majority of the fission product releases occur between the onset of core damage and vessel failure in both cases. However, in the isolated case, the releases are limited to the cycles of the relief valve opening. The unisolated case with a relief valve stuck open leads to a continuous release of fission products. Thus, the CsI release fraction is much higher (0.276) in the unisolated case compared to the isolated case (0.067).

After vessel failure in the isolated case, the broken loop steam generator pressure equalizes with the containment pressure below the relief valve setpoint and the steam generator relief valve remains closed thereafter. Fission product releases are then limited to leakage as containment heat removal systems prevent a later containment failure. The fission product releases may be accompanied by another release at a later time if radionuclides are released through some other containment failure mechanism. This possibility was ignored in the source term characterization because the severity of the earlier releases would dominate any subsequent releases. The full set of the calculated release fractions for all 12 of the MAAP fission product groups for these cases and all of the other representative source term cases are presented in Section 4.7.3 and summarized on Table 4.7-2.

4.7 Source Term Characterization

The end points of the containment event tree (CET) represent the outcomes of possible containment accident progression sequences. These endpoints represent complete severe accident sequences from initiating event to release of radionuclides to the environment. An atmospheric radionuclide source term may be associated with each of these containment sequences. Because of the large number of CET sequences and because of similarities in the sequence characteristics, it is neither necessary nor practical to develop a source term estimate for each containment sequence. Sequences with similar characteristics are therefore grouped into release categories to reduce the required source term assessment effort.

4.7.1 Release Category Grouping Parameters

The first step in the source term assessment effort is to identify the sequence characteristics which are most important to definition of the source term. These characteristics are identifiable from the Plant Damage State (PDS) characteristics and from the containment event tree headings since one of the primary objectives in the PDS grouping and CET evaluation has been to define those events and conditions most important to source term assessment. This selected set of sequence characteristics important to source term assessment are used as grouping criteria to define the release categories and the associated source term magnitude, composition and timing.

The containment sequence characteristics selected for use in definition of the Ginna source term release categories are:

Containment Bypass (ISLOCA, SGTR)
Debris Cooled In-Vessel
Alpha Mode Containment Failure
Status of Containment Isolation
Time of Containment Failure (relative to core melt)
Availability of Containment Heat Removal
Mode of Containment Failure
Type of Ex-Vessel Core Concrete Interactions
Steam Generator Isolation (for SGTR Sequences)
Steam Generator Break Covered (for SGTR Sequences)

The reasons for selection of these parameters for use in defining the different release categories are discussed below.

4.7.1.1 Containment Bypass

Containment natural and engineered mitigation features are ineffective in reducing fission product releases if the accident causes the opening of a release path directly from the reactor coolant system to a point outside of the containment boundary which bypasses the main containment gas volumes.

The two ways that this can occur are if a steam generator tube rupture occurs or an interfacing system LOCA (ISLOCA) occurs. These are both defined by the plant damage state attribute "Containment Bypass".

For the dominant interfacing system LOCAs the failure occurs into the auxiliary building because of failure of the check valves and motor operated valves between the RCS and the low pressure residual heat removal (RHR) system, and subsequent failure of the RHR piping outside of the containment. Because of the size of the bypass, subsequent events in containment do not have a material impact on the atmospheric source term.

The ISLOCA and SGTR classes are explicitly treated in the release category logic because they represent the two major ways that fission products can be directly released outside of containment relatively early in time without any significant containment mitigation of the source term.

4.7.1.2 Debris Cooled In-Vessel

This characteristic is important since there is a significant probability of arresting the core-melt process in-vessel, thus preventing vessel failure, ex-vessel radionuclide releases (from core-concrete interactions) and containment failure. If the debris is cooled in-vessel then containment integrity is not challenged and only minor releases of radionuclides to the atmosphere would be expected.

4.7.1.3 Alpha Mode Containment Failure

The in-vessel steam explosion induced (alpha mode) containment failure is important because it allows the direct release of fission products to the atmosphere at the time of vessel failure. This is because of the assumption that an in-vessel steam explosion which causes failure of the top closure head of the vessel also generates a missile from a portion of the reactor vessel head which impacts upon, and fails the containment. The debris particles resulting from the steam explosion are assumed to be dispersed from the reactor vessel and to oxidize in the containment atmosphere resulting in the release of additional radionuclides.

Alpha mode failures are included as a source term characteristic and a CET heading because the uncertainties regarding this phenomena are large and, at the upper end of the uncertainty range, the contribution of alpha mode failures to the probability of early containment failure may not be negligible.

4.7.1.4 Containment Isolation Status

This attribute is considered important because any fission products in the containment atmosphere are released to the environment early (i.e. near the time of core melt) and continuously, if the containment is not isolated.

With failure to isolate containment, the available effective time for fission product deposition and mitigation by containment engineered safeguards (fan coolers and sprays) is reduced. The size of the most likely isolation failure path (2 in^2) is large enough so that even if a later larger area containment failure were to occur it should not significantly increase radionuclide release magnitudes.

4.7.1.5 Time of Containment Failure

This release category attribute is considered important because it affects the time available for fission product mitigation by natural removal processes and containment engineered safeguards.

The time periods considered significant for overpressure containment failure are Early and Late. Early containment failure is at, or near, the time of reactor vessel failure. Late containment failures occurs many hours after vessel failure. Basemat meltthrough cases are assigned to a separate category labeled Very Late.

The possibility of no containment failure exists and is assigned to its own unique source term category.

4.7.1.6 Containment Heat Removal Available

This attribute is considered significant because it determines whether or not late gradual overpressure failure of containment can occur and whether fission product mitigation by the fan coolers or sprays is present.

4.7.1.7 Mode of Containment Failure

This attribute is important because it governs the rate at which fission products are released to the atmosphere. It also affects the magnitude of the release by governing the time available for effective fission product attenuation in containment.

The two attributes considered significant for overpressure failure of containment are local liner failure or global rupture of the containment structure.

Other possible failure modes which are treated include liner thermal failure due to direct debris contact with the liner and basemat meltthrough.

4.7.1.8 Type of Ex-vessel Core Concrete Interactions (CCI)

This grouping criteria is considered significant since ex-vessel CCI results in the release of additional radionuclides following vessel failure and the production of additional flammable gases (hydrogen and carbon monoxide).

The three categories of ex-vessel CCI which are considered are:

No Ex-vessel CCI - The debris was coolable in the reactor cavity and little or no concrete erosion occurred.

Wet CCI - The debris in the reactor cavity was covered by a water pool. However, the debris was not coolable and debris concrete attack occurs in the presence of an overlying water pool. The presence of the water pool would provide mitigation of the radionuclides released from the CCI and would provide enhanced heat transfer from the debris surface reducing the rate and extent of concrete attack.

Dry CCI - The debris was not covered by a water pool and CCI occurs in a dry cavity.

4.7.1.9 Steam Generator Isolated

If the containment bypass is a SGTR sequence, then the most important questions are whether the tube break is submerged and whether the steam generator is isolated. If the steam generator is isolated then steam (and radionuclide) discharges from the steam generator occur through cycling relief valves. If the steam generator is not isolated (or isolation fails) then the secondary side of the steam generator will depressurize and radionuclide holdup times in the steam generator will be reduced.

4.7.1.10 Steam Generator Break Covered

Radionuclides released from the primary coolant system through the break into a flooded steam generator will be scrubbed if the break location is submerged. MAAP results indicate that the broken steam generator boils essentially dry by the time radionuclide release occurs unless auxiliary feedwater flow is maintained into the affected steam generator.

4.7.2 Release Category Grouping Logic

The approach to the definition of release categories is similar to that discussed in Section 4.3 for definition of plant damage states. It consisted of construction of a logic diagram with the grouping criteria defined above as headings. The end points on the logic diagram represent unique release (source term) categories with their individual characteristics defined by the pathway through the logic diagram.

The goal of the grouping process is to develop the minimum number of release categories necessary to distinguish the important combinations of sequence characteristics that can result in distinctly different atmospheric source terms. The Release Category Grouping logic diagram developed for Ginna is shown in Figure 4.7-1. It defines 20 release categories. Specific branch assignment decisions used in the logic diagram under each decision heading are discussed below.

4.7.2.1 Containment Bypass

Containment bypass is the first heading in the source term grouping logic diagram. This question is asked directly for all CET sequences.

ISLOCAs are assigned to a unique release category. Steam generator tube rupture sequences are subdivided into four possible release categories as described below.

4.7.2.2 Debris Cooled In-Vessel

This characteristic is only considered if containment is not bypassed. Interfacing system LOCAs and SGTRs generally preclude long-term cooling as RCS and RWST inventory is lost from containment.

The logic contained in the CET precludes in-vessel debris cooling if the containment has failed to isolate. Hence, sequences with both loss of isolation and in-vessel debris cooling are not possible. Furthermore, there is a requirement that containment heat removal be available in order for in-vessel cooling to be considered successful.

If the debris is cooled in-vessel then there are no credible mechanisms which will threaten containment integrity. Consequently, sequences which are successfully cooled in-vessel are assigned to a unique release category without further subdivision.

4.7.2.3 Alpha Mode Containment Failure

This attribute is considered only for non-bypass CET sequences where the core melt process has not been terminated in-vessel. For bypass sequences the radionuclide source term will be relatively large and the additional releases due to an alpha mode failure would not significantly increase the source term (particularly for volatile radionuclide species). For sequences where the debris is cooled in-vessel, core support plate failure and a large coherent pour of debris into the lower reactor vessel head would not be expected. Hence, large in-vessel steam explosions are not considered credible for these sequences.

4.7.2.4 Containment Isolation Status

For sequences assigned the attribute of Not Isolated, the remaining important question is whether or not the containment fan coolers or the containment sprays are operating. With one of these modes of containment heat removal available the leakage rate from containment will be reduced and the radionuclides in containment will attenuated. The results of the systems analysis indicates that the containment fan coolers will be available for all sequences with the exception of SBOs without power recovery. Consequently, at the plant damage state grouping level, it was determined that for all loss of isolation sequences the containment fan coolers were available. Consequently, there is no further subdivision of loss of isolation sequences and they are all assigned to a single release category.

4.7.2.5 Time of Containment Failure

The attribute, time of containment failure, is used to classify all sequences (with the debris not cooled in-vessel) where containment integrity is still intact. That is, for non-bypass sequences where the containment is isolated and an alpha mode failure has not occurred.

4.7.2.6 Containment Heat Removal Available

Classification of sequences under this heading is done only for sequences with early or late containment failure. For sequences with no containment failure or with basemat meltthrough overpressure containment failure did not occur because containment heat removal was available.

As discussed above, for loss of isolation sequences the containment fan coolers were determined to be available in all cases. For sequences with the debris cooled in-vessel containment heat removal was a requirement in the CET. For all other sequences the availability of containment heat removal is considered irrelevant to the determination of the source term.

4.7.2.7 Mode of Containment Failure

This attribute is only considered to classify those sequences with an early or late containment failure. "Mode of Containment Failure" is clearly not a discriminant for sequences with no containment failure, and alpha mode sequences (for which it is classically assumed that the containment failure is very large) and is not relevant, (or at least not significant) for containment bypass sequences, as most of the fission products escape through the bypass pathway. Containment failure is also considered not relevant for sequences that have an isolation failure since the fission products will escape through the isolation path defect and containment structural failure is less likely because of the existing pressure relief path. It is not considered relevant for sequences with the core melt arrested in-vessel as containment failure is not considered credible.

For sequences with early containment failure and CHR failed the only failure mode resulting from the CET analysis was liner meltthough. For sequences with late containment failure and CHR available the only failure mode resulting from the CET analysis was global failure. The remainder of the sequences with either early or late containment failures had either liner failure or global failure modes. Very late containment failure sequences are all the result of basemat meltthrough.

4.7.2.8 Type of Ex-Vessel Core Concrete Interactions

This grouping criterion was applied only to sequences with early or late containment failure. For all other sequences it was either not applicable or not considered significant for definition of the source term.

All late containment failure sequences have dry CCI. This occurs because all late containment failures are a result of station blackout sequences with either no power recovery (LATE-NO CHR) or with power recovery after vessel failure (LATE-CHR). For these sequences dry CCI will be predicted by the CET model since either the contents of the RWST are never injected into containment or the RWST is injected well after vessel failure.

All early containment failure sequences with liner meltthrough have dry CCI. This occurs because liner meltthrough will be prevented if the RWST is injected. For sequences without the RWST injected dry CCI will be predicted by the CET model.

4.7.2.9 Steam Generator Isolated

This criterion is applied to all SGTR sequences.

4.7.2.10 Steam Generator Break Covered

This criterion is applied to all SGTR sequences.

4.7.3 Release Category Source Term Characteristics

Once the CET endstates have been grouped into a minimum number of release categories, fission product releases can be readily quantified. For the purposes of this discussion, the source term characteristics are defined as a release of radionuclides from the containment of a specific magnitude and distribution. MAAP3.0B-PWR, Revision 19.0 with the minor modifications as described in Reference 4.9-2 was used to develop the source term characteristics for the representative accident progressions described below.

Specific accident progression sequences were chosen to best approximate the representative source term results for each relevant Source Term Category (STC) end state. Based on consideration of the dominant sequence for each end state and based on other factors which influence the source term results, representative sequence descriptions were developed to perform MAAP calculations to quantify the source terms. The magnitudes of the fission product releases were taken directly from the MAAP calculations. Typically, the MAAP calculations were continued for 48 hours from sequence initiation. Thus, most of the fission product releases were essentially complete at the time at which the calculation was ended. In a few cases, notably those with late revaporization or with continuing core-concrete interactions, the fission product releases were still increasing at the time the calculation was terminated. Explicit consideration of recovery (or severe accident management) actions to terminate these slow, continuing releases is beyond the scope of this analysis.

It is important to note that these calculations were performed to provide <u>representative</u> source term results. Uncertainties in the MAAP modelling of fission product behavior and variations in the specific sequence definition could lead to somewhat different results. Because of this inherent uncertainty, the point estimate results are further subdivided to provide general characteristic results for discussion purposes. The discussion which follows will elaborate on the selection of the representative sequences, provide key insights on the sequence results, and then summarize the overall source term results with further grouping techniques. The results will also be presented with respect to the percent contribution to core damage frequency (CDF). Table 4.7-1 summarizes the selected representative sequences.

4.7.3.1 Discussion

STC #1 (34.9%)

This STC end state describes a scenario with vessel failure, but without containment failure due to the long term availability of containment heat removal. Plant Damage State (PDS) 12, as described in section 4.3, comprises the majority of this source term category. The representative sequence was chosen as a medium break LOCA without the recirculation mode of injection available. Vessel failure occurs at low pressure with all molten material entering the cavity at that time. About 15% of the original core material is left behind in the vessel. With fan coolers available and with the RWST inventory in containment, water is available to cover the core debris in the cavity. The debris is assumed to be in a coolable configuration with only 0.05 ft of concrete attack calculated to occur before the debris mixture is quenched. Containment failure is not predicted and the fission product releases are limited to that which occurs due to leakage. The radionuclide release fraction results are presented for this and the other representative sequences in Table 4.7-2.

STC #2 (<0.1%)

This STC end state describes a scenario with vessel failure and an early containment failure. A leak-before-break type of failure occurs (assumed to be 0.025 ft^2 for Ginna). With containment heat removal available, no appreciable core-concrete interactions occur. PDS 15 and PDS 17 represent the majority of this source term category. The representative sequence was again chosen as a medium break LOCA without the recirculation mode of injection available, but with containment failure assumed to occur two seconds after vessel failure. The majority of the fission product releases occur in the few hours immediately following the assumed containment failure. The calculated radionuclide release fractions at 48 hours for this case are presented in Table 4.7-2.

STC #3 (<0.1%)

This low likelihood STC end state describes a scenario similar to STC #2, but with core-concrete interactions occurring in the cavity even in the presence of water. This was achieved in MAAP by reducing the critical heat flux multiplier model parameter (FCHF) by a factor of five from its default value to 0.02. The resulting generation of non-condensible gases acts as a pressurization source to containment even with fan coolers available, and the fission product releases through the early containment failure are larger compared to the STC #2 results. The noble gases and volatile releases increase slightly because of the aforementioned 'source' to containment. Additionally, due to the core-concrete interactions in this case, the non-volatile releases increase more dramatically compared to STC #2 results which had only a small amount of non-volatile releases. The calculated radionuclide release fractions at 48 hours for this case are also shown in Table 4.7-2.

STC #4 (<0.1%)

For this low likelihood STC end state, core-concrete interactions are assumed to occur under dry conditions since the RWST is not injected. However, containment fan coolers are operating. The representative MAAP case was chosen as a medium break LOCA to allow the majority of the core debris to enter the cavity and maximize the potential for concrete attack. Input parameters were set to prevent water from entering the cavity even with fan coolers operational. Two seconds after vessel failure, the leak-before-break containment failure is assumed to occur due to the end state definition. In this case, about 5 ft of concrete attack occurs by 48 hours (compared to ~2 ft in the wet CCI case represented by STC #3). The resulting larger production of non-condensible gases and inert aerosols leads to larger noble gas, volatile, and non-volatile releases compared to the STC #3 results as can be seen in Table 4.7-2.

STC #5 (<0.1%)

This STC end state is identical to STC #2 except for the assumed size of containment failure. In this case, a global failure area of 1.0 ft^2 was forced to occur two seconds after vessel failure instead of the leak-before-break area of 0.025 ft^2. This led to more rapid containment depressurization, and since the majority of the releases occur during this depressurization period, the releases are larger than those exhibited in STC #2 as can be seen in Table 4.7-2.

STC #7 (<0.1%)

Similarly, STC #7 is identical to STC #4 except for the assumed size of containment failure. In this case, a global failure area of 1.0 ft^2 was forced to occur two seconds after vessel failure instead of the previous assumption of 0.025 ft^2. Again, the resulting more rapid depressurization leads to, in general, larger releases compared to those from the representative STC #4 case results. The calculated radionuclide release fractions at 48 hours for this case are also presented in Table 4.7-2.

STC #8 (<0.1%)

This STC end state describes a scenario with vessel failure and early containment failure assumed to occur by liner melt-through as debris expelled from the vessel comes into contact with the steel liner. This low likelihood STC end state definition assumes that containment heat removal is unavailable and core-concrete interactions occur in containment without water present. The representative scenario was chosen as a station blackout with an induced hot leg rupture. This led to a low pressure vessel failure with all molten core debris expelled to the cavity. This is inconsistent with the assumption of an early liner melt-through containment failure, but was done to get dry core-concrete interactions consistent with the end state definition. Since liner melt-through is not explicitly modeled in MAAP, containment failure was simply forced to occur with an area of 1.0 ft^2 two seconds after vessel failure. This was deemed adequate to provide conservative representative source term results for this end state category. The calculated radionuclide release fractions at 48 hours for this case without accounting for any retention of fission products in the liner gap are given in Table 4.7-2.

STC #9 (0.3%)

This STC end state describes a scenario with vessel failure and a late global containment failure assumed to occur with containment heat removal available, but with dry core-concrete interactions also occurring. PDS 7 comprises the majority of this STC end state. The representative scenario was chosen as a station blackout with an induced hot leg rupture. This allows for all molten core debris to stay in the cavity following vessel failure and dry core-concrete interactions ensue in earnest. At 10 hours, however, it is assumed that fan coolers become available and are restored. This reduces the steam concentration in containment below the inert flammability limits and the hydrogen burn which occurs at 11.7 hours is assumed to fail containment. The restoration of the fan coolers also puts water in the cavity, cools the debris, and terminates core-concrete attack. However, the source term results afforded by the assumed containment failure in this case are deemed adequate to represent STC #9. The calculated releases for this case are again given in Table 4.7-2.

STC #10 (0.1%)

This STC end state describes a vessel failure scenario with a late leak-before-break containment failure assumed to occur without containment heat removal available and with dry core-concrete interactions also presumed to occur. The major contributor for this STC end state is PDS 8. Thus, a station blackout scenario with induced hot leg rupture and no power recovery was chosen as the representative sequence. All core debris enters the cavity following vessel failure and concrete attack quickly ensues. At 19.2 hours, the containment is calculated to reach its assumed failure pressure of approximately 144 psia. The leak-before-break assumed failure area of 0.025 ft^2 leads to a gradual containment depressurization down to below 40 psia by the end of the run at 48 hours. Without containment heat removal, concrete attack continues over this entire time period. The calculated radionuclide release fractions at 48 hours for this case are shown in Table 4.7-2.

STC #11 (<0.1%)

This STC end state is identical to STC #10 except for the assumed size of containment failure. In this case, a global failure area of 1.0 ft^2 was assumed to occur at the time of containment failure instead of the leak-before-break area of 0.025 ft^2. This leads to much more rapid containment depressurization, and since the depressurization rate dictates the airborne fission product release rate, the releases are larger than those exhibited for STC #10 as can be seen in Table 4.7-2.

STC #12 (14.2%)

This STC end state is for a very late containment failure case assumed to occur due to basemat meltthrough. The representative MAAP case was chosen as a medium break LOCA with core debris in the cavity, and only fan coolers operational. Input parameters were set to prevent water from entering the cavity. A late containment failure was assumed to occur after more than 1.5 ft of concrete attack had occured (at approx. 13.6 hours) to simulate basemat meltthrough failure. A small failure area of 0.025 ft^2 was chosen to provide representative source term results since no credit is taken in the MAAP model for retention of fission products in the liner gap or through the soil after the basemat meltthrough occurs. The calculated radionuclide release fractions at 48 hours for this case are also presented in Table 4.7-2.

STC #13 (3.0%)

This STC end state describes a vessel failure scenario with a containment isolation failure. PDS 1 is the dominant contributor to this end state with containment fan coolers operational, but with no injection or containment sprays available. The source term results for this case are represented by the STC #7 results. This is a large early containment failure case with fan coolers available and core-concrete interactions in the cavity. Thus, it is similar enough to provide representative source term information.

STC #14 (<0.1%)

This low frequency STC end state is for an alpha-mode early containment failure. Since this cannot be explicitly modeled in MAAP, the characteristic source terms are taken to be similar to those for STC #8. That case was an early containment failure case (by liner melt-through) which included no containment heat removal and prolonged core-concrete interactions in the cavity. This should conservatively approximate the characteristic source terms from this containment failure mode.

STC #15 (5.1%)

This describes an end state with no containment bypass (as do all of the previous cases as well), with no containment isolation failure, with debris cooled in-vessel, and with no subsequent containment failure. Although slight differences may occur in the relative noble, volatile, and non-volatile releases in this case compared to the STC #1 releases, since neither end state leads to containment failure, the releases for this end state are judged to be adequately represented by the calculated STC #1 releases.

STC #16 (9.7%)

This end state represents a containment bypass scenario via an interfacing system LOCA (ISLOCA) outside of containment. The representative ISLOCA was chosen as a medium break LOCA with no injection or containment heat removal available. AFW and accumulators are assumed to be available. In this case, core damage is indicated within one hour and vessel failure is predicted in about an hour and a half. The fission product releases occur early through the bypass of containment. With no credit taken for retention in the auxiliary building, the releases are rather large. The calculated releases at 48 hours for this case are also reported in Table 4.7-2.

STC #18 (17.1%)

This STC end state is for an isolated steam generator tube rupture scenario without feedwater being supplied to the affected steam generator. The representative case assumes no injection is available, and feedwater to the faulted steam generator is terminated at 30 minutes. The majority of the fission product releases reported in Table 4.7-2 occur as the broken loop steam generator PORV cycles during core damage. After vessel failure, the broken loop steam generator pressure equalizes with the containment pressure below the PORV opening setpoint and doesn't open anymore. Fission product releases are then limited to leakage as containment heat removal systems are assumed to prevent a later containment failure.

STC #20 (15.6%)

This STC end state is for an unisolated steam generator tube rupture scenario without feedwater being applied to the affected unit. The representative case is a steam generator tube rupture initiator with no high pressure injection and with the affected unit PORV assumed to stick open at 20 minutes. With no injection or AFW to the broken loop, the primary and broken loop secondary inventory eventually boils away. The majority of the fission product releases as reported in Table 4.7-2 occur through the tube rupture out through the stuck steam generator relief valve during core degradation prior to vessel failure at about 7.3 hours. Note this STC end state may be accompanied by another release at a later time if radionuclides are released through some other containment failure mechanism. This possibility is ignored here, because the severity of the earlier releases would dominate any subsequent release.

4.7.3.2 Results

The results from the MAAP analysis for each of the relevant STC end states are shown in Table 4.7-2. The table shows the representative MAAP case identification designator, the radionuclide release fractions for each of the twelve MAAP fission product groups, and the sequence time at which the results are presented.

4.7.3.3 Summary

The representative source term results shown in Table 4.7-2 can be binned to provide for more general conclusions about the results. Due to the rather large uncertainties associated with any source term analysis, previous studies have typically grouped the magnitude of the releases based on the following scheme.

Low-Low	(LL)	Release Fraction <0.1%
Low	(L)	0.1% < Release Fraction <1.0%
Medium	(M)	1.0% < Release Fraction <10%
High	(H)	Release Fraction > 10%

This scheme is adopted here and this categorization is applied to noble gases, volatile releases (typically characterized by CsI or CsOH releases), and non-volatile releases (as characterized by the largest of the tellurium, strontium, or barium release). This is motivated by the fact that sequences with large volatile releases may well have small non-volatile releases or vice-versa. Thus calling the aggregate of all releases "High" or "Low" as is sometimes done can be confusing. The results after this grouping scheme was applied along with an indication of the timing (early (E) or late (L)) and the contribution to core damage frequency (% CDF) for each relevant STC and state are given in Table 4.7-3.

Examining the results in Table 4.7-3, the source terms can be even further subdivided into Type I, II, III, IV, V, or VI releases based on the combination of the noble, volatile, and non-volatile releases magnitudes. These categories have been developed specifically to better characterize the overall results. Type I releases are those limited to leakage with no containment failure or bypass. Type II releases consist of high noble gas releases, but with low or low-low volatile and non-volatile releases. Type III releases are represented by high noble gas releases, medium volatile releases, and low or low-low non-volatile releases. Type IV releases consist of high noble gas, medium volatile releases, and medium non-volatile releases. Type V releases characterize the sequences with high noble gas and volatile releases, but with medium or lower non-volatile releases. Finally, type VI releases are considered for sequences with high noble, volatile, and non-volatile releases from containment. Other combinations of results based on the high, medium, and low or low-low release categorization were not prevalent for Ginna. Table 4.7-4 summarizes the results based on this final categorization scheme.

In summary, the representative releases are limited to leakage (Type I) in 40.0% of all core damage sequences. Type II releases with high noble gas, but with low or low-low volatile and non-volatile releases comprise 14.5% of the core damage sequences mostly comprised of late basemat melt-thru scenarios (STC #12). The next category (Type III) with medium volatile releases represents 17.1% of the sequences. This is made up of the STC end states for early containment failures with containment heat removal and no core-concrete interactions (STC #5), and isolated SGTR scenarios (STC #18). Type IV releases with high noble gas, and medium volatile and non-volatile releases represent 3.1% of the total core damage frequency comprised mostly of containment isolation failure cases with containment heat removal available (STC #13). The more serious Type V releases with high noble gas and volatile releases, but medium non-volatile releases represents 25.3% of the total CDF. This is mostly representative of interfacing system LOCA, and unisolated steam generator tube rupture scenarios. Type VI releases with high noble gas, volatile, and non-volatile releases represents less than 0.1% of the total CDF. This is representative of alpha mode containment failure or liner melt-thru scenarios with sustained core-concrete interactions.

4.7.4 Release Category Frequencies and Dominant Sequences

Table 4.7-5 presents the source term release categories sorted by frequency. It should be noted that the release category point estimate frequencies shown in table 4.7-5 are the plant damage state point estimate frequencies multiplied by the conditional probability that a sequence in a particular plant damage state will have a containment response outcome (as modeled by the containment event tree) that results in its assignment to a particular source term release category (summed over all plant damage states).

Release category 1 which represents 34.9% of the total core damage frequency (CDF) ranks first in frequency. This release category contains sequences with the reactor vessel failed but with the containment intact. This release category has a very low (volatile radionuclide species) source term due to preservation of containment integrity. The high reliability of containment heat removal (particularly the fan cooler system) contributes to the dominance of this release category.

Release categories 18 and 20, which rank 2nd and 3rd, are steam generator tube rupture (SGTR) sequences. These release categories represent 17.1 and 15.6% of the total CDF, respectively. Release category 18 contains SGTR sequences with the steam generator isolated and release category 20 contains SGTR sequences with failure to isolate the impacted steam generator. For both of these release categories the secondary side of the steam generator is dry during the time period of core damage and fission product release from the core. Medium to large early radionuclide source terms are expected for these release categories. These SGTR release categories along with the interfacing system LOCA release category (RC 16) can be expected to dominate severe accident risks for Ginna.

Release category 12 (14.2% of total CDF) is ranked 4th. This release category contains sequences where containment integrity is lost by meltthrough of the basemat. Since the Ginna containment is founded on bedrock the pathway for the airborne release of radionuclides would be expected to be long and tortuous through the underlying strata. Consequently, the airborne radionuclide source term would be expected to be low. In addition, basemat meltthrough would not be expected to occur until many hours after reactor vessel failure, allowing substantial time for deposition of the volatile radionuclide species in containment. Note that for sequences in this release category the containment fan coolers and/or the containment sprays were available. Operation of either the fan coolers or sprays would significantly reduce the release of volatile radionuclides. A major factor affecting the relatively high frequency of this release category is the estimated impact of the reactor cavity sump on debris coolability in the cavity and the relatively thin basemat beneath the sump.

Release category 16 (9.7% of total CDF) contains interfacing system LOCA containment bypass sequences. High early source terms are expected for sequences in this release category.

For sequences in release category 15 (5.1% of total CDF) the damaged core is cooled in-vessel and reactor vessel and containment integrity are maintained. Consequently, the source term for sequences in this release category are expected to be very low.

Release category 13 (3.0% of total CDF) contains all sequences where containment isolation has failed. For these sequences containment heat removal is generally available and the radionuclide source term is expected to be medium as a result.

The seven release categories summarized above represent 99.6% of the total CDF. Release categories containing sequences with early containment failure (RCs 2,3,4,5,6,7,8 and 14) together represent approximately .05% of the total CDF. These release categories include sequences with containment failure resulting from in-vessel steam explosions; overpressurization at the time of reactor vessel failure due to direct containment heating, hydrogen combustion and related phenomena; and containment liner thermal failure following vessel failure.

The release categories containing sequences with late overpressure containment failure (RCs 9,10 and 11) represent approximately 0.4% of the total CDF. The high reliability of containment heat removal is a major reason these release category frequencies are so small.

The overall containment accident progression results are compared with the those presented in NUREG-1150 for the Surry plant in Table 4.7-6.

4.8 Sensitivity Calculations

4.8.1 Containment Event Tree Sensitivity Analysis

An important element of the Level 2 containment analyses is addressing the question: "To which aspects of the containment modeling are the overall results most sensitive?" The sensitivity analysis presented here aids in the identification of possible weaknesses in the analysis or areas which may require further effort or further support.

A sensitivity analysis can be represented by the equation.

$$\Delta R = f\ (\Delta I)$$

where ΔR is the change in an important result (for example the change in the conditional probability of a source term release category)

ΔI is the change in value of an input to the model (for example, a change in an event split fraction probability)

and f is the functional relationship between the two defined by the overall backend containment event analysis.

Important sensitivities can be considered as those where a "reasonable" change in a basic CET (or DET) event probability results in a significant change in the overall results. For example, a change may produce a significant increase (decrease) in the probability of a high source term release category and a corresponding decrease (increase) in a low source term release category. A "reasonable" change in a basic event probability refers to a change that is within the assessed uncertainty range for the event probability.

For phenomenological events the range of reasonable values to use in a sensitivity analyses is not always evident. These event probabilities can be interpreted as being degrees-of-belief in the outcome of an uncertain event where only one outcome is physically possible but we are not completely certain which is the correct one. Two approaches can be taken for these type events. The first approach acknowledges that either event may be possible and that our probability estimates merely state our belief as to which is most likely to be the correct outcome. For this approach we would set the value of one event branch equal to 1 (and the other branches equal 0) and assess the impact on release category probabilities. This type of approach addresses the question of what the impact on the final results are if this event branch is the correct one for the phenomenological process. We then systematically assign a value of 1 to the other event branch probabilities and repeat the analyses. A second approach to sensitivity analyses for phenomenological events is to investigate the impact of variations in the degree-of-belief probability estimates on the overall results for each of the phenomenological events - i.e., change the assessed probabilities from the baseline values but not necessarily to (1,0), (0,1) combinations discussed above. This approach is analogous to assuming what other experts might select.

The type of sensitivity calculations performed for the Ginna PRA involved varying the probability of an event in the CET/DETs and assessing the impact of these variations on important Level 2 outcomes such as the frequency of high-magnitude source term categories.

The CET and DETs were reviewed and the phenomenological events which were judged to either have large uncertainties or were expected to have a substantial influence on important outcomes were identified. Sensitivity calculations were performed for most of these phenomenological events. The parameters which were varied in the Level 2 sensitivity study are discussed below along with the parameter variations investigated in each case. For most parameters the sensitivity calculation involved changing one branch probability to one (with all other branch probabilities set to zero) and requantifying the CETs.

The principal observations made for the sensitivity studies are presented below. The sensitivity calculations were based on an earlier quantification than has been presented in this analysis. Minor changes were made in the loss of isolation sequences which caused minor changes in the final results. The minor changes do not affect the overall results of the sensitivity analysis.

4.8.1.1 Induced Hot Leg Failure Sensitivities

Sensitivity calculations were performed to assess the impact of assumptions regarding the probability of induced RCS failure on important level 2 results. For this sensitivity calculation the probability for induced RCS failure for "High" and "Hi Hi" pressure sequences was set equal to zero for case 1A and to one (for all cases without an induced tube rupture) for case 1B. For both cases the probability of induced SGTR remained the same as in the base calculation.

Only minor changes in the relative frequency for individual release categories was observed for this sensitivity calculation. All changes in release category frequency were less than one-half of 1% of the total CDF. For Case 1A (no induced RCS failures), there was a marginal decrease in the frequency of debris cooled in-vessel sequences (Release category 15 changed from 5.0 to 4.3% of the total core damage sequence frequency). For case 1B (hot leg failure for all "High" and "Hi Hi" pressure sequences) there was a similar small increase in the frequency of debris cooled in-vessel sequences from 5.0% to 5.3%.

The lack of sensitivity to changes in the probability of induced hot leg failures results from the relatively small fraction of all core damage sequences which are at High (0% of total CDF) or Hi Hi pressure (4% of total CDF) during core damage (see Section 4.3.4). Table 4.8-1 shows the results for sensitivity cases 1A and 1B.

4.8.1.2 Direct Containment Heating Sensitivities

The importance of DCH and related phenomenon to early containment failure was investigated by performing a bounding sensitivity calculation. For sensitivity calculation 2A the probability of the most severe branch in each of the four events in the DET for Early Containment Failure (Figure 4.5-4) related to DCH pressurization were all simultaneously set to one. In this calculation the probability of the following event branches were set to 1.

Event	Branch
Mass Debris Expelled Early	40-60%
Fraction Debris Involved in DCH	HI (100%)
Fraction Debris Dispersed Outside Lower Comp.	HIGH (25%)
Hydrogen Burn	UCHB

The results from this calculation are shown on Table 4.8-2. Even with this very conservative representation of DCH pressurization effects the relative frequency of early containment overpressure failures is relatively low (sum of RCs 2 through 7 equals approximately 4.4% of total CDF).

4.8.1.3 Containment Failure Pressure Sensitivities

A containment failure pressure sensitivity calculation was run assuming that the (actual) containment failure pressure was the pressure at the fifth percentile on the containment fragility curve (133 psia). This sensitivity calculation was performed by assigning a probability of containment failure of 1.0 for all sequence pathways (in the DET for Early Containment Failure) where the pressure was above 133 psia and a probability of 0. for sequence pathways with a peak pressure of 133 psia or less.

There was no change in the overall results with the containment failure pressure set to the 5th percentile value on the fragility curve as shown on Table 4.8-3.

4.8.1.4 Debris Depth in Sump Sensitivities

In the decomposition event tree for Type of Ex-vessel CCI (Figure 4.5-6) the amount of debris that is transported into the cavity sump is judged to be a critical parameter. Consequently, the event "Depth of Debris in Sump" was selected for sensitivity analysis. Two sensitivity calculations have been performed. In Case 4A the debris depth in the sump has been minimized and in Case 4B the depth has been maximized.

For Case 4A the probability of the "Nominal" branch has been set equal to 1.0 for all sequence pathways. This sensitivity calculation represents the case of no preferential debris transport into the sump. In case 4B the probability of the branch representing the maximum depth of debris in the sump has been set equal to 1.0.

The results from these sensitivity cases are shown on Table 4.8-4. The only release categories impacted by these changes are RC 1 which contains sequences without containment failure and RC 12 which represents containment basemat meltthrough. The relative frequencies for these two release categories are fairly sensitive to assumptions regarding the amount of debris in the sump. The relative frequency of basemat meltthrough (RC 12) is decreased by 1.6% and increased by 16.9% from the base calculation for sensitivity cases 4A and 4B, respectively. There is also a corresponding change in the no containment failure release category (RC 1).

4.8.1.5 Steam Explosion Disperses Debris in Cavity Sensitivities

If water is present in the reactor cavity at the time of vessel failure steam explosions may occur and disperse and fragment the debris. This process is modelled in event "Steam Explosion Disperses Debris" in the DET for Type of Ex-vessel CCI (Figure 4.5-6). In the base case calculation the probability of a significant ex-vessel steam explosion which disperses the debris throughout the reactor cavity was nominally 0.43. Sensitivity calculations 5A and 5B assess the sensitivity to variations in this probability. In case 5A the probability of a dispersive steam explosion is set equal to 1.0 and in Case 5B the probability is set to 0.0.

The results from these sensitivity cases are shown on Table 4.8-5. Similar to sensitivity cases 4A and 4B discussed above, the only release categories impacted by these changes are RC 1 which contains sequences without containment failure and RC 12 which represents containment basemat meltthrough. Similar to 4A and 4B, the relative frequencies for RCs 1 and 12 are fairly sensitive to assumptions regarding the probability of a dispersive steam explosion. The relative frequency of basemat meltthrough (RC 12) is decreased by 7.9% and increased by 5.9% from the base calculation for sensitivity cases 5A and 5B, respectively. There is also a corresponding change in the no containment failure release category (RC 1).

4.8.2 MAAP Code Sensitivity Analysis

As part of the containment evaluation, there are phenomenological issues that may have a large impact on the course of the events in the Level 2 evaluation of the radionuclide release magnitude and timing. To ensure that a broad range of phenomena was considered in the Ginna PRA, several deterministic sensitivity analyses were performed using the MAAP code. These analyses were performed in accordance with: (1) the recommendations made in the EPRI Guidance Document for performing sensitivity studies with MAAP 3.0B [Ref. 4.9-4], (2) the augmentations to these recommendations provided in the NRC sponsored MAAP 3.0B code evaluation [Ref. 4.9-42], and (3) other specific areas deemed important for Ginna.

In the MAAP code, model parameters generally represent inputs to phenomenological models in which significant uncertainties exist. Variations in the values of these parameters can be made to assess the impact of uncertainties in important physical models. The best estimate values provided in the Ginna MAAP parameter file are also based on the recommendations provided in the EPRI Guidance Document [Ref. 4.9-4]. The base MAAP analyses used these default values in their calculations. In this section, the results from cases where variations in these (and other) parameters were made to explore uncertainties in various phenomena will be reported.

For purposes of discussion, the relevant MAAP sensitivity cases have been divided into five categories.

- Core melt progression and in-vessel hydrogen generation
- Natural circulation, induced ruptures of the primary system, and RCS pressure at vessel failure
- Fission product release and revaporization
- Ex-vessel debris coolability
- Energetic events in containment (i.e. H_2 burns and DCH)

The results from the MAAP analyses for each of these categories are described in the sections which follow.

4.8.2.1 Core Melt Progression and In-Vessel Hydrogen Generation

One critical parameter in MAAP for core melt progression is the choice of the core blockage model parameter (FCRBLK). The base MAAP calculations in the Ginna PRA were performed with the "blockage" model turned off as recommended in Ref. 4.9-4. In practice, this means that little credit is taken for the effects of geometry degradation or zirconium relocation on the cessation of hydrogen production, and the results obtained have historically corresponded fairly well to results from more detailed NRC codes such as MELCOR and MELPROG. The calculations performed with MAAP for Ginna generally support this conclusion as Table 4.8-6 indicates. The NUREG-1150 results reported in this table are based on the median hydrogen source terms quoted in the Surry expert ellicitations with all of the results expressed in terms of the fraction of the total in-core Zircalloy mass that is oxidized.

In addition, an SBO calculation was made in which induced rupture did not occur and the MAAP blockage model was activated (FCRBLK=1: Case SBO22). A separate SBO case used an increased value for the eutectic latent heat of fusion (LHEU=400 KJ/Kg: Case SBO23). The activation of the blockage model resulted in 35% clad reacted, and the increased latent heat of fusion case resulted in 52% clad reacted. As can be seen in Table 4.8-6, however, the MAAP calculations without the blockage model employed are reasonably consistent with those estimated in NUREG-1150.

4.8.2.2 Natural Circulation, Induced Ruptures of the Primary System, and RCS Pressure at Vessel Failure

Code calculations and scale model experiments support the conclusion that the hot legs and surge line will be substantially heated by natural circulation of hot gases from the core to the upper plenum and from there into the hot legs [Ref. 4.9-43]. Calculations by both MAAP and the SCDAP/RELAP code indicate that the steam generator tubes will not see a great increase in their temperature due to the same effects [Ref. 4.9-44]. Higher hot leg than surge line temperatures are predicted in MAAP for the simple reason that flow into the surge line is reduced dramatically once the water level nears the bottom of the core and steaming diminishes. Typical SCDAP results predict the opposite for reasons that are not currently understood. Consistent with the SCDAP results, however, steam generator tube temperatures are much lower than either the hot leg or surge line temperatures. In any event, it is of great interest to assess whether the hot legs or surge line are heated enough to cause failure and depressurization of the RCS prior to RPV melt-through, since this would prevent phenomena which depend on an energetic blowdown of the RCS.

MAAP uncertainty analyses on the predicted hot leg and steam generator tube temperatures have been considered as was described in Section 4.6.2 to assist with the determination of the likelihood of induced ruptures at Ginna. Another aspect deemed worthy of consideration in the EPRI MAAP Guidance Document [Ref. 4.9-4] for this issue is whether or not pump suction loop seals are assumed to clear. Thus, case SBO24 was run in which both loop seals are assumed to clear in an SBO scenario. The final sensitivity case on this issue considered the choice of FNCBP which is used to select whether natural circulation from the upper plenum passes down the outer part of the core (FNCBP=0) or down the core barrel/core baffle annulus (FNCBP=1). The EPRI MAAP Guidance Document states that this parameter should be set to zero for Westinghouse plants. BNL/NRC [Ref. 4.9-42] recommends that this parameter be set to one in a high pressure station blackout sequence. This was done for Ginna in MAAP case SBO25.

Table 4.8-7 summarizes the predicted hot leg temperatures at vessel failure for each of the relevant cases. In all but the pump suction loop seal clearing case (SBO24), the predicted temperatures are high enough that creep rupture of the hot leg can be considered likely. The fact that the pump suction loop seal clearing case predicted lower temperatures should be expected. In this case, with both of the loop seals clear, global circulation of hot gases can occur from the core to the upper plenum to the hot leg to the steam generator tubes to the intermediate leg to the cold leg into the downcomer and through the other loop circuit in the reverse direction. This affords much more opportunity to distribute the hot gases and reduce the peak temperatures achieved by the hot legs compared to the other cases. The key point, however, is that both intermediate leg loop seals need to clear to establish this path. If only one loop seal clears, then that loop would only become continuous once the downcomer water lever dropped below the core barrel such that gas in the downcomer could flow into the core closing the loop for that circulation path. Until that time, natural circulation from the upper plenum into the hot legs with a separate path into and out of the steam generator tubes would persist in the same fashion as if the loop seals had not cleared. Flow in the other loop would also be sustained in the same fashion as in the base analyses. Thus, the peak hot leg temperature would be about the same as the other cases if only one loop seal were to clear. If loop seal clearing were to occur, it is considered to be much more likely that one loop seal clears rather than both loop seals. This is because the pressure differential across the loop seals required to clear them would be gone as soon as one of the loop seals were to clear. Any asymmetries whatsoever in the loops would allow one loop to clear before the other. Thus, it is judged that the higher predicted hot leg temperatures exhibited in all but the double loop seal clearing case represent the more likely outcome.

To investigate the uncertainty associated with the primary system pressure at vessel failure, as recommended in the Guidance Document, additional LOCA cases were run in which the time to fail the RPV head (TTRX) was increased to 30 minutes from its default value of 1 minute. This was done for 2" diameter cold leg LOCAs with and without injection and secondary depressurization for Ginna as summarized in Table 4.8-8. The resulting higher primary system pressures are due to steaming of the remaining water pool as core debris slumps into the lower plenum. Although vessel failure, if it occurs, is most likely to occur early after debris slump (before steaming of water in lower plenum quenches the debris) or late (after the remaining water in the lower plenum boils away and the debris heats up again), this uncertainty analysis indicates the potential for increased pressures at vessel failure.

4.8.2.3 Fission Product Release and Revaporization

One of the potential long term sources of fission products in severe accidents results from previously settled aerosols which revaporize from overheated primary system structures. The temperatures of the primary system heat sinks depend on the total heat load in the RCS. This will be strongly affected by the presence of core material in the vessel after vessel failure. The default assumption in the MAAP analyses was to allow all remaining core material to drop from the vessel after 90% of the original core material had melted. Since it is questionable whether portions of a severely damaged core could actually stay intact, and since the default assumption could lead to overestimating the amount of revaporization, the MAAP Guidance Document [Ref. 4.9-4] recommends that at least one sensitivity case be run which allows all of the core material to leave the vessel following RPV failure (FCRDR=0.8). BNL/NRC [Ref. 4.9-42] extended this recommendation to consider all representative sequences which predict vessel failure prior to containment failure.

For Ginna, the large majority of the long-term cases that lead to containment failure resulted in all core material eventually being discharged from the vessel. Since the concerns addressed above would not be an issue for cases with all material discharged from the vessel, sensitivity analyses were not deemed necessary for Ginna. However, one case (SBO07) did predict core material retained in-vessel. Therefore, that case was rerun with the core drop fraction set to 0.8 to force all of the debris from the vessel following vessel failure. Key results from this analysis are shown in Table 4.8-9. With all material discharged from the vessel, the decay heat that goes to boiling water in the cavity is greater. This leads to a slightly earlier time to containment failure compared to the base case. Since more energy goes to the containment, the primary system temperature is lower in the sensitivity case at the time of containment failure. With lower primary system temperatures, the amount of revaporization is smaller, and lesser amounts of fission products are released from containment.

A separate issue related to revaporization involves chemical reactions between deposited fission products and heat sink surfaces which are ignored in MAAP. It has been hypothesized that such reactions (chiefly from cesium iodide and cesium hydroxide) could suppress revaporization so that materials were more concentrated in one location and consequently were vaporizing in quantity at a later time. Therefore, it was recommended [Ref. 4.9-4] that in at least one calculation (e.g. in a high pressure blackout scenario), a sensitivity calculation be run with the revaporization vapor pressure multiplier reduced (FVPREV). This could be done to mimic the suppression of revaporization that could occur if the chemical reactions had been modeled. This was done for Ginna in cases SBO06 and SBO21, and key results from this sensitivity analysis are presented in Table 4.8-10. As can be seen, these cases did not lead to significant differences in the results compared to the base case analyses with the anticipated effect of increasing revaporization at the time of containment failure not occurring, and with the actual releases reduced in both sensitivity cases.

One additional MAAP sensitivity case was performed related to this issue, and that was for the assumed equipment mass in containment. The default values in the Ginna MAAP parameter file were 2.4E5 lb and 1.4E4 lb in the upper and lower compartments, respectively. This may have been too conservatively estimated, so the station blackout base case was rerun with these values increased by a factor of ten based on a review of other plant MAAP parameters. Key results from this uncertainty analysis are given in Table 4.8-11. Due to the increased heat capacity of containment, containment failure is delayed by more than 3.5 hours in the sensitivity case. However, the suppression of revaporization that occurs in this case due to the overall lower temperature conditions, allows slightly more CsI releases to occur later in the sensitivity case compared to the base case. Future accident management developments will need to take into account the types of uncertainties associated with fission product revaporization that were explored in the sensitivity cases discussed here.

4.8.2.4 Ex-Vessel Debris Coolability

Sequences that lead to vessel failure in which a containment heat removal system is operational must consider if the expelled core debris can be cooled sufficiently to avoid concrete attack and thus prevent containment pressurization. In low pressure vessel failure cases at Ginna, the core debris will be confined to the cavity region. On the other hand, high pressure vessel failure cases are assumed to result in the debris being spread over a wide area in the lower compartment and in the refueling pool. For reference, if one assumes that all of the core debris is spread uniformly over the cavity floor (~29m^2), at 1% decay power of which 80% is still in the debris (the remainder having been released in the form of volatile fission products and noble gases), the required heat flux for steady state is about 420 kw/m^2; this neglects any heat load from chemical reactions which would eventually cease.

The IPE generic letter states that the possibility that the debris may not be coolable should be considered for debris layers deeper than 25 cm. At Ginna, 100% of the core material (~64,000 kg) at a theoretical density of 8,000 kg/m^3 would result in a debris bed thickness of over 25 cm if all of the debris is in the cavity. Much smaller debris depths can then be expected for debris expelled out of the cavity. Additionally, experiments performed at Sandia National Laboratory and Fauske and Associates have produced asymptotic heat fluxes of about 800 kw/m^2, (more than the 420 kw/m^2 required to cool debris in the cavity). These analyses assume uniform debris distribution in the cavity. Debris retention in the cavity sump was considered separately in the containment event tree calculation (section 4.5). In any event, sensitivity cases were run for low pressure vessel failure scenarios with a reduced heat flux multiplier model parameter and a uniform distribution of debris on the cavity floor.

In the sensitivity cases, the core debris to overlying water pool heat flux multiplier (FCHF) was reduced by a factor of five from its default value of 0.10 to 0.02. As recommended in the MAAP Guidance Document [Ref. 4.9-4], this is about the value which can be sustained by conduction alone. Thus, with this minimum choice of FCHF, concrete attack ensues in the cavity following vessel failure even with water in the cavity. Key results for these cases are presented in Table 4.8-12. The first case with fan coolers available and no containment failures sees only a gradual increase in releases due to the cavity concrete attack. It is interesting to note, however, that the sensitivity case does predict burns to occur later in the sequence as hydrogen builds up from the concrete attack. The second sensitivity case, with early containment failure assumed, shows a more dramatic increase in the releases especially for the non-volatile releases represented by tellurium. In the second sensitivity case (STC03), cavity concrete attack does not cease until about 40 hours.

4.8.2.5 Energetic Events in Containment

Direct containment heating (DCH) is the first issue that needs to be explored in the category of energetic events in containment. The major uncertainty in the MAAP model for this phenomena is considered to be the fraction of the debris leaving the reactor cavity (FCMDCH) which is fragmented finely by gas. For Ginna, several MAAP sensitivity cases were performed to explore this issue and they are described in Section 4.6.2. These included variations of FCMDCH, the assumed entrainment time constant (TTENTR), the fraction of debris dispersed to the upper versus the lower compartment (FCMDA), and whether or not unconditional hydrogen burns occurred coincident with the DCH event.

Hydrogen burning is the other issue which needs to be explored for this category. The situation of interest here is the case where core-concrete attack occurs which increases the amount of hydrogen in containment. In the base case (SLOCA02), fan coolers were operational but core-concrete attack was still allowed to occur in the cavity. Jet burning in the cavity occurred following vessel failure, and global burns were predicted to occur at 6.2 and 13.0 hours. A peak containment pressure of 105.2 psia was reached after the last burn was initiated. This is still well below the median failure pressure for Ginna of 144 psia.

In the sensitivity case (SLOCA06), burns were totally disabled for 24 hours. This resulted in about 820 lb of hydrogen distributed throughout containment with an average H_2 mole fraction slightly greater than 10% by the end of the run. The second sensitivity case (SLOCA07) allowed burns to occur at 24 hours. In this case, the peak containment pressure of 144.9 psia resulting from a global burn of more than 10% hydrogen was very close to the median failure pressure of the Ginna containment. Consequently, the possibility of late hydrogen burns leading to containment failure must not be discounted when severe accident management recovery actions are considered.

4.9 References

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Table 4.1-1
Ginna Design Information

Type of Reactor	Pressurized Water Reactor
Manufacturer	Westinghouse
Date of Commercial Operation	1970
Reactor Core	
Nominal Power	1520 MWt
Number of fuel assemblies	121
Number of fuel rods	21,659
Core weight	
Uranium dioxide	105,500 lb
Zircaloy	25,927 lb
Equilibrium Enrichment	3.6 wt %
Number of control rods	528
Control rod material	
Silver 80 %	
Indium 15 %	
Cadmium	5 %
Reactor Vessel	
Inside diameter	132 in.
Overall internal height	39.1 ft.
Thickness at beltline (min)	6.5 in.
Lower Head thickness (min)	4.125 in.
Water capacity with core and internals in place	2525 ft^3
Reactor Coolant System (nominal)	
Volume (including PZR)	6616 ft^3
Water in system	392,000 lb
Operating temperature	573.5°F
Operating pressure	2250 psia
Number of RCPs	2
Number of Steam Generators	2
Type of Steam Generators	U-tube (W Model 44)
Total flowrate	6.8E7 lb/hr

Table 4.1-1 (Continued)
Ginna Design Information

Pzr Safety valves	
Number	2
Capacity	288,000 lb/hr
Setpoint	2485 psig
Pzr PORVs	
Number	2
Capacity	179,000 lb/hr
Setpoint	2335 psig
Containment	
Inside diameter	105 ft
Maximum inside height	164.5 ft
Free volume	972,000 ft^3
Maximum allowed leak rate	0.20 wt % per day
Design pressure	60 psig
Operating pressure	14.7 psia
Operating temperature	100°F
Concrete type	Limestone/common sand
Construction	Reinforced concrete
Wall thickness	3.5 ft
Dome thickness	2.5 ft
Basemat thickness	2.0 ft
Floor thickness above liner	2.0 ft
Containment Liner	Welded steel liner
Liner thickness, walls	0.375 in.
Liner thickness, dome	0.375 in.
Liner thickness, base	0.250 in.
Liner thickness, cavity	0.250 in.
Reactor Cavity	
Floor area	312 ft^2
Water capacity	6053 ft^3

Table 4.1-1 (Continued)
Ginna Design Information

Refueling Water Storage Tank	
Volume	300,000 gal
Temperature	80°F
Accumulators	
Number	2
Pressure	760 psig
Water capacity (total min)	2216 ft^3
Charging Pumps	
Number	3
Capacity	60 gpm
Design pressure	3000 psig
Max shutoff head	6931 ft
Safety Injection Pumps	
Number	3
Design flow	300 gpm
Design head	2700 ft
Design pressure	1750 psig
Max shutoff head	3400 ft
Max flow	625 gpm
Residual Heat Removal Pumps	
Number	2
Design flow	1560 gpm
Design head	280 ft
Design pressure	600 psig
Max shutoff head	340 ft
Max flow	2500 gpm
RHR Heat Exchangers	
Number	2
Design capacity	24.15E6 BTU/hr

Table 4.1-1 (continued)
Ginna Design Information

Containment Spray Pumps	
Number	2
Design flow	1200 gpm
Shutoff head	576 ft
Spray initiation setpoint	28 psig
Fan Coolers	
Number	4
Heat removal capacity (max)	61.7 MBtu/hr
Service Water flow (min)	900 gpm
Initiation setpoint	4 psig
Motor Driven Auxiliary Feedwater Pumps	
Number	2
Design flow	200 gpm
Design pressure	1085 psig
Max shutoff head	2575 ft
Max flow	240 gpm
Turbine Driven Auxiliary Feedwater Pump	
Number	1
Design flow	400 gpm
Design pressure	1085 psig
Max shutoff head	2380 ft
Max flow	475 gpm

Source for Table 4.1-1 Information

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   b. Drawing 33013-2132
   c. Design Analysis "Sump A and B Volumes"

Table 4.3-1
Systems and Plant States Important to the Containment Analysis

In-vessel Cooling Systems

- Low Pressure Injection
- Low Pressure Recirculation
- High Pressure Injection
- High Pressure Recirculation

Containment Heat Removal

- Containment Spray Injection
- Containment Spray Recirculation
- Containment Fan Coolers
- RHR Heat Exchangers

Electric Power

- Station Blackout
- Offsite Power Recovery
  - Prior Reactor Vessel Failure
  - Prior Containment Overpressure Failure

Containment Bypass

- Steam Generator Tube Rupture
- Interfacing Systems LOCA

Containment Isolation

Sequence Type

- LOCA
  - Small
  - Medium
  - Large
- Transient

Table 4.3-1 (continued)
Systems and Plant States Important to the Containment Analysis

Reactor Coolant System Pressure

- During Core Damage
- At RV Failure
- RCS Depressurization Using Pressurizer PORVs

Secondary Heat Removal

- Auxiliary Feedwater

Reactor Scram

Table 4.3-2
Split Fractions for Power Recovery

Case	Non-Recovery				Split Fraction	
	Vessel Failure		Containment Failure		PRV	PRC
	Time hr	Prob.	Time hr	Prob.		
AFW fails due to loss of ventilation	12	.0444	21	0.0566	0.622	0.127

Table 4.3-3
CSET Quantification Results

Core Damage Sequence	CSET Sequence Number	Probability
TB1L1P1	1	1.08×10^{-06}
	2	8.56×10^{-09}
	9	9.12×10^{-08}
	25	1.22×10^{-07}
	26	1.35×10^{-09}
	33	7.70×10^{-08}
	34	1.44×10^{-10}
TB1L1UH1	47	2.89×10^{-07}
	48	2.42×10^{-09}
	55	2.26×10^{-09}
	63	6.34×10^{-10}
	71	1.96×10^{-08}
	72	3.24×10^{-10}
	75	1.95×10^{-11}
	79	2.61×10^{-09}
	87	8.12×10^{-11}
	93	4.52×10^{-07}
	94	2.44×10^{-09}
	101	6.61×10^{-08}
TB1L1XL	33	2.48×10^{-07}
	34	1.84×10^{-08}

Table 4.3-3 - continued
CSET Quantification Results

Core Damage Sequence	CSET Sequence Number	Probability
TQ2UH2	17	2.69×10^{-06}
	18	2.26×10^{-08}
	29	2.73×10^{-07}
	30	3.28×10^{-09}
	39	2.40×10^{-08}
	41	3.50×10^{-07}
	42	3.33×10^{-09}
TQ2XL	25	7.40×10^{-06}
	26	1.49×10^{-06}
	33	9.22×10^{-06}
	34	9.08×10^{-08}
AUL	33	1.42×10^{-06}
	34	1.36×10^{-08}
	39	3.10×10^{-09}
	41	4.16×10^{-10}
	42	1.02×10^{-11}
AXL	25	1.45×10^{-06}
	26	1.99×10^{-07}
	29	3.18×10^{-09}
	30	4.10×10^{-10}

Table 4.3-3 - continued
CSET Quantification Results

Core Damage Sequence	CSET Sequence Number	Probability
MUH	17	7.54×10^{-07}
	18	6.35×10^{-09}
	29	5.09×10^{-09}
	30	8.41×10^{-10}
	39	7.00×10^{-09}
	41	1.02×10^{-07}
	42	9.39×10^{-10}
MXL	25	1.62×10^{-06}
	26	4.26×10^{-07}
	33	2.75×10^{-06}
	34	2.73×10^{-08}
SUH	17	6.98×10^{-07}
	18	5.88×10^{-09}
	29	4.71×10^{-08}
	30	7.79×10^{-10}
	39	5.70×10^{-09}
	41	9.44×10^{-08}
	42	8.68×10^{-10}
SXH	9	2.29×10^{-06}
	10	1.92×10^{-08}
	25	1.60×10^{-06}
	26	1.63×10^{-07}
	33	1.81×10^{-07}
	34	1.42×10^{-08}

Table 4.3-3 - continued
CSET Quantification Results

Core Damage Sequence	CSET Sequence Number	Probability
SSXH	9	$4.89x10^{-06}$
	10	$4.14x10^{-08}$
	25	$4.07x10^{-06}$
	26	$4.08x10^{-08}$
	33	$3.48x10^{-07}$
	34	$2.43x10^{-08}$
SSU10	17	$5.15x10^{-08}$
	18	$3.99x10^{-10}$
	29	$3.59x10^{-09}$
	30	$5.75x10^{-11}$
	39	$4.48x10^{-10}$
	41	$1.44x10^{-11}$
SSU11	41	$1.86x10^{-07}$
	42	$1.77x10^{-09}$

Table 4.3-4
Percentage Ranking of Plant Damage States

Rank	PDS No.	Frequency	Percent of Total
1	12	2.44E-05	29.67
2	22	1.41E-05	17.12
3	24	1.28E-05	15.54
4	20	7.96E-06	9.66
5	15	7.93E-06	9.63
6	17	6.20E-06	7.53
7	11	3.44E-06	4.18
8	1	2.47E-06	3.00
9	9	1.17E-06	1.42
10	7	4.52E-07	0.55
11	14	4.52E-07	0.55
12	2	2.92E-07	0.35
13	19	2.80E-07	0.34
14	10	1.99E-07	0.24
15	8	6.61E-08	0.08
16	16	5.07E-08	0.06
17	13	3.41E-08	0.04
18	3	2.22E-08	0.03
19	18	6.15E-09	0.01
20	4	8:12E-11	<0.01
21	5	0.00E-00	<0.01
22	6	0.00E-00	<0.01
23	21	0.00E-00	<0.01
24	23	0.00E-00	<0.01

Table 4.3-5
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 1 TOTAL FREQUENCY = 0.247127E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TQ2XL	26	1	0.15E-05	60.29
MXL	26	2	0.43E-06	17.24
AXL	26	3	0.20E-06	8.05
TQ2XL	34	4	0.91E-07	3.67
SSXH	10	5	0.41E-07	1.68
SSXH	26	6	0.41E-07	1.65
MXL	34	7	0.27E-07	1.10
SSXH	34	8	0.24E-07	0.98
TQ2UH2	18	9	0.23E-07	0.91
SXH	10	10	0.19E-07	0.78
TBIL1XL	34	11	0.18E-07	0.74
SXH	26	12	0.16E-07	0.66
AUL	34	13	0.14E-07	0.55
TBIL1P1	2	14	0.86E-08	0.35
MUH	18	15	0.64E-08	0.26
SUH	18	16	0.59E-08	0.24
TQ2UH2	42	17	0.33E-08	0.13
TQ2UH2	30	18	0.33E-08	0.13
TB1L1UH1	94	19	0.24E-08	0.10
TB1L1UH1	48	20	0.24E-08	0.10
SSU11	42	21	0.18E-08	0.07
SXH	34	22	0.14E-08	0.06
TBIL1P1	26	23	0.14E-08	0.05
MUH	42	24	0.94E-09	0.04
SUH	42	25	0.87E-09	0.04
MUH	30	26	0.84E-09	0.03
SUH	30	27	0.78E-09	0.03
AXL	30	28	0.41E-09	0.02
SSU10	18	29	0.40E-09	0.02
TB1L1UH1	72	30	0.32E-09	0.01
TBIL1P1	34	31	0.14E-09	0.01
SSU10	30	32	0.58E-10	0.00
AUL	42	33	0.10E-10	0.00

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 2 TOTAL FREQUENCY = 0.291894E-06

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TB1L1UH1	47	1	0.29E-06	99.01
TB1L1UH1	55	2	0.23E-08	0.77
TB1L1UH1	63	3	0.63E-09	0.22

PLANT DAMAGE STATE 3 TOTAL FREQUENCY = 0.222295E-07

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TB1L1UH1	71	1	0.20E-07	88.17
TB1L1UH1	79	2	0.26E-08	11.74
TB1L1UH1	71	3	0.20E-10	0.09

PLANT DAMAGE STATE 4 TOTAL FREQUENCY = 0.812000E-10

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TB1L1UH1	.87	1	0.81E-10	100.00

PLANT DAMAGE STATE 5 TOTAL FREQUENCY = 0.000000

PLANT DAMAGE STATE 6 TOTAL FREQUENCY = 0.000000

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 7 TOTAL FREQUENCY = 0.452000E-06

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TB1L1UH1	93	1	0.45E-06	100.00

PLANT DAMAGE STATE 8 TOTAL FREQUENCY = 0.661000E-07

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TB1L1UH1	101	1	0.66E-07	100.00

PLANT DAMAGE STATE 9 TOTAL FREQUENCY = 0.117120E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TBIL1P1	1	1	0.11E-05	92.21
TBIL1P1	9	2	0.91E-07	7.79

PLANT DAMAGE STATE 10 TOTAL FREQUENCY = 0.981000E-07

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TBIL1P1	25	1	0.12E-06	61.31
TBIL1P1	33	2	0.77E-07	38.69

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 11 TOTAL FREQUENCY = 0.344400E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TQ2UH2	17	1	0.27E-05	78.11
MUH	17	2	0.75E-06	21.89

PLANT DAMAGE STATE 12 TOTAL FREQUENCY = 0.244351E-04

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TQ2XL	33	1	0.92E-05	37.73
TQ2XL	25	2	0.74E-05	30.28
MXL	33	3	0.28E-05	11.25
MXL	25	4	0.16E-05	6.63
AXL	25	5	0.15E-05	5.93
AUL	33	6	0.14E-05	5.81
TQ2UH2	29	7	0.27E-06	1.12
TB1L1UH1	33	8	0.25E-06	1.01
MUH	29	9	0.51E-07	0.21
AXL	29	10	0.32E-08	0.01

PLANT DAMAGE STATE 13 TOTAL FREQUENCY = 0.341000E-07

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TQ2UH2	39	1	0.24E-07	70.38
MUH	39	2	0.70E-08	20.53
AUL	39	3	0.31E-08	9.09

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 14 TOTAL FREQUENCY = 0.452416E-06

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
TQ2UH2	41	1	0.35E-06	77.36
MUH	41	2	0.10E-06	22.55
AUL	41	3	0.42E-09	0.09

PLANT DAMAGE STATE 15 TOTAL FREQUENCY = 0.792950E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
SSXH	9	1	0.49E-05	61.67
SXH	9	2	0.23E-05	28.88
SUH	17	3	0.70E-06	8.80
SSU10	17	4	0.51E-07	0.65

PLANT DAMAGE STATE 16 TOTAL FREQUENCY = 0.506900E-07

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
SUH	29	1	0.47E-07	92.92
SSU10	29	2	0.36E-08	7.08

PLANT DAMAGE STATE 17 TOTAL FREQUENCY = 0.619900E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
SSXH	25	1	0.41E-05	65.66
SXH	25	2	0.16E-05	25.81
SSXH	33	3	0.35E-06	5.61
SXH	33	4	0.18E-06	2.92

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 18 TOTAL FREQUENCY = 0.614800E-08

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
SUH	39	1	0.57E-08	92.71
SSU10	39	2	0.45E-09	7.29

PLANT DAMAGE STATE 19 TOTAL FREQUENCY = 0.280414E-06

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
SSU11	41	1	0.19E-06	66.33
SUH	41	2	0.94E-07	33.66
SSU10	41	3	0.14E-10	0.01

PLANT DAMAGE STATE 20 TOTAL FREQUENCY = 0.796000E-05

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
ISLOCA	NA	1	0.80E-05	100.00

PLANT DAMAGE STATE 21 TOTAL FREQUENCY = 0.000000

PLANT DAMAGE STATE 22 TOTAL FREQUENCY = 0.141000E-04

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
RD	NA	1	0.14E-04	99.1
RB1D	NA	2	0.13E-06	0.9

PLANT DAMAGE STATE 23 TOTAL FREQUENCY = 0.000000

Table 4.3-5 (continued)
Sequence Contribution To Plant Damage State Frequency

PLANT DAMAGE STATE 24 TOTAL FREQUENCY = 0.128000E-04

Level 1 Sequence	CSET Endpoint	Rank	Sequence Frequency	Percent of Total PDS Frequency
RI1P3TR1	NA	1	0.12E-04	93.8
RI1SC	NA	2	0.80E-06	6.2

Table 4.5-1
Potentially Important Containment Event Topics

Item	Phenomenological Events	Time Phase
P-1	Debris Cooled In-Vessel	Before RV Failure
P-2	In-vessel Steam Explosion	"
P-3	Mode/Time Vessel Failure	At/Near RV Failure
P-4	Direct containment Heating	"
P-5	Early H2 Burn/Detonation	"
P-6	Debris Dispersal Out of Cavity	"
P-7	Ex-vessel Steam Explosion/Spikes	"
P-8	Liner Melt-through	"
P-9	Mode Early Containment Failure	"
P-10	Debris Cooled Ex-Vessel	Longer Term
P-11	Late H2 Burn/Detonation	"
P-12	Late containment Over Pressure Failure	"
P-13	Mode Late Containment Failure	"
P-14	Safeguards/Auxiliary Building Source Term Attenuation Effectiveness	"
	Operator, Recovery, Mitigation Actions	
0-1	In-vessel Injection Restored	Before/After RV Failure
0-2	RCS Depressurized	Before RV Failure
0-3	Power Recovery	Before/After RV Failure
0-4	Containment Spray Recovered	After RV Failure
0-5	Containment Heat Removal Recovered	After RV Failure
	Consequential Systems Failures	
F-1	Late Spray Failure	After RV Failure
F-2	Late containment Heat Removal Failure	After RV Failure

Table 4.5-2
Summary of MAAP DCH Parametric Cases for Ginna PRA

MAAP Case	Mass of Debris Expelled Early	DCH Fraction (FCMDCH)	Fraction Debris Dispersed Outside Lower Compartment (FCMDA)	Mode of H_2 Burns-Standard or Unconditional	Entrainment Time Constant (TTENTR)	Peak Containment Pressure Following Vessel Failure (psia)
SBO08	~50%	1.00	.25	UCHB	0.5	135
SBO09	~50%	1.00	.09	UCHB	0.5	122
SBO10	~30%	1.00	.25	UCHB	0.5	120
SBO12	~50%	1.00	.25	STD	0.5	115
SBO13	~50%	.50	.25	UCHB	0.5	118
SBO14	~50%	1.00	.09	UCHB	2.0	133
SBO17	~50%	1.00	.25	UCHB	2.0	143

Table 4.5-3
Parameters for Assessing Debris Depth Near Liner

Mass Debris Expelled Early	Fraction Debris Involved In DCH	Volume Debris on Lower Compartment Floor (ft^3/m^3)	Spread Area (ft^2/m^2)	Debris Depth (ft/cm)	Upward Heat Flux to Cool Debris (kw/m^2)
50%	100%	132./3.8	1455/135	.091/2.8	48.
50%	100%	132./3.8	728/67.6	.18/5.5	97.
50%	50%	66./1.9	1455/135	.046/1.4	24.
50%	50%	66./1.9	728/67.6	.091/2.8	48.
30%	100%	79./2.3	1455/135	.055/1.7	30.
30%	100%	79./2.3	728/67.6	.109/3.3	58.
30%	50%	40./1.1	1455/135	.027/0.8	15.
30%	50%	40./1.1	728/67.6	.055/1.7	30.
10%	100%	26./.8	1455/135	.018/0.6	9.
10%	100%	26./.8	728/67.6	.036/1.1	19.
10%	50%	13./.4	1455/135	.009/0.3	6.
10%	50%	13./.4	728/67.6	.018/0.6	9.

Table 4.5-4
Core Debris Mass, Volume and Thermal Conductivity

Material	Mass (lbm)	Density lbm/ft^2(kg/m^3)	Volume (m^3)	Volume Fraction	Conductivity (W/m-°K)
UO_2	105,500	629.2(10100)	4.75	0.63	3.3
Zr	12,963	404.9(6500)	.91	0.12	18.
$Zr0_2$	17,510	348.8(5600)	1.42	0.19	3.0
Steel	4,459	498.4(8000)	.25	0.03	50.
Ag	2,028	435.5(6990)	.13	0.02	
In	380	499. (8010)	.02	<.01	
Cd	357	571.2(9170)	.02	<.01	
Totals	143,197		7.5		
Average		540.6(8678)			7.8

Table 4.5-5
Allowable Debris Upper Surface Temperature

Debris Depth (cm)	Heat Flux at Upper Surface (q) (KW/m^2)	Lower Surface Temp. (T_0) (°K)	Upper Surface Temp. (T_s)(°K) (K = 7.8)	Upper Surface Temp. (T_s)(°K) (K = 3.9)
5.5	97	1586	1244	902
3.3	58	1586	1463	1340
2.8	48	1586	1500	1414
1.7	30	1586	1553	1521

Table 4.5-6
Ginna Debris Spread Area (M2) - (Greene)

Mass of Total Core Debris Released At Vessel Failure

10%	30%	50%
5.1	12.7	19.5

Table 4.5-7
Ginna Debris Spread Radius (M) - (Moody)

Mass of Total Core Debris Released At Vessel Failure
and Average Debris Pour Rate

10% (220 kg/s)	30% (564 kg/s)	50% (880 kg/s)
2.0 m	3.3 m	4.1 m

Table 4.5-8
Ginna Debris Spread Radius (M) - (Moody)
High Pressure Conditions (16.2 MPA)

Mass of Total Core Debris Released At Vessel Failure
and Average Debris Pour Rate

10% (5430 kg/s)	30% (10800 kg/s)	50% (14800 kg/s)
10.1 m	14.3 m	16.8 m

Table 4.5-9
Water Depth To Debris Pour Steam
Diameter Ratio (L/D) - 3 M Water Depth

Fraction of Total Core Debris Released At Vessel Failure		
10%	30%	50%
21	14	12

Table 4.6-1
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
9FB12A, 9FB12D, 9FB12G, 9FB12H - Level 1 Feed and Bleed runs											
9S0ABCDE, 9S11BCDE, 9S11BCDE_2, 9S21BCD2, 9S21BC2E, 9S2A2C2E, 9S31BCDE, 9S3AB12E, 9S41BC2E, 9S4AB12E, 9S5AB12E, 9S51BC2E, 9S6AB12E, 9S8AB12E.- Level 1 LOCA success criteria runs											
FB13E - Level 1 Feed and Bleed runs											
<u>LLOCA01</u> - 27.5 ID CL break, 1 RHR w/ Hx, no spray, no FC	10.6 sec	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.0	0.0	12.0 hr
<u>LLOCA02</u> - 27.5 ID CL break, 1 RHR no Hx, no spray, 1 FC	10.6 sec	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.0	0.0	12.0 hr
<u>LLOCA04</u> - 27.5 ID CL break, RWST in, no sprays or FC, 1/2" isolation failure	10.6 sec	3.82 hr	0	14.4E4	0	0	Yes	21.3 hr	0.999	0.110E-1	29.3 hr
<u>LLOCA05</u> - LLOCA04 w/ 1" isolation failure	10.6 sec	3.81 hr	0	14.3E4	0	0	Yes	25.8 hr	0.999	0.621E-2	33.8 hr
<u>LLOCA06</u> - LLOCA04 w/ 2" isolation failure	10.6 sec	3.81 hr	0	14.4E4	0	0	Yes	N/A	0.881	0.399E-2	48.0 hr
<u>LLOCA07</u> - LLOCA04 w/ 4" isolation failure	10.6 sec	3.76 hr	0	14.4E4	0	0	Yes	N/A	0.997	0.208E-1	48.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
LLOCA09 - 27.5 ID CL break, no RWST, no sprays or FC, 1" isolation failure	10.6 sec	1.42 hr	0	62.3E4	0	0	No	31.2 hr	0.980	0.456E-2	39.2 hr
LLOCA10 - LLOCA09 w/ 2" isolation failure	10.6 sec	1.38 hr	1.463E4	58.6E4	0	0	No	N/A	0.893	0.289E-1	48.0 hr
LLOCA11 - LLOCA09 w/ 4" isolation failure	10.6 sec	1.40 hr	1.418E4	64.4E4	0	0	No	N/A	0.999	0.122	48.0 hr
LLOCA12 - LLOCA04 w/ 1.5" isol failure	10.6 sec	3.88 hr	1.669E4	12.5E4	0	0	Yes	39.7 hr	1.000	0.208E-1	47.7 hr
LLOCA13 - LLOCA09 w/ 1.5"isol failure	10.6 sec	1.39 hr	1.414E4	62.5E4	0	0	No	N/A	0.716	0.861E-2	48.0 hr
LLOCA14 - LLOCA12 w/ fan coolers avail	10.6 sec	3.69 hr	0	14.6E4	0	0	Yes	N/A	0.172	0.292E-2	48.0 hr
LLOCA15 - LLOCA13 w/ fan coolers avail	10.6 sec	1.28 hr	0	14.5E4	0	0	No	N/A	0.239	0.333E-2	48.0 hr
LLOCA16 - 1 CL break, no SI, Accum, Sprays or FC	12.0 sec	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.837E-7	0.340E-7	0.1 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
LLOCA17 - LLOCA16 w/ .5 RHR to downcomer	12.0 sec	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.133E-6	0.714E-7	0.1 hr
LLOCA18 - LLOCA17 w/ 1 Accumulator	10.6 sec	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.0	0.0	0.1 hr
MLOCA01 - 1.5" LOCA w/ AFW, no SI, no recirc.	0.865 hr	N/A	13.7E4	0	0	0	Yes	N/A	0.567E-3	0.909E-5	24.0 hr
MLOCA02 - 3.5" LOCA w/ AFW, no SI, no recirc.	1.10 hr	19.3 hr	1.33E4	12.8E4	0	0	Yes	N/A	0.217E-3	0.681E-5	24.0 hr
MLOCA03 - 5.5" LOCA w/ AFW, no SI, no recirc.	4.27 hr	5.96 hr	1.94E4	12.3E4	0	0	Yes	N/A	0.701E-3	0.792E-5	24.0 hr
MLOCA04 - 1.5" LOCA w/ AFW, w/ SI, no recirc.	9.56 hr	11.1 hr	0	14.2E4	0	0	Yes	N/A	0.576E-3	0.455E-5	24.0 hr
MLOCA05 - 3.5" LOCA w/ AFW, w/ SI, no recirc.	4.48 hr	6.10 hr	2.25E4	11.7E4	0	0	Yes	N/A	0.305E-4	0.526E-5	6.11 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
MLOCA06 - 5.5" LOCA w/ AFW, w/ SI, no recirc.	3.78 hr	5.40 hr	1.50E4	12.8E4	0	0	Yes	N/A	0.726E-3	0.797E-5	24.0 hr
MLOCA07 - 1.5" LOCA no AFW, no SI, no recirc.	0.801 hr	3.85 hr	3.74E4	10.4E4	0	0	Yes	N/A	0.813E-3	0.304E-4	24.0 hr
MLOCA08 - 3.5" LOCA no AFW, no SI, no recirc.	1.17 hr	21.9 hr	1.51E4	12.6E4	0	0	Yes	N/A	0.121E-3	0.626E-5	24.0 hr
MLOCA09 - 5.5" LOCA no AFW, no SI, no recirc.	4.75 hr	6.46 hr	1.42E4	12.8E4	0	0	Yes	N/A	0.683E-3	0.777E-5	24.0 hr
MLOCA10 - 1.5" LOCA no AFW, w/ SI, no recirc.	9.45 hr	11.2 hr	0	14.3E4	0	0	Yes	N/A	0.589E-3	0.468E-5	24.0 hr
MLOCA11 - 3.5" LOCA no AFW, w/ SI, no recirc.	4.89 hr	6.44 hr	1.42E4	12.7E4	0	0	Yes	N/A	0.775E-3	0.774E-5	24.0 hr
MLOCA12 - 5.5" LOCA no AFW, w/ SI, no recirc.	4.00 hr	5.65 hr	1.94E4	12.3E4	0	0	Yes	N/A	0.716E-3	0.803E-5	24.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
RUH2A, RUH2B, RUH2C, RUH2D, RUH2E, RUH2F, RUH2G, RUH2H, RUH2I - Level 1 SGTR runs with steam generator depressurization											
SBO00 - base SBO, no AFW, no seal LOCA, no recovery	2.28 hr	3.71 hr	0	3.15E4	8.08E4	3.20E4	No	12.6 hr	0.971	0.247E-2	20.6 hr
SBO00R - SBO00 for 48 hours	2.28 hr	7.71 hr	0	3.15E4	8.08E4	3.20E4	No	12.6 hr	0.994	0.322E-2	48.0 hr
SBO01 - base w/ induced HL rupture @ 1,000°K	2.28 hr	5.27 hr	0	39.6E4	0	0	No	17.8 hr	0.987	0.237E-2	25.8 hr
SBO02 - late SBO, AFW for 4 hrs	7.45 hr	9.49 hr	0	4.06E4	7.41E4	2.94E4	No	18.6 hr	0.973	0.983E-3	26.6 hr
SBO03 - base w/ PORV in auto	2.23 hr	3.70 hr	0	3.19E4	8.04E4	3.19E4	No	13.0 hr	0.971	0.241E-2	21.0 hr
SBO04 - SBO01 w/ no burn til 10 hr, FC & CS avail @ 10 hr	2.28 hr	5.27 hr	0	21.5E4	0	0	Yes	N/A	0.751E-3	0.310E-4	20.0 hr
SBO05 - SBO03 w/ TEU = 2700°K	2.23 hr	3.80 hr	0	2.25E4	8.73E4	3.42E4	No	N/A	0.239E-3	0.417E-5	8.0 hr
SBO06 - base w/ FVPREV = 0.2	2.28 hr	3.71 hr	0	3.25E4	7.97E4	3.16E4	No	11.9 hr	0.968	0.178E-2	19.9 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SBO07 - SBO03 w/ seal LOCA at 45 min	1.89 hr	3.80 hr	1.554E4	0.464E4	8.64E4	3.43E4	No	12.2 hr	0.944	0.457E-2	20.2 hr
SBO08 - base w/ FCMDCH=1, FCMDA=0.25 50% debris, UCHB	2.28 hr	3.71 hr	2.540E4	4.71E4	5.31E4	1.77E4	No	N/A	0.241E-4	0.110E-5	4.0 hr
SBO09 - base w/ FCMDCH=1, FCMDA=0.09 50% debris, UCHB	2.28 hr	3.71 hr	2.546E4	4.75E4	6.40E4	0.633E4	No	N/A	0.278E-4	0.119E-5	4.0 hr
SBO10 - base w/ FCMDCH=1, FCMDA=0.25 30% debris, UCHB	2.28 hr	3.71 hr	2.529E4	7.29E4	3.30E4	1.10E4	No	N/A	0.206E-4	0.963E-6	4.0 hr
SBO11- SBO03 w/ TEU = 3000°K	2.23 hr	4.02 hr	3.833E4	12.6	7.60E4	2.95E4	No	N/A	0.122E-3	0.271E-5	6.0 hr
SBO12 - base w/ FCMDCH=1, FCMDA=0.25 50% debris, std burn	2.28 hr	3.71 hr	2.544E4	4.74E4	5.28E4	1.76E4	No	N/A	0.183E-4	0.821E-6	4.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SBO13 - base w/ FCMDCH=.5, FCMDA=.25 50% debris, UCHB	2.28 hr	3.71 hr	2.543E4	4.57E4	5.30E4	1.77E4	No	N/A	0.202E-4	0.939E-6	4.0 hr
SBO14 - SBO09 w/ TTENTR = 2.0 sec	2.28 hr	3.71 hr	2.537E4	4.77E4	6.39E4	0.632E4	No	N/A	0.234E-4	0.107E-5	4.0 hr
SBO15 - base w/ alternate S/G insul	2.27 hr	3.71 hr	0	3.32E4	7.92E4	3.14E4	No	12.0 hr	0.969	0.240E-2	20.0 hr
SBO16 - SBO00 w/ 1.5" isolation failure	2.27 hr	3.73 hr	1.609E4	3.32E4	7.95E4	3.15E4	No	N/A	0.699	0.250E-2	48.0 hr
SBO17 - SBO08 w/ TTENTR = 2.0 sec	2.28 hr	3.71 hr	2.540E4	4.77E4	5.27E4	1.76E4	No	N/A	0.206E-4	0.100E-5	4.0 hr
SBO18 - base w/ stuck open S/G PORV	2.19 hr	3.49 hr	0	3.43E4	7.83E5	3.10E4	No	N/A	0.836E-4	0.334E-5	5.0 hr
SBO19 - SBO03 w/ stuck open S/G PORV	2.14 hr	3.55 hr	1.835E4	1.43E4	7.73E4	3.06E4	No	N/A	0.806E-4	0.246E-5	5.0 hr
SBO20 - SBO00 w/ ACMPLB = 822 FT**2	2.28 hr	3.74 hr	0	2.94E4	8.19E4	3.25E4	No	11.6 hr	0.969	0.288E-2	19.6 hr
SBO21 - SBO07 w/ FVPREV = 0.2	1.89 hr	3.78 hr	1.553E4	0.464E4	8.63E4	3.42E4	No	12.2 hr	0.944	0.209E-2	20.2 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SBO22 - SBO00 w/ FCRBLK = 1.0	2.28 hr	3.84 hr	1.993E4	0.598	5.93E4	0	No	12.8 hr	0.977	0.428E-2	48.0 hr
SBO23 - SBO00 w/ LHEU = 400 KJ/KG	2.28 hr	3.81 hr	1.938E4	1.45E4	7.63E4	3.02E4	No	12.8 hr	0.973	0.111E-1	48.0 hr
SBO24 - SBO00 w/ loop seals cleared	2.35 hr	5.55 hr	4.297E4	2.63E4	5.31E4	2.10E4	No	15.0 hr	0.967	0.259E-1	48.0 hr
SBO25 - SBO00 w/ FNCBP = 1.0	2.28 hr	3.69 hr	1.953E4	1.08E4	7.99E4	3.17E4	No	12.9 hr	0.988	0.115E-1	48.0 hr
SBO26 - SBO07 w/ FCRDR = 0.8	1.89 hr	3.73 hr	0	2.82E4	8.24E4	3.27E4	No	10.9 hr	0.995	0.770E-2	48.0 hr
SBO27 - SBO00 w/ increased equip mass	2.28 hr	3.75 hr	0	2.52E4	8.50E4	3.37E4	No	16.3 hr	0.994	0.443E-2	48.0 hr
SBO28 - SBO08 w/ FCMDCH = 0.0	2.28 hr	3.71 hr	2.527E4	4.46E4	5.29E4	1.76E4	No	N/A	0.182E-4	0.832E-6	4.0 hr
SLOCA00 - 2 ID CL break, no injection, sprays & FC avail	0.487 hr	4.70 hr	0	14.3E4	0	0	No	N/A	0.502E-3	0.545E-5	16.1 hr
SLOCA01 - base w/ spray only, no recirc	0.487 hr	4.75 hr	0	14.2E4	0	0	Yes	27.8 hr	0.999	0.158E-4	35.8 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SLOCA02 - base w/ FENTR = 1000, FCHF = 0.02	0.487 hr	4.70 hr	0	25.7E4	0	0	Yes	N/A	0.745E-3	0.647E-5	24.0 hr
SLOCA03 - base w/ TTRX = 0.5 hr	0.487 hr	5.45 hr	0	14.2E4	0	0	No	N/A	0.818E-3	0.629E-5	24.0 hr
SLOCA04 - base w/ FCMDCH=1, FCMDA=0.25 50% debris, UCHB, FCs avail, Sprays in inj only	22.9 hr	27.6 hr	1.542E4	5.82E4	5.26E4	1.75E4	Yes	N/A	0.498E-4	0.175E-4	28.1 hr
SLOCA05 - base w/ FCMDCH=1, FCMDA=0.25 50% debris, std burn, FCs avail, Sprays in inj only	22.9 hr	27.6 hr	1.534E4	5.78E4	5.30E4	1.77E4	Yes	N/A	0.515E-4	0.176E-5	28.1 hr
SLOCA06 - base w/ FCHF = 0.02, no burns	0.487 hr	4.70 hr	0	24.4E4	0	0	No	N/A	0.877E-3	0.843E-5	24.0 hr
SLOCA07 - base w/ FCHF = 0.02, burns after 24 hr	0.487 hr	4.70 hr	0	25.1E4	0	0	Yes	N/A	0.108E-2	0.843E-5	30.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SLOCA08 - SBLOCA, HPI avail, SG depress, TTRX = 0.5 hr	9.19 hr	12.9 hr	2.225E4	11.6E4	0	0	Yes	N/A	0.560E-3	0.785E-5	24.0 hr
SLOCA09 - SLOCA08 w/o SG depress, TTRX = 0.5 hr	9.16 hr	12.1 hr	2.218E4	11.6E4	0	0	Yes	N/A	0.573E-3	0.844E-5	24.0 hr
SLOCA10 - base w/ FCs avail, sprays in inj, 1.5" isol fail	9.15 hr	10.7 hr	1.660E4	12.2E4	0	0	Yes	N/A	0.668E-1	0.203E-2	48.0 hr
SLOCA11 - base w/ FCs avail, no sprays, 1.5" isol fail	29.2 min	4.72 hr	0	14.3E4	0	0	No	N/A	0.124	0.236E-2	48.0 hr
SLOCA12 - base w/ no FCs, no sprays, 1.5" isol fail	29.2 min	4.97 hr	0	61.8E4	0	0	No	N/A	0.691	0.259E-2	48.0 hr
SLOCA13 - 1.5" CL LOCA, 1 RHR, 1 SI, no FC, no sprays	N/A	N/A	N/A	N/A	N/A	N/A	Yes	N/A	N/A	N/A	30.0 hr
SLOCA14 - SLOCA13 w/ 3" LOCA	0.263 hr	N/A	N/A	N/A	N/A	N/A	Yes	N/A	0.0	0.0	30.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SLOCA15 - 0.5" LOCA w/ FC & CS, no inj, no AFW	1.64 hr	2.97 hr	0	12.4	0	0	No	N/A	0.258E-5	0.178E-6	3.0 hr
SLOCA16 - 0.5" LOCA w/ FC & CS, no inj, AFW avail	7.26 hr	10.7 hr	1.416E4	12.3	1.28E5	0	No	N/A	0.557E-3	0.302E-5	24.0 hr
SLOCA17 - SLOCA15 w/ 1" LOCA	1.48 hr	2.50 hr	0	9.52	0	0	No	N/A	0.974E-3	0.723E-6	2.50 hr
SLOCA18 - SLOCA16 w/ 1" LOCA	1.87 hr	4.17 hr	4.116E4	2.55E4	7.32E4	0	No	N/A	0.815E-3	0.487E-5	24.0 hr
SLOCA19 - SLOCA15 w/ 1.5" LOCA	0.804 hr	3.93 hr	3.910E4	10.3E4	0	0	No	N/A	0.911E-3	0.133E-4	24.0 hr
SLOCA20 - SLOCA16 w/ 1.5" LOCA	0.864 hr	7.99 hr	2.237E4	11.8E6	0	0	No	N/A	0.746E-3	0.112E-4	24.0 hr
SLOCA21, SLOCA22, SLOCA23, SLOCA24, SLOCA25, SLOCA26, SLOCA26B, SLOCA27 - Level 1 small LOCAs with steam generator depressurization											
SLOCA28 - 0.5" LOCA no AFW, w/ SI, no recirc.	1.40 hr	2.68 hr	7.30E4	12.4	0	0	No	N/A	0.292E-5	0.214E-6	2.68 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
SLOCA29 - 0.5" LOCA w/ AFW, w/ SI, no recirc.	65.0 hr	71.2 hr	13.1E4	8.08	0	0	Yes	N/A	0.768E-4	0.223E-5	71.2 hr
SLOCA30 - 1.0" LOCA no AFW, w/ SI, no recirc.	13.6 hr	16.8 hr	2.11E4	7.24	0	0	Yes	N/A	0.732E-4	0.292E-5	16.8 hr
SLOCA31 - 1.0" LOCA w/ AFW, w/ SI, no recirc.	12.5 hr	15.2 hr	1.74E4	6.99	0	0	Yes	N/A	0.500E-4	0.223E-5	15.2 hr
SLOCA32 - Level 1 LOCA success criteria run											
STC01 - MLOCA03 for 48 hours	4.27 hr	5.96 hr	1.942E4	12.3E4	0	0	Yes	N/A	0.152E-2	0.152E-4	48.0 hr
STC02 - 5.5" LOCA w/ AFW, FC, RHR, no recirc, early forced CF	4.27 hr	5.96 hr	1.855E4	12.4E4	0	0	Yes	5.96 hr	0.204	0.196E-2	48.0 hr
STC03 - 2.0" LOCA w/ AFW, FC, no inj, no recirc, early forced CF, FCHF = 0.02	0.547 hr	4.86 hr	2.230E4	25.7E4	0	0	No	4.86 hr	0.330	0.551E-2	48.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
STC04 - 5.5" LOCA w/ AFW, FC, no inj or CS, early forced CF	0.700 hr	1.55 hr	2.503E4	62.6E4	0	0	No	1.55 hr	0.721	0.157E-1	48.0 hr
STC05 - STC02 w/ ACFPR = 1.0 ft²	4.27 hr	5.96 hr	1.411E4	12.9E4	0	0	Yes	5.96 hr	0.575	0.178E-1	48.0 hr
STC07 - STC04 w/ ACFPR = 1.0 ft²	0.700 hr	1.55 hr	2.502E4	70.9E4	0	0	No	1.55 hr	0.883	0.607E-1	48.0 hr
STC08 - SBO w/ induced HL rupture, early LMT CF	2.28 hr	5.36 hr	0	60.9E4	0	0	No	5.36 hr	1.00	0.236	48.0 hr
STC09 - SBO, FC recovered @ 10 hr, large CF due to burn	2.28 hr	5.28 hr	0	20.7E4	0	0	No	11.7 hr	0.667	0.353E-2	48.0 hr
STC10 - SBO w/ induced HL rupture, late CF - leak	2.28 hr	5.36 hr	0	61.1E4	0	0	No	19.2 hr	0.883	0.686E-2	48.0 hr
STC11 - SBO w/ induced HL rupture, late CF - large	2.28 hr	5.36 hr	0	69.9E4	0	0	No	19.2 hr	0.999	0.106	48.0 hr

Table 4.6-1 (continued)
Summary of Timing of Key Events for MAAP Runs

Sequence ID and Description	Core uncovery time	Vessel failure time	Debris Distribution (mass in each area - lb)				RWST in cnmt?	Cnmt failure time	Fraction released to environment:		End time
			Vessel	Cavity	B compt	A compt			Nobles	CsI	
STC12 - STC04 w/ forced late CF	0.700 hr	1.55 hr	2.503E4	70.4E4	0	0	No	41.6 hr	0.631	0.131E-2	64.0 hr
STC12A - STC12 w/ forced CF at 12 hr after VF	0.700	1.55 hr	2.503E4	60.8E4	0	0	No	13.6 hr	0.671	0.992E-2	48.0 hr
STC16 - 5.5" ISLOCA w/ AFW, FC, no inj or CS	0.727 hr	1.57 hr	2.638E4	21.0E4	0	0	No	N/A	0.993	0.687	48.0 hr
STC18 - SGTR, no inj, isolate faulted SG at 30 min	2.71 hr	5.27 hr	0	1.51E4	13.5E4	0	No	N/A	0.442	0.673E-2	48.0 hr
STC20 - SGTR, no SI, w/ RHR, at 20 min SG PORV open, AFW isol to faulted SG	5.56 hr	7.28 hr	2.217E4	11.6E4	0	0	Yes	N/A	0.949	0.276	48.0 hr

Table 4.6-2
Summary of Containment Isolation
Failure MAAP Results

Case	Loss of Iso. Size	Containment Heat Removal	RWST In?	CF Time	CsI Rel at CF	End of Run Time	CsI Rel at End of Run
SBO16	1.5"	None	No	N/A	N/A	48.0 hrs	2.50E-3
SLOCA10	1.5"	Fan Coolers	Yes	N/A	N/A	48.0 hrs	2.03E-3
SLOCA11	1.5"	Fan Coolers	No	N/A	N/A	48.0 hrs	2.36E-3
SLOCA12	1.5"	None	No	N/A	N/A	48.0 hrs	2.59E-3
LLOCA04	0.5"	None	Yes	21.3 hrs	2.30E-4	29.3 hrs	1.10E-2
LLOCA05	1"	None	Yes	25.8 hrs	9.04E-4	33.8 hrs	6.21E-3
LLOCA06	2"	None	Yes	N/A	N/A	48.0 hrs	3.99E-3
LLOCA07	4"	None	Yes	N/A	N/A	48.0 hrs	2.08E-2
LLOCA09	1"	None	No	31.2 hrs	2.58E-3	39.2 hrs	4.56E-3
LLOCA10	2"	None	No	N/A	N/A	48.0 hrs	2.89E-2
LLOCA11	4"	None	No	N/A	N/A	48.0 hrs	1.22E-1
LLOCA12	1.5"	None	Yes	39.7 hrs	1.99E-3	47.7 hrs	2.08E-2
LLOCA13	1.5"	None	No	N/A	N/A	48.0 hrs	8.61E-3
LLOCA14	1.5"	Fan Coolers	Yes	N/A	N/A	48.0 hrs	2.92E-3
LLOCA15	1.5"	Fan Coolers	No	N/A	N/A	48.0 hrs	3.33E-3

Table 4.6-3
Summary of LMP Post-Processed MAAP Results

MAAP Case	Description	RPV Pressure at Vessel Failure (PSIA)	Secondary Depress-urized (Yes/No)?	Vessel Failure Time (Hrs)	Induced HL Rupture Predicted (Hrs)/CREEP Summation at VF	Induced SG Tube Rupture Predicted with 50% Thinning (Hrs)/CREEP Summation at VF	Induced SG Tube Rupture Predicted with 75% Thinning (Hrs)/CREEP Summation at VF
SBO00	Base SBO; no AFW, no PORV, no seal LOCA	2480	No	3.71	3.43 / 3.18	(N/A) / 5.36E-3	(N/A) / 0.665
SBO03	Base Total LOFW; no seal LOCA, but PORV in auto	2360	No	3.70	3.56 / 1.49	(N/A) / 2.17E-3	(N/A) / 0.276
SBO05	Total LOFW; no seal LOCA, PORV in auto, TEU=2700K	2360	No	3.80	3.35 / 78.47	(N/A) / 6.33E-3	(N/A) / 0.746
SBO07	Total LOFW; 3/4" seal LOCAs at 45 minutes, PORV in auto	592	No	3.80	(N/A) / 1.71E-4	(N/A) / ~0.0	(N/A) / ~0.0
SBO11	Total LOFW; no seal LOCA, PORV in auto, TEU=3000K	2350	No	4.02	3.34 / 67.30	(N/A) / 8.62E-3	(N/A) / 0.977

Table 4.6-3
Summary of LMP Post-Processed MAAP Results

MAAP Case	Description	RPV Pressure at Vessel Failure (PSIA)	Secondary Depress-urized (Yes/No)?	Vessel Failure Time (Hrs)	Induced HL Rupture Predicted (Hrs)/CREEP Summation at VF	Induced SG Tube Rupture Predicted with 50% Thinning (Hrs)/CREEP Summation at VF	Induced SG Tube Rupture Predicted with 75% Thinning (Hrs)/CREEP Summation at VF
SBO18	SBO; no AFW, no PORV, no seal LOCA, but stuck SG PORV	2450	Yes	3.49	3.45 / 1.11	(N/A) / 0.975	3.03 / 103.64
SBO19	Total LOFW; no seal LOCA, PORV in auto, but stuck SG PORV	2330	Yes	3.55	3.44 / 1.29	(N/A) / 0.705	3.02 / 76.73
SLOCA00	Base 2" CL LOCA; No Injection	78	No	4.70	(N/A) / ~0.0	(N/A) / ~0.0	(N/A) / ~0.0

Table 4.6-4
Summary of DCH Parametric
Cases for Ginna

MAAP Case	Mass of Debris Expelled Early	DCH Fraction (FCMDCH)	Fraction Dispersed Outside Lower Compartment (FCMDA)	Mode of H_2 Burns (Standard or Unconditional)*	Entrainment Time Constant (TTENTR)	Containment Peak Pressure Following Vessel Failure (PSIA)
SBO00	~78%	0.03	0.284	STD	0.5 s	80
SBO03	~78%	0.03	0.284	STD	0.5 s	80
SBO07	~86%	0.03	0.284	STD	0.5 s	88
SBO08	~50%	1.00	0.250	UCHB	0.5 s	135
SBO09	~50%	1.00	0.090	UCHB	0.5 s	122
SBO10	~30%	1.00	0.250	UCHB	0.5 s	120
SBO12	~50%	1.00	0.250	STD	0.5 s	115
SBO13	~50%	0.50	0.250	UCHB	0.5 s	118
SBO14	~50%	1.00	0.090	UCHB	2.0 s	133
SBO17	~50%	1.00	0.250	UCHB	2.0 s	143
SLOCA04	~50%	1.00	0.250	UCHB	0.5 s	107
SLOCA05	~50%	1.00	0.250	STD	0.5 s	80

* Standard burn designated with STD and unconditional hydrogen burn designated with UCHB.

Table 4.7-1
Representative Sequence Selection for
the Development of Source Term Characteristics

STC	CDF	Sequence Description
1	34.9%	Medium break LOCA; No SI, No RHR recirc; AFW & FCUs OK; Containment failure does not occur
2	<0.1%	Medium break LOCA; No SI, No RHR recirc; AFW & FCUs OK; Early containment failure (leak) after vessel failure
3	<0.1%	Medium break LOCA; No injection or recirc; AFW & FCUs OK; CCI occurs despite water in cavity, Early containment failure (leak) after vessel failure
4	<0.1%	Medium break LOCA; No injection or recirc; AFW & CHR OK; Water does not enter cavity such that dry CCI occurs, Early containment failure (leak) after vessel failure
5	<0.1%	Same as STC #2 with global containment failure area
6	-	None
7	<0.1%	Same as STC #4 with global containment failure area
8	<0.1%	SBO; dry CCI occurs in cavity; Early LMT containment failure assumed after vessel failure
9	0.3%	SBO; FCUs recovered @ 10 hrs. which induces a burn which is assumed to fail containment; CCI occurs in cavity prior to recovery of FCUs
10	0.1%	SBO with induced hot leg rupture; CCI occurs in dry cavity; Late containment failure (leak) on overpressure
11	<0.1%	Same as STC #10 with global containment failure area
12	14.2%	Medium break LOCA; no injection or recirc; AFW & FCUs OK; water does not enter cavity such that CCI occurs; very late containment failure by basemat melt-thru
13	3.0%	Source term characterized by STC #7 results
14	<0.1%	Source term characterized by STC #8 results
15	5.1%	Source term characterized by STC #1 results
16	9.7%	Interfacing system LOCA; No injection or recirc; AFW and FCUs OK
17	-	None
18	17.1%	SGTR; No injection; faulted SG isolated at 30 minutes; CHR available
19	-	None
20	15.6%	SGTR; No SI; Faulted SG PORV sticks open; CHR available

Representative S[illegible]Term Results

Calculated Source Terms from MAAP 3.0B-PWR, Rev. 19.0+														
STC End State	MAAP Case	Radionuclide Release Fractions												End Time
		Noble Gases	CsI	TeO_2	SrO	MoO_2	CsOH	BaO	Lanthanides	CeO_2	Sb	Te_2	UO_2	(hrs)
1	STC01	1.52E-3	1.52E-5	<1E-5	<1E-5	<1E-5	1.72E-5	<1E-5	<1E-5	<1E-5	<1E-5	<1E-5	<1E-5	48.0
2	STC02	0.204	1.96E-3	<1E-5	<1E-5	<1E-5	1.96E-3	1.01E-5	1.40E-3	1.40E3	3.11E-4	<1E-5	<1E-5	48.0
3	STC03	0.330	5.51E-3	<1E-5	1.46E-4	1.13E-5	5.56E-3	8.75E-5	2.02E-5	1.78E-4	2.06E-3	2.62E-3	<1E-5	48.0
4	STC04	0.721	0.016	0.019	1.63E-3	1.17E-5	0.015	8.12E-4	1.48E-3	3.05E-3	0.023	6.48E-3	<1E-5	48.0
5	STC05	0.575	0.018	<1E-5	1.45E-5	4.64E-5	0.018	1.34E-4	0.019	0.019	2.34E-3	1.58E-5	<1E-5	48.0
7	STC07	0.883	0.061	1.95E-5	4.25E-3	1.28E-4	0.060	2.24E-3	0.015	0.019	0.046	0.073	1.75E-5	48.0
8	STC08	1.000	0.236	0.157	9.44E-3	3.78E-4	0.236	4.74E-3	0.011	0.021	0.150	0.023	4.59E-5	48.0
9	STC09	0.667	3.53E-3	1.93E-4	1.93E-5	<1E-5	3.74E-3	<1E-5	4.51E-5	8.97E-5	1.72E-3	5.17E-3	2.42E-7	48.0
10	STC10	0.883	6.86E-3	8.18E-4	2.26E-5	<1E-5	0.015	1.61E-5	2.02E-5	7.86E-5	7.71E-3	0.020	<1E-5	48.0
11	STC11	0.999	0.106	0.028	4.43E-5	<1E-5	0.122	6.19E-5	3.86E-5	1.53E-4	0.037	0.024	<1E-5	48.0
12	STC12	0.600	9.64E-3	7.21E-4	2.73E-5	<1E-5	8.90E-3	8.28E-5	<1E-5	4.33E-5	4.94E-3	2.73E-5	<1E-5	48.0
13	-	(Represented by STC #7 Results)												
14	-	(Represented by STC #8 Results)												
15	-	(Represented by STC #1 Results)												
16	STC16	0.993	0.678	4.21E-5	5.16E-3	1.40E-3	0.688	4.68E-3	5.55E-4	5.92E-3	0.127	0.080	1.73E-5	48.0
18	STC18	0.442	0.067	<1E-5	<1E-5	<1E-5	6.58E-3	<1E-5	<1E-5	<1E-5	2.87E-4	<1E-5	<1E-5	48.0
20	STC20	0.949	0.276	<1E-5	8.08E-5	1.09E-4	0.269	5.71E-4	<1E-5	<1E-5	0.045	<1E-5	<1E-5	48.0

+ Minor modifications to revision 19.0 are described in Reference 4.9-2

Table 4.7-3
Source Term Magnitude and Timing Characteristics

STC End State	CDF	Timing	Noble	Volatiles	Non-Volatiles
1	34.9%	-	L	LL	LL
2	<0.1%	E	H	L	LL
3	<0.1%	E	H	L	L
4	<0.1%	E	H	M	M
5	<0.1%	E	H	M	LL
7	<0.1%	E	H	M	M
8	<0.1%	E	H	H	H
9	0.3%	L	H	L	L
10	0.1%	L	H	M	M
11	<0.1%	L	H	H	M
12	14.2%	L	H	L	L
13[1]	3.0%	E	H	M	M
14[2]	<0.1%	E	H	H	H
15[3]	5.1%	-	L	LL	LL
16	9.7%	E	H	H	M
18	17.1%	E	H	M	LL
20	15.6%	E	H	H	LL

[1]Inferred from STC #7 results
[2]Inferred from STC #8 results
[3]Inferred from STC #1 results

Table 4.7-4
Summary Source Term Categorization

Category	Description	Relevant STC End States	Total % of CDF
I	Release limited to leakage	STC1, STC15	40.0%
II	High noble gas, low or low-low volatile and non-volatile releases	STC2, STC3, STC9, STC 12	14.5%
III	High noble gas, medium volatile, and low or low-low non-volatile releases	STC5, STC18	17.1%
IV	High noble gas release, medium volatile release, and medium non-volatile release	STC4, STC7, STC10, STC13	3.1%
V	High noble gas, high volatile, and medium or lower non-volatile releases	STC11, STC16, STC20	25.3%
VI	High noble gas, volatile, and non-volatile releases	STC8, STC14	<0.1%

Table 4.7-5
Ginna Release Categories Ranked By Frequency

Rank	Release Category	Frequency	Percent Total CDF
1	1	2.86E-05	34.9
2	18	1.40E-05	17.1
3	20	1.28E-05	15.6
4	12	1.16E-05	14.2
5	16	7.92E-06	9.7
6	15	4.21E-06	5.1
7	13	2.46E-06	3.0
8	9	2.17E-07	0.3
9	10	4.44E-08	0.1
10	14	2.68E-08	<0.1
11	11	1.90E-08	<0.1
12	2	8.76E-09	<0.1
13	8	7.58E-09	<0.1
14	5	6.92E-10	<0.1
15	4	1.68E-10	<0.1
16	3	5.42E-11	<0.1
17	7	1.05E-12	<0.1
18	6	0	0.0
19	17	0	0.0
20	19	0	0.0
		8.20E-05	

Table 4.7-6
Comparison Of Containment Accident Progression Results
Ginna PRA And Surry NUREG-1150
(% of Total CDF)

	Ginna	Surry
No VB	5.1	46.0
VB, No CF	34.9	34.0
VB, BMT, late CF	14.6	5.9
VB, early CF[1]	3.0	0.7
Bypass	42.4	12.0

Key: BMT = Basemat Meltthrough
CF = Containment Failure
VB = Vessel Breach

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[1] - Includes loss of isolation sequences for Ginna

Table 4.8-1
Sensitivity Cases 1A and 1B
Induced Hot Leg Failure Probability

Base Calculation			Sensitivity Calculation 1A	Sensitivity Calculation 1B
Rank	Release Category	Percent Total CDF	Percent Total CDF	Percent Total CDF
1	1	32.4	32.84	32.24
2	18	17.2	17.18	17.18
3	20	15.6	15.64	15.64
4	12	13.4	13.7	13.3
5	16	9.7	9.7	9.7
6	13	6.3	6.3	6.3
7	15	5.0	4.3	5.3
8	9	0.3	0.3	0.3
9	10	0.1	0.1	0.1
10	14	<0.1	<0.1	<0.1
11	11	<0.1	<0.1	<0.1
12	2	<0.1	<0.1	<0.1
13	8	<0.1	<0.1	<0.1
14	5	<0.1	<0.1	<0.1
15	4	<0.1	<0.1	<0.1
16	3	<0.1	<0.1	<0.1
17	7	<0.1	<0.1	<0.1
18	6	0.0	0.0	0.0
19	17	0.0	0.0	0.0
20	19	0.0	0.0	0.0

Table 4.8-2
Sensitivity Case 2A
DCH Probability Maximized

	Base Calculation		Sensitivity Calculation 2A
Rank	**Release Category**	**Percent Total CDF**	**Percent Total CDF**
1	1	32.4	29.7
2	18	17.2	17.2
3	20	15.6	15.6
4	12	13.4	11.7
5	16	9.7	9.7
6	13	6.3	6.3
7	15	5.0	5.0
8	9	0.3	0.2
9	10	0.1	0.1
10	14	<0.1	<0.1
11	11	<0.1	<0.1
12	2	<0.1	3.8
13	8	<0.1	<0.1
14	5	<0.1	0.5
15	4	<0.1	0.1
16	3	<0.1	<0.1
17	7	<0.1	<0.1
18	6	0.0	0.0
19	17	0.0	0.0
20	19	0.0	0.0

Table 4.8-3
Sensitivity Case 3A
Containment Failure Pressure at 5th Percentile

	Base Calculation		Sensitivity Calculation 3A
Rank	Release Category	Percent Total CDF	Percent Total CDF
1	1	32.4	32.4
2	18	17.2	17.2
3	20	15.6	15.6
4	12	13.4	13.4
5	16	9.7	9.7
6	13	6.3	6.3
7	15	5.0	5.0
8	9	0.3	0.3
9	10	0.1	0.1
10	14	<0.1	<0.1
11	11	<0.1	<0.1
12	2	<0.1	<0.1
13	8	<0.1	<0.1
14	5	<0.1	<0.1
15	4	<0.1	<0.1
16	3	<0.1	<0.1
17	7	<0.1	<0.1
18	6	0.0	0.0
19	17	0.0	0.0
20	19	0.0	0.0

Table 4.8-4
Sensitivity Cases 4A and 4B
Debris Depth in Cavity Sump

Base Calculation			Sensitivity Calculation 4A	Sensitivity Calculation 4B
Rank	Release Category	Percent Total CDF	Percent Total CDF	Percent Total CDF
1	1	32.4	34.0	15.5
2	18	17.2	17.2	17.2
3	20	15.6	15.6	15.6
4	12	13.4	11.8	30.3
5	16	9.7	9.7	9.7
6	13	6.3	6.3	6.3
7	15	5.0	5.0	5.0
8	9	0.3	0.3	0.3
9	10	0.1	0.1	0.1
10	14	<0.1	<0.1	<0.1
11	11	<0.1	<0.1	<0.1
12	2	<0.1	<0.1	<0.1
13	8	<0.1	<0.1	<0.1
14	5	<0.1	<0.1	<0.1
15	4	<0.1	<0.1	<0.1
16	3	<0.1	<0.1	<0.1
17	7	<0.1	<0.1	<0.1
18	6	0.0	0.0	0.0
19	17	0.0	0.0	0.0
20	19	0.0	0.0	0.0

Table 4.8-5
Sensitivity Cases 5A and 5B
Steam Explosion Disperses Debris in Cavity

Base Calculation			Sensitivity Calculation 5A	Sensitivity Calculation 5B
Rank	Release Category	Percent Total CDF	Percent Total CDF	Percent Total CDF
1	1	32.4	40.3	26.5
2	18	17.2	17.2	17.2
3	20	15.6	15.6	15.6
4	12	13.4	5.5	19.3
5	16	9.7	9.7	9.7
6	13	6.3	6.3	6.3
7	15	5.0	5.0	5.0
8	9	0.3	0.3	0.3
9	10	0.1	0.1	0.1
10	14	<0.1	<0.1	<0.1
11	11	<0.1	<0.1	<0.1
12	2	<0.1	<0.1	<0.1
13	8	<0.1	<0.1	<0.1
14	5	<0.1	<0.1	<0.1
15	4	<0.1	<0.1	<0.1
16	3	<0.1	<0.1	<0.1
17	7	<0.1	<0.1	<0.1
18	6	0.0	0.0	0.0
19	17	0.0	0.0	0.0
20	19	0.0	0.0	0.0

Table 4.8-6
In-Core Oxidation: Base MAAP Results for
Ginna and Surry Results from NUREG-1150

Case Description	MAAP Case	Percent Clad Reacted	
		Ginna (MAAP)	Surry (NUREG-1150)
Base case station blackout (SBO)	SBO00	49%	44%
SBO with a large induced rupture of the hot leg	SBO01	40%	50%
Small LOCA with failure of injection	SLOCA15	41%	48%

Table 4.8-7
Summary of Predicted Hot Leg Temperatures
in High Pressure Sensitivity Cases

Case Description	Ginna MAAP Case	Time of Vessel Failure	Peak Hot Leg Temperature Prior to Vessel Failure
Base Case station blackout (SBO); no AFW, no PORV, no seal LOCA	SBO00	3.71 hrs	1640°F
Total LOFW; no seal LOCA, but PORV in auto	SBO03	3.70 hrs	1620°F
Total LOFW; no seal LOCA, PORV in auto increased eutectic melting temperature (TEU=2700 K)	SBO05	3.90 hrs	1842°F
SBO; pump bowl loop seals clear	SBO24	5.55 hrs	1041°F
SBO; FNCBP=1.0	SBO25	3.69 hrs	1578°F

Table 4.8-8
Summary of Sensitivity Analyses with
Increased Time to Vessel Failure

Case Description	Ginna MAAP Case	Time from Core Plate Failure to Vessel Failure (TTRX)	Time of Vessel Failure	Peak Pressure between Time of Core Plate Failure and Vessel Failure
2" DIA LOCA; no injection available; no secondary depressurization	SLOCA00	1 minute	4.70 hrs	~80 psia
2" DIA LOCA; no injection available; no secondary depressurization	SLOCA03	30 minutes	5.45 hrs	~650 psia
2" DIA LOCA; SI available, but no recirc; steam generators depressurized	SLOCA08	30 minutes	12.9 hrs	~200 psia
2" DIA LOCA; SI available, but no recirc; steam generator not manually depressurized	SLOCA09	30 minutes	12.1 hrs	~500 psia

Table 4.8-9
Key Results for Core Drop Fraction Sensitivity Case

Case Description	Ginna MAAP Case	Core Debris Retained in Vessel	Containment Failure Conditions			CsI Release 8 Hrs After Containment Failure
			Primary System Gas Temperature	Containment Pressure	Time	
TLOFW; no injection, seal LOCA at 45 minutes, no recovery (FCRDR=0.1)	SBO07	1.554E4 Lb	840°F	145 psia	12.2 hrs	4.57E-3
TLOFW; no injection, seal LOCA at 45 minutes, no recovery (FCRDR=0.8)	SBO26	0.0E0 Lb	742°F	145 psia	10.9 hrs	3.75E-3

Table [illegible]0

Key Results for Vapor Pressure Multiplier Sensitivity Analyses

Case Description	Ginna MAAP Case	Vessel Failure Time	Containment Failure Time	Conditions at End of Run				
				Time	Primary System Gas Temperature	Containment Temperature	Release Fractions	
							Nobles	CsI
Base SBO; no AFW, no injection, no seal LOCA, no recovery (FVPREV=1.0)	SBO00	3.71 hrs	12.6 hrs	20.6 hrs	850°F	464°F	0.971	2.47E-3
SBO; no AFW, no injection, no seal LOCA, no recovery (FVPREV=0.2)	SBO06	3.71 hrs	11.9 hrs	19.9 hrs	830°F	455°F	0.968	1.78E-3
TLOFW; no injection, seal LOCA at 45 minutes, no recovery (FVPREV=1.0)	SBO07	3.80 hrs	12.2 hrs	20.2 hrs	994°F	470°F	0.944	4.57E-3
TLOFW; no injection, seal LOCA at 45 minutes, no recovery (FVPREV=0.2)	SBO21	3.78 hrs	12.2 hrs	20.2 hrs	997°F	469°F	0.944	2.09E-3

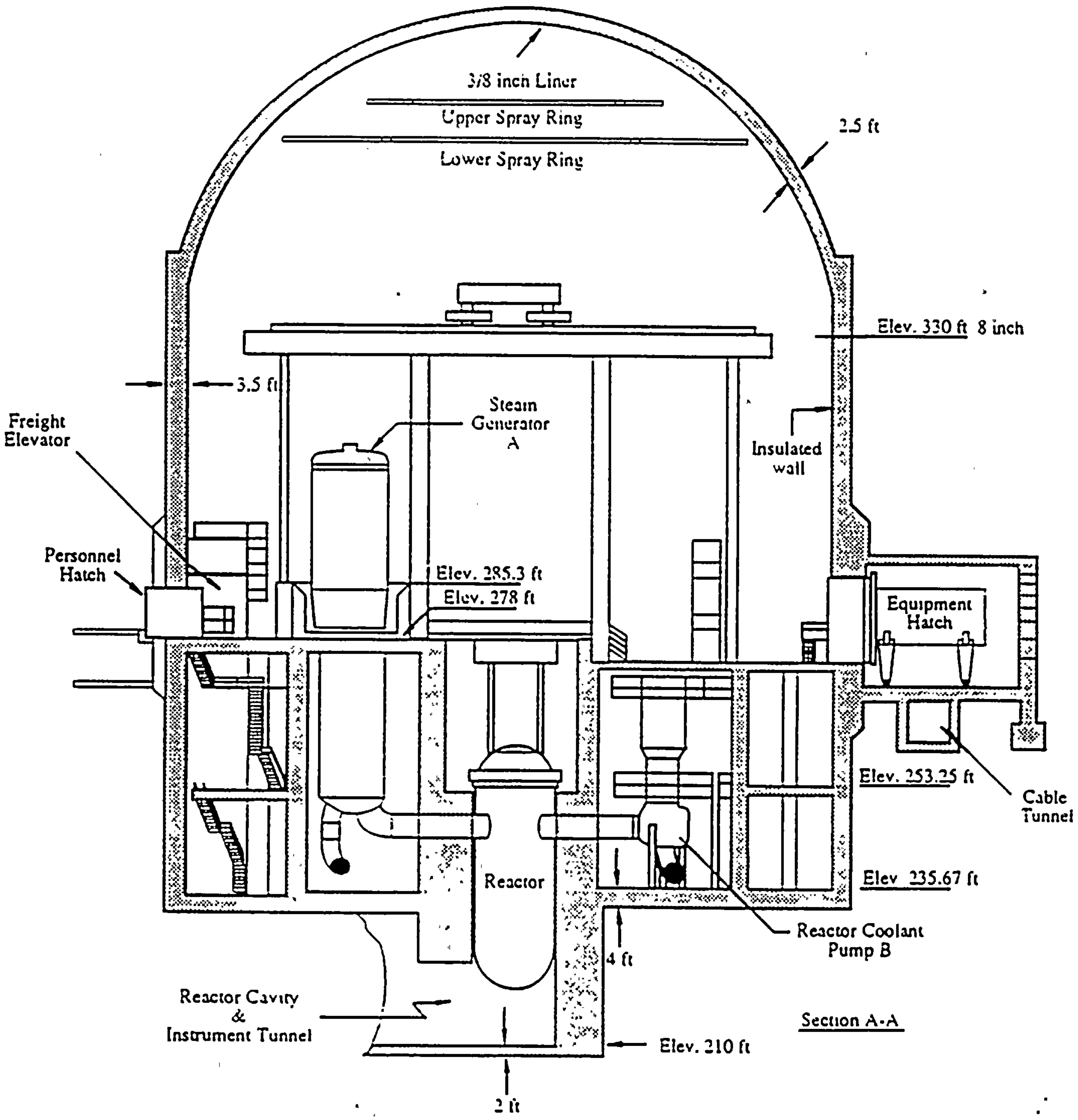
Table 4.8-11
Key Results for the Containment Equipment Mass Uncertainty Analysis

Case Description	Ginna MAAP Case	Vessel Failure Time	Containment Failure Time	Conditions at End of Run				
				Time	Primary System Gas Temperature	Containment Temperature	Release Fractions	
							Nobles	CsI
Base SBO: no AFW, no injection, no seal LOCA, no recovery (default equipment mass)	SBO00R	3.71 hrs	12.6 hrs	48.0 hrs	1030°F	591°F	0.994	3.22E-3
SBO; no AFW, no injection, no seal LOCA, no recovery (10X default equipment mass)	SBO27	3.75 hrs	16.3 hrs	48.0 hrs	978°F	562°F	0.994	4.43E-3

Table 4.8-12
Key Results for the Core Debris to Overlying
Water Pool Heat Flux Multiplier Sensitivity Analyses

Case Description	Ginna MAAP Case	Cavity Concrete Attack	Containment Failure Time	End of Run	Fission Product Release Fractions		
					Nobles	CsI	Te_2
2" DIA LOCA; no injection, fan coolers available (FCHF=0.10)	SLOCA00	0.01 ft	N/A	16.1 hrs	5.02E-4	5.45E-6	8.5E-8
2" DIA LOCA; no injection, fan coolers available (FCHF=0.02)	SLOCA02	1.74 ft	N/A	24.0 hrs	7.45E-4	6.47E-6	1.6E-6
5.5" DIA LOCA; injection but no recirculation, containment failure early after vessel failure, fan coolers available (FCHF=0.10)	STC02	0.05 ft	5.96 hrs	48.0 hrs	0.204	1.96E-3	1.8E-6
5.5" DIA LOCA; injection but no recirculation, containment failure early after vessel failure, fan coolers available (FCHF=0.02)	STC03	2.06 ft	5.96 hrs	48.0 hrs	0.330	5.51E-3	2.7E-3

Figure 4.1-1
Containment Section



Reference Drawings:
RGE 33013-2131

Figure 4.1-2
Reactor Cavity Three Dimensional View

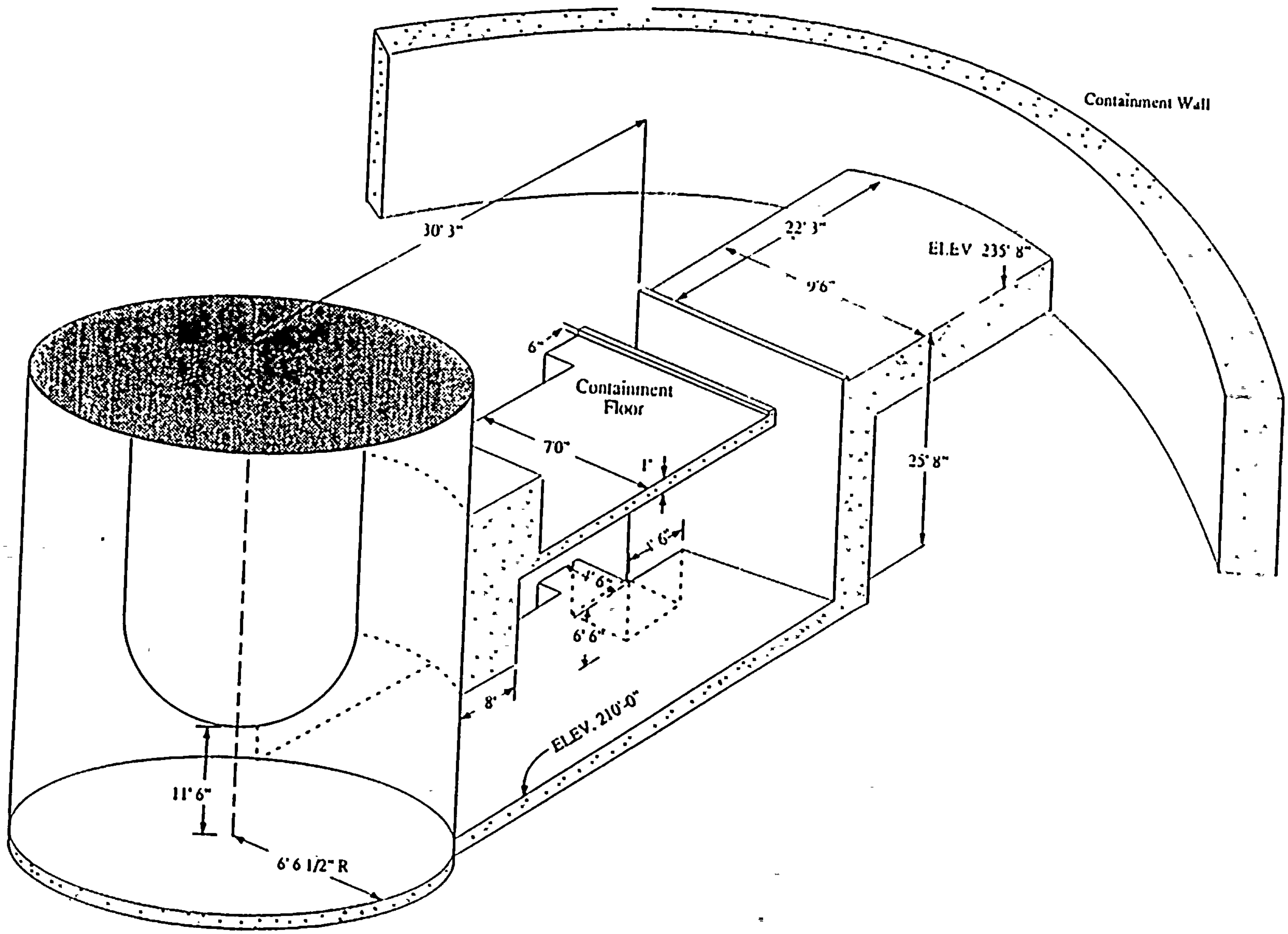
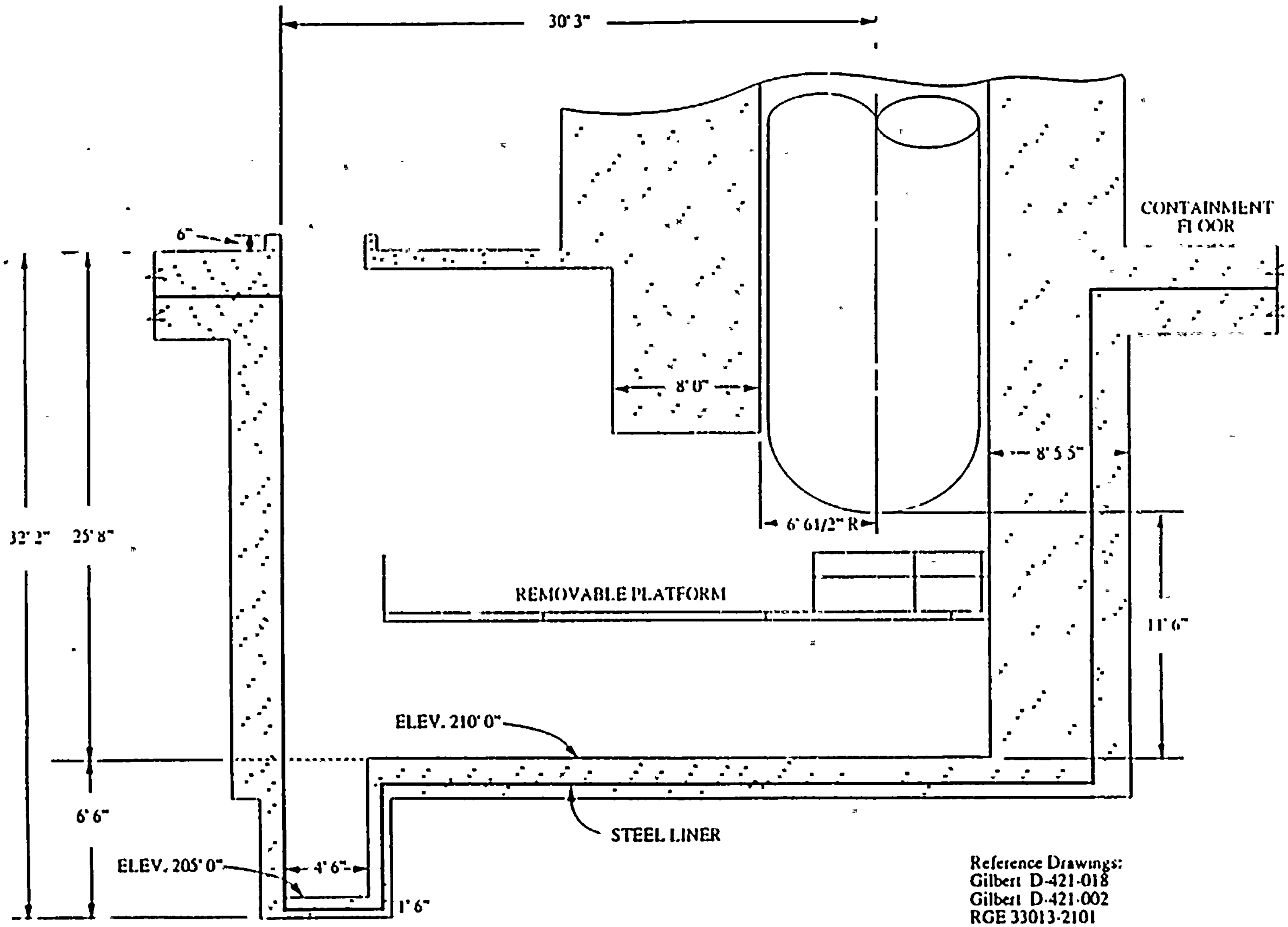


Figure 4.1-3
Reactor Cavity Section



Reference Drawings:
Gilbert D-421-018
Gilbert D-421-002
RGE 33013-2101
RGE 33013-1225
RGE Walkdown

Figure 4.3-1
Containment System Event Tree Diagram

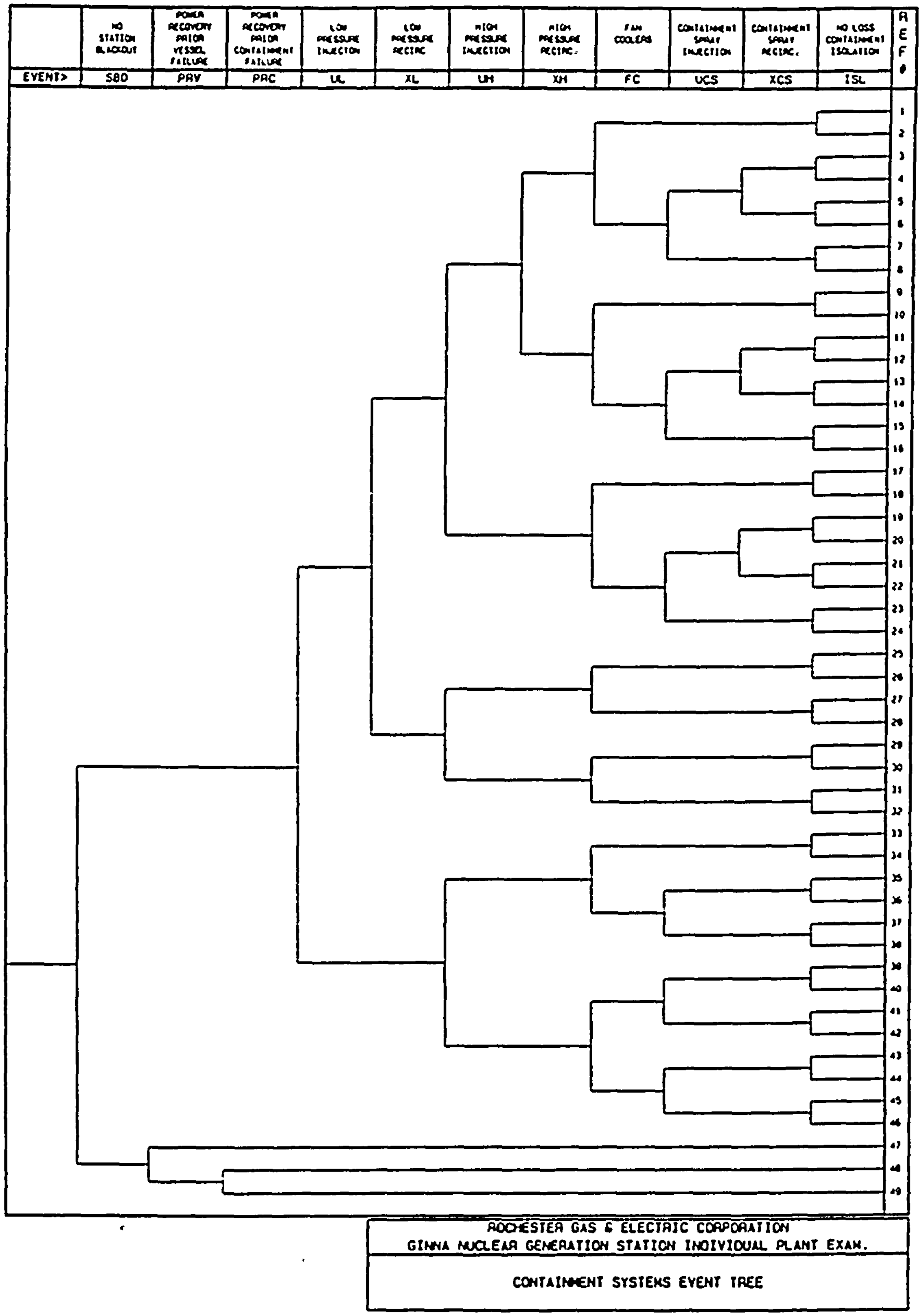


Figure 4.3-2
Plant Damage State Logic Diagram

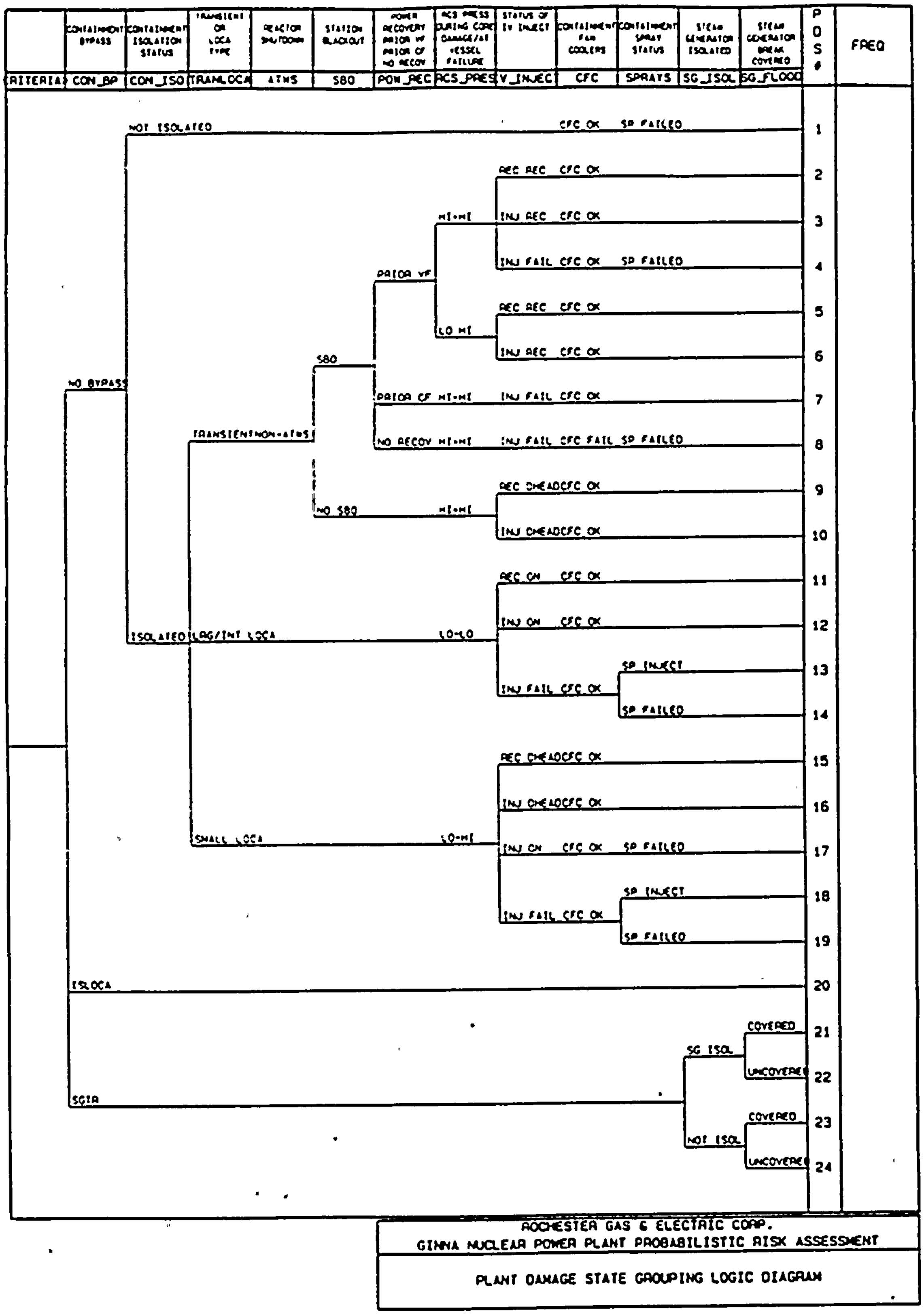


Figure 4.4-1
Containment General Arrangement Sketch

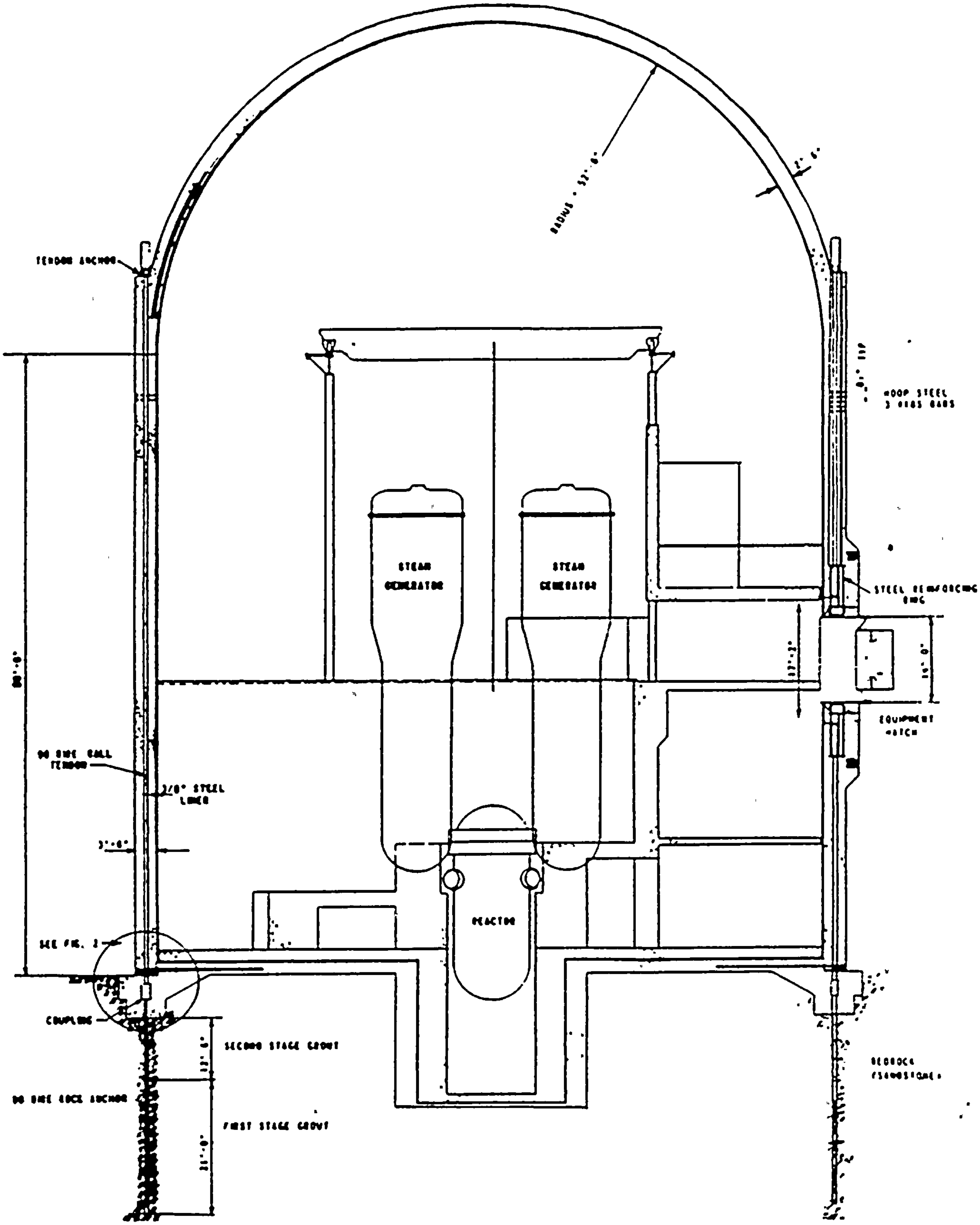


Figure 4.4-2 Normal Density Function

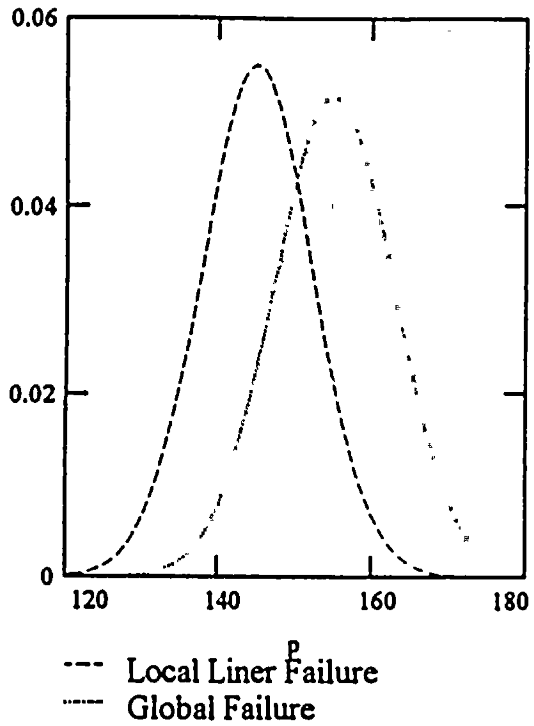


Figure 4.4-3 Cumulative Distribution Function

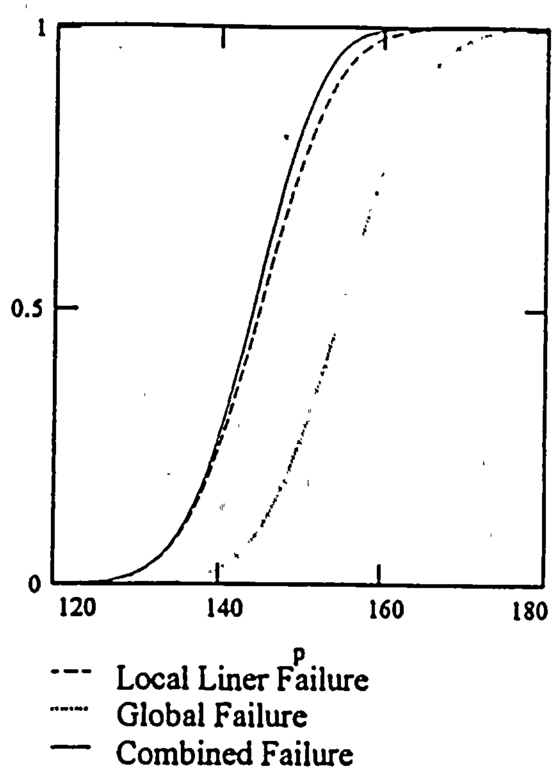


Figure 4.4-4 Conditional Probability of Containment Failure for Slow Pressurization

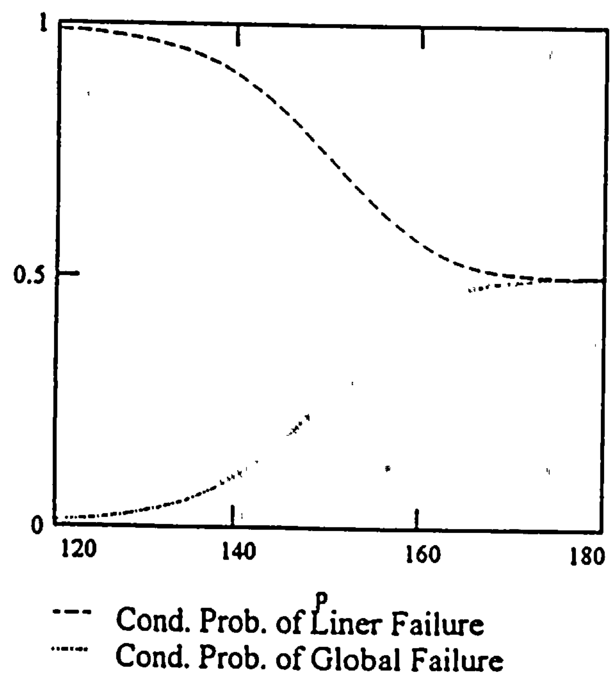


Figure 4.4-5 Conditional Probability of Containment Failure for Rapid Pressurization

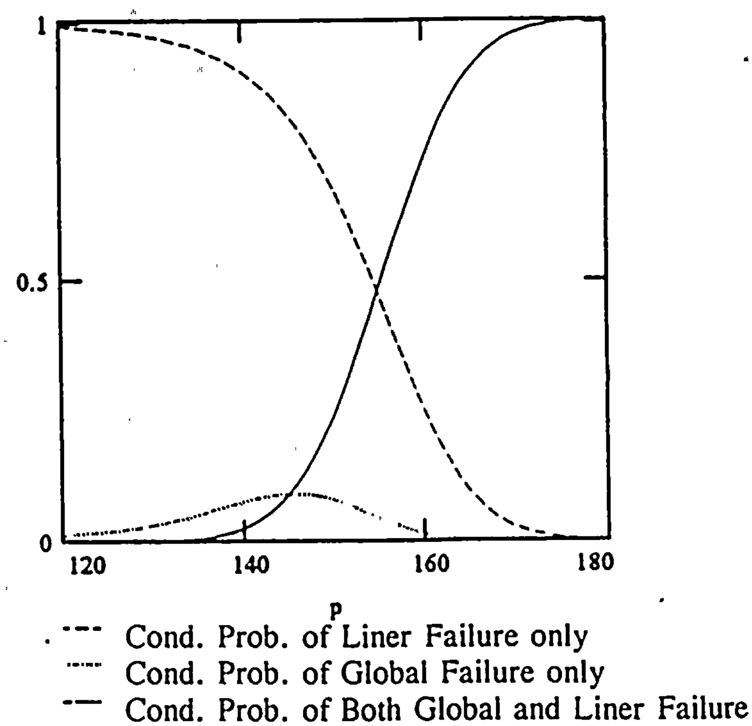


Figure 4.5-1
Containment Event Tree

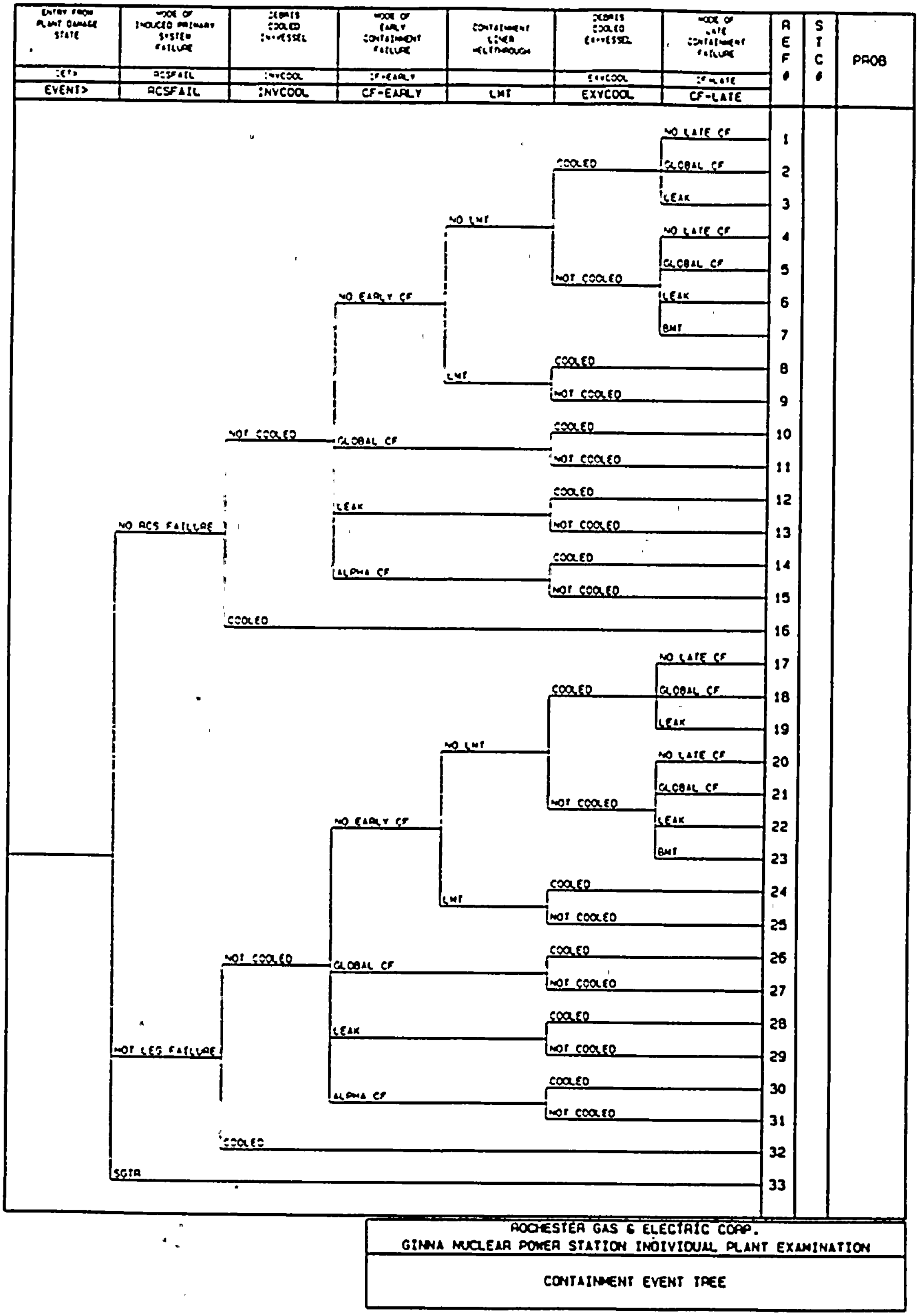


Figure 4.5-2
Mode of Induced Primary System Failure Decomposition Event Tree

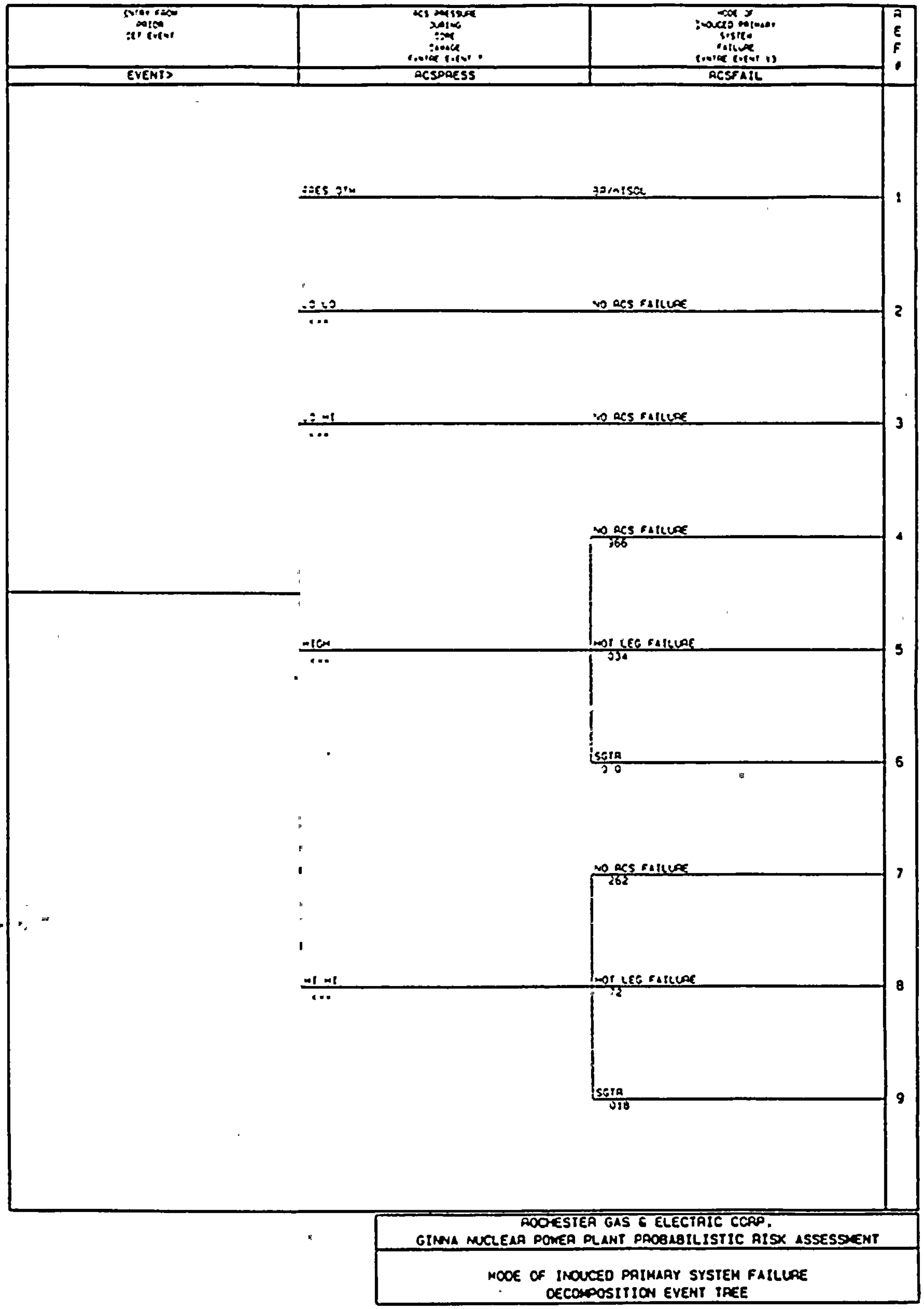


Figure 4.5-3
Debris Cooled In-Vessel Decomposition Event Tree

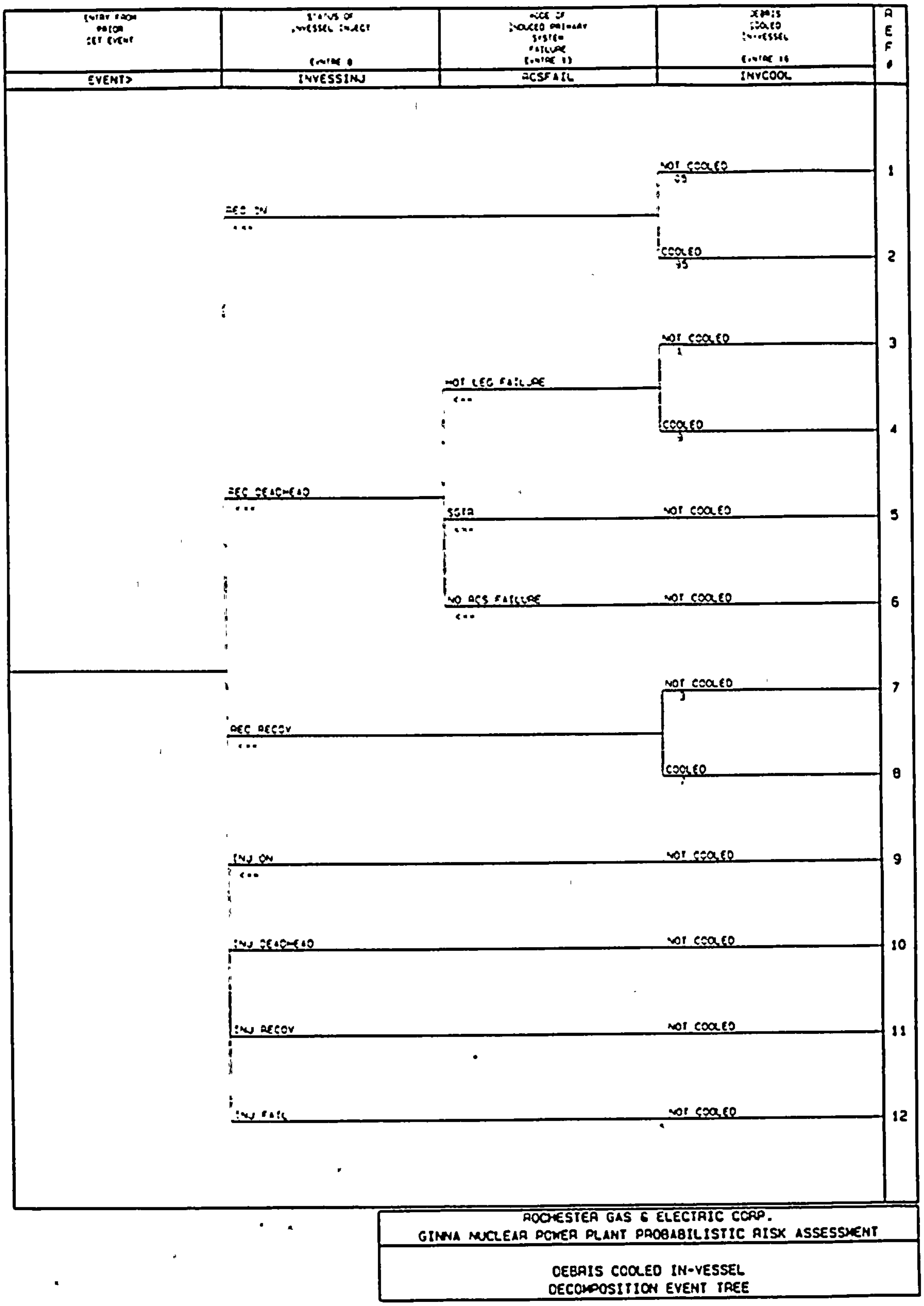
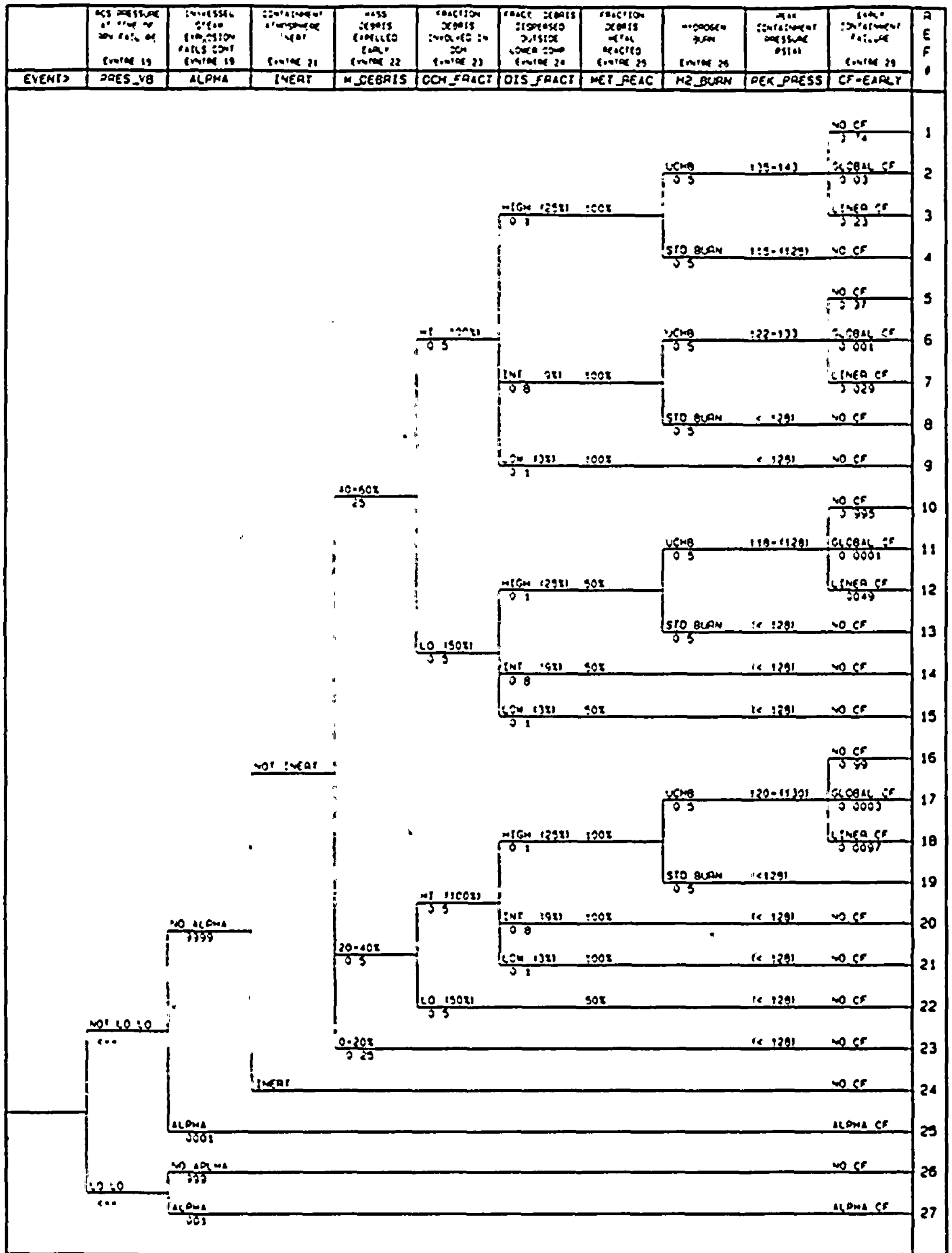


Figure4.5-4
Early Containment Failure Decomposition Event Tree



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EARLY CONTAINMENT FAILURE
DECOMPOSITION EVENT TREE

Figure 4.5-5
Containment Liner Meltthrough Decomposition Event Tree

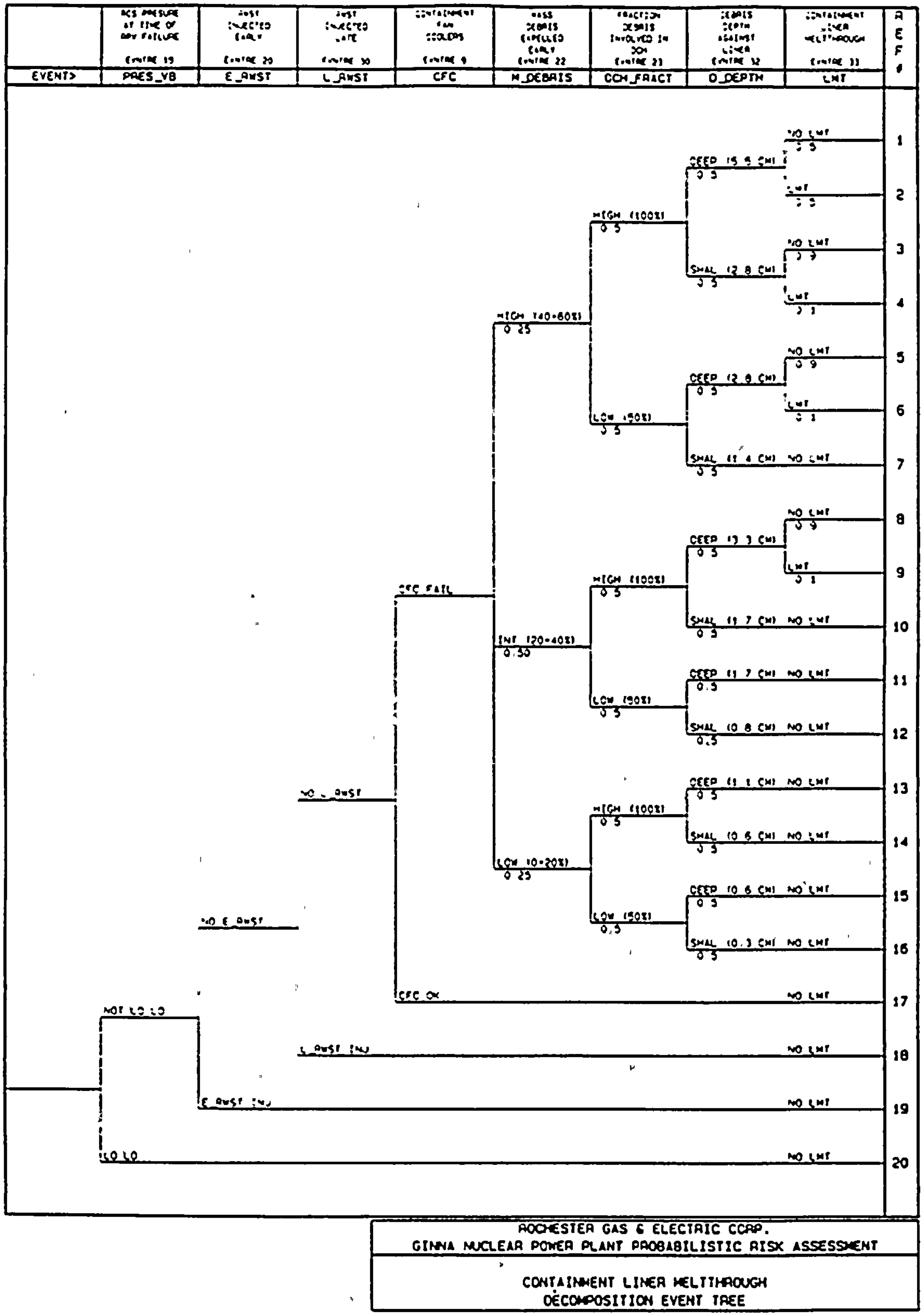


Figure 4.5-6
Type of Ex-vessel CCI Decomposition Event Tree

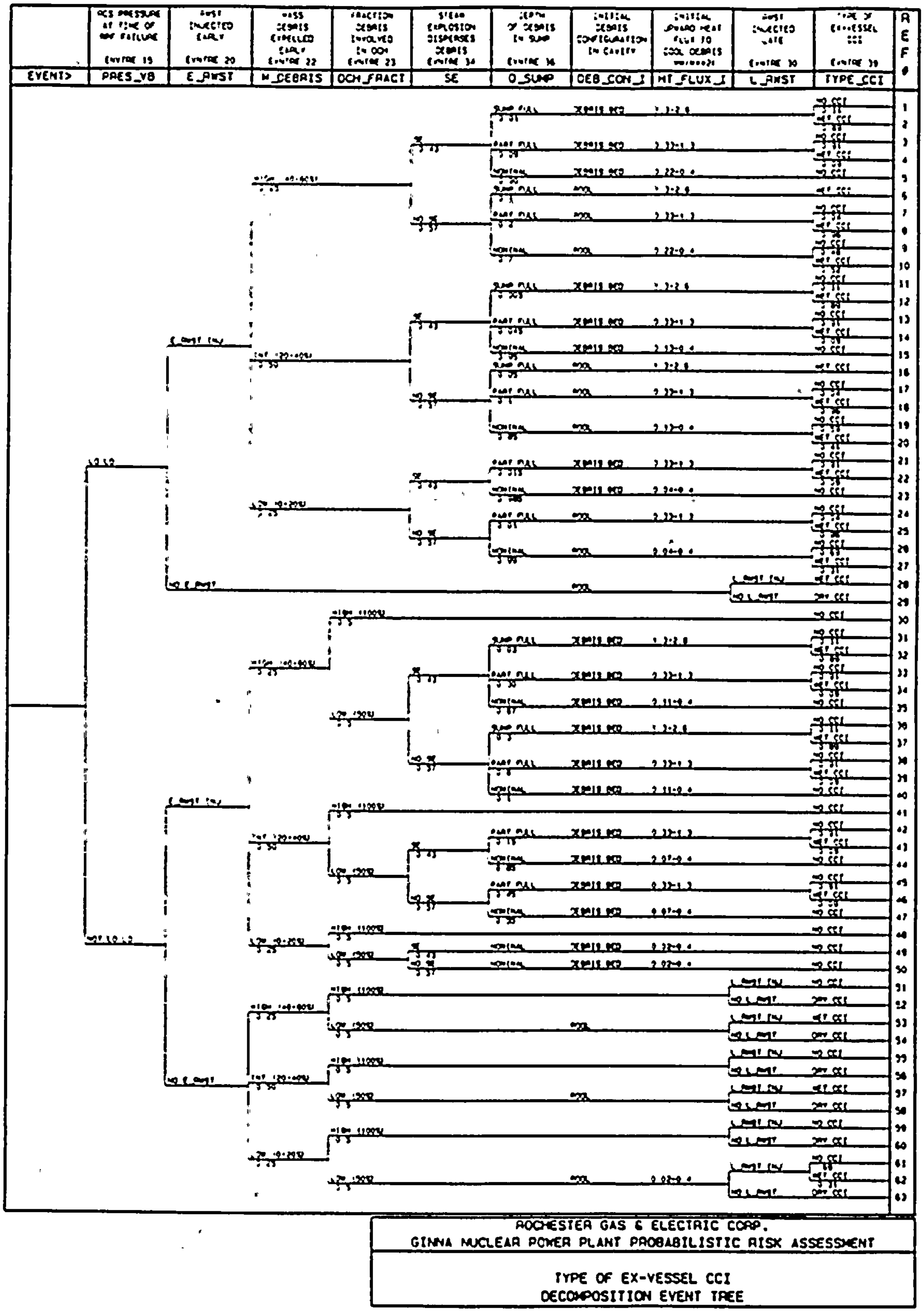


Figure 4.5-7
Mode of Late Containment Failure Decomposition Event Tree

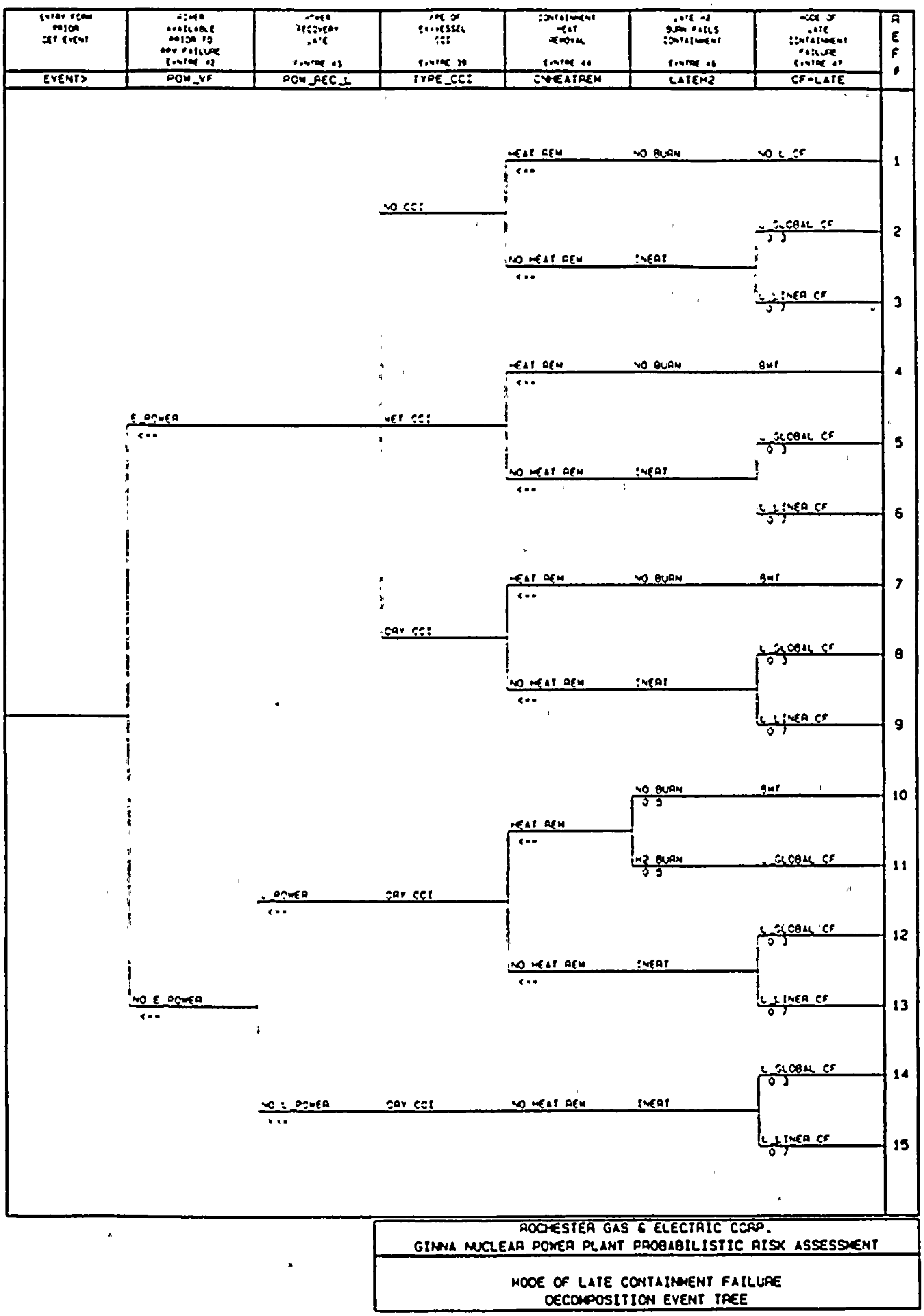


Figure 4.5-8
Core Fraction Ejected

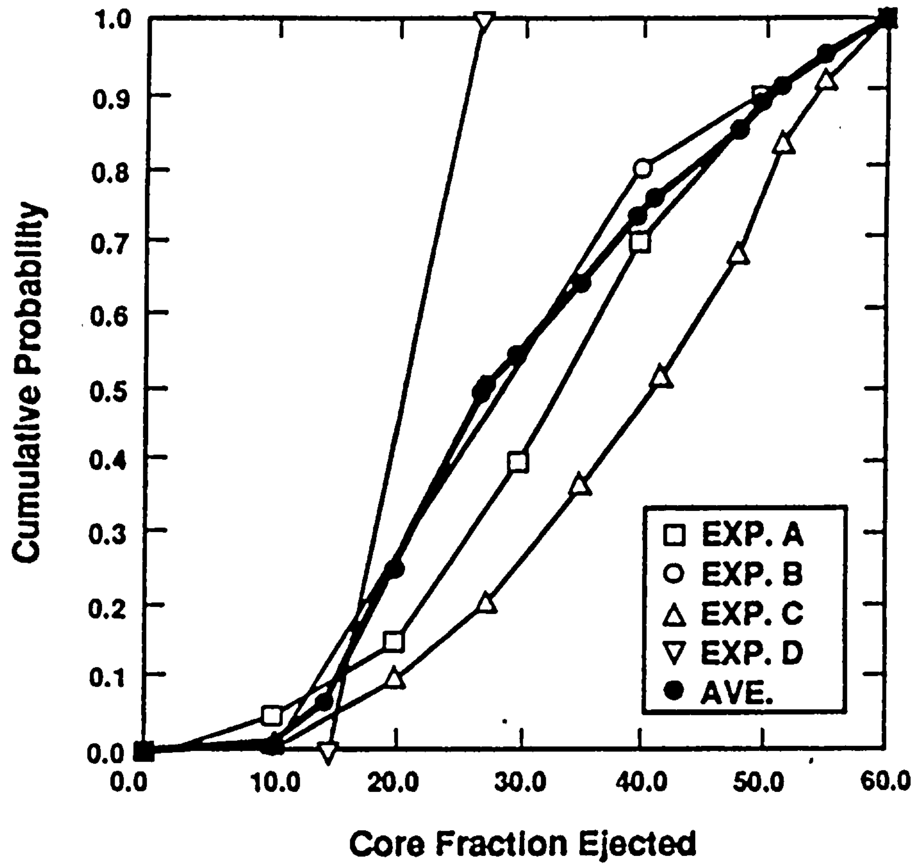


Figure 4.5-9
Experimental Model of Ringhals 2 Vault

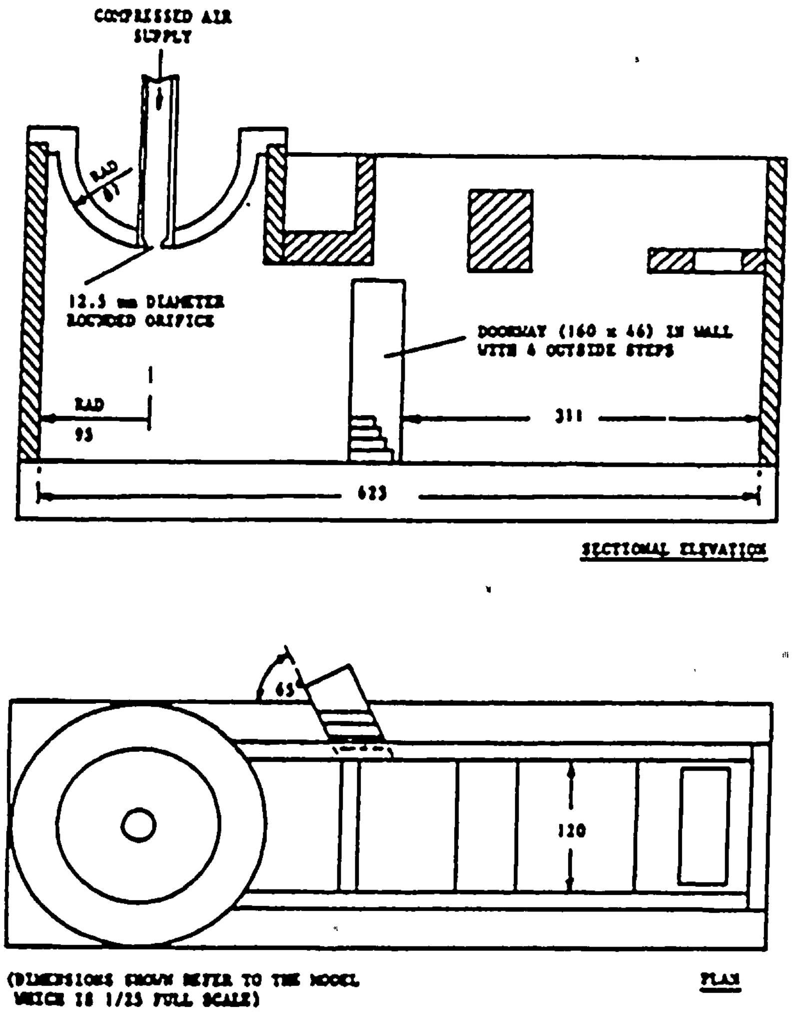


Figure 4.5-10
Comparison of Dryout Heat Flux Predictions With Data

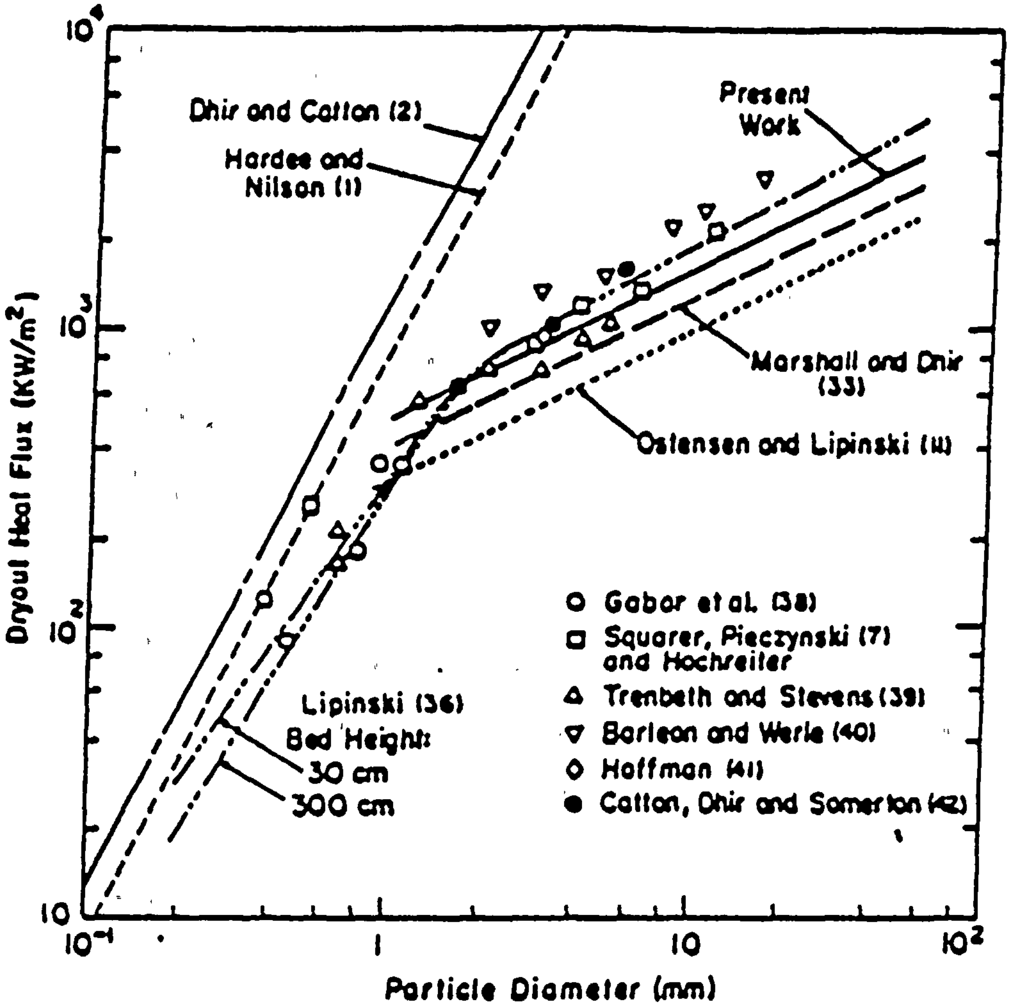
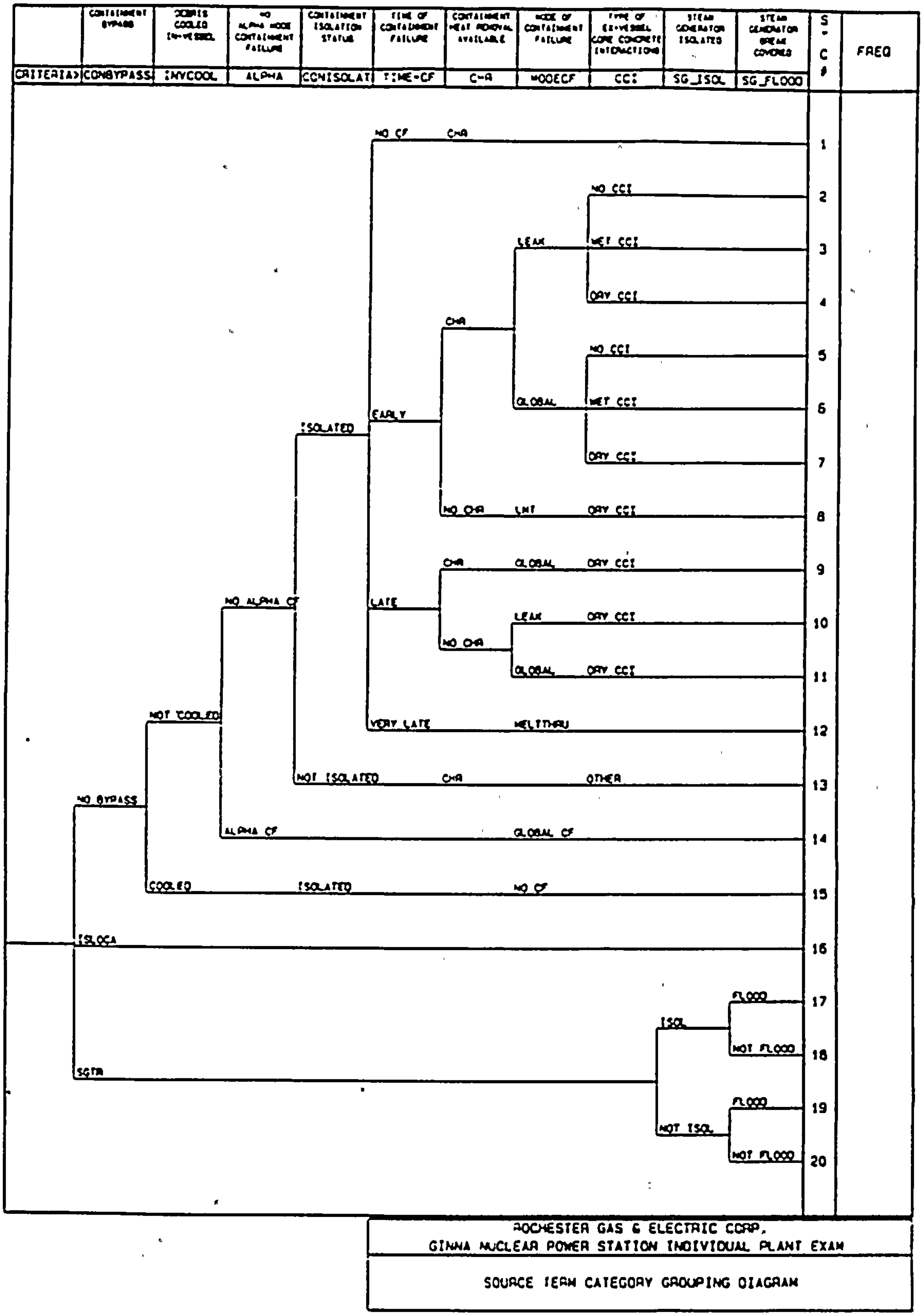


Figure 4.7-1
Source Term Category Grouping Diagram



5.0 Utility Participation and RG&E Review

5.1 R. E. Ginna PRA Project Team

The R. E. Ginna PRA Project was competed by a joint team of RG&E personnel and contractors over a four year period. The project was initially organized into the 14 tasks shown in Table 5.1-1. As this table shows, several of the original tasks were either dropped, deffered or restructured due to leasons learned, limited resources, shifting industry direction and constraints of time and budget.

In January of 1989, anticipating the release of USNRC's Generic Letter 88-20, RG&E began assembling an internal team to conduct a PRA for Ginna. This core team eventually included two new hires with extensive previous utility PRA experience, another new hire with no previous PRA experience, and an RG&E employee previously trained as a Ginna Auxiliary Operator.

The RG&E project manager has 14 years of experience in accident and systems analysis; 11 of these years have been spent in PRA, starting with participation in the NSAC-60 project. RG&E's lead data analyst had previously conducted data analysis and other Level 1 analysis for another PWR. The Ginna-specific MAAP model was assembled and implemented in-house by an RG&E employee who has, during the course of this project, received extensive training in severe accident analysis from acknowledged industry experts.

Many other experienced RG&E personnel were also called upon to assist the core team as required. In the end, RG&E personnel contributed over 20,000 hours of labor to this project; this represents over one-half of the total hours spent completing the project.

Collection of the raw, plant-specific data was completed by contractor personnel under the direct supervision of the RG&E lead data analyst, who then processed this data for use in the analyses. RG&E personnel were:

- Initially responsible for five of the 14 systems work packages (Safety Injection, Containment Spray, Containment Isolation, Auxiliary Feedwater and Service Water), and later assumed responsiblity for major rework on two others (Electric Power and ESFAS);
- Responsible for all walkdowns;
- Responsible for initiating events analysis;
- Major contributors to event tree definition and analysis;
- Responsible for the interfacing systems loss of coolant accidents (ISLOCAs) analysis;

- Major contributors to sequence quantification and recovery analysis;
- Responsible for flood zones and flood sources analysis;
- Responsible for compiling and analyzing the component and subcomponent location database for the internal flooding analysis;
- Major contributors to the screening and detailed flooding analyses;
- Responsible for construction and maintenance of the Ginna-specific MAAP model;
- Responsible for planning and execution of all MAAP runs for both Level 1 and Level 2 support;
- Major contributors to containment event tree quantification efforts;
- Major contributors to source term analysis;
- Major contributors to the uncertainty, sensitivity and modifications analyses;
- Responsible for overall project management and integration; and,
- Responsible for the preparation and review of this document.

In 1989, RG&E contracted with the former Advanced Technology for Engineering Systems, Incorporated (ATESI) to collect the raw data needed for the plant-specific data analysis. ATESI had just completed a joint RG&E / Electric Power Research Institute (EPRI) Reliability Centered Maintenance (RCM) study for Ginna, and was very familiar with the required maintenance records.

RG&E contracted with Science Applications International Corporation's (SAIC) Clearwater, Florida office in 1990 to provide Level 1 / Level 2 PRA consulting services. SAIC personnel served as Task Leaders for all of the tasks shown in Table 5.1-1 as dictated by a SAIC quality assurance program designed joinlty by SAIC and RG&E. Initially, a SAIC Project Manager, reporting to the RG&E Project Manager, provided the majority of the day-to-day direction to the contract analysts. The last twelve months of the project were under the direct control of the RG&E Project Manager.

SAIC sub-contracted EBASCO Services to perform a containment structural analysis; this analysis provided input to the Level 2 analyses.

In 1993, RG&E brought in Gabor, Kenton and Associates (GKA) to provide Level 2 consulting services. GKA personnel reviewed RG&E's work on the MAAP model and provided guidance and manpower to complete the Level 2 analyses.

As a result of this project, RG&E has developed both the tools and the internal organization needed to support the PRA-related needs of Ginna operations, maintenance and licensing.

5.2 RG&E Review

Under the Ginna PRA quality assurance program, all analyses and documentation were performed and reviewed under a quality assurance program designed to meet the requirements of 10 CFR Appendix B. RG&E personnel involved with the project provided review and comments on all work products under this program. In addition, RG&E personnel not directly involved with the project were periodically tasked to review work products that fell into their areas of expertise (for example, RG&E accident analysis experts reviewed the accident sequence analyses, etc.). All systems work packages were reviewed by Ginna licensed operators.

5.3 Areas of Review

All comments generated within the Ginna PRA Project have been documented per the requirements of the project quality assurance program, This documentation is stored per the requirements of 10 CFR 50 Appendix B.

In early 1993, RG&E Ginna PRA Project personnel instituted a complete review of previously generated systems models. This review resulted in major changes in most of the system models; most of these changes involved AC and DC electric power interfaces.

Also in 1993, RG&E had recognized industry experts from Gabor, Kenton and Associates (GKA) review completed Level 2 analyses. As a result of the reviews, extensive revisions to the analyses were completeld by RG&E and GKA personnel.

5.4 Resolution of Review Comments

Resolution of all comments generated within the Ginna PRA Project have been documented per the requirements of the project quality assurance program. This documentation is stored per the requirements of 10 CFR 50 Appendix B.

6.0 Unique Safety Features and Plant Improvements

6.1 Unique Safety Features

One of the unique Ginna safety features that contributes to a relatively low risk for a plant built in the late 1960s is the Standby Auxiliary Feedwater System. The existence of this system means that there are four complete trains of motor driven auxiliary feedwater available in addition to the turbine driven train. Probability of a complete loss of secondary heat removal is, therefore, very remote. This probability is further lowered by the diversity of water sources available to the AFW and SAFW Systems, including condensate, service water (i.e., Lake Ontario), fire service water, and domestic water.

Internal plant flooding did not prove to be a significant contributor to the total calculated core damage frequency; at first inspection, this seems somewhat odd, due to the fact that the Refueling Water Storage Tank (TSI01) is located inside the Auxiliary Building. Offsetting this potential vulnerability, however, is the relatively open nature of the Ginna Auxiliary Building design. Pumps, switchgear, panels and other vital pieces of equipment are not located in separate rooms or cubicles where water could pool. In addition, considerable effort was spent during the Systematic Evaluation Program (SEP) to identify equipment that could be vulnerable to spray and / or dripping effects during potential pipe breaks and cracks. This equipment was given attention (i.e., spray shields, etc. were installed) as a result of the SEP analyses, and was found not to be vulnerable during the Ginna PRA analyses.

6.2 Plant Improvements

Two areas have been identified through evaluation of the importance of human failure events in Section 3.4 that will be further acted on:

Failure to cooldown and depressurize following a steam generator tube rupture event was identified as the key operator action in the Ginna PRA. The Ginna Operations and Training Departments will review the appropriate SGTR procedures: if potential improvements are identified, these improvements will be forwarded to the Westinghouse Owners Group Operations Subcommittee for possible additions / modifications to the Westinghouse emergency response guidelines; and,

Failure to manually isolate containment isolation air operated valve 371 or valve 204A following a failure of 371 to automatically close was significant to both the Level 1 and Level 2 results. This situation will also be reviewed by the Ginna Operations and Training Departments for emphasis during licensed operator training classes.

Several plant improvements that were identified during the course of the Ginna PRA have already been either carried out or are planned for implementation during the 1994 refueling outage:

When the Ginna PRA was started in 1989, the safety injection pumps were required to be aligned to the boric acid storage tanks while in standby. The USNRC has approved a Technical Specifications change that will change the safety injection pumps initial alignment to the refueling water storage tank at all times. This change has been reflected in the as-quantified Ginna PRA models; it resulted in a substantial reduction in calculated core damage frequency;

Preliminary results of the Ginna PRA indicated that long-term cooling of the turbine driven auxiliary feedwater pump (PAF03) under station blackout conditions was critical. Based on this finding, procedures have been modified to provide for alternate cooling of PAF03 via the Fire Service Water System through a temporary hose connection. The procedural modification and the hose and its associated fittings are already in place, and have been reflected in the as-quantified Ginna PRA models.

The RG&E Electrical Engineering group identified a potential AC power dependency in the 480 VAC Vital Buses Undervoltage auxiliary relays during the course of the Ginna PRA. This dependency is included in the as-quantified Ginna PRA models; it does not, however, contribute significantly to the total calculated core damage frequency. This potential dependency will be corrected through a modification planned for implementation during the 1994 refueling outage.

7.0 Results, Conclusions and Summary

7.1 Level 1 Results

The total calculated core damage frequency from internal initiating events was 8.23E-05 / year. The dominant contributors to this frequency were a tube rupture in steam generator B (EMS01B) at about 23.5% of the total core damage frequency; loss of instrument air at about 27% of the total core damage frequency; small-small break LOCAs at about 12.1% of the total core damage frequency; and, a tube rupture in steam generator A (EMS01A) at about 10.4% of the total core damage frequency. Other initiating events contributing to the total calculated core damage frequency were interfacing systems LOCAs (9.6%); medium break LOCAs (7.2%); small break LOCAs (6.2%); and, large break LOCAs (3.9%).

Table 7-1 contains a complete listing of Level 1 results. Figure 7-1 shows a breakdown of calculated core damage frequency by sequence; Figure 7-2 shows a breakdown of calculated core damage frequency by initiating event.

7.2 Level 1 Conclusions

As can be seen from the Level 1 results, steam generator tube rupture events dominate the calculated core damage frequency at Ginna. This is a conservative observation; several factors should be considered in judging whether this result represents a true, Ginna-specific vulnerability.

The SGTR initiating event frequency is a conservative number, based on industry-wide experience. It should be noted that the SGTR event at Ginna in 1982 was traced to foreign object-induced damage, and not to chemistry or other operational problems. A metal impact monitoring system was also installed, and has been in use since that time. It should also be noted that RG&E is currently engineering the replacement of the Ginna steam generators. These new steam generators will be constructed of superior materials, and will benefit from the accumulated industry experience. Thus, one could reasonably expect that the SGTR initiating event frequency for Ginna should be reduced after the installation o the new steam generators.

Other dominant contributors to the total calculated core damage frequency for internal initiating events include:

- Operator response to steam generator tube ruptures;
- PORV and / or safety valve LOCAs;
- Failures of the recirculation function;
- Isolation of the ruptured steam generator during a SGTR event;

- Failures of Safety (high pressure) Injection; and,
- Restoration of off-site power.

Several interesting inter-system dependencies were discovered during the course of the Ginna PRA project. While these dependencies are not dominant contributors to calculated risk, they should be noted:

- Reliance of major safety functions on the B Station Battery (BTRYB) -- Several important safety functions require 125 VDC power from the B Station Battery. These functions include automatic opening of Reactor Coolant System (RCS) PORVs 430 and 431C, and operation of Turbine Driven AFW Pump DC Lube Oil Pump PLO11. Because of these dependencies, loss of BTRYB is more risk significant than loss of BTRYA.

- Single-point failure of switch to off-site power -- Normally, power generated on-site is used for loads such as Reactor Coolant Pumps PRC01A and PRC01B; Main Feedwater Pumps PFW01A and PFW01B; Circulating Water Pumps PCW01A and PCW01B; Instrument Air Compressors CIA02A, CIA02B and CIA02C and Service Air Compressor CSA02; and other large, 4160 VAC loads and 480 VAC non-vital loads. Following a turbine trip, Turbine Lube Oil Pressure Switches 63-3/AST, 63-4/AST and 63-5/AST energize Turbine Trip Auxiliary Relays 63/X3, 63/X4 and 63/X5 (powered from Main Control Board 125 VDC Distribution Panel A [DCPDPCB04A]). These relays, in conjunction with Station 13A 115 kVAC Circuit Breakers Auxiliary Relay 52Z, energize Turbine Auto Stop Timer Relay 62AST, which will energize Generator Primary Lockout Relay 86P/1G. Either 86P/1G or Generator Backup Lockout Relay 86BU/1G (powered from Main Control Board 125 VDC Distribution Panel A [DCPDPCB04A]) must energize and signal Generator Auxiliary Lockout Relay 86X/1G (powered from Main Control Board 125 VDC Distribution Panel B [DCPDPCB04B]) to energize in order for the circuit breakers feeding 4160 VAC buses 11A and 11B to automatically switch over to being fed from Auxiliary Transformers 12A (PXYD012A) and 12B (PXYD012B), respectively. Thus, failure of 125 VDC from either DCPDPCB04A or DCPDPCB04B following a turbine trip would result in failure to automatically switch to the off-site sources.

7.3 Internal Plant Flooding Analysis Results and Conclusions

The total calculated core damage frequency for internal plant flooding sequences is 5.05E-06 per year of operation. This conservative estimate is dominated by feedwater line break initiating events on the turbine building mezzanine level (4.01E-06 / year, about 79% of the total). In these sequences, the bulk of the serious damage comes from the high energy line break's initial destructive force; the effects of high energy line breaks (destruction of block walls between the Turbine Building and the Intermediate Building, etc.) are conservatively included in the internal initiating events models. Additional failures assumed to be caused from the flooding nature of these sequences include a loss of the 4160 VAC / 480 VAC electrical buses that are located at the east end of the floor. In reality, loss of this equipment during a feedwater line break would not be a certainty; the buses and the main feedwater lines are located at opposite ends of the building, with the main condenser and much other heavy equipment located in between.

7.4 Level 2 Results

Table 7-2 shows the absolute frequency assigned to each source term category (STC) from each plant damage state (PDS) resulting from the containment event tree (CET) analysis. Table 7-3 shows the percentage of the total frequency of each source term category resulting from each plant damages state.

The following discussion summarizes the PDS contribution to each STC containing more than 1% of the total core damage frequency.

Source Term Category 1 (34.9% of Total CDF)

This STC contains sequences with reactor vessel lower head failure but where the containment integrity remains intact. Sequences in PDSs 12, 17 and 15 are the dominant contributors to this STC (contributing 61%, 21% and 16% of the frequency of this STC, respectively). PDSs 12, 17 and 15 are the dominant non-bypass PDSs. These PDSs contain LOCA sequences with containment heat removal (containment fan coolers) available throughout the accident.

Source Term Categories 18 and 20 (17.1% and 15.6% of Total CDF)

These STCs contains sequences with containment bypass due to steam generator tube ruptures. These STCs are dominated by core damage sequences initiated by a tube rupture (as opposed to the tube rupture being induced following core damage for other sequence initiators). PDS 22 contributes approximately 100% of the frequency of STC 18 and PDS 24 contributes 99.7% of the frequency of STC 20.

Source Term Category 12 (14.2% of Total CDF)

This STC contains sequences with reactor vessel lower head failure and with late containment failure as a result of basemat meltthrough (above ground containment failure due to overpressurization and other mechanisms has been avoided for sequences in this STC). Sequences in PDSs 12 and 15 are the dominant contributors to this STC (contributing 59% and 28% of the frequency of this STC, respectively). PDSs 12 and 15 are dominant non-bypass PDSs which contain LOCA sequences with containment heat removal (containment fan coolers) available throughout the accident.

Source Term Category 16 (9.7% of Total CDF)

This STC contains sequences with containment bypass due to an interfacing systems LOCA. All sequences in this STC are from PDS 20.

Source Term Category 15 (5.1% of Total CDF)

This STC contains sequences with successful in-vessel cooling of the core debris and no reactor vessel lower head failure nor loss of containment integrity. Sequences in PDSs 11, 9 and 2 are the dominant contributors to this STC (contributing 77%, 18% and 5% of the frequency of this STC, respectively). PDS 11 contains large and intermediate break LOCA sequences where in-vessel injection (either high or low pressure safety injection system) is provided throughout the accident (both injection and recirculation modes of injection are available). PDS 9 contains non-station blackout transient sequences where the in-vessel injection systems are available but the reactor vessel pressure at the inception of core damage is elevated above the shutoff head of the available system(s). Following core damage initiation an induced hot leg rupture of the hot leg or surge line results in reactor vessel depressurization and the initiation of in-vessel injection. PDS 2 contains station blackout sequences with power recovery after core damage initiation but prior to reactor vessel failure. For sequences in this PDS the in-vessel injection systems are also recovered following AC power recovery.

Source Term Category 13 (3.0% of Total CDF)

This STC contains all sequences with failure to isolate containment. All sequences in this STC are from PDS 1.

7.5 Level 2 Conclusions

The Level 2 analysis clearly shows that the dominant contributors to the calculated release frequency are the containment bypass sequences. Steam generator tube ruptures and interfacing systems LOCAs (ISLOCAs) account for approximately 42% of the total core damage frequency.

The second most important set of core damage sequences impacting the Level 2 results are basemat meltthrough sequences. Specific design details of the Ginna containment reactor cavity appear to play a major role in the assessment of ex-vessel debris cooling, extent or core concrete attack and basemat meltthrough failure. On the positive side is the location of the cavity below the elevation of the main containment floor. This design arrangement ensures that if the refueling water storage tank inventory is injected into containment, the cavity will be flooded.

The presence of the sump in the reactor cavity seems to have a negative impact on ex-vessel debris coolability and basemat meltthrough failure. The five foot deep sump is a preferential location for debris to accumulate. If debris is preferentially transported into this sump, coolability will be adversely impacted. Furthermore, the thickness of the basemat concrete under the cavity sump is only 1.5 feet, compared to four feet elsewhere. Sensitivity studies indicate that ex-vessel debris cooling and basemat meltthrough are highly sensitive to assumptions which impact the amount of debris transported into the sump.

Also important are loss of containment isolation sequences. These sequences would result in early radionuclide releases. This class of sequences represents about 3% of the total core damage frequency.

The Level 2 analysis indicates that the structural integrity of the Ginna containment is very unlikely to be significantly challenged by the physical processes and loading mechanisms that occur at or before containment failure. The conditional probability of early containment failure due to in-vessel steam explosions, direct containment heating, hydrogen combustion and related phenomena is calculated to be approximately 0.05%.

As a result of the high reliability of containment heat removal systems (principally the containment recirculating fan coolers) the threat of long-term containment overpressure failure is negligible. The Ginna systems analysis for core damage and containment systems indicates that, for all significant core damage sequences with AC power available or recovered, containment heat removal would also be available. Hence, long-term overpressurization of containment resulting from steam production is negligible.

7.6 Summary of the R.E. Ginna PRA Project

The logic models and databases constructed for the R.E. Ginna PRA project are already being put to use by RG&E personnel to support such diverse areas and programs as outage planning and risk assessment; training; response to USNRC Generic Letter 89-10 (motor operated valve testing); implementation of the USNRC's maintenance rule; and, the future industry initiative on severe accident management.

Perhaps more important than any of the tools constructed during the Ginna PRA is the additional, unique insights that RG&E personnel have gained into the operation of the Ginna plant. The Ginna PRA project has already impacted drawing upgrade programs, procedures, and other areas not specifically involved in the construction and maintenance of the PRA models through the walkdowns and general insights into systems operations and dependencies.

Table 7-1
Final Results of the R. E. Ginna PRA Project Level 1 Analyses

Sequence	Number of Quantified Cut Sets	Quantified Frequency	Number of Recovered Cut Sets	Recovered Frequency	% of Total CDF
T/Q2/XL	220	3.14E-04	54	1.82E-05	21%
R/D	127	3.40E-03	27	1.40E-05	16%
R/I1/P3TR1	129	6.30E-04	29	1.20E-05	14%
SS/XH	44	8.23E-05	44	9.40E-06	11%
ISLOCA LI000111				5.79E-06	7%
M/XL	17	6.76E-05	15	4.83E-06	6%
S/XH	25	4.11E-05	24	4.11E-06	5%
T/Q2/UH2	12	3.37E-06	12	3.37E-06	4%
Flood: TBM/TBB/FW/T/B1/L1/XL				2.85E-06	3%
A/XL	9	2.91E-05	9	1.65E-06	2%
A/UL	4	1.44E-06	4	1.44E-06	2%
ISLOCA LI000140				1.37E-06	2%
Flood: TBM/TBB/FW/T/Q2/XL				1.16E-06	1%
T/B1/L1/P1	25	3.02E-06	15	1.12E-06	1%
M/UH2	4	9.22E-07	4	9.22E-07	1%
S/UH2	4	8.53E-07	4	8.53E-07	1%
T/B1/L1/UH1	169	4.69E-05	4	8.37E-07	1%
R/I1/SC	41	2.36E-03	8	7.96E-07	1%
Flood: TBM/G/T/Q2/XL				4.47E-07	1%
T/B1/L1/XL	20	3.94E-06	3	2.66E-07	0%
ISLOCA LI000101				2.66E-07	0%
ISLOCA LI000113				2.66E-07	0%
SS/UH2/UL	1	1.88E-07	1	1.88E-07	0%
R/B1/D	22	9.65E-06	1	1.34E-07	0%
IE/KM/PL/MF/LT	1	1.14E-07	1	1.14E-07	0%
Flood: ABO/G/T/Q1/XH				1.04E-07	0%
Flood: ABO/SWA/T/Q1/XH				1.04E-07	0%
Flood: ABO/CCW/T/Q1/XH				1.04E-07	0%
Flood: BR1A/G/T/B1/L1/P1				7.70E-08	0%
Flood: BR1B/G/T/B1/L1/P1				7.70E-08	0%
Flood: ABB/CCW/T/Q1/UH2/P3SS				6.54E-08	0%
Flood: IBS/CCW/T/B1/L1/XL				6.47E-08	0%
SS/UH2/UA	1	5.60E-08	1	5.60E-08	0%
IE/KM/LT	1	5.13E-08	1	5.13E-08	0%
T/Q1/B1/L1/XL	1	1.78E-07	0	0.00E+00	0%
SS/B1/XH	2	1.61E-07	0	0.00E+00	0%
SS/UH2/P3SS	1	6.12E-08	0	0.00E+00	0%
SS/UH2/XL	1	6.12E-08	0	0.00E+00	0%
R/13S/SC	2	1.03E-05	0	0.00E+00	0%
R/UH2/SC	13	2.96E-05	0	0.00E+00	0%
R/UH2/P3TR2	23	7.44E-06	0	0.00E+00	0%
R/I1/B1/SC	28	6.01E-06	0	0.00E+00	0%
R/I1/B1/P3TR1	7	6.39E-07	0	0.00E+00	0%

Table 7-2

Absolute Frequency Assigned to Each Source Term Category From Each Plant Damage State

STC / PDS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20		
1	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.47E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		2.47E-06
2	6.73E-08	1.39E-11	2.14E-14	0.00E+00	1.11E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.86E-08	0.00E+00	6.51E-11	2.01E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.26E-09		2.92E-07
3	1.71E-08	3.53E-12	6.52E-15	0.00E+00	2.81E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.72E-09	0.00E+00	1.66E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.00E-10		2.22E-08
4	0.00E+00	0.00E+00	0.00E+00	1.29E-14	0.00E+00	0.00E+00	1.03E-15	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.97E-11	0.00E+00	6.06E-14	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.46E-12		8.12E-11
5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		0.00E+00
6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		0.00E+00
7	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.66E-09	2.18E-07	0.00E+00	0.00E+00	2.18E-07	0.00E+00	3.37E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.14E-09		4.51E-07
8	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.74E-10	0.00E+00	4.47E-08	1.92E-08	0.00E+00	0.00E+00	4.93E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.19E-09		6.61E-08
9	2.40E-07	1.84E-10	1.88E-12	0.00E+00	1.48E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.51E-07	0.00E+00	1.14E-10	7.58E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.11E-08		1.17E-06
10	1.33E-07	3.14E-11	3.19E-13	0.00E+00	2.52E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.21E-08	0.00E+00	1.48E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.58E-09		1.99E-07
11	1.23E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.87E-08	0.00E+00	1.71E-10	3.27E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		3.44E-06
12	1.75E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.91E-06	0.00E+00	2.44E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		2.44E-05
13	2.44E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.65E-09	0.00E+00	3.41E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		3.41E-08
14	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.52E-07	0.00E+00	4.52E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		4.52E-07
15	4.64E-06	4.77E-09	4.86E-11	0.00E+00	3.83E-10	9.91E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.28E-06	0.00E+00	7.93E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		7.93E-06
16	2.97E-08	1.05E-11	3.11E-13	0.00E+00	2.45E-12	6.34E-15	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.10E-08	0.00E+00	5.07E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		5.07E-08
17	5.99E-06	3.76E-09	7.82E-12	0.00E+00	3.00E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.04E-07	0.00E+00	6.19E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		6.20E-06
18	0.00E+00	0.00E+00	0.00E+00	3.74E-12	0.00E+00	0.00E+00	2.97E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.15E-09	0.00E+00	6.15E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		6.15E-09
19	0.00E+00	0.00E+00	0.00E+00	1.70E-10	0.00E+00	0.00E+00	1.35E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.80E-07	0.00E+00	2.80E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		2.80E-07
20	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.96E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00		7.96E-06
21	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		0.00E+00
22	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.41E-05	0.00E+00	0.00E+00		1.41E-05
23	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00		0.00E+00
24	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.28E-05		1.28E-05
																						8.24E-05
	2.88E-05	8.79E-09	5.90E-11	1.74E-10	7.04E-10	9.97E-13	1.38E-11	7.63E-09	2.18E-07	4.47E-08	1.92E-08	1.17E-05	2.47E-06	2.72E-08	4.23E-06	7.96E-06	0.00E+00	1.41E-05	0.00E+00	1.28E-05	8.24E-05	

Table 7-3
Percentage of the Total Frequency of Each Source Term Category Resulting From Each Plant Damage State

STC / PDS	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.23	0.16	0.04	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.24	4.75	0.00	0.00	0.00	0.00	0.04
3	0.06	0.04	0.01	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	87.24	100.00	0.00	0.00	1.87	0.00	1.24	0.00	0.00	0.00	0.00	0.00	0.06
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.76	0.00	100.00	100.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00	0.01
9	0.83	2.09	3.19	0.00	2.10	0.00	0.00	0.00	0.00	0.00	0.00	1.29	0.00	0.42	17.92	0.00	0.00	0.00	0.00	0.16
10	0.46	0.36	0.54	0.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.53	0.00	0.54	0.00	0.00	0.00	0.00	0.00	0.03
11	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.63	77.32	0.00	0.00	0.00	0.00	0.00
12	60.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.23	0.00	89.60	0.00	0.00	0.00	0.00	0.00	0.00
13	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.87	0.00	1.66	0.00	0.00	0.00	0.00	0.00	0.00
15	16.13	54.25	82.43	0.00	54.39	99.36	0.00	0.00	0.00	0.00	0.00	28.12	0.00	2.91	0.00	0.00	0.00	0.00	0.00	0.00
16	0.10	0.35	0.53	0.00	0.35	0.64	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00
17	20.82	42.76	13.26	0.00	42.60	0.00	0.00	0.00	0.00	0.00	0.00	1.75	0.00	2.27	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	2.15	0.00	0.00	2.15	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	97.84	0.00	0.00	97.84	0.00	0.00	0.00	0.00	2.40	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	99.69
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00	100.00	0.00	100.00

Figure 7-1
Total Calculated Core Damage Frequency for Internal Initiating Events by Sequence

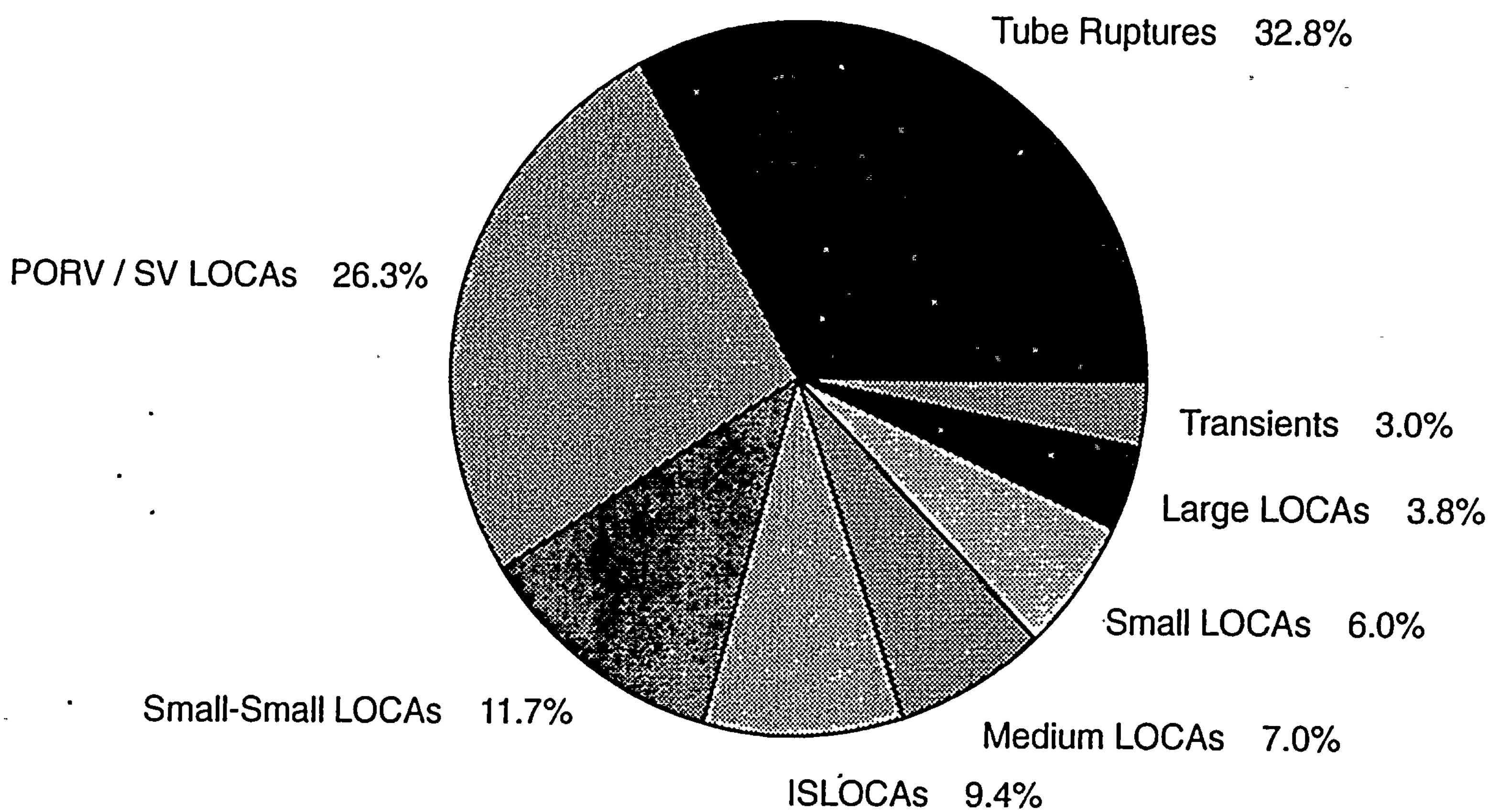


Figure 7-2
Total Calculated Core Damage Frequency for Internal Initiating Events by Initiating Event