PRAIRIE ISLAND

INDIVIDUAL PLANT
EXAMINATION
(IPE)

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EXECUTIVE SUMMARY

In July and August of 1985, the NRC published its policy statement on issues related to severe accidents in NUREG-1070 and 10CFR Part 50. The Severe Accident Policy states that on the basis of currently available information, existing plants pose "no undue risk" to the health and safety to the general public. Therefore, the NRC sees no justification to take immediate action on generic rulemaking or other regulatory changes for existing plants because of issues related to severe accidents. The Commission's conclusion of "no undue risk" is based upon actions taken as a result of the Three Mile Island action plan (NUREG-0737), information that resulted from NRC and industry sponsored research, information obtained from Probabilistic Risk Assessments (PRAs) and operating experience, and the results of the Industry Degraded Core Rulemaking Committee (IDCOR) technical program.

In November 1988, the NRC staff issued Generic Letter 88-20 which formalizes the requirement for an Individual Plant Examination (IPE) under 10CFR50.54(f). This generic letter requires utilities to perform their IPEs, identify potential improvements to address important contributors to risk and implement improvements that they believe are appropriate for their plant. In August 1989, the NRC issued its guidance on utility IPE submittals (NUREG-1335). That document specified the information that should be reported in the IPE submittal as well as a recommended format for the utility reports.

NSP initiated an examination of the Prairie Island plant in early 1989 using IDCOR's IPE Methodology (IPEM). This decision was made to provide NSP with an interim PRA tool for application to plant design, identify recommendations for safety improvements, and focus work on the full scope PRA. The IDCOR's IPEM analysis was completed early in 1991. NSP fulfilled the IPE requirement by performing a Level 2 PRA, which is documented in this report.

The core damage frequency for a given unit at Prairie Island is calculated to be approximately 5E-5/year. This measure of plant safety and the qualitative evaluation of the Prairie Island models indicates that there are no vulnerabilities that result in outliers in core damage frequency or containment performance. This results from the following characteristics of the Prairie Island plant:

1. Prairie Island-specific initiating event frequencies related to plant challenges are lower than the industry average. This results in fewer challenges to the safety systems.

2. Prairie Island has a sufficient safety system and balance of plant design to prevent core damage.

3. Prairie Island plant specific data indicates a high availability of plant systems to perform a safe shutdown. This results in reliable prevention of core damage.

4. Prairie Island procedures are based on WOG Emergency Procedure Guidelines which provide excellent guidance for operator actions during response to potential accidents.

5. The free standing steel containment building is extremely robust. Plant specific analysis calculates that the best estimate failure pressure is about three times the design pressure of 46 psig. In addition, the cavity design provides a relatively large area to spread out the corium from the postulated melting of the reactor core through the reactor vessel lower shell.

The IPE evaluates the plant response to a set of internal initiating events identified in the IPE and expanded by a plant specific evaluation at Prairie Island, and calculates a probability of core damage following each initiating event. Any sequence of system failures following plant trip that can result in core damage is called a core damage sequence. The total core damage frequency is determined by summing the frequencies of all sequences that result in core damage which is called a Level 1 PRA. The total core damage frequency for a given unit at Prairie Island has been calculated to be 5E-5 per year, or approximately one core damage event in 20,000 years. The contribution to the overall core damage frequency from each initiating event can be seen in Figure 1. As shown in Figure 1, no one accident sequence type dominates risk. The SGTR sequences, LOCA sequences, transients with loss of secondary heat removal and the flood sequences together account for nearly 80% of the total Prairie Island core damage frequency.

Steam Generator Tube Rupture, LOCA and transient initiated sequences dominating risk is not unusual in PRAs for PWRs of similar vintage. Kewaunee and Point Beach results show similar contributions from these events as does Surry, one of the NUREG-1150 plants. Having an internal flooding initiator that is a significant contributor to risk is not as common, although other PRAs have found such sequences with the Oconee and Surry PRAs being examples. It should be noted that the core damage due to flooding in the Prairie Island PRA is relatively low as compared to these other PRAs by over an order of magnitude, principally because only a small amount of piping is involved. While there is a low potential for this pipe rupture, this initiating event emphasizes a potentially important location dependency for several systems at Prairie Island since the AFW pumps (secondary heat removal) and the instrument air compressors (support for pressurizer PORV operation for bleed and feed) are located in the same room.

The Prairie Island PRA results also demonstrate that the plant design is somewhat unique in other ways. For example, there is relatively low risk associated with station blackout events which dominate the results of many PRAs including those referenced above. The relatively low contribution to risk from blackout at Prairie Island is a result of the emergency AC power configuration which includes four diesel generators of diverse design and support system requirements. In the event of an SBO condition, each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of essential loads of the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. The crosstie of an emergency bus from one unit to the diesel generator for the other unit can be performed from the control room.

A containment analysis is also a part of the Prairie Island PRA. This Level 2 analysis evaluates containment response to accident condition which may exist following a core damage event. The analysis considers not only the performance of containment systems, but evaluates the response of containment to various severe accident phenomena which may occur following an accident. The potential for loss of the containment boundary during a severe accident is estimated to be less than 2E-5/yr or once in 50,000 years. The contribution to various containment failure modes is shown in Figure 2.

With a strong, large containment only a small potential for significant releases exists. The two largest release categories for the Prairie Island PRA require the containment to be bypassed as a part of the initiating event (such as steam generator tube rupture) or occur very late in the accident sequence (on the order of several days for events in which extended core concrete interaction or failure to remove decay heat from containment are postulated). Of these two types of releases, only steam generator tube rupture events can lead to potentially significant releases of volatile fission products (Iodine and Cesium) in addition to Noble gases. While dominant in comparison to other Prairie Island release modes, they constitute only 13% of the overall core damage frequency at 7E-6/yr or less than once in 100,000 years.

Throughout the PRA the operator plays a significant role in both the prevention and mitigation of severe accidents. The following operator actions are found to have a major effect on the frequency of a number of dominant accident sequences:

- Secondary Heat Removal
  - Restoration of feedwater following a plant trip
  - Crosstie motor driven AFW pump from second unit
- Reactor inventory control during transients

- Initiation of bleed and feed operation

o Reactor inventory control during LOCA

- Switchover from injection to recirculation

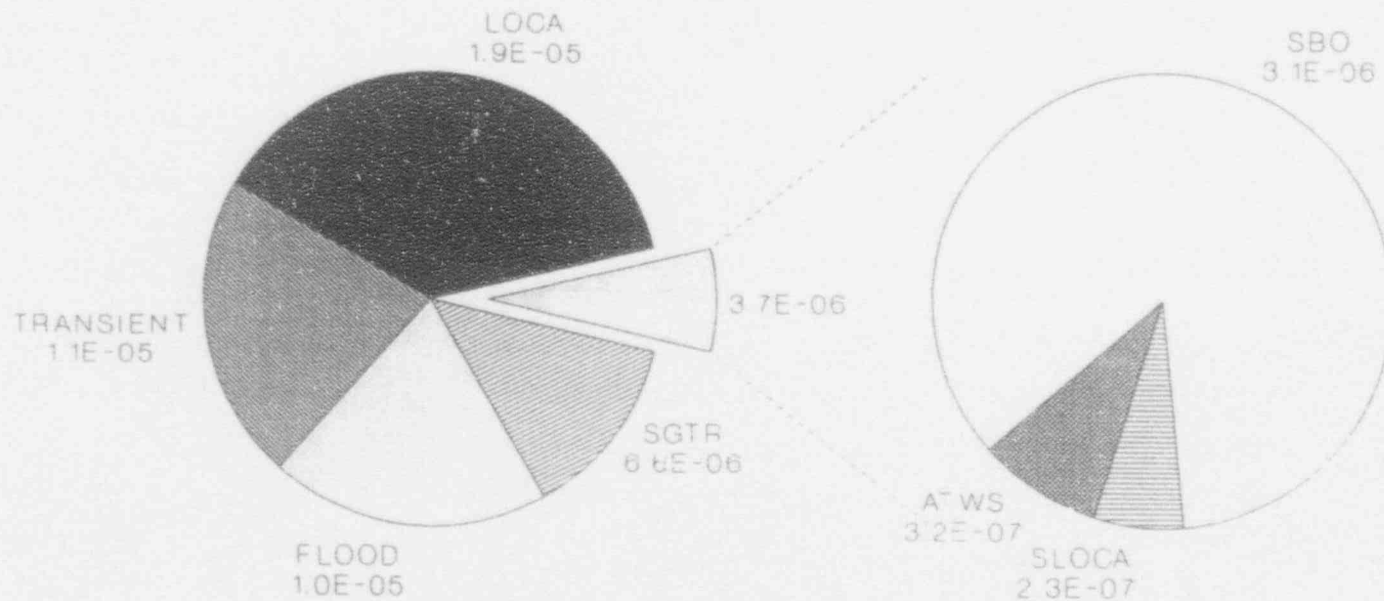
o Steam Generator Tube Rupture

- Steam generator depressurization to limit reactor coolant system losses.

The PRA underscores the role of the operator during transient and accidents and emphasizes those scenarios which are useful to highlight in procedures and training.

The attached report summarizes the results of the PRA and completes commitments made for severe accident closure with respect to the IPE (Generic Letter 88-20) and Decay Heat Removal (USI A-45).

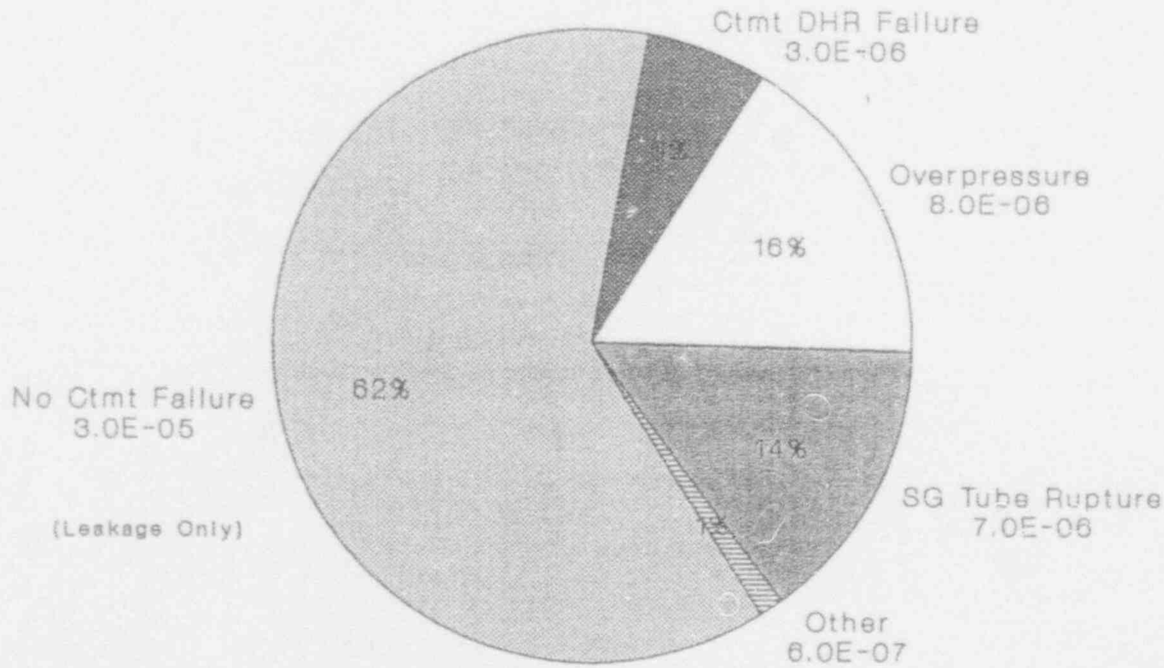
Prairie Island
Core Damage Frequency
Internal Events



TOTAL = 5E-05/YR

Figure 1

Prairie Island Level II PRA
Int. Events by Ctmt. Failure Mode



Note: Excludes SG Tube Creep Rupture

(Other: H2 Combustion, 0.7%; ISLOCA, 0.5; Core Concrete Interaction, Ctmt. Isolation Failure <0.1%)

Figure 2

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LIST OF ACRONYMS

AC	Alternating Current
ACCUM	Accumulators
AICC	Adiabatic Isochoric Complete Combustion
AFW	Auxiliary Feedwater
AMSAC	ATWS Mitigating Systems Actuation Circuitry
ASEP	Accident Sequence Evaluation Program (NUREG/CR-4772)
ATWS	Anticipated Transient(s) Without Scram
BAST	Boric Acid Storage Tank
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owner's Group
CAFTA	Computer Assisted Fault Tree Analysis (computer code)
CC	Common Cause
CC	Component Cooling
CCF	Common Cause Failure
C/D	Cooldown
CDF	Core Damage Frequency
CET	Containment Event Tree
CL	Cooling Water
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
CSF	Critical Safety Function
CST	Condensate Storage Tank
CV	Control Valve
CVCS	Chemical and Volume Control System
CW	Circulating Water
DBA	Design Basis Accident
DC	Direct Current
DCH	Direct Containment Heating
DDT	Deflagration to Detonation Transition
DG	Diesel Generator
DHR	Decay Heat Removal
DLTRM	Delete Term (command in PCSETs)
ECCS	Emergency Core Coolant System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedures
EPRI	Electric Power Research Institute
FAI	Fauske and Associates Incorporated
FCU	Containment Fan Coil Units
FMEA	Failure Modes and Effects Analysis
GL	NRC Generic Letter
HELB	High Energy Line Break

HEP	Human Error Probability
HP	Hewlett Packard
HPME	High Pressure Melt Ejection
HPSETS	Hewlett Packard Set Equation Transformation System (computer code)
HRA	Human reliability Analysis
HX	Heat Exchanger
I&C	Instrumentation and Control
IA	Instrument Air
IDCOR	Industry Degraded Core Rulemaking Program
IE	NRC Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
INPO	Institute of Nuclear Power Operations
IORV	Inadvertently Open Relief Valve
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination for External Events
IPEM	Individual Plant Evaluation Methodology
IPEP	Individual Plant Evaluation Partnership
ISLOCA	Interfacing System Loss of Coolant Accident
LER	NRC Licensee Event Report
LLOCA	Large Loss of Coolant Accident
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MAAP	Modular Accident Analysis Program
MCC	Motor Control Center
MCCI	Molten Core Concrete Interaction
MFLB	Main Feed Line Break
MFW	Main Feedwater
MG	Motor Generator
MGL	Multiple Greek Letter
MLOCA	Medium Loss of Coolant Accident
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valves
MSLB	Main Steam Line Break
NPRDS	Nuclear Power Reliability Data System
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Utility Management and Research Council
OSP	Offsite Power
P&ID	Piping and Instrumentation Drawing

PCS	Power Conversion System
PCSETS	Personal Computer Set Equation Transformation System (computer code)
PCV	Pressure Control Valve
PI	Prairie Island
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PRT	Pressure Relief Tank
PWR	Pressurized Water Reactor
PZR	Pressurizer
QA	Quality Assurance
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMW	Reactor Makeup Water
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWST	Refueling Water Storage Tank
"S"	Safety Injection Signal
SBLOCA	Small Break Loss of Coolant Accident
SBO	Station Blackout
SCET	Streamlined Containment Event Tree
SDC	Shutdown Cooling
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SHARP	Systematic Human Action Reliability Procedure (EPRI)
SI	Safety Injection
SIR	Safety injection Recirculation
SLOCA	Small Loss of Coolant Accident
SOER	INPO Significant Operating Event Report
SORV	Stuck Open Relief Valve
SRI	Safety Review Item
SRO	Senior Reactor Operator
SRT	Senior Review Team
SRV	Safety Relief Valve
TDAFW	Turbine Driven Auxiliary Feedwater
TMI	Three Mile Island
USI	Unresolved Safety Issue

LIST OF ACRONYMS (continued)

USAR	Updated Safety Analysis Report
VCT	Volume Control Tank
WOG	Westinghouse Owners Group

1. SUMMARY AND CONCLUSIONS

1.1 Background and Objective

In July and August of 1985, the NRC published its policy statement on issues related to severe accidents in NUREG-1070 and 10CFR Part 50. The Severe Accident Policy states that on the basis of currently available information, existing plants pose "no undue risk" to the health and safety of the public. Therefore, the NRC sees no justification to take immediate action on generic rulemaking or other regulatory changes for existing plants because of issues related to severe accidents. The Commission's conclusion of "no undue risk" is based upon actions taken as a result of the Three Mile Island action plan (NUREG-0737), information that resulted from NRC and industry sponsored research, information obtained from published Probabilistic Risk Assessments (PRAs) and operating experience, and the results of the IDCOR technical program.

In November 1988, the NRC staff issued Generic Letter 88-20 which formalized the requirement for an Individual Plant Examination (IPE) under 10CFR50.54(f). This generic letter requires utilities to perform their IPEs, identify potential improvements to address important contributors to risk and implement improvements that they believe are appropriate for their plant. In August 1989, the NRC issued its guidance for utility IPE submittals (NUREG-1335). That document specified the information that should be reported in the IPE submittal as well as a recommended format for the utility reports.

Upon receipt of Generic Letter 88-20, NSP elected to fulfill the IPE requirement by performing a full scope level 2 PRA, which is documented in this report. The IPE of NSP's Prairie Island Nuclear Generating Plant was performed to develop an improved understanding of the plant response to potential accident conditions and to identify any significant vulnerabilities to severe accidents. The specific objectives are summarized as follows:

- Establish a realistic estimate of the frequency of a core damage event at Prairie Island.
- Identify the potential accident sequences that contribute to the overall core damage frequency.
- Determine the timing and nature of any radionuclide releases to the environment that might be associated with these dominant accident sequences.
- Identify any dominant accident sequence that occurs with a frequency significantly higher than similar sequences at the other plants that have

been judged to be acceptably safe.

- Identify any instance of unusually poor containment performance for these dominant accident sequences.

- Identify cost effective modifications to the plant design, operating procedures, training or maintenance practices that would reduce the likelihood of any accident sequence outliers which are identified.

- Maximize participation in the evaluation process by NSP personnel and maximize the technology transfer from the consultant to NSP to ensure the PRA can be maintained and understood by NSP personnel.

- Provide a well organized and clearly written summary of the Prairie Island IPE to facilitate communication of the results to both the NRC and NSP, as well as to serve as a tool for communicating the results to interested members of the public.

- Develop the risk based tools and documentation to support resolution of future regulatory, safety, or operational issues for Prairie Island.

1.2 Plant Familiarization

Units 1 and 2 of the Prairie Island Nuclear Generating Plant are 2-loop PWRs with large dry containments. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system and the turbine-generator units. Pioneer Service and Engineering (now Fluor Power Services, Inc.) was the plant's architect-engineer. Northern States Power Company constructed the plant. Each reactor core produces 1650 MWt with an electrical output of 560 MWe, using 121 fuel assemblies. The plant is located within the city limits of Red Wing, Minnesota. Construction started on June 26, 1968, and full commercial operation began on December 16, 1973 for Unit 1 and December 21, 1974 for Unit 2.

The IPE was performed for the plant design as it existed in the fall of 1993. This relatively recent plant configuration includes changes made to the AC power distribution system that are important to accident sequences associated with loss of offsite power initiators and station blackout.

1.3 Overall Methodology

NSP has elected to perform a full scope Level 2 PRA as a basis for the IPE. NSP analysts performed most of the work, using consultants primarily for training, guidance and review.

The Level 1 event trees are similar to those used in other PRAs and are functionally oriented patterned after the EOPs. The accident sequence binning is also similar to other PRAs. The 14 accident classes are shown in Table 1.3-1.

Level 2 event trees were developed to represent each of the accident classes and are also patterned after the functions of the EOPs. Phenomenological papers were developed for each of the containment failure modes and mechanisms found in Section 7 of NUREG-2300. The phenomenological papers were used to:

- Determine the applicability of the phenomena to Prairie Island, given specific design features.
- Identify system success criteria for prevention and mitigation of the various phenomena.
- Assign the phenomena to the containment event tree branches or identify the headings into which the phenomena should be included if appropriate.

There was an extensive data collection effort to develop plant specific initiating event frequencies and component failure rates. Plant-specific initiating event frequencies were derived from data collected for the eleven-year period between 1980 and 1990. Plant-specific component and maintenance unavailability data was collected for a ten-year period between 1978 and 1987. This data was used in both the Level 1 and Level 2 event trees and fault trees.

Mission times were established for use throughout the Level 1 and Level 2 analysis to determine the reliability of plants systems and equipment in performing core cooling and containment functions. Mission times for logic model quantification were generally on the order of 24 hours. The consequences of system and equipment failure that might occur during this period were examined well beyond this mission time. Containment response and source term analysis were carried out to at least 48 hours to establish important trends in plant response. Timing and magnitude of potential releases that might occur beyond 48 hours were established based on these trends where necessary.

Common cause events were included in the fault trees using generic data through use of the multiple greek letter (MGL) methodology. Analysis of the core damage frequency for both units was performed. While there are some asymmetries in the Unit 1 and Unit 2 AC distribution systems, they are shown to have a minor effect on the results.

The same analysts that performed the Level 1 sequence quantification developed the Level 2 models and quantified the CET sequences. Having the same analysts throughout the project ensured the proper integration of the Level 1 and 2 analyses. CAFTA software from EPRI and HPSETS software from Logic Analysts were used as the principal tools for fault tree management and cutset generation. MAAP 3.0B Revision 19 was the principal tool used for deterministic best estimate analysis of reactor and containment response during severe accident sequence conditions. Best estimate analysis was performed for both the front end and back end portions of the assessment. Deterministic or probabilistic sensitivity studies were conducted to assess the impact of key assumptions.

1.4 Summary of Major Findings

A summary of the IPE analysis results is given below. A detailed accounting of the results can be found in Sections 3.4 (Level 1), 4.6 (Level 2 CET Quantification), and 4.7 (Source Term Quantification). No significant differences in the results were observed in the results for both units. This is due to the near mirror-image plant design and similar operating characteristics between the two units. Where differences were found to exist, their effects on the overall core damage frequency or containment failure probability were treated explicitly in the modeling. However, the results of these differences were not significant in terms of plant core damage risk. The effect of dual unit initiating events and their impact on the availability of key shared plant equipment (see Section 3.1.1) was a part of the analysis. Explicit descriptions of results for both units would necessitate the development of two sets of tables and charts containing nearly identical information. For this reason, results for Unit 1 only are presented in this section. See Section 3.5 for a description of the Unit 2 quantification and results. Note that a separate Level 2 analysis was not performed for Unit 2 core damage sequences due to the similarity in the Level 1 results and containment structures and release mitigating systems between the two units (see Section 3.5).

1.4.1 Unit 1 Level 1 Results

The level 1 analysis for Unit 1 resulted in a total CDF of 5.0E-5/yr due to internal events initiators. This frequency is within the range of results reported for other plants' IPEs, and is typical of other two-loop Westinghouse PWR results.

Overview - No one initiating event or accident class dominates the results of the Prairie Island PRA. Together the LOCAs (RCS pipe rupture initiators), loss of offsite power, flood and steam generator tube rupture make up 80% of the core damage risk in roughly equal proportions.

The distribution of core damage is split approximately equally between five accident classes. Together these accident classes account for over 85% of the total core damage frequency.

Small LOCA with safety injection failure (Accident	A significant fraction of sequences in this accident

Class SEH).	class are consequential reactor coolant pump seal LOCAs with dependencies occurring between seal cooling and SI.
Medium to large LOCA with recirculation failure (Accident Class SLL).	Manual switchover to recirc in a short time frame and common cause failure of support system components contribute to this accident class.
Transients with loss of secondary cooling and failure of bleed and feed (Accident Class TEH).	The reliance of MFW and pressurizer PORVs on instrument air results in a dependency between secondary cooling and bleed and feed operation.
Internal flooding initiators leading to loss of secondary cooling and failure of bleed and feed (Accident Class FEH).	Passive failure of Cooling Water piping in the AFW pump rooms is assumed to lead to failure of both AFW, MFW, bleed and feed cooling and instrument air, due to dependencies between instrument air, secondary cooling and bleed and feed operation.
Steam generator tube rupture with failure to depressurize reactor prior to RWST depletion (Accident Class GLH).	Operator action to depressurize the reactor before steam generator overfill or RWST depletion is important to this accident class.

Comparison to other PRAs shows that most of these accident sequences are not unique to Prairie Island, showing up at roughly the same probability for Kewaunee and Point Beach, 2-loop Westinghouse plants of the same vintage. The results are also not unlike Surry frequencies, a NUREG-1150 plant. Section 2.4.2 provides a brief comparison of the Prairie Island Plant with these PRAs. Flooding has also shown up as contribution to other PRAs such as the Oconee and the Surry PRAs for it's IPE submittal, although the Prairie Island PRA contribution is substantially less than those PRAs due to the relatively limited amount of piping which must fail to lead to this accident class. Regardless of the frequency of this internal flooding initiator, the PRA points out a potentially important location dependency associated with the AFW pumps (required for secondary heat removal) and instrument air compressors (support system for feedwater and the pressurizer PORVs).

While the IPE points out a number of similarities with other plants it also identifies some aspects of the Prairie Island design which differ from PRAs performed for these plants. Kewaunee, Point Beach and Surry all have a significant contribution from Station Blackout that does not exist for Prairie Island. The relatively limited station blackout potential at Prairie Island is due to the Emergency AC power configuration. Emergency AC power at Prairie Island consists of four emergency diesel generators, each of which has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of the essential loads of the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. The diesel generator designs between units are diverse as two of the diesels were built by different manufacturers and have different cooling systems. The ability to crosstie from one unit to the other can also be performed from the control room.

Reportable Core Damage Sequences - Appendix 2 to Generic Letter 88-20 identifies the screening criteria for reporting potentially important sequences that might lead to core damage or unusually poor containment performance. The criteria applicable to Prairie Island are listed below:

1. Any functional sequence that contributes 1E-6 or more per reactor year to core damage.

2. Any functional sequence that contributes 5% or more to the total core damage frequency.

3. Any functional sequence that has a core damage frequency greater than or equal to 1E-6 per reactor year and that leads to containment failure which can result in a radioactive release magnitude greater than or equal to the PWR-4 release categories of WASH-1400.

4. Functional sequences that contribute to a containment bypass frequency in excess of 1E-7 per reactor year. (Prairie Island is also reporting containment failure functional sequences with frequencies in excess of 1E-7 per reactor year - see Table 1.4-5.)

5. Any functional sequences that the utility determines from previous applicable PRAs or by utility engineering judgement to be important contributors to core damage frequency or poor containment performance.

Prairie Island elected to use the functional sequence reporting criteria as the event trees described in section 3.1.2 were developed around a set of safety functions based on the EOPs. Each safety function consists of a set of frontline and support systems that can be used to perform the specified safety function. By using functional event trees, the core damage sequences that emerge, are sets of components and initiating events that fail the safety functions, thereby the choice of the functional reporting criteria from Generic letter 88-20. In addition, Prairie Island went one step further in reporting requirements by equating accident classes with functional sequences. In this case, core damage sequences are grouped together as to their similarity in regard to initiators, timing of core melt and effect on containment pressure at the time of core melt. The accident classes that meet this reporting criteria are listed in Table 1.4-1 with a description of the accident class together with a representative sequence from each accident class. Some accident classes that do not meet the reporting criteria are also included in Table 1.4-1 for completeness.

Dominant Accident Classes - Figure 1.4-1 shows the Core Damage Frequency (CDF) for Prairie Island separated by accident (damage) class. Refer to Table 1.4-1 for a breakdown of the CDF by accident class and Table 1.3-1 for the accident class identification scheme. The accident classes are categorized by initiating event, whether early or late core damage occurred (which is dependent on whether ECCS injection or recirculation failed, respectively), and RCS pressure at the time of core damage (high or low), which has an impact on the Level 2 analysis.

A summary of the dominant Unit 1 Level 1 damage classes (those which were responsible for more than 10% of the core damage frequency) is given below:

FEH (21%): The FEH accident class (internal flooding, early core damage with RCS at high pressure) was one of the top contributors to the CDF, with a frequency of approximately 1.0E-5. Nearly all of the FEH contribution is due to one flooding sequence, FEH-TB1 (reported separately in Table 1.4-1). This sequence involves a cooling water (service water) header break in the turbine building auxiliary feedwater pump/instrument air compressor room which leads to core damage. The identification of this sequence is one of the most significant findings from the IPE. It is discussed in detail in Section 3.4.

TEH (20%): The TEH accident class (transient with early core damage at high pressure) was also one of the top contributors to the CDF, with a frequency of 1.0E-5. A key dependency on instrument air with respect to the availability of both main feedwater and bleed and feed cooling was identified which dominates this accident class. Unavailability of instrument air causes the feedwater regulating and bypass (air-operated) valves to fail closed. If local operator actions to reopen the valves fails, main feedwater to the steam generators is unavailable. Also, the instrument air to containment isolation (air-operated) valves fail closed on loss of air, which causes the air-operated pressurizer Power Operated Relief Valves (PORVs) to fail closed. This results in failure of RCS bleed and feed cooling. On loss of instrument air, therefore, only the auxiliary feedwater system is available for decay heat removal. Like many of the transient events which lead to core damage, the existence of the internal flooding sequence described above is partly due to this dependency.

SLL (17%): The SLL accident class (LOCA leading to late core damage at low pressure) was also shown to be a relatively large contributor with a frequency of 8.3E-6. This accident class is dominated by medium and large LOCAs with subsequent failure of high head recirculation (credited for medium LOCA only) and low head recirculation (medium and large LOCAs). The primary cause of recirculation failure was found to be operator failure to perform the transfer alignments.

SEH (16%): The SEH accident class (LOCA leading to early core damage at high pressure) was also shown to be a dominant contributor with a frequency of 8.2E-6. This accident class is dominated by RCP seal LOCAs with subsequent failure of the Safety Injection (SI) system for high pressure injection. Failure of the Component Cooling Water (CC) system is assumed to cause failure of SI injection and also contributes to (but doesn't cause) failure of the RCP seals. Charging system failure, which is also required before seal failure is assumed is independent of CC. However, the charging system relies on safeguards 480 V AC power, which (for Unit 1) is assumed to fail in a short amount of time (1 hour) if room cooling for the bus rooms fails and operators are not able to restore room cooling per procedures. Room cooling, in turn, is dependent on cooling water, as is the CC system.

There are several significant considerations to note with respect to the 480 V bus room cooling dependency described above:

1. The 480 V bus dependency on room cooling may not exist following electrical system upgrade work which will be completed during the June, 1994 Unit 1 outage (this has not yet been verified with heatup calculations for the new configuration). The buses will be divided into two separate buses per train, with one train being relocated to different

safeguards bus rooms in the plant.

2. It was assumed that Unit 2 480 V bus room cooling failure is not a significant concern for Unit 2 (see Section 3.5).

3. The Unit 1 480 V dependency has an impact on both units, since two of the three instrument air compressors are dependent on Unit 1 safeguards 480 V power. However, only the Unit 1 charging pumps, motor-operated valves and Fan Coil Units (FCUs) are affected (corresponding equipment for Unit 2 is powered by Unit 2 480 V AC).

GLH (12%): The GLH accident class (steam generator tube rupture leading to late core damage at high pressure) had a frequency of 6.0E-6. This accident class is dominated by SGTR followed by failure of the operators to cooldown and depressurize the primary coolant system to stop the leak in time before steam generator overfill occurs. A steam generator relief valve is assumed to fail open, followed by failure of the operators to cooldown and depressurize the RCS to RHR shutdown cooling conditions before RWST depletion occurs. Loss of the RWST causes failure of injection and loss of inventory in the RCS which eventually leads to core damage. An important insight for this accident class is the dependence on the operator to perform RCS C/D and depressurization before RWST depletion occurs.

Dominant Initiating Events - Figure 1.4-2 gives the contribution to the CDF by initiating event. Refer to Table 1.4-2 for a breakdown of the CDF by initiating event. A discussion of the dominant accident initiating events (those which were responsible for more than 10% of the core damage frequency) is given below:

I-LOOP: Loss of Offsite Power accounted for over 21% of the core damage frequency. The dominant mechanisms leading to core damage following this initiator were failure of the emergency diesel generators together with failure of ECCS restart following recovery of AC power (typical of TEH sequences), or failure of diesel generators followed by failure to recover AC power prior to core uncovery from RCP seal leakage (typical of BEH sequences).

I-T1FLD: Internal flooding of the auxiliary feedwater pump/instrument air compressor room in the Turbine Building (zone TB1) accounted for 21% of the core damage frequency. This is the dominant (and almost the only) sequence for accident class FEH (see discussion above).

I-SGTR: Steam Generator Tube Rupture accounted for over 13% of the core damage frequency. This is the exclusive initiating event for accident classes GLH (see discussion above) and GEH (SGTR leading to early core damage at high pressure).

I-MLOCA: Medium LOCA accounted for over 9% of the core damage frequency. The dominant accident sequence for this initiator was Medium LOCA with failure of the operator to transfer to recirculation (Class SLL).

I-SLOCA: Small LOCA accounted for over 8% of the core damage frequency. This initiating event included only the random pipe break events. Small LOCAs from Reactor Coolant Pump (RCP) seal failures are events which occur following an initiating transient. Therefore, in Table 1.4-2 the contribution of RCP seal LOCAs are incorporated into the core damage frequency for the corresponding initiating event that caused the seal LOCA.

I-LLOCA: Large LOCA accounted for over 7% of the core damage frequency. The dominant accident sequence for this initiator was Large LOCA with failure of the operator to transfer to recirculation (Class SLL).

I-INSTAIR: Loss of instrument air accounted for over 6% of the core damage frequency. As described previously, failure of instrument air causes failure of main feedwater (if attempts to open the feed regulating and bypass valves locally is unsuccessful) and failure of bleed and feed cooling.

See Section 3.1 for descriptions of the sequence of events for the accidents analyzed in the IPE and Figures 3.1-1 through 3.1-9 for event tree diagrams. See Section 3.3 for a description of the accident sequence quantification. The results of the individual sequence quantification are summarized by the preceding discussions of the dominant accident classes and initiating events. Therefore, a description of each dominant sequence will not be given in this section.

1.4.2 Unit 2 Level 1 Results

The results for the Unit 2 Level 1 analysis were nearly identical to the Unit 1 results described in Section 1.4.1 above. The reasons for this are:

1. The two units are nearly identical to each other in terms of plant configuration.

2. Where differences do exist, they do not have a significant impact on the results. An example of this is 480 V bus room cooling. Failure of the Unit 1 bus room cooling fails the Unit 1 480 V buses, while failure of the

Unit 2 480 V bus room cooling does not (see Section 3.5). However, failure of Unit 1 480 V bus room cooling still affects Unit 2, because two of the three instrument air compressors are lost which causes instrument air system failure for both units. This effectively negates the benefit of the Unit 2 480 V bus independence on room cooling.

3. Neither unit is significantly more susceptible to an initiating event than the other unit (verified through a review of plant operating history).

4. The two units use (primarily) the same operations and maintenance crews.

Table 1.4-3 gives results of the Unit 2 quantification by initiating event and compares this to the Unit 1 results. As can be seen, there is almost no difference in the results between Unit 1 and Unit 2.

1.4.3 Unit 1 Level 2 Results

The Level 2 analysis used the results of the Level 1 analysis in the quantification of containment event trees (CETs). The containment event tree quantification results were then used in the determination of the expected source term for representative CET sequences.

Containment Event Tree Quantification - Containment event trees were developed around the major accident classes of level 1 sequence quantification. CET sequences were binned into categories or plant end (damage) states.

The results of the CET sequence quantification by plant end state are given in Table 1.4-4. This table also gives a general description of each end state and the dominant sequence(s) for each end state. See Section 4.6 for a detailed discussion of the end states and dominant level 2 sequences.

From a containment performance perspective, only a limited potential for containment failure exists even under severe accident conditions. This is in large part due to a very large containment volume with a high ultimate capacity, on the order of 150 psig.

The containment size and strength allows the plant to accommodate challenges which might result early during a potential severe accident such as hydrogen combustion or direct containment heating. These passive containment features result in the contribution to risk from early containment challenges contributing only fractions of a percent to the potential for a release.

Releases from containment in an intermediate time frame require the containment to be bypassed as a part of the initiator, in the form of steam generator tube rupture. The majority of accident sequences in this category can be mitigated by operation of safety injection and operator action to depressurize the reactor and terminate leakage to the steam generator. Six to ten hours is available before RWST depletion occurs allowing significant time for the operator to accomplish these actions.

Long term challenge to containment is also of limited risk because steam from decay heat or noncondensible gas generation from core concrete interaction would take several days to pressurize containment to its ultimate capacity. While only 20% of all postulated core damage sequences contribute to long term challenges to containment, accident management strategies not credited in the PRA are expected to result in even lower contribution to risk from this plant damage state.

Containment performance is further enhanced by a very large reactor cavity over which debris would be able to spread should a severe accident proceed to the point of lower vessel head penetration. A thin debris depth (on the order of 25 cm if 100% of the core material is considered) promotes quenching and long term decay heat removal once water is provided to the debris. The potential for challenges to containment associated with ex-vessel phenomena is further reduced by the configuration of the reactor within the containment and the size of the RWST. Injection of all RWST water to the containment submerges the lower head of the vessel promoting cooling of core debris through the vessel wall, if injection to the vessel were to be unavailable, and reduces the potential for debris penetrating the lower head and entering the containment.

The dominant containment failure sequences are listed in Table 1.4-5. Detailed descriptions of these sequences can be found in Section 4.6.2.

After all the possible sequences were quantified, they were sorted by containment failure mode, reactor failure pressure, and release timing. These results were then used to create Figures 1.4-3 through 1.4-6 for internally initiated accidents.

Source Term Quantification - Representative sequences from the containment event tree quantification were analyzed to determine characteristic source terms for the plant end states. The source term results were further subdivided into five release categories based on the combination of the noble, volatile, and non-volatile release magnitudes. Figures 1.4-7 (includes SG Tube Creep Rupture) and 1.4-8 (excludes SG Tube Creep Rupture) and Table 1.4-6 give the results of the source term analysis by release category.

With a strong, large containment only a small potential for significant releases exists. The two largest release categories for the Prairie Island PRA require the containment to be bypassed as a part of the initiating event (such as steam generator tube rupture), occur very late in the accident sequence (on the order of several days for events in which extended core concrete interaction or failure to remove decay heat from containment are postulated) or result in a temporary release through the steam generators that is terminated early in the event (steam generator tube creep failure). Of these three types of releases, only steam generator tube rupture events can lead to potentially significant releases of volatile fission products (Iodine and Cesium) in addition to Noble gases. While dominant in comparison to other Prairie Island release modes, they constitute only 13% of the overall core damage frequency at 7E-6/yr or less than once in 100,000 years.

1.4.4 Unit 2 Level 2 Results

Due to the close correlation of the Unit 1 and Unit 2 Level 1 analyses results, and due to the lack of differences in the containment systems and structures between the two units, no explicit Unit 2 Level 2 modeling or quantification was performed. The results and insights from the Unit 1 Level 2 apply directly to Unit 2, and no further Unit 2 analysis is necessary.

1.4.5 Level 1 and Level 2 Sensitivity Studies

Studies of the Level 1 and Level 2 IPE results were performed to determine the sensitivity to important assumptions and other inputs, particularly where uncertainties regarding these inputs were relatively large. These sensitivity studies are described below.

1.4.5.1 Level 1 Sensitivity Studies

Once the dominant accident sequences leading to core damage were screened to determine the important contributors to core damage, sensitivity studies were conducted. Sensitivity studies were conducted on initiating event frequencies, operator actions, common cause, test and maintenance and for certain system components.

Human Reliability Importance - Throughout both the Level 1 and Level 2 analysis, the role of the operator is highlighted by the PRA. The most significant operator actions with respect to their contribution to core damage are provided in Table 1.4-7. With respect to contribution to current results, the dominant operator actions include:

- o Initiation of bleed and feed on loss of secondary heat removal,

- o Cooldown and depressurize the reactor during steam generator tube rupture to prevent steam generator overfill and terminate leakage to the steam generator prior to RWST depletion, and

- o Transfer to recirculation following a LOCA.

The importance of these actions is not unexpected given the initiating events that contribute most to risk; steam generator tube rupture, LOCA and loss of offsite power with failure to makeup to the steam generators.

The sensitivity of the PRA results to operator action reliability was performed to determine not only the dominant contributors to current risk, but also to identify those actions which could contribute significantly to risk were the operator not able to take the action. In addition to those identified above, the PRA is sensitive to the following actions:

- o Crosstie emergency diesel generator from the opposite unit,

- o Restoration of main feedwater on a reactor trip,

- o Crosstie motor driven AFW pump from the opposite unit.

The operator trains in the performance of these actions and can accomplish them successfully from the control room. Each of them is directed at assuring secondary heat removal to avoid the need for bleed and feed operation.

Additional results of the human reliability importance sensitivity studies are presented in Section 3.4.5.

Equipment Reliability Importance - In addition to operator actions, the sensitivity of the PRA results to the reliability of plant systems and their components was evaluated. Studies were performed to determine the sensitivity of the Level 1 results to system reliability (including diesel generator reliability), and test and maintenance unavailability. Section 3.4.5 provides importance measures associated with systems and major components.

Initiating Event Importance - The Level 1 results were also analyzed for sensitivity to initiating event frequency. Section 3.4.5 provides the results of this sensitivity study.

1.4.5.2 Level 2 Sensitivity Studies

A number of assumptions made in the quantification of potential containment failure modes and the source term analysis may be important to the outcome of the Level 2 analysis. Two types of sensitivity studies were performed to determine the effects of key assumptions on the final results. The first of these sensitivity studies are probabilistic in nature and address uncertainties in the quantification of the various containment failure modes modeled in the containment event trees. The probabilistic sensitivity studies are described in Section 4.8.1. Deterministic analyses were also performed to establish the sensitivity of the Level 2 analysis to uncertainties in the physical modeling of containment response and the source term. The deterministic analyses are described in Section 4.8.2.

Probabilistic studies included the following:

- o Potential for termination of an accident in the vessel by injection of the RWST to containment and submerging the lower head of the vessel
- o Depressurization of the vessel resulting from creep rupture of reactor coolant system components such as the hot leg
- o Containment spray cooling of debris carried to the upper parts of containment during reactor blowdown from high pressure
- o Debris cooling in the reactor cavity

Deterministic sensitivities include the following (performed with MAAP):

- o Core Melt Progression and In-Vessel Hydrogen Generation
- o Natural Circulation, Induced Ruptures of the Primary System, and RCS Pressure at Vessel Failure
- o Fission Product Release and Revaporization
- o Ex-Vessel Debris Coolability
- o Energetic Events in Containment
- o Containment Failure Mode

Results of both the probabilistic and deterministic sensitivity studies are provided in section 4.8. The probabilistic studies showed that the CET quantification results were sensitive only to the debris cooling assumptions. The insight from the debris coolability sensitivities was that submerging the vessel to prevent vessel penetration is appropriate and the best course of action (as currently required by the EOPs). Most deterministic sensitivity studies showed no significant effect on Level 2 conclusions due to uncertainties in phenomenology. However, debris spreading area in the upper compartment for High Pressure Melt Ejection (HPME) did make a significant difference in the character of the source term. Cases from the sensitivity studies were used for the source term results (where molten core concrete interaction occurs in the upper compartment) because they were more limiting than the original cases.

1.4.6 IPE Recommendations

It is important to remember that the primary benefit of a risk assessment is not in the actual numbers that are generated, but in the engineering insights about how to prevent accident sequences from occurring, and any potential system, operational and maintenance improvements that are identified. A summary of the recommendations generated from this study is provided below:

The following recommendations are generated based on the results of the Level 1 IPE analysis:

1. Proceduralize the cross-tie from station air to instrument air such that C34 AOP1, Rev 0, "Loss of Instrument Air" utilizes the cross-tie. The station air compressors are cooled from loop B cooling water and would not be affected by a LOOP A CL pipe break. If the cross-tie could be accomplished within 1 hour after the flood initiator, main feedwater or bleed and feed cooling could be restored and core melt could be prevented. The instrument air operating procedure should also be more emphatic in stating that the station air cross-tie should be used whenever an instrument air compressor is out of service for maintenance. It is recognized that this recommendation will only restore instrument air if the flood occurs as a result of a Loop A CL pipe break. However, this recommendation would be effective for many other events in which instrument air was lost.

2. Revise C35 AOP1, rev 2, "Loss of Cooling Water Header A or B" such that it addresses the problem of closure of the turbine building cooling water header isolation valve and the subsequent loss of cooling water to the main feedwater lube oil coolers and condensate pump oil coolers. Analysis has shown that the main feedwater pumps can conservatively operate without cooling water for approximately 20 minutes before possible pump damage.

3. To limit the impact of AFW pump room flooding due to Cooling Water System header rupture, provide a means to either allow additional water flow out of the room (through modifications to the Unit 1 and Unit 2 side doors, for example) or to segregate the room into two compartments (close the fire door between the two halves of the AFW pump room and upgrade the ability of the door to block water flow, for example).

4. Emphasize in training the importance of bleed and feed and the operator actions that are necessary for success as bleed and feed is a significant contributor to class TEH and the overall CDF.

5. Emphasize in training the importance of the crosstie between the motor driven AFW pumps and the operator actions that are necessary for success as the AFW crosstie is a significant contributor to class TEH and the overall CDF.

6. Emphasize in training the importance of switchover to high and low head recirculation and the operator actions that are necessary for success as switchover to recirculation is a significant contributor to class SLL and the overall CDF.

7. Emphasize in training the importance of RCS cooldown and depressurization to terminate SI before ruptured SG overfill and the operator actions that are necessary for success this action is a significant contributor to class GLH and the overall CDF.

Since the starting point of the Level 2 analysis is the Level 1 core damage sequences, the preceding Level 1 recommendations will also have a positive effect on the Level 2 release frequency. The following recommendations are generated based on the results of the Level 2 analysis:

1. Revise FR-C.1, Rev 5, "Response to Inadequate Core Cooling" step 18 such that the operator checks for adequate steam generator level before attempting to start an RCP. If the RCPs are started with a "dry" steam generator with core exit thermocouples greater than 1200°F, hot gases could be pushed up into the steam generator tubes causing creep rupture of the tubes and a possible containment bypass if one of the steam generator relief valves were to lift.

2. The in-core instrument tube hatches for both units should be secured open during normal operation. This could be accomplished by using a solid bar or other device, instead of a chain, to keep the hatch open but still prevent inadvertent entry during normal operation. Having this hatch open greatly improves the probability of recovering from a core damage event in-vessel (without vessel rupture), by allowing injection water from the RWST to flow into the reactor cavity and to provide cooling to the lower vessel head, and improves debris coolability in the reactor cavity following events in which the vessel fails at low pressure. For this recommendation, consideration is being given to credit given in the Level 2 analysis model for these hatches being open during normal operation.

Table 1.3-1
Accident Class Definition Prairie Island IPE

ACCIDENT CLASS[1]	DESCRIPTION
TEH	Transient initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor pressure is high at the time of core damage.
TLH	Transient initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.
BEH	Station blackout in which core damage occurs prior to recovery of AC power or bleed and feed fails upon recovery of AC power. Reactor pressure is high at the time of core damage.
SEH	LOCA initiated events in which high head safety injection is not capable of preventing core damage. Reactor pressure is high at the time of core damage.
SLH	LOCA initiated events in which high head safety injection is successful but high head recirculation is not. Reactor pressure is high at the time of core damage.
SEL	LOCA initiated events in which high head and low head safety injection do not prevent core damage. Reactor pressure is low at the time of core damage.
SLL	LOCA initiated events in which safety injection was effective but high and low head recirculation is not. Reactor pressure is low at the time of core damage.
FEH	Internal flood-initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor Pressure is high at the time of core damage.
FLH	Internal flood-initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.

(continued next page)

(1) Key

1st Character
(Initiator)

T - Transient
B - Station Blackout
S - LOCA
G - Steam Generator Tube Rupture
V - Interfacing LOCA
F - Internal Flooding
R - ATWS

2nd Character
(Timing)

E - Early (prior to recirculation)
L - Late (after recirculation)

3rd Character
(Reactor Conditions)

H - High pressure (above shutoff of low pressure pumps)
L - Low pressure
O - High pressure, Failure of Long Term Shutdown
P - High pressure, RCS Overpressure

Table 1.3-1, continued
Accident Class Definition Prairie Island IPE

ACCIDENT CLASS[1]	DESCRIPTION
REP	ATWS events in which reactor vessel overpressure occurs.
RLO	ATWS events in which long term negative reactivity insertion is not successful.
GLH	Steam Generator Tube rupture sequences leading to core damage as a result of failure to depressurize the RCS before RWST depletion. Reactor pressure is high at the time of core damage.
GEH	Steam Generator Tube rupture sequences with failure of high head injection or failure of secondary heat removal. Reactor pressure is high at the time of core damage.
V	Interfacing LOCA sequences between the reactor and low pressure piping systems in the auxiliary building.

(1) Key

1st Character (Initiator)

- T - Transient
- B - Station Blackout
- S - LOCA
- G - Steam Generator Tube Rupture
- V - Interfacing LOCA
- F - Internal Flooding
- R - ATWS

2nd Character (Timing)

- E - Early (prior to recirculation)
- L - Late (after recirculation)

3rd Character (Reactor Conditions)

- H - High pressure (above shutoff of low pressure pumps)
- L - Low pressure
- O - High pressure, Failure of Long Term Shutdown
- P - High pressure, RCS Overpressure

Table 1.4-1
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
FEH-TB1	Flood with core damage early and at high RCS pressures.	1E-5	21	A flood occurs in the AFW pump room from the Loop A or B CL header. Reactor trip and RCP seal cooling are successful. All AFW pumps fail, along with all instrument air compressors due to the flood. MFW fails due to closure of the main feed regulating and bypass valves and loss of lube oil cooling to the MFW pumps. Bleed and feed cooling fails due to loss of instrument air.	1E-5	21
TEH	Transient with core damage early and at high RCS pressures	1E-5	20	Loss of instrument air causing rx trip due to loss of MFW. RCP seal cooling is successful but 11, 12 and 22 AFW pumps FTR so 21 AFW pump cannot be used for Unit 1. Bleed and feed fails due to loss of instrument air and local restoration of main feedwater is unsuccessful.	4.4E-7	0.9
SLL	Medium or large LOCA with core damage late and at low RCS pressures	8.3E-6	16.6	Large LOCA with successful short term RCS inventory but long term RCS inventory fails due to operator error in lining up for recirculation	2.5E-6	5
				Medium LOCA with successful reactor trip and short term RCS inventory but long term RCS inventory fails due to operator error in lining up for recirculation	2.2E-6	4.3
SEH	Small LOCA with early core damage at high RCS pressures	8.2E-6	16.4	Loss of cooling water causing eventual reactor trip due to loss of CC to the RCP motors. Loss of CL causes loss of chilled water which causes loss of room cooling to the 480V safeguards bus rooms. Loss of room cooling is assumed to result in the eventual 480V bus failure causing loss of all charging pumps leading to an RCP seal LOCA that cannot be mitigated by the SI pumps as they have lost CC cooling to their lube oil coolers. Local operator actions to restore cooling water and 480V bus room cooling also fail.	6.3E-7	1.3
GLH	SGTR with core damage late and at high RCS pressures	6E-6	12	SGTR with operator failing to C/D & depressurize the RCS before ruptured SG overfill. A Ruptured SG relief sticks open followed by the operator failing to C/D and depressurize the RCS to RHR SDC temperature and pressure before RWST depletion.	1.1E-6	2.1

Table 1.4-1 (continued)
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
BEH-NOPWR	SBO with early core damage at high RCS pressures	2.8E-6	5.6	LOOP with successful reactor trip followed by D1, D2, D5 and D6 diesel generators failing to run due to common cause. The TD AFW pump runs for 2 hours before batteries are depleted and SG level instrumentation is lost. The operator is successful in depressurizing the SGs with the SG PORVs to reduce RCP seal leakage but the operator fails to restore offsite and onsite AC power at 5 hours.	2.3E-7	0.5
SLH	Small LOCA with late core damage at high RCS pressures	2.4E-6	4.8	Small LOCA with successful Rx trip, secondary cooling and short term RCS inventory. RCS C/D and depressurization to RHR SDC conditions is successful but the CC valves to the RHR heat exchangers fail to open failing RHR SDC and recirculation. Local attempts at recovery are also unsuccessful.	3.5E-7	0.7
TLH	Transient with late core damage at high RCS pressures	8E-7	1.6	LOOP with successful reactor trip followed by failure of D2 and D6 diesel generators to run which fails all train B safeguards equipment. 11 and 22 AFW pumps then fail to run followed by failure of the CC supply valve to 11 RHR heat exchanger to open, failing recirculation.	2.4E-8	0.05
GEH	SGTR with early core damage high RCS pressures	6E-7	1.2	SGTR followed by successful reactor trip and secondary cooling. RCS short term injection fails because the SI suction valves from the RWST fail to open due to common cause. The operator then fails to cooldown and depressurize the RCS before core damage occurs.	3.5E-8	0.07
BEH	SBO with early core damage at high RCS pressures	2.6E-7	0.5	LOOP with successful reactor trip followed by D1, D2, D5 and D6 diesel generators failing to run due to common cause. The TD AFW pump runs for 2 hours before batteries are depleted. The operator is successful in depressurizing the SGs with the SG PORVs to reduce RCP seal leakage and the operator is successful in restoring offsite AC power at 5 hours but an RCP seal LOCA has caused core damage.	2.6E-8	0.05
V	Interfacing systems LOCA	2.3E-7	0.5	Catastrophic failure of both of the RHR series loop A suction isolation motor valves followed by failure of both of the RHR pump seals causing a small LOCA outside of containment and the operator is unsuccessful in cooling down and depressurizing the RCS before RWST depletion.	5.5E-8	0.1

Table 1.4-1 (continued)
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
RLO	ATWS with operator failing to perform local reactor shutdown actions	1.6E-7	0.3	Normal transient followed by failure of the reactor protection system. The reactor power level is greater than 40%, main feedwater is successful but the operator fails to perform local action to make the reactor subcritical.	8.3E-8	0.2
REP	ATWS without adequate RCS pressure relief capacity	1.6E-7	0.3	Loss of main feedwater transient followed by failure of the reactor protection system. The reactor power level is greater than 40% and the operator fails to manually drive rods in for 1 minute. Auxiliary feedwater is successful but there is not adequate RCS pressure relief to prevent RCS overpressure.	2.8E-8	0.06
SEL	Large or medium LOCA with early core damage at low RCS pressures	7.6E-8	0.2	Large LOCA followed by failure of both RHR pumps to start due to common cause.	2.1E-8	0.04
FEH	Flood with early core damage at low RCS pressures	7.2E-10	1E-3	Auxiliary building zone 7 flood with successful reactor trip and RCP seal cooling. 11 and 12 AFW pumps fail to run and the operator fails to restore main feedwater and also fails to crosstie 21 AFW pump to unit 1. The operator then fails to initiate bleed and feed cooling.	1.5E-10	3E-4

Table 1.4-2
Core Damage Frequency By Initiating Event for Unit 1

Initiating Event	Initiating Event Frequency (per reactor year)	CDF from Initiating Event (per reactor year)	% of Total CDF from Initiating Event
I-TR1	1.68	6.4E-7	1.3
I-TR2	9.00E-2	2.9E-8	0.06
I-TR3	0.23	1.2E-6	2.4
I-TR4	9.00E-2	5.2E-7	1.0
I-LOCC	3.46E-3	5.5E-7	1.1
I-LOCL	1.82E-5	6.4E-7	1.3
I-LODCA	8.69E-3	2.2E-6	4.4
I-LODCB	8.69E-3	4.6E-7	0.9
I-INSTAIR	1.17E-2	3.2E-6	6.3
I-LOOP	6.50E-2	1.1E-5	21.2
I-MSLB	3.90E-4	*	*
I-MFLB	2.50E-5	*	*
I-SLOCA	3.00E-3	4.1E-6	8.2
I-MLOCA	8.00E-4	4.6E-6	9.3
I-LLOCA	3.00E-4	3.7E-6	7.5
I-SGTR	1.50E-2	6.6E-6	13.2
I-T1FLD	1.04E-5	1E-5	21
I-T13FLD	2.68E-5	*	*
I-AB7FLD	5.05E-3	8.5E-10	2E-3
I-AB8FLD	1.34E-4	*	*
I-SH1FLD	6.09E-6	4.1E-7	0.8
I-SH2FLD	2.54E-3	4.3E-10	9E-4
V	2.3E-7	2.3E-7	0.5

(continued on next page)

Table 1.4-2 (continued)
Core Damage Frequency By Initiating Event for Unit 1

Definitions of Initiators

I-TR1	Normal transients
I-TR2	SG Hi Hi level transient
I-TR3	Inadvertent "S" signal transient
I-TR4	Loss of main feedwater transient
I-LOCC	Loss of component cooling water
I-LOCL	Loss of cooling water
I-LODCA	Loss of train A DC
I-LODCB	Loss of train B DC
I-INSTAIR	Loss of instrument air
I-LOOP	Loss of offsite power
I-MSLB	Main steam line break
I-MFLB	Min feedwater line break
I-SLOCA	Small LOCA (3/8" to 5" equivalent pipe diameter)
I-MLOCA	Medium LOCA (5" to 12" equivalent pipe diameter)
I-LLOCA	Large LOCA (12" up to design basis pipe diameter)
I-SGTR	Steam generator tube rupture
I-T1FLD	Turbine building zone 1 flood
I-T13FLD	Turbine building zone 13 flood
I-SH1FLD	Screenhouse zone 1 flood
I-SH2FLD	Screenhouse zone 2 flood
I-AB7FLD	Auxiliary building zone 7 flood
I-AB8FLD	Auxiliary building zone 8 flood
V	Interfacing systems LOCA
*	These results were truncated out

Table 1.4-3
Core Damage Frequency By Initiating Event for Unit 2

Initiating Event	Initiating Event Frequency (per reactor year, Unit 2)	CDF from Initiating Event (per reactor year, Unit 2)	% of Total CDF from Initiating Event (Unit 2)	% of Total CDF from Initiating Event (Unit 1)
I-TR1	1.68	6.6E-07	1.3	1.3
I-TR2	9.00E-02	3.1-08	0.06	0.06
I-TR3	0.23	1.2E-06	2.4	2.4
I-TR4	9.00E-02	5.5E-07	1.1	1.0
I-LOCC	3.46E-03	5.5E-07	1.1	1.1
I-LOCL	1.82E-05	6.4E-07	1.3	1.3
I-LODCA	8.69E-03	2.2E-06	4.3	4.4
I-LODCB	8.69E-03	4.8E-07	0.9	0.9
I-INSTAIR	1.17E-02	3.2E-06	6.2	6.3
I-LOOP	6.5E-02	1.1E-05	22.4	21.2
I-MSLB	3.9E-04	*	*	*
I-MFLB	2.5E-05	*	*	*
I-SLOCA	3.00E-03	4.2E-06	8.2	8.2
I-MLOCA	8.00E-04	4.6E-06	9.	9.3
I-LLOCA	3.00E-04	3.8E-06	7.3	7.5
I-SGTR	1.50E-02	6.6E-06	13.0	13.2
I-T1FLD	1.04E-05	1.04E-05	20.4	21
I-T13FLD	2.68E-05	*	*	*
I-AB7FLD	5.05E-03	1.5E-09	0.00	2E-3
I-AB8FLD	1.34E-04	*	*	*
I-SH1FLD	6.09E-06	4.1E-07	0.80	0.80
I-SH2FLD	2.54E-03	5.6E-10	0.00	9E-4
I-ISLOCA	2.27E-07	2.27E-07	0.5	0.5

* These results were truncated out

(continued on next page)

Table 1.4-3 (continued)
Core Damage Frequency By Initiating Event for Unit 2

Definitions of Initiators

I-TR1	Normal transients
I-TR2	SG Hi Hi level transient
I-TR3	Inadvertent "S" signal transient
I-TR4	Loss of main feedwater transient
I-LOCC	Loss of component cooling water
I-LOCL	Loss of cooling water
I-LODCA	Loss of train A DC
I-LODCB	Loss of train B DC
I-INSTAIR	Loss of instrument air
I-LOOP	Loss of offsite power
I-MSLB	Main steam line break
I-MFLB	Min feedwater line break
I-SLOCA	Small LOCA (3/8" to 5" equivalent pipe diameter)
I-MLOCA	Medium LOCA (5" to 12" equivalent pipe diameter)
I-LLOCA	Large LOCA (12" up to design basis pipe diameter)
I-SGTR	Steam generator tube rupture
I-T1FLD	Turbine building zone 1 flood
I-T13FLD	Turbine building zone 13 flood
I-SH1FLD	Screenhouse zone 1 flood
I-SH2FLD	Screenhouse zone 2 flood
I-AB7FLD	Auxiliary building zone 7 flood
I-AB8FLD	Auxiliary building zone 8 flood
V	Interfacing systems LOCA
*	These results were truncated out

Table 1.4-4
Level 2 Containment Event Tree Results By Plant End State

End State	Probability	Cond. Prob. Following Core Damage (%)	End State Description	Dominant CET Sequences	Probability
X-XX-X	1E-05	20.0	No Vessel Failure No Containment Failure	SLLCET-01 SLHCET-01	8E-06 3E-06
X-DH-L	0.0	0.0	No Vessel Failure Containment DHR Failure Late Containment Failure	N/A	N/A
X-H2-E	9E-08	0.2	No Vessel Failure Hydrogen Combustion Early Containment Failure	SLLCET-04	5E-08
L-XX-X	8E-08	0.2	Low Pressure Vessel Failure No Containment Failure	SELCET-08	4E-08
L-DH-L	8E-09	<<0.1	Low Pressure Vessel Failure Containment DHR Failure Late Containment Failure	TLHCET-10	7E-09
L-CC-L	4E-08	0.1	Low Pressure Vessel Failure Core-Concrete Interaction Late Containment Failure	SELCET-12 SELCET-11	3E-08 8E-09
L-H2-E	8E-10	<<0.1	Low Pressure Vessel Failure Hydrogen Combustion Early Containment Failure	SELCET-13 SELCET-18	3E-10 3E-10
H-XX-X	2E-05	40.0	High Pressure Vessel Failure No Containment Failure	FEHCET-19	1E-05
H-DH-L	3E-06	6.0	High Pressure Vessel Failure Containment DHR Failure Late Containment Failure	SEHCET-21 TEHCET-21	2E-06 5E-07
H-OT-L	8E-06	16.0	High Pressure Vessel Failure Containment Overpressure Late Containment Failure	SEHCET-23 TEHCET-23	5E-06 4E-06
H-H2-E	3E-07	0.6	High Pressure Vessel Failure Hydrogen Combustion Early Containment Failure	FEHCET-24	1E-07
X-CI-E	4E-09	<<0.1	No Vessel Failure Containment Isolation Failure Early Containment Failure	SLLCET-15	3E-09
L-CI-E	0.0	0.0	Low Pressure Vessel Failure Containment Isolation Failure Early Containment Failure	N/A	N/A
H-CI-E	8E-09	<<0.1	High Pressure Vessel Failure Containment Isolation Failure Early Containment Failure	FEHCET-40	6E-09

(continued on next page)

Table 1.4-4, cont.
Level 2 Containment Event Tree Results By Plant End State

End State	Probability	Cond. Prob. Following Core Damage (%)	End State Description	Dominant CET Sequences	Probability
GLH[2]	6E-06	12.0	Steam Generator Tube Rupture Late Core Damage at High Pressure	SGTR-SEQ5[1]	6E-06
GEH[2]	6E-07	1.2	Steam Generator Tube Rupture Early Core Damage at High Pressure	SGTR-SEQ9[1]	6E-07
ISLOCA[2]	2E-07	0.5	Intersystem LOCA	ISLOCA-SEQ1[1]	2E-07
"Puff"[3] Release	1.5E-5	30.0	Steam Generator Tube Creep Rupture Early Core Damage at High Pressure (SG Relief Valves Cycle)	N/A	1.5E-05
L-SR-E[3]	7E-07	1.4	Steam Generator Tube Creep Rupture Early Core Damage at High Pressure (SG Relief Valve Fail Open)	TEHCET-SEQ46 FEHCET-SEQ46	5E-07 1E-07

NOTE 1: These are Level 1 core damage sequences rather than CET sequences. They are listed here because they involve containment failure. See Section 3.4 for descriptions of these sequences.

NOTE 2: These are Level 1 accident classes rather than CET end states. They are listed here because they involve containment failure. See Section 4.3 for descriptions of these accident classes.

NOTE 3: The frequencies for the SG Tube Creep Rupture end states were not subtracted from the other end states results for this table, but were in the source term results table (see discussion Section 4.6.1 and Table 1.4-6).

Table 1.4-5
Dominant Level 2 Containment Event Tree Sequences

No.	Probability	Cond. Prob. Following Core Damage (%)	Sequence	End State
1	1.5E-05	30.0[3]	N/A[3]	"Puff" Release[3]
2	6E-06	12.0	SGTR-SEQ5[1]	GLH[2]
3	5E-06	10.0	SEHCET-23	H-OT-L
4	4E-06	8.0	TEHCET-23	H-OT-L
5	2E-06	4.0	SEHCET-21	H-DH-L
6	6E-07	1.2	SGTR-SEQ9[1]	GEH[2]
7	5E-07	1.0	TEHCET-21	H-DH-L
8	5E-07	1.0[3]	TEHCET-46[3]	L-SR-E[3]
9	2E-07	0.4	BEHCET-24	H-OT-L
10	1E-07	0.2	FEHCET-24	H-H2-E
11	1E-07	0.2[3]	FEHCET-46[3]	L-SR-E[3]

NOTE 1: These are Level 1 core damage sequences rather than CET sequences. They are listed here because they involve containment failure. See Section 3.4 for descriptions of these sequences.

NOTE 2: These are Level 1 accident classes rather than CET end states. They are listed here because they involve containment failure. See Section 4.3 for descriptions of these accident classes.

NOTE 3: The frequencies for the SG Tube Creep Rupture sequences were not subtracted from the other sequence results for this table, but were in the source term results table (see discussion Section 4.6.1 and Table 1.4-6).

Table 1.4-6
Summary Source Term Categorization

Category	Description	Relevant CET End States	Total % CDF
I	Releases limited to leakage	H-XX-X, L-XX-X, and X-XX-X	31.2% (60.2%)[1]
II	High Noble gas, low or low-low volatile and non-volatile releases	H-OT-L, H-DH-L, and L-DH-L, and "Puff" release	52.0% (22.0%)[1]
III	High Noble Gas, medium volatile, and low or low-low non-volatile releases	L-H2-E, X-H2-E, L-CI-E, X-CI-E, and L-CC-L	0.3%
IV	High noble gas, medium volatile, and high non-volatile	H-H2-E and H-CI-E	0.6%
V	High noble gas, high volatile, and low non-volatile releases	SGTR and L-SR-E	14.6% (13.2%)[1]
VI	High noble gas, volatile, and non-volatile releases	ISLOCA	0.5%

[1]Excluding SG Tube Creep Rupture contribution

Table 1.4-7

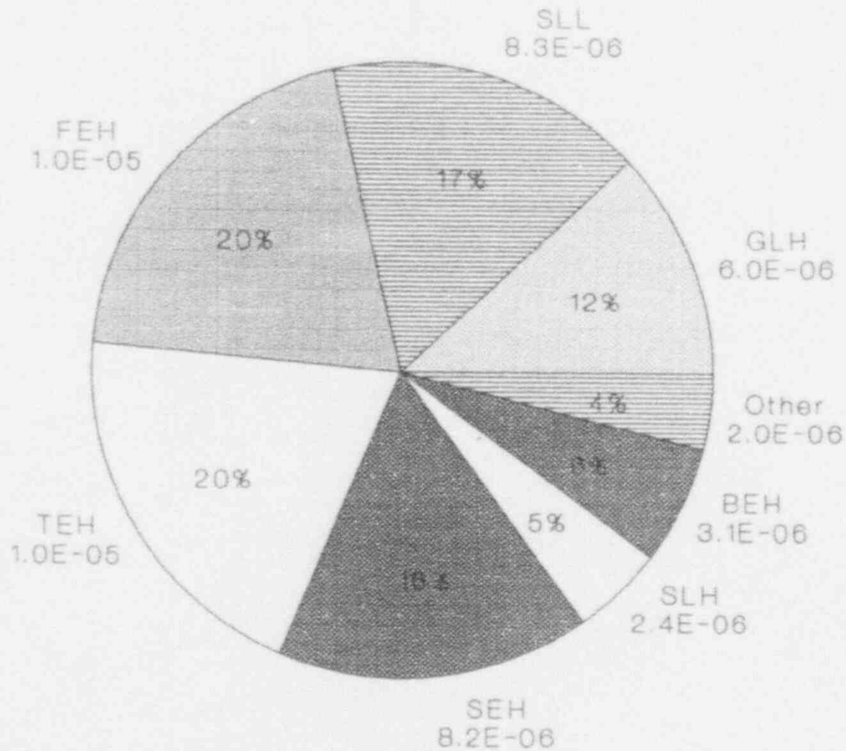
Prairie Island IPE
Important Operator Actions

Operator Action	Diagnosis time	Fussell-Vesely[1]	Birnbaum[2]
Bleed and Feed	8 to 22min	0.09	1.0E-4/yr
Depressurize RCS before SG overfill following a SGTR	49 min	0.07	3.1E-4/yr
Transfer to Low Head Recirc following LOCA	Diagnosis time not applicable here. The annunciator response model (Table 8-4 of NUREG/CR-4772) was used to determine operator diagnosis error.	0.05	3.0E-4/yr
Transfer to High Head Recirc following LOCA	Diagnosis time not applicable here. The annunciator response model (Table 8-4 of NUREG/CR-4772) was used to determine operator diagnosis error.	0.05	9.8E-4/yr
Crosstie motor driven AFW pump from opposite unit	24 min	0.04	5.6E-5/yr
Open doors on loss of room cooling to 480v switchgear	15min	0.03	2.5E-5/yr
Depressurize RCS to RHR SDC before RWST depletion following ruptured SG overfill	146 min	0.02	1.7E-4/yr
Restore main feedwater after a reactor trip	39 min	0.01	1.1E-4/yr
Crosstie EDG to emergency bus in opposite unit	95 min	0.01	2.0E-4/yr

[1] Fussell-Vesely importance is a measure of risk reduction potential and represents that fraction of core damage frequency to which the operator actions in the table contribute.

[2] Birnbaum importance is a measure of risk increase potential and in this table is roughly equivalent to the increase in core damage frequency if the operator were not able to perform each of these actions.

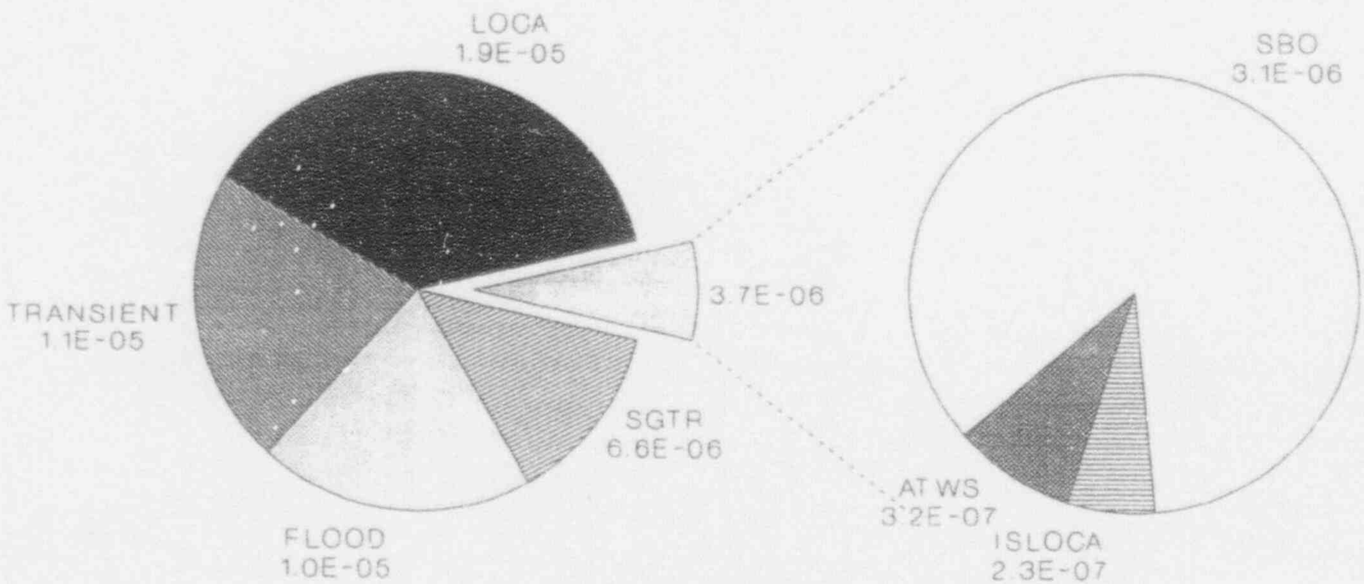
Prairie Island Level II PRA
Core Damage Frequency by Accident Class



Other: TLH (1.6%), GEH (1.2%),
V (0.5), RLO (0.3%), REP (0.3%),
SEL (0.2), FLH <<1%

Figure 1.4-1

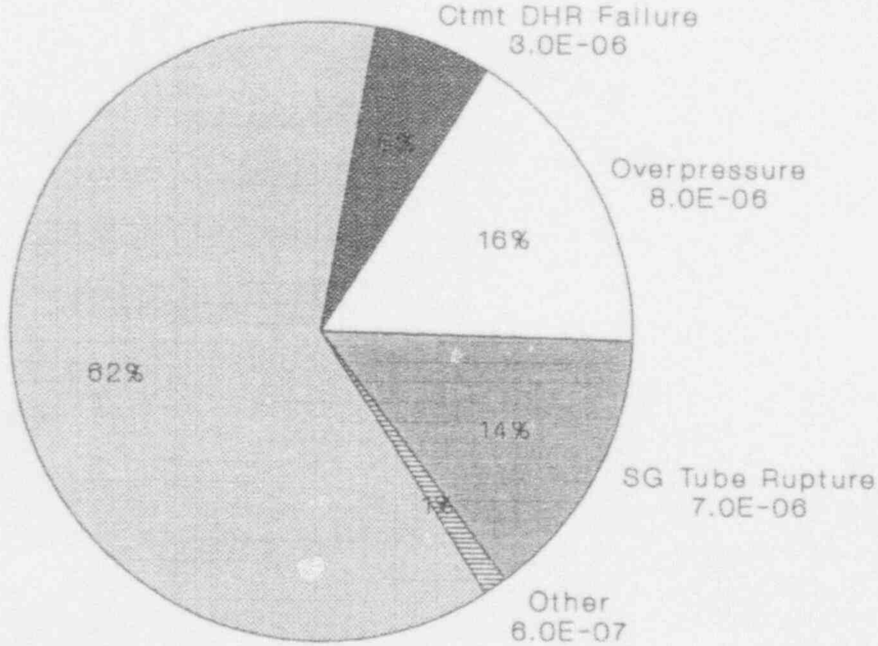
Prairie Island
Core Damage Frequency
Internal Events



TOTAL = 5E-05/YR

Figure 1.4-2

Prairie Island Level II PRA
Int. Events by Ctmt. Failure Mode

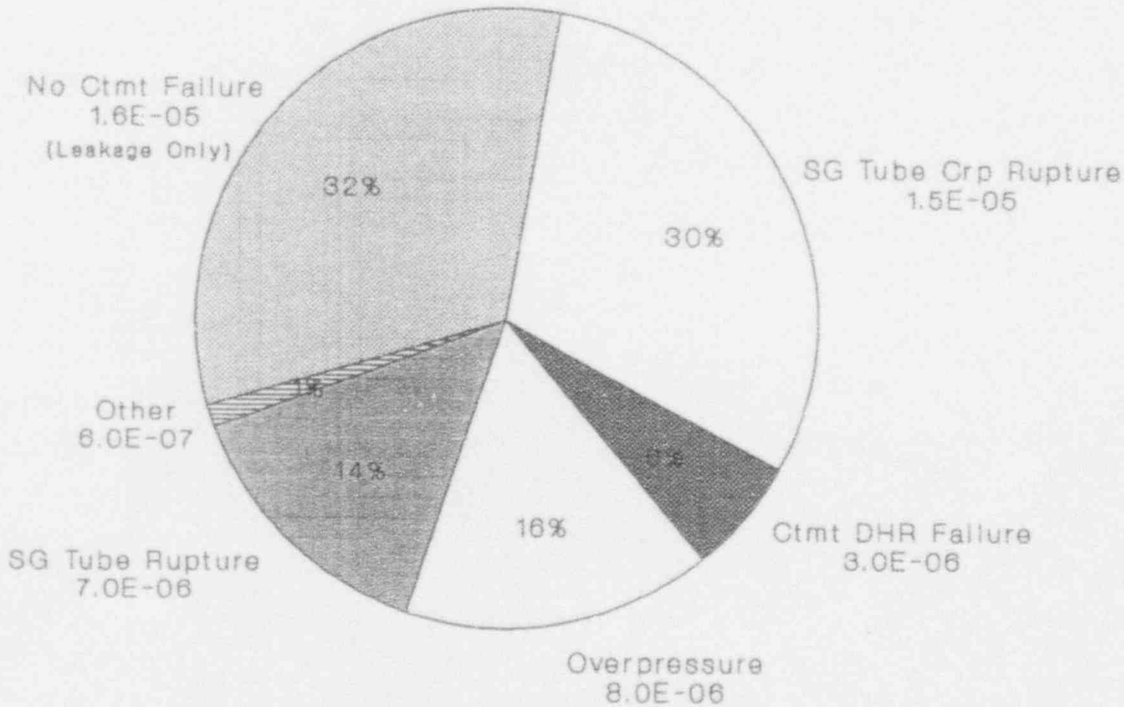


Note: Excludes SG Tube Creep Rupture

(Other: H2 Combustion, 0.7%; ISLOCA, 0.5; Core Concrete Interaction, Ctmt. Isolation Failure <0.1%)

Figure 1.4-3

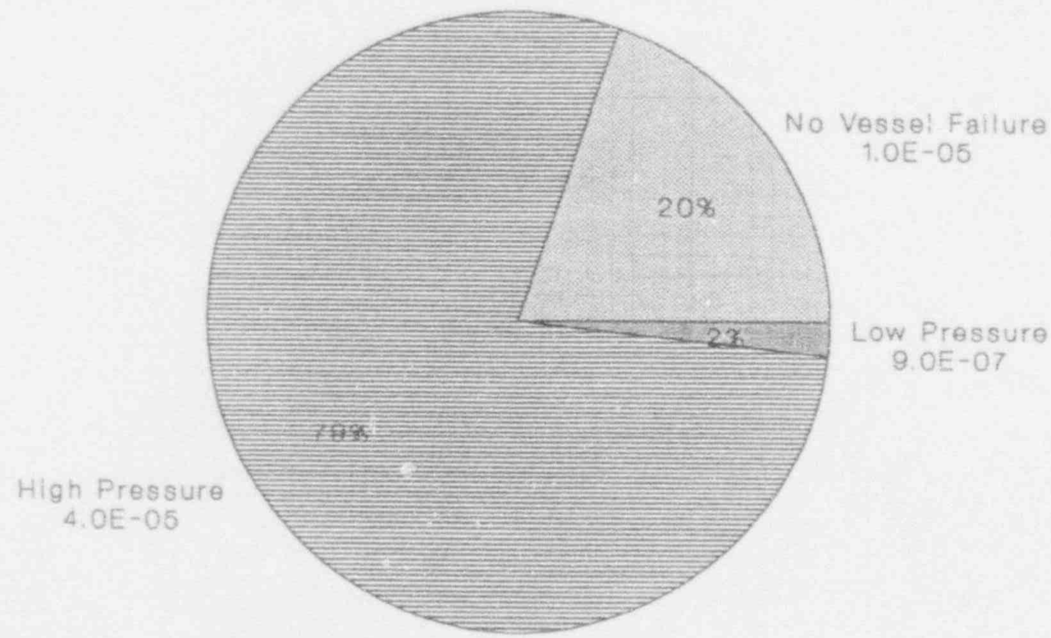
Prairie Island Level II PRA
Int. Events by Ctmt. Failure Mode



(Other: H2 Combustion, 0.7%; ISLOCA, 0.5; Core Concrete Interaction, Ctmt. Isolation Failure <0.1%)

Figure 1.4-4

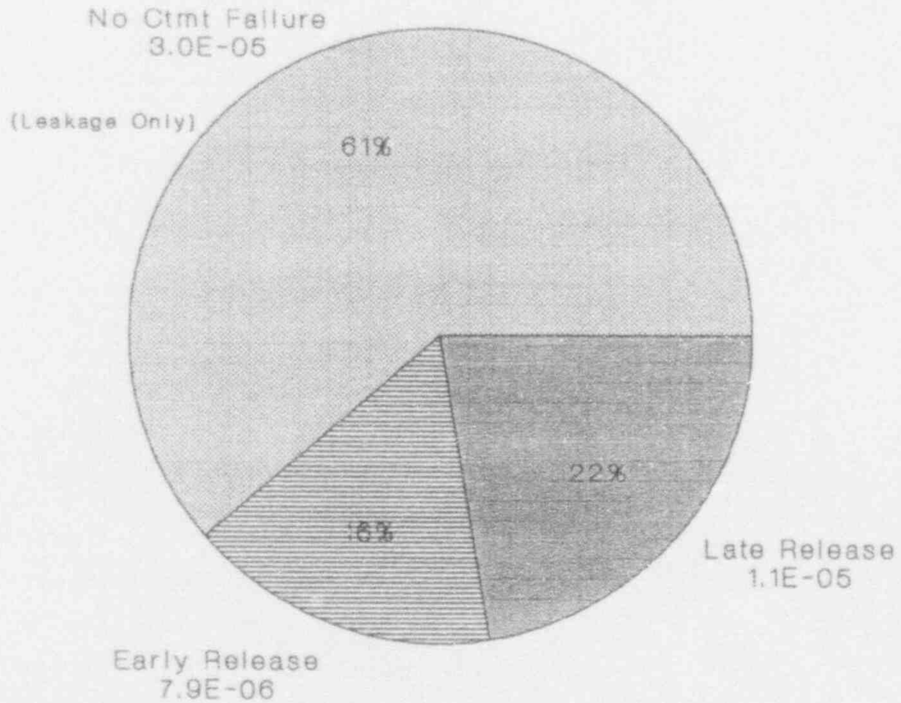
Prairie Island Level II PRA
Int. Events by Vessel Failure Pressure



Note: Excludes Containment Bypass Events

Figure 1.4-5

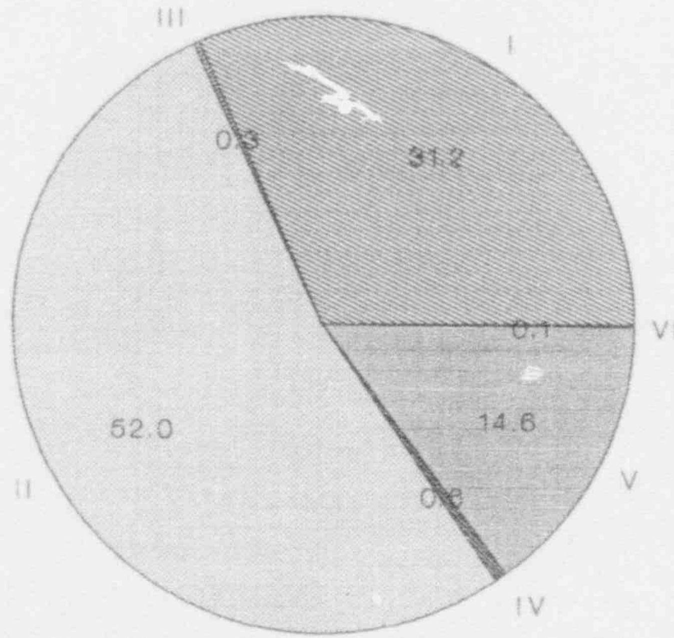
Prairie Island Level II PRA
Internal Events by Release Timing



(Early Release includes Ctmt Bypass except for SG Tube Creep Rupture)

Figure 1.4-6

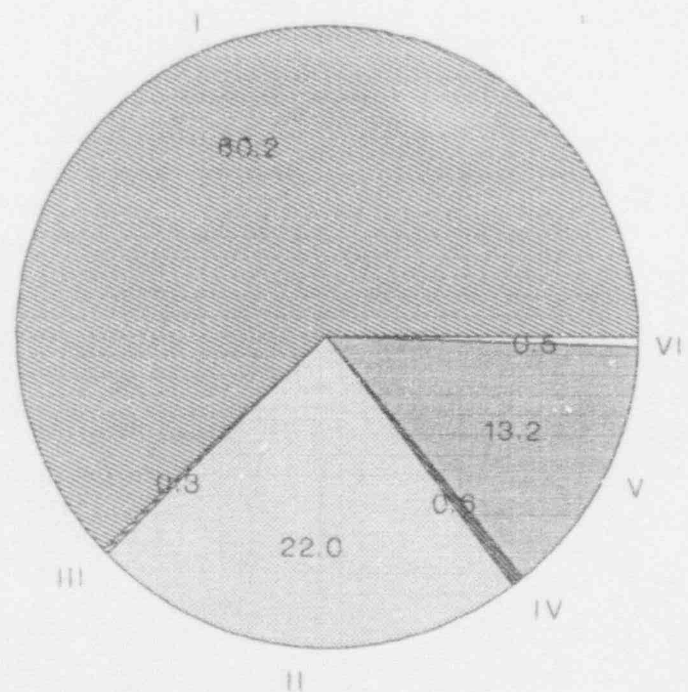
Prairie Island Level II PRA
Source Term Results
(Includes SG Tube Creep Rupture)



(See Table 1.4-6 for category descriptions)

Figure 1.4-7

Prairie Island Level II PRA
Source Term Results
(Excludes SG Tube Creep Rupture)



(See Table 1.4-6 for category descriptions)

Figure 1.4-8

2. EXAMINATION DESCRIPTION

2.1 Introduction

This section describes how the primary objectives of the IPE are met and that the methods used to perform the IPE conform with the provisions of the generic letter.

The primary objectives of the IPE, as stated by the NRC in the generic letter, are for each utility to: develop an overall appreciation of severe accident behavior; understand the most likely severe accident sequences that could occur at its plant; gain a more quantitative understanding of the overall probabilities of core damage and fission product releases; and, if necessary, to reduce the overall probabilities of core damage and fission product releases by modifying hardware and procedures.

The method used for the IPE was a full scope level 2 PRA with containment analysis meeting the intent of Appendix 1 to the Generic Letter.

2.2 Conformance with Generic Letter and Supporting Material

The NSP plant and general office engineering staff have been involved with the IPE process since its inception. They directed all aspects of the analysis with consulting services provided by TENERA, L.P., Fauske & Associates, Westinghouse Electric Corporation, and Gabor, Kenton & Associates. This was done to insure the knowledge gained from the examination would become an integral part of plant procedures and training programs and allow future activities to be performed with limited involvement by consultants. Further details of the organization are provided in Section 5.0.

A comprehensive review of the IPE work was performed by NSP personnel in addition to the standard practice of calculation verification. A review team composed of a multidisciplinary group of plant and corporate staff members reviewed this report prior to publication. Operations personnel and plant technical staff will be trained on the results of the IPE which will provide an additional review.

The internal events are covered in Section 3. A level 2 PRA was used for the containment release analysis and is presented in Section 4. An analysis of the reliability of decay heat removal (USI A-45) was performed and is documented in Section 3.4. An evaluation of internal flooding was performed and is provided in Section 3.3.8. The general review of results to determine the insights is covered in Section 6.

2.3 General Methodology

2.3.1 Event Trees

The Level I event trees were functionally oriented, based on safety functions used in the EOPs. This allowed for comparison of the Level I results with the IDCOR conclusions as well as those from other PRAs. The event tree structure includes:

- Reactivity Control
- Secondary Heat Removal
- Short Term Inventory Control (Injection)
- Long Term Inventory Control (Recirculation)
- Containment Control.

The event tree initiators are grouped by similarity of the resulting accident sequences and by their effect on mitigation systems. Event trees used for the analysis are shown in Section 3. No support state event trees were found to be necessary in this analysis, since fault tree linking was used to accomplish sequence quantification. Fault tree linking explicitly accounts for the success and failure of frontline systems in the quantification process as well as the interrelationships among frontline systems and support systems.

The Level I analysis was used as direct input to the Level II sequence quantification. The focus of the Level II analysis was on containment response to core damage. As a number of the functions important to core damage may also impact containment response, many of the same functions and systems appear in the containment event trees. The functions on Level II event trees are listed below and have been structured to reflect those actions specified in the plant EOPs.

- Containment Isolation
- Recovery In-vessel
- Reactor Depressurization
- Early Phenomenological Containment Challenges
- Ex-vessel Debris Cooling
- Containment Pressure Control
- Release Control (Containment Spray).

Level II containment event trees (CETs) are structured around the major accident classes of the Level I PRA. These CETs were used to determine the containment response and ultimately the release mode, given a core damage event has occurred.

All CETs represent containment response to events in which core damage occurs with an intact containment. The various challenges to containment that might occur as a result of phenomena associated with core melt progression are examined as part of these CETs. Section 4 provides further description of post accident phenomena and CETs.

Interfacing systems LOCA and steam generator tube rupture accident sequences represent bypass of the containment as part of the initiator, and therefore the need for a separate containment event tree is not required.

2.3.2 System Analysis

2.3.2.1 Systems List for PRA by Function

The Level I PRA functions were discussed in Section 2.3.1. This section will summarize the plant systems analyzed under each function.

PRA Function	Plant Systems Credited
Reactivity Control	Reactor Protection System
Secondary Heat Removal	Auxiliary Feedwater Main Feedwater
Short Term Reactor Inventory Control (Injection)	High Head Safety Injection Low Head Safety Injection Pressurizer PORV
Long Term Reactor Inventory Control (Recirculation)	High Head Recirculation Low Head Recirculation
Containment Pressure/ Temperature Control	Residual Heat Removal Modes - Shutdown cooling - Recirculation Fan Coil Units Containment Spray Injection

A detailed description of each of the above systems can be found in Section 3.1.2.1. These safety functions were used as headings for the event trees constructed for each initiating event category.

2.3.2.2 Success Criteria

Success criteria for each of the systems listed above are summarized in Section 3. The bases for the success criteria were a combination of realistic calculations using MAAP, USAR and operations manual descriptions.

2.3.2.3 Fault Tree Modeling

The IPE/PRA attempts to represent realistic failure potential for each system in the PRA through development of fault trees. Fault tree top events were defined for each function for systems that served multiple functions. RHR injection and RHR recirculation provide an example of a fault tree for each function of the same system. Transfers to other systems were included to account for dependencies on support systems. Support systems were modeled up to the interface with the frontline system or another support system.

The level of detail is a prime consideration in failure model development. Two criteria were used in developing the Prairie Island fault trees: the availability of data to support quantification of system components; and the relative importance of failure modes for a given system or component. It is not necessary to model a pump down to the bearings or control circuits if the available data does not include these types of subcomponent failures and further insights would not result from more detailed fault trees. Faults associated with passive components, such as pipes and manual valves with failure rates that are orders of magnitude lower than the active component failure rates, were excluded from the model. The major components that were included in the Prairie Island fault trees are listed below:

All major active components - motors, pumps, diesel generators, air compressors.

All components required to change position to fulfill function (including check valves).

Instrumentation and controls (I&C) to contact/relay level when the I&C affected the success of an entire system or redundant components in more than one system.

Removal of equipment from service for testing or maintenance.

Restoration of equipment that may have been out of service for testing or maintenance.

Human actions necessary to initiate non-automatic system operation.

With rare exceptions, no passive component failures (e.g. pipe failure) were included.

2.3.2.4 Dependency Treatment

Dependency matrices were also developed as part of the PRA. These matrices are presented in Section 3.2.3 of this report. The dependency matrices were developed to document the following:

Initiator effect on frontline and support systems.

Support system effect on frontline and other support systems.

Frontline system effect on other frontline systems.

The dependency matrices were used to assist in understanding the results of sequence analysis. With the use of fault tree linking, the dependencies between systems were explicitly accounted for by the cutset generator during sequence quantification.

2.3.2.5. Quantification Process

The computer program CAFTA (EPRI) was used for managing fault trees. CAFTA operates on 80386-based personal computers. The computer programs HPSETS and PCSETS (Logic Analysts, Inc.) were used for sequence quantification. PCSETS and HPSETS are identical codes that run on different platforms (80386-based personal computer and Hewlett-Packard workstation respectively) and are based on the SETS computer code which is described in NUREG/CR-4213, "SETS Reference Manual". Fault tree solution sequence quantification were primarily performed with HPSETS on the HP workstation.

NSP used the fault tree linking approach as opposed to developing support states or special fault tree models depending on previous success or failure of supporting systems. The failure equations of support systems were linked to the frontline system fault trees as a part of the sequence quantification. Therefore each frontline system fault tree contains explicit modeling of support system failures that could disable the frontline system. Dependencies of several frontline systems on a given support system are therefore modeled explicitly in the Boolean logic used to combine frontline system failures.

The event tree functional headings were defined by using the Boolean "AND" and "OR" operators to combine the failure equations of multiple systems which must fail for the safety function to be unsuccessful. For instance, the equation for Short Term Injection during medium LOCA is the combined failure of Safety Injection "AND"ed with RHR. Short Term Injection for transients without secondary cooling is the "OR" of safety Injection and pressurizer PORVs.

Core damage sequence cutsets were calculated by "AND"ing together an appropriate initiating event with the failure equations of the safety functions that must fail to reach a particular endstate. Credit for successful safety functions was taken using the delete term feature of HPSETS. This eliminated cutsets which would indicate a loss of systems which were already determined to be successful by the event tree. This produced minimal cutset equations for core damage sequences for the Level I portion of the PRA and a core damage probability for Prairie Island.

The probability and characterization of radioactive release was the subject of the Level II sequence quantification. The Level I results acted as the input to the Level II analysis. Sequence quantification proceeded as described above, by "AND"ing the failure equations for the safety functions in the CETs to produce equations for each sequence and plant damage state.

Throughout these analyses, a truncation limit of 1E-9/yr or less was used. This truncation limit is well below the reporting criterion of 1E-6/yr.

2.4 Information Assembly

2.4.1 Design Features

This section provides an overview of the design features, positive (+) or negative (-), significant to the results of the Level I and II PRA. A more complete description of the Prairie Island plant design features and operating characteristics, and their effects on the results, can be found in Section 6. The first area to be discussed is Secondary Heat Removal, which is considered reliable due to the following:

- Motor driven feedpumps which are independent of main steam availability. (+)
- Feedwater regulating and bypass valves which fail closed on loss of instrument air or a train of DC. (-)
- Diverse drivers for auxiliary feedwater pumps (one motor and one turbine for each unit). (+)
- Ability to crosstie motor driven auxiliary feedwater pumps between units. (+)
- Large condensate storage tanks which provide several days of decay heat removal without the need for makeup. (+)
- Reliable switchyard configuration. (+)

The second area was grouped under inventory control. The important features are listed below:

- A large RWST which provides many hours of makeup to the reactor for small break LOCA and SGTR. (+)
- A high containment spray actuation setpoint (23 psig) which preserves RWST inventory for a large fraction of the break spectrum. (+)
- Pressurizer PORV dependencies on instrument air and both trains of DC power for bleed and feed operation. (-)
- SI pump suction MOV breakers from RHR which are locked open during power operation. (-)

The third area covers reactivity control, and an important feature is:

- Favorable moderator temperature coefficient for the majority of the cycle allowing the plant to effectively ride out an ATWS with feedwater or AFW. (+)

- A reliable RPS. (+)

The last Level I area to be discussed is grouped under station blackout.

- Multiple diverse emergency diesel generators having good reliability. (+)

- Each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of essential loads for the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. (+)

- The emergency batteries have two hours of capacity. (-)

- Diverse cooling water pumps. (+)

Added features concerning the Level II analysis are the following:

- Diverse, multiple systems exist for containment heat removal\pressure control, i.e., RHR heat exchangers, FCUs, CS. (+)

- On injection of the RWST, the vessel is submerged, permitting a means of terminating the event in the reactor by ex-vessel cooling. (+)

- Should the accident proceed to the point that lower vessel head penetration occurs, the reactor cavity is very large promoting debris spreading and enhancing coolability. (+)

- The containment is very large, requiring days to pressurize to its ultimate capacity either from decay heat or noncondensible gas generation. (+)

- The ultimate failure pressure of containment is about three times its design pressure. (+)

2.4.2 PRA or IPEM Used for Comparison

The Industry Degraded Core Rulemaking Individual Plant Evaluation Methodology (IDCOR IPEM) was used in the initial development stage of the Prairie Island PRA. This was used as a starting point for a more detailed PRA analysis. The PRA differs from the IPEM primarily because:

- More detailed component data analysis was done.

- Common cause was added.

- Detailed fault trees were developed and linked in the PRA.

- More detailed CET development with explicit quantification of sequences is used in the PRA.

- More detailed internal flooding analysis was done.

As part of initial information gathering, NUREG-1150 (10/1990) was reviewed for information specifically pertaining to Surry, since this plant most closely resembles Prairie Island. In addition, during performance of the PRA, results from the Kewaunee and Point Beach (two loop Westinghouse units of similar design) IPEs were made available. Some of the insights gained from reviewing the PRA for these plants are discussed below. Table 2.4-1 shows the core damage frequencies for these plants.

The most notable difference is Prairie Island's CDF for station blackout sequences is computed to be significantly less than that for other plants. This is due to four diesel generators (of diverse design) that are available at the PI site to mitigate loss of offsite power compared to Kewanuee and Point Beach sites which have two diesels each. The Surry site has three diesels with one for each unit with the third one used to swing between the two units.

Prairie Island's steam generator tube rupture (SGTR) CDF is consistent with the other PRAs with a slightly higher initiating event frequency, as the plant has experienced a tube failure, and has similar operator actions and timing. LOCA CDFs are also similar as LOCA sequences are dominated by injection failures for small LOCA and recirculation failures for large LOCAs. Surry's LOCA CDF is somewhat lower due its capability to crosstie the charging system from the other unit and an automatic recirculation switchover. The flooding initiator has a contribution to core damage frequency very similar to that for Point Beach, although the majority of the risk is associated with a single flood zone whereas Point Beach risk due to flooding is associated with several areas. ATWS CDF is higher in Surry due to a higher assumption regarding unfavorable moderator temperature coefficient of about 1.4% (mean value) of the cycle (5% upper value). Similarly, for interfacing system LOCA, Surry values are higher. This is due to no credit taken in the Surry PRA for low pressure components and piping to survive ingress of high pressure coolant. In the PI PRA, a probability of 0.4% is assigned to low pressure system failure on exposure to reactor coolant pressure. Support system initiators vary between the PRAs although there appears similarity between Prairie Island and the other 2 loop Westinghouse plants for Loss of Offsite Power (with successful diesel generator operation) and loss of instrument air.

As for containment failure modes, a comparison between PI and Surry plants are considered. The conditional probability of containment failure given that core damage occurs is shown in the table below for both plants. It can be seen from this table that the conditional failure probability of various containment failure modes are similar for both plants. The difference in bypass release is attributed to slightly higher SGTR probability for PI as discussed above. Early containment failure for Surry consists of alpha mode (in vessel steam explosion) and direct containment heating due to vessel failure at high pressures (greater than 200 psi). Slightly better performance of the Surry containment can be attributed to larger containment volume (1.8E6 ft^3) and higher failure pressure margin due to subatmospheric operation (10 psia) even though failure pressures are similar (140 psia for Surry).

Containment Failure mode	PI	Surry
No failure	0.60	0.84
Bypass*	0.14	0.08
Early	0.03	0.01
Late**	0.22	0.07

* SG tube rupture & Interfacing system LOCA

** Basemat melt-through and late containment leakage

The Surry results as presented in the NUREG/CR4551 report categorizes the bypass group differently by including, in addition to SGTR and ISLOCA, the LOOP, ATWS and transient initiated sequences leading to containment bypass as part of the bypass group. In order to compare the results with that of PI's, these additional sequences in Surry's bypass group has been regrouped into early containment failure group, thereby leaving the bypass group to contain only the SGTR and ISLOCA initiated sequences as per PI's grouping.

The specific insights from the Prairie Island PRA study are described in Section 6 of this report.

2.4.3 Reference Documents Used

The documents used for this study are listed below along with the general type of information taken from each area.

1. Updated Safety Analysis Report (USAR)

   - Initiating event
   - System success criteria

2. Plant Operations Manuals

   - System descriptions
   - Operating procedures

3. Emergency Operating Procedures

- System Operations during an emergency
- Operator actions during an emergency

4. PI Drawings and Plant Information Computer Files

- System components
- System layout
- System interconnections
- Building layout

5. Trip Reports, Significant Operating Event Reports, License Event Reports

- Failure data
- Plant Response

6. Plant Surveillance Procedures and Plant Computer Logs

- Demand data
- Test frequencies
- Run times
- Test unavailability time

7. Work Requests

- Failure data
- Maintenance unavailability time

8. NPRDS

- Failure data
- Pump data
- Run time

9. Design Basis Documents

- System descriptions
- System success criteria

10. SOER 85-05

- Flooding analysis

11. NUREGs, WCAPs and EPRI Documents

- Generic failure data
- Common cause data

12. Vendor Technical Manuals

- Component description
- Maintenance requirements

A number of means were used to confirm the accuracy of the above documents. Since the system analysts were located at the site, they had ready access to the systems, the system engineers, the operators, and the plant simulator to verify the accuracy of the data. The system engineers were utilized to review and comment on system descriptions, success criteria, and major insights.

2.4.4 Walkdowns

Many walkdowns were performed throughout the IPE. In most cases, the individual walkdowns performed for systems analysis and fault tree construction were part of an iterative process. They were performed as often as necessary to answer questions that arose during fault tree construction. Individual walkdowns were performed by this method because NSP analysts are stationed at the Prairie Island plant and all NSP analysts have easy access to the plant. All fault trees were prepared by NSP analysts. SRO trained individuals either developed or reviewed every fault tree.

The initial internal flood walkdown was performed by two members of the PRA group. One individual on the initial walkdown had performed the flood analysis for the Monticello IPE and therefore was familiar with the methodology, and the other individual was the PRA analyst stationed at Prairie Island that performed the majority of the internal flood analysis. Individual follow up walkdowns were conducted by the PRA analyst stationed at Prairie Island. The internal flood walkdowns were performed to look at the flood sources, components, and drains in each area, and the interconnections to adjacent areas.

The human factors walkdown included the NSP analyst responsible for the human error probability derivation and a consultant with extensive experience in Human Reliability Analysis (HRA). The human factors review in support of the HRA included the following three task:

1) Review of the "Control Room Design Review" documents for factors not previously considered in the Prairie Island PRA HRA.

2) Walkdowns of selected local operator actions and control room panels to verify assumptions made during the HRA, and to look for factors not previously considered in the HRA.

3) Interviews with control room personnel to discuss roles and responsibilities during actions, timing of operator actions, and performance of specific actions important to the PRA.

A general walkdown of the containment building was performed by a member of the PRA staff and a consultant. This walkdown was for the level 2 portion of the PRA.

Table 2.4-1

Contribution to Core Damage

Sequence	PI	Surry*	Kewanuee	Pt.Beach
Station Blackout	3.1E-6	26.8E-6	26.4E-6	15.1E-6
SGTR	6.6E-6	1.8E-6	5.3E-6	6.3E-6
LOCA	12.4E-6	6.0E-6	24.0E-6	39.2E-6
Flood	10.4E-6	-	-	10.8E-6
Transient	2.4E-6	2.1E-6	3.2E-6	17.3E-6
ATWS	0.2E-6**	1.6E-6	<0.1E-6	0.3E-6
ISLOCA	<0.1E-6	1.6E-6	<0.1E-6	<0.1E-6
LOOP	7.9E-6	-	4.5E-6	9.0E-6
Loss of DC Bus	2.7E-6	-	0.2E-6	0.5E-6
Loss of Inst. Air	3.2E-6	-	2.1E-6	3.0E-6
Loss of SW	0.6E-6	-	0.4E-6	8.4E-6
Loss of CC	<0.6E-6	-	<0.1E-6	5.1E-6
Others	-		-	-
Total CDF	5.0E-5	4.0E-5	6.7E-5	11.4E-5

* Mean value

** ATWS already included in Transient/LOOP groups

3.0 FRONT END ANALYSIS

This section contains the results of the Prairie Island Level 1 PRA, beginning with an introduction of initiating events and continuing through the quantification of accident sequences potentially leading to core damage. The contents are summarized as follows:

Section	Summary
3.1 Accident Sequence Description	- Initiating events - Level 1 event trees - Frontline system success criteria - Accident sequence classification
3.2 System Analysis	- Frontline and support system descriptions - Fault tree modeling methods - Dependency matrices
3.3 Sequence Quantification	- Generic and plant-specific data - Human actions - Common cause analysis - Sequence quantification method - Internal flooding analysis method
3.4 Results and Screening	- Screening criteria - Sequence results by accident class - Vulnerability screening - Decay heat removal evaluation - Internal flooding evaluation

3.1. Accident Sequence Description

3.1.1 Initiating Events

3.1.1.1 Plant-Specific and Generic Initiating Events

Events which require a manual shutdown or a trip, either manually or automatically initiated, are called initiating events. There are many potential types of initiating events. They include internal events, such as a loss of feedwater, loss of offsite power, loss of cooling (service) water and LOCA, as well as external events (e.g., earthquakes, fires, tornadoes, etc.). This report focuses on internal events in accordance with Generic Letter 88-20. Evaluation of initiators caused by external events will be addressed as a part of NSP's response to the NRC's IPEEE requirement. Table 3.1-1 summarizes the initiating events evaluated in the Prairie Island IPE and provides the frequency for each initiating event. The plant-specific initiating events (derived from operating experience data) used in the IPE were:

1. Reactor Trip (due to transient events other than SG Hi-Hi Level, Inadvertent SI, and Loss of All Main Feedwater)
2. Reactor Trip due to SG Hi-Hi Level
3. Reactor Trip due to Inadvertent Safety Injection
4. Reactor Trip due to Loss of all Main Feedwater
5. Steam Generator Tube Rupture

Generic frequencies or frequencies derived from plant-specific analysis using NRC and/or industry documents were used for those initiators where plant-specific initiating frequencies could not be derived. The following list identifies the generic initiating events used in the Prairie Island IPE along with the source of the frequency:

1.	Large LOCA	(PWR IPEM)
2.	Medium LOCA	(PWR IPEM)
3.	Small LOCA	(PWR IPEM)
4.	Loss of Offsite Power	(NUREG-1032, NUMARC-8700)
5.	Loss of all Cooling Water	Fault Tree (see below)
6.	Loss of all Component Cooling Water	Fault Tree (see below)
7.	Loss of DC Train A	Fault Tree (see below)
8.	Loss of DC Train B	Fault Tree (see below)
9.	Loss of Instrument Air	Fault Tree (see below)
10.	Main Feedwater Line Break	(Plant-specific estimate of pipe lengths, valve failure rates, and generic pipe break frequency).
11.	Main Steam Line Break	(Plant-specific estimate of pipe lengths, valve failure rates, and generic pipe break frequency).
12.	Internal flooding	(Plant-specific estimate of pipe lengths, valve failure rates, and generic pipe break frequency).
13.	Intersystem LOCA	Fault Tree, NUREG-5102 (see below)

3.1.1.2 Initiating Event Frequencies

Transient occurrence data from the period 1/1/80 through 12/31/90 were used to derive the plant-specific initiating event frequency estimates. Descriptions of the occurrences from trip reports, LERs, significant operating event reports, and monthly operating data reports were used to classify the events according to transient initiator categories. Transient initiator frequency estimates were derived by dividing the number of events by the number of years of data. Generic initiating event frequencies were obtained from the published sources noted in Section 3.1.1.1.

One steam generator tube rupture event has occurred at Prairie Island (in 1979), so the frequency for this event was determined using plant specific data from the beginning of plant operation (12/73 for Unit 1 and 12/74 for Unit 2). The SGTR that occurred at Prairie Island was due to a loose part that had been left in the RCS following a refueling outage. Since this cause is not unique to Prairie Island (all plants are subject to this type of error), and due to the increased measures taken to prevent such an occurrence since the event (100% eddy current testing each outage, training, excellent primary and secondary water chemistry control, etc.) it is felt that Prairie Island is not more susceptible to this event than other plants. Therefore, a Bayesian update of the SGTR initiating event frequency was performed to more accurately reflect these considerations, but still take into account the one event that did occur. This technique only decreased the frequency by one-half (to 1.5E-2/yr).

Plant-specific system fault tree analysis was used to quantify the special initiating events (Loss of Cooling Water, Component Cooling Water, DC Train A, DC Train B and Instrument Air) and Intersystem LOCA. The fault trees were quantified using a combination of plant-specific and generic component failure rates.

Main feedwater and main steam line breaks were quantified by performing a review of piping from the steam generator to the outside containment isolation valve (MSIV for main steam lines, feedwater regulating and bypass valves for feedwater lines, assuming no S-signal generated). These valves were chosen as they would isolate any break downstream (steamline) or upstream (feedline) following the event. A generic pipe rupture frequency was then applied to these piping sections. Failure of the isolation function was handled in the main steamline/feedline break event tree.

Intersystem LOCA (Event V) involves an unisolable LOCA through a system which interfaces with the RCS. The LOCA causes core damage and the release bypasses containment. The approach taken to quantify this initiating event was the following:

1. Each containment penetration was analyzed to determine whether it could be an intersystem LOCA pathway. Screening criteria used included the following:

   a) the pathway must penetrate both the containment and the RCS,

   b) the design pressure of the pathway must be lower than that of the RCS,

   c) the overpressurization event must be possible during power operation,

d) the pathway must present a significant challenge to plant shutdown capability. This is dependent on the line size and the valve configuration. Lines were screened out if they were <2 inches in diameter or included four or more normally closed isolation valves in series. Unless the break is in the vicinity of critical ESF equipment, it is unlikely that breaks of water lines with diameters <2 inches will have a significant impact on recovery from the event. This is due to the low coolant loss rate that would occur, the time available for the operator to identify and isolate the leak, and the possibility of makeup capability greater than the leak rate. However, if the line was found to run near critical ESF equipment, then the screening criteria for line size was smaller (<1").

2. For the pathways identified from 1. above, a fault tree was constructed and quantified to determine the probability of exposure of the low pressure lines to reactor pressure.

3. The failure probability of low pressure lines outside containment due to exposure to RCS pressure was determined using plant-specific pipe size and materials and applying the appropriate conditional failure probability from NUREG/CR-5102.

   Failures of RHR pump seals were also included in the calculation. Seal failure has a higher probability than pipe failure (it was assumed to always occur on overpressurization of the low pressure piping), it would have a low break flow similar to a small LOCA and would not immediately affect operation of other auxiliary building system equipment. Therefore, there would be time available (similar to the small LOCA case) for the operator to cooldown and depressurize the RCS to minimize break flow before the RWST empties. The charging system would then be used for long term RCS makeup to the RCS. Time would be available for the operators to either isolate the leak or evaluate alternative means for going to cold shutdown.

3.1.1.3 Rationale For Grouping

Although the number of possible individual initiating events is large, the number of significantly different ways in which the plant responds is much smaller. Therefore, initiating events are grouped into categories based on similarities in plant response. The representative event is chosen so that the challenges to critical safety functions, as well as the plant responses to and operator actions following the event, encompass those for other events within the category. Therefore, the initiators within each group were quantified with nearly identical event tree structures (success criteria for each functional heading may differ depending on the initiator). See Section 3.1.2 for a discussion of the Level 1 event trees.

The grouping for plant initiating events is:

1. Loss of coolant accidents (LOCA)
   - Small
   - Medium
   - Large

2. Anticipated transients and special initiators
   - Reactor trip (normal)
   - Reactor trip (SG Hi-Hi Level)
   - Reactor trip (Inadvertent SI Signal)
   - Loss of all Main Feedwater
   - Loss of all Cooling Water
   - Loss of all Component Cooling Water
   - Loss of Train A DC Power
   - Loss of Train B DC Power
   - Loss of Instrument Air
   - Internal flooding

3. Unanticipated transients
   - Main feedwater line break
   - Main steam line break

4. Loss of offsite power

5. Intersystem LOCA

6. Steam generator tube rupture

7. Anticipated transients without scram (ATWS)
   - Small and Medium LOCA
   - Any of the above listed transient events
   - Main feedwater line break
   - Main steamline break
   - Loss of offsite power
   - Internal flooding.

A description of the various groups of initiating events with specific discussion of the rationale for grouping follows:

Loss of Coolant Accidents- A LOCA is defined as any reactor inventory loss which exceeds the plant technical specifications for primary coolant leakage, or that causes a low pressurizer pressure reactor trip. LOCAs can be separated into break sizes for evaluating the plant response to this class of initiator. In many risk analyses the break sizes are classified according to the requirements for success of the ECCS. This distinction is not related to the licensing basis LOCA sizes but rather as an input into the definition of the success criteria of equipment required for mitigation of the postulated LOCA. LOCA events were grouped separately to reflect unique event tree modeling which included:

- the capability of the Auxiliary Feedwater System to remove decay heat
- different success criteria for high and low pressure injection systems
- the use of bleed and feed to maintain inventory
- the ability of the operator to depressurize the RCS and/or the SGs

The Prairie Island IPE classifications for LOCAs are:

1. Large LOCA - Defined as any break in the reactor system piping which leads to a loss of coolant of sufficient size that:

   a) the RCS is rapidly depressurized to the point where low pressure injection systems can operate,

   b) Low pressure coolant recirculation (from the containment sump) is required for long term decay heat removal,

   c) Decay heat removal through the secondary system (SGs) is ineffective due to loss of primary inventory and flow to the SGs, and

   d) RHR injection is assumed to be required to handle the inventory requirements.

   Based on MAAP code runs (see Section 7.1), RCS break sizes greater than 12 inches equivalent pipe diameter are included in this category.

2. Medium LOCA - Defined as any break in the reactor system piping which leads to a loss of coolant of sufficient size that:

   a) high head or low head injection is sufficient,

   b) the rapid depressurization described for large LOCAs does not occur, but it is rapid enough that successful inventory control through RHR injection occurs without operator intervention should high head injection fail,

c) high or low head recirculation is required for long term decay heat removal, and

d) Decay heat removal through the secondary system (SGs) is ineffective due to loss of primary inventory and flow to the SGs.

MAAP code runs (see Section 7.1) indicate that RCS break sizes between 5 and 12 inches equivalent pipe diameter fall into the Medium LOCA category.

3. Small LOCA - Defined as any break in the reactor system piping which leads to a loss of coolant of sufficient size that:

a) inventory will gradually be lost from the vessel unless maintained with high head injection,

b) auxiliary feedwater with high head injection operation is required for secondary cooling and RCS inventory control,

c) the RCS cannot be depressurized in time for low head injection to be successful, and

d) high head recirculation is required for long term heat removal.

MAAP code runs (see Section 7.1) indicate that break sizes between 3/8 and 5 inches in equivalent pipe diameter fall into the Small LOCA category. Breaks (leaks) smaller than 3/8 inches can be handled by the normal charging system.

Anticipated Transients and Special Initiators- This category includes anticipated transient initiators and support system related initiators. These events include common event tree modeling such as:

- reactor decay heat removal through the steam generators through operation of auxiliary and/or main feedwater and steam removal to either the condenser or atmosphere,

- availability of RCP seal cooling to prevent degradation of the event into a Small LOCA,

- inventory makeup via bleed and feed should secondary cooling fail, and

- high pressure recirculation for long term decay heat removal should bleed and feed be necessary.

Transient and special initiators included in the IDCOR PWR IPE methodology (IPEM) were reviewed to develop a preliminary list of initiating events appropriate for consideration in the Prairie Island PRA. A review of the initiating events from the IPEM (which was based on NUREG/CR-3862) indicated that most were potentially applicable to Prairie Island. The IPE plant-specific data base was developed from the number of transients in each transient category reported in NUREG/CR-3862. Loss of cooling water (service water) and loss of component cooling water events are treated as special initiators and are analyzed separately. Loss of offsite power is analyzed as a separate initiator (see below). Fires are external initiating events and are not included with the internal plant transients.

Loss of Offsite Power - The loss of offsite power initiating event was modeled separately from the anticipated transients described above. The primary factors which required special treatment were consideration of recovery of offsite power and repair of diesel generators. In addition, a time phased event tree was required to account for the possible recovery of power during station blackout events.

Unanticipated Transients - The main steam line break and main feedwater line break initiating events are rare events which require isolation of the break to preserve secondary cooling from at least one steam generator. Safety injection occurs automatically due to the rapid depressurization of the faulted steam generator. Operator response to these events is much different than that for anticipated transients.

Steam Generator Tube Rupture - These are small LOCAs which are caused by failure of one or more of the steam generator U-tubes. Primary coolant is then lost to the secondary system through the break as long as the primary side pressure is above the secondary side pressure. RCS cooldown and depressurization is necessary before RWST depletion occurs to prevent core damage as recirculation from the containment sump is not possible. Another potential problem is steam generator overfill, which will occur if the operators are unsuccessful in cooling and depressurizing the RCS quickly.

Interfacing System LOCA (ISLOCA) - These are LOCAs which occur outside of the containment boundary and for which the following conditions may exist:

a) isolation of the break is not possible,

b) there may be a high environmental stress produced on equipment in the auxiliary building, and therefore the operation of ECCS equipment may be compromised, and

c) the consequences of a core melt in this situation could be significantly different than other situations because of the direct pathway from the primary system to the auxiliary building.

Based on these considerations, ISLOCA events (and small ISLOCAs through RHR pump seals with failure of operator cooldown and depressurization before RWST depletion) are assumed to result in core damage.

ATWS - This category includes all transients (including internal flooding) and small and medium LOCAs, coupled with an electrical or mechanical failure of reactor trip, i.e., failure to insert the control rods following a signal (or the need for a signal) from the Reactor Protection System. The Prairie Island IPE utilizes a specific event tree to investigate ATWS sequences. Modeling unique to the ATWS event includes failure of RCS overpressure protection systems, availability of the AMSAC system for automatic startup of the auxiliary feedwater pumps and modified success criteria for the auxiliary feedwater system.

Large LOCA and ISLOCA were not analyzed for ATWS conditions. For Large LOCA, it is assumed that voiding in the RCS would provide enough negative reactivity to shut down the reactor until the borated injection flow reaches the core. This would also be true for some ISLOCA events. However, the primary reason that ISLOCA is not analyzed for ATWS conditions is because it is assumed to cause core damage directly (see above).

Internal Flooding - Internal flooding events used the same basic event tree structure as anticipated transient events. Flooding is a spatially dependent initiator, where the impact on core cooling and containment systems is dependent on the location of the flood. Internal flooding was modeled with separate damage classes in the Prairie Island internal events IPE.

3.1.2 Event Trees

Figures 3.1-1 through 3.1-9 are the event trees used to represent the Prairie Island plant response to the transient and accident initiators identified in Section 3.1.1. In this Section, the functional headings of the event trees are defined, as well as important assumptions made in the development of the event trees for each of the initiators. Wherever MAAP analysis is referenced for success criteria, section 7.1 contains the pertinent MAAP runs.

3.1.2.1 Safety Functions

As mentioned previously, the event trees used for the Prairie Island IPE analysis were developed around a framework of safety functions that may be required following any given plant transient. Generally, a safety function can be defined as a condition that when satisfied, limits the potential for breaching (or mitigate challenges to) the barriers to fission product release; the fuel cladding, the reactor coolant system, and the containment. The safety functions can be fulfilled by automatic actuation of plant systems, by passive system performance, or by operator action taken as directed by the plant procedures. Together, the safety functions for the Level 1 analysis address a complete set of conditions which must exist to ensure fuel integrity following an abnormal plant transient. The safety functions can be grouped into categories associated with reactor control, secondary heat removal, inventory control and containment.

This section provides a general description of each safety function considered in the Prairie Island Level 1 IPE. These safety functions closely follow the subcriticality, core cooling, heatsink, and containment functions contained within the functional recovery guidelines of the Emergency Operating Procedures. The safety functions that provide the framework for modeling shutdown and adequate core cooling for the Prairie Island include the following:

1. Reactivity Control (Subcriticality)
2. Secondary Cooling (Heat Sink)
3. Short Term Injection (Heat Sink and Core Cooling)
4. Long Term Injection/Recirculation (Heat Sink and Core Cooling)
5. Containment Pressure Control (Containment).

Each of these five safety functions are considered in the Prairie Island Level 1 event trees and are described below. Other important event tree headings are associated with repair and recovery activities or changing the nature of the transient in progress (such as consequential LOCAs). These additional headings are somewhat transient specific and are further described as a part of the frontline event tree discussion in the next section.

Reactivity Control (Event tree heading S) - During a postulated accident sequence, an important safety function to be performed is the insertion of negative reactivity to bring the reactor subcritical. The primary method for inserting negative reactivity is to trip the reactor by rapid insertion of control rods into the reactor core. For event trees other than ATWS trees, there is no detailed breakdown of this safety function. Initiating events in which rod insertion is assumed to be unsuccessful are transferred to the ATWS event tree for further analysis.

The Reactor Protection System (RPS) is designed to perform this safety function. Rapid reactivity shutdown is provided by the insertion of rod cluster control assemblies (RCCA) by free fall following loss of power to the control rod drive mechanisms (CRDM). There is no detailed fault tree development of the RPS so failure probabilities from WCAP-11993 (Assessment of Compliance With ATWS Rule Basis for Westinghouse PWRS) are used instead. The failure probability used for RPS failure includes operator action to manually trip the reactor if the automatic trip signal has failed. For failure to trip events in which a large loss of reactor inventory is occurring, such as a large LOCA, reactivity control is not included as a heading as borated water addition will occur provided safety injection is successful assisted by the high degree of voiding occurring in the core caused by the large break.

Secondary Heat Removal (Event tree heading H) - For transient initiators, steam generator tube ruptures and small LOCAs, long term decay heat removal from the primary system is provided by the steam generators. Secondary heat removal is not required for events in which significant loss of reactor coolant is occurring (medium and large LOCA) as the break size is sufficient for decay heat removal.

For transients and small LOCA, the steam generator initial inventory and rate of heat removal is sufficient to prevent a significant pressure rise in the reactor coolant system following a reactor trip, thereby precluding a demand on pressurizer PORVs or safety valves. Normal inventory in the steam generator is sufficient to prevent steam generator dryout for approximately 40 minutes at normal decay heat levels. The secondary heat removal heading credits two systems for long term steam generator makeup; auxiliary feedwater and main feedwater.

Auxiliary feedwater can be provided to either or both steam generators from one of three pumps, a motor or turbine driven pump from the unit in which the trip occurred, or a motor driven pump from the second unit. As it was modeled in the AFW fault trees, failure of the opposite unit turbine driven AFW pump with a concurrent dual unit initiating event (LOOP, Loss of CL or loss of IA), fails the AFW crosstie as the motor driven pump would be required to provide secondary cooling for its associated unit.

Main feedwater is also credited as a source of inventory makeup to the steam generators if auxiliary feedwater is unavailable. Main feedwater is normally lost on a reactor trip but can be easily restored from the control room. The main feedwater pumps are motor driven and if tripped as a result of the initiator can be returned to service from the control room. Feedwater addition through the condensate pumps by depressurizing the steam generators is not credited in the IPE as the majority of the failures for feedwater also fail condensate so it was felt that this method of feedwater addition would not significantly reduce the potential for loss of secondary cooling. Operator actions to restore MFW from the control room for initiating events which do not produce an "S" signal and for those events in which an "S" signal are generated are included under the secondary cooling heading.

RCS Short Term Inventory Control (Event tree heading STI) - This heading varies as a function of the initiating event.

For transient initiated events, no short term inventory makeup is required provided secondary heat removal has been successful. Heat removal through the steam generators prevents reactor coolant loss by minimizing the challenges to the pressurizer PORVs and safeties thereby maintaining reactor coolant inventory. Where secondary heat removal is assumed not to be successful, the short term inventory heading represents bleed and feed operation. Bleed and feed requires manual start of at least one safety injection pump and opening of a pressurizer PORV in order provide short term RCS inventory control and to remove RCS decay heat. The operator action to start an SI pump and manually open a pressurizer PORV is included under the transient event trees heading for short term RCS inventory.

For small LOCA initiators and SGTR, a safety injection signal will occur on low pressurizer pressure and the SI pumps will start automatically. If secondary heat removal has been successful, injection by a single SI pump is all that is necessary to satisfy short term RCS inventory control. If secondary heat removal is not available, bleed and feed operation is capable of providing short term RCS inventory control, similar to transient initiated events. Operator action for bleed and feed consists of opening one of the two pressurizer PORVs to provide sufficient bleed and feed cooling in conjunction with an already running SI pump. Short term RCS inventory using bleed and feed was not credited for the SGTR initiating events as the combination of a SGTR together with failure of secondary cooling was a small contributor to overall CDF.

Larger loss of coolant initiators are broken into medium and large LOCA categories. Operation of an SI pump or an RHR pump is all that is necessary to satisfy short term RCS inventory control for the medium LOCA break spectrum. Operator action is not necessary for RHR injection during a medium LOCA as if SI should fail, the RCS will depressurize on its own below the RHR pump shutoff head before core damage will occur (see section 7.1). For the largest LOCAs, SI flow rates are assumed to be insufficient to maintain core cooling while blowdown is in progress. For these break sizes, an RHR pump provides a sufficient rate of makeup to prevent core damage for the short term inventory heading. SI and RHR pump operation are automatic on a safety injection signal from either low pressurizer pressure or high containment pressure. MAAP analysis has been used to shown that SI accumulators are not a requirement for short term RCS inventory control for any of the LOCA sizes utilized in the Prairie Island IPE.

Long Term Inventory Control (Event tree heading LTI) - Success criteria for long term inventory control also varies as a function of the initiating events.

For transients in which bleed and feed was successful, approximately 8 to 10 hours is available prior to depletion of the RWST. To continue adequate core cooling, initiation of recirculation from the containment sump is required. As the reactor is at elevated pressures, high head recirculation with an SI pump continuing injection to the reactor is necessary. High head recirculation requires realignment of an RHR pump suction from the RWST to the containment sump then to the to the suction of an SI pump, "piggy backing" the two systems. It is assumed that heat removal through the RHR heat exchanger is necessary to remove decay heat from the RCS and to provide pump protection from fluid temperature effects such as NPSH. Operator action to lineup for high head recirculation was included in the fault trees for the SI system.

Success criteria for long term inventory control for small LOCAs in which secondary cooling is not available is the same as for the transient events in which bleed and feed occurs. That is, recirculation by alignment of an SI pump to the discharge of RHR is required. Again, operation of the RHR heat exchanger is assumed to be necessary.

An additional means of long term cooling is available for small LOCA sequences in which secondary cooling can be used to reduce reactor pressure through steam dump from the steam generators followed by RCS depressurization using spray (event tree heading CD). In these sequences, the shutdown cooling mode of RHR can be entered prior to depletion of the RWST thereby precluding the need for high head recirculation. Included under event tree heading CD is an operator action to cooldown and depressurize the RCS using SG PORVs and pressurizer PORVs or auxiliary spray, to get the RCS to the RHR SDC temperature and pressure limits before RWST depletion. MAAP analysis was used to show that containment fan coil units can maintain containment pressure below the containment spray setpoint (23 psig), thus limiting the rate of RWST depletion to that associated with SI flow.

Large loss of coolant accidents are assumed to require initiation of the recirculation mode of RHR. The break size for these events is such that the steam generators are not necessary to assist in reducing reactor pressure. The time frame for initiation of recirculation is much shorter than for small LOCAs due to the assumed operation of containment spray in addition to RHR and SI. Heat removal through the RHR heat exchangers is assumed to be required for long term operation of all modes of RHR. An operator action to lineup to low head recirculation was included in the RHR system fault tree.

Containment Control (Event tree heading C) - Successful operation of a means of containment heat removal is assumed to be required for any accident sequence in which long term recirculation from the sump is occurring. Containment pressure control can be provided by operation of two fan coil units or a train of containment spray. Similar to SI, spray recirculation requires the containment spray pump suction to be aligned to RHR after the suction from the RHR pumps has been shifted to the containment sump. Operator action to lineup for CS recirculation is included in the CS fault tree.

However, even without decay heat removal, several days are required to pressurize the large containment volume to its ultimate pressure capacity of 150 psig. Further, because the RHR heat exchangers are already assumed to be required for support of long term injection to the reactor, the containment control heading is of limited significance to the Level 1 results.

3.1.2.2 Front-Line Event Trees

The event trees established for the Level 1 portion of the IPE study model the systems and operational failures which may result in core damage. Event trees were constructed for each of a number of initiating event categories. The event trees developed for the Prairie Island IPE are small and structured around the safety functions discussed in the preceding section. Further discussions of the event tree structure and the safety functions associated with each event tree type are provided in this section.

Six general types of event trees are used to analyze the plant response to various initiating events:

- Transients, special initiators and internal flooding.
- Loss of offsite power (including station blackout).
- Loss of coolant accidents (LOCAs).
- Steam Generator Tube Rupture (SGTR).
- Secondary depressurization events (steam and feedline breaks).
- Anticipated transients coupled with a failure to scram (ATWS).

A review of the Prairie Island plant design and operating experience indicates that the above general types of event trees accurately reflect the plant response for any plausible initiating event. It was concluded that there were no other anticipated transients or other initiating events which might occur at Prairie Island which exhibit significantly different characteristics of plant response. Each of these groups of Level 1 event trees used in the Prairie Island IPE are described below.

Transients and Special Initiators - The event tree used for the evaluation of anticipated transients and special initiators is shown in Figure 3.1-1. The form of the event tree is the same for each of the following events:

- Reactor trip with feedwater (TR1)
- Steam generator high level trip (TR2)
- Spurious safety Injection Signal (TR3)
- Loss of feedwater (TR4)
- Loss of Train A DC (LODCA) or Train B (LODCB)
- Loss of instrument air (INSTAIR)
- Loss of cooling water (LOCL)
- Loss of component cooling water (LOCC)
- Internal flooding (SH1, SH2, T1, T13, AB7, AB8)

Besides the safety functions described in Section 3.1.2.1, an additional heading is included in the structure of the transient event tree for determination of the potential for a consequential LOCA from the reactor coolant pump seals (event tree heading RCP). As noted in the discussion of the secondary heat removal function, the initial heat transfer rate in the steam generators is sufficient to preclude a demand on the pressurizer PORVs following a reactor trip. As a result, the principal contributor to a consequential LOCA would be loss of seal injection or loss of cooling to the reactor coolant pump thermal barrier heat exchanger. Success criteria for this heading is therefore associated with the operation of component cooling to the thermal barrier heat exchangers or operation of a charging pump supplying seal injection to the seals. Plant response to the failure of the seal cooling function is not modeled further in the transient event trees, but is transferred to the small LOCA event trees for further development.

The remaining headings on this event tree are the same as those described in Section 3.1.2.1.

Loss of Offsite Power (LOOP) - Because of the pervasive effect of offsite and onsite AC power on frontline and support systems, the LOOP event tree models are developed as separate event trees. The LOOP event tree models in the IPE again are structured around the safety functions described earlier but also include headings to accurately reflect the Prairie Island offsite and onsite AC power design. The resulting LOOP event trees for the Prairie Island IPE are shown in Figures 3.1-2 (loss of offsite power with successful EDG operation), and 3.1-3 (Station Blackout).

The loss of offsite power event tree structure differs from the transient event trees only in the addition of a heading to determine the status of onsite emergency AC power (event tree heading EDG). The Prairie Island onsite emergency AC power system includes four safeguards diesel generators, with two diesel generators per unit. In the event of an SBO condition, each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of the essential loads of the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. The emergency AC power heading in the loss of offsite power event tree therefore includes an operator action to manually close the bus tie breakers to attempt to restore power to the blacked out unit.

Once the status of onsite emergency AC power sources is determined, the evaluation of loss of offsite power events continues by considering the status of a consequential LOCA from seal cooling failure, secondary heat removal, short and long term RCS inventory control if necessary, and containment control, the same headings included in the transient event tree.

<u>Station Blackout</u>

The failure of the emergency AC power event tree heading EDG, transfers to an event tree associated with station blackout conditions. The secondary cooling heading in the SBO event tree considers only the operation of the turbine driven auxiliary feedwater pump (heading AFT), as there is no AC power to operate the motor driven pumps. A heading also exists in this event tree for operator action to cooldown the RCS with steam generator PORVs, lowering the temperature and pressure in the reactor coolant system (heading OA7). This operator action is intended to prolong the integrity of the reactor coolant pump seals, increase the time available to recover AC power should an extended blackout occur and inject the accumulators.

Two headings also exist for recovery of an AC power source (headings 2HR and XHR). The times associated with these recoveries depend on the success or failure of secondary cooling. If the turbine driven auxiliary feedwater pump were to be unsuccessful in makeup to the steam generator, a relatively short time is assumed to be available for AC power restoration (approximately 2 hours for heading 2HR, see section 7.1) before core damage is expected to occur. This time, is that over which the steam generators would boil down and reactor coolant system inventory depletion through the pressurizer PORVs or safety valves would occur. It is assumed it will take the operator 30 minutes to restore systems to normal status after restoration of an AC power source. AC power recovery for the 2HR heading is the probability of failure to recover either offsite power or a single diesel generator within two hours after the occurrence of the SBO. On successful operation of the turbine driven auxiliary feedwater pump, the time available to recover AC power is based on the capacity of the batteries and whether or not the operator cooldown of the RCS (event tree heading OA7) was successful or not. Event tree heading OA7 models the local operation of a SG PORV by an operator to cooldown and depressurize the RCS to inject the accumulators.

There are two trains of DC power associated with each Prairie Island unit. The battery banks in each of the trains of DC are conservatively assumed to have a capacity of approximately 2 hours at design basis loads. The two hour capacity is the capacity of the shortest lived battery; all of the other batteries have capacities greater than two hours. For the purpose of quantifying the station blackout event tree, 4 hours is assumed to be available to recover an AC power source to avoid core damage if event tree heading OA7 has failed (heading XHR) based on MAAP results (see section 7.1). This time is based on the two hours in which batteries are available to power SG level instrumentation which is assumed to be necessary to operate the turbine auxiliary feedwater pump plus at least an additional two hours to boil off the inventory in the steam generators and deplete the water in the reactor coolant system. XHR in this case, represents the failure to restore either offsite power or a diesel generator conditional on failure to recover offsite or onsite power at two hours. With successful operation of the turbine driven auxiliary feedwater pump and success of heading OA7, 5 hours are assumed to be available to recover an AC power source to prevent core damage according to MAAP analysis (see section 7.1). This additional hour is a result of the successful operator induced RCS cooldown which results in less RCP seal leakage and injects the contents of the accumulators into the RCS.

Successful recovery of an AC power source within two hours (if the turbine driven AFW pump were unavailable), four, or five hours (with turbine driven AFW pump operation) allows a means of preventing core damage by makeup with an SI pump together with opening one of two pressurizer PORVs to utilize bleed and feed cooling (heading STI). It is assumed that the RCS pressure at the time of AC power restoration will be above the shutoff head of the SI pumps, thereby requiring bleed and feed to inject into the RCS. The operator action to perform bleed and feed is the same as was used for the transient bleed and feed. If inventory loss associated with an RCP seal failure during blackout conditions was not sufficiently great to cause core uncovery during the blackout then bleed and feed is a viable option to increase RCS inventory. If the RCS inventory loss due to RCP seal leakage is significant, the CNU heading of the blackout event tree estimates the potential for a significant seal LOCA causing core uncovery during the time in which blackout conditions have existed.

Efforts may be successful following the blackout to restore either offsite power or one or more diesels. It should be noted however, that quantification of the SBO event tree headings following AC power recovery conservatively assume only one train of emergency power is returned to service.

Following restoration of AC power, conditions associated with the need for bleed and feed operation are considered, e.g., steam generators are assumed to be dry. Operation of a pressurizer PORV and eventual alignment to high head recirculation is therefore included in the short term and long term inventory control headings following AC power recovery. It should be recognized that bleed and feed operation or recirculation may not be necessary if feedwater or auxiliary feedwater are restored to service sufficiently early following AC power restoration and if any RCP seal leakage that may be occurring is small.

Loss of Coolant Accidents (LOCAs) - The LOCA event trees used in the Prairie Island IPE are shown in Figures 3.1-4 through 3.1-6. Once again, they principally consist of the safety function headings described in Section 3.1.2.1. The small LOCA differs from the transient event tree in that SI is assumed to be required even on success of secondary cooling as a result of the primary system inventory loss. Also, the potential for terminating the event before recirculation is considered by operator initiated RCS cooldown and depressurization to utilize RHR shutdown cooling before RWST depletion (heading CD). For medium and large LOCAs, the reactor will eventually depressurize on its own and low pressure injection systems become available without the need to consider secondary cooling. No ISLOCA event tree was built because these events are assumed to directly cause core damage.

Steam Generator Tube Rupture - The steam generator tube rupture event tree is shown in Figure 3.1-7. This event tree is structured differently than a small LOCA because reactor inventory loss is into a steam generator as opposed to containment. Long term inventory control by recirculation is not considered in the event tree, as a result. Instead, operator actions to isolate the ruptured steam generator to minimize the release of radioactivity and establish a pressure differential between the ruptured and intact steam generator in order to cool the RCS and stop primary to secondary leakage are included in event tree heading B. The ruptured steam generator is assumed to be isolated by MSIV closure and termination of feedwater to the ruptured generator. To prevent overfill and lifting of the ruptured steam generator relief valves, an operator action is modeled whereby the RCS is cooled by relieving steam through the intact SG generator PORVs and depressurized through use of pressurizer PORVs or auxiliary spray (heading CD). Approximately one hour is available for the operator to accomplish these actions before ruptured SG overfill occurs according to MAAP analysis. Should ruptured SG overfill occur, relief valves are assumed to actuate to maintain the ruptured steam generator pressure as SI injection pressure is greater than the SG relief actuation pressures. As they have not been demonstrated to reclose following relief of water, one or more steam generator relief valves are assumed to fail open following ruptured SG overfill (heading ISG) with a probability of 1.0. Depressurization of the ruptured steam generator then occurs, increasing the differential pressure from the RCS to the ruptured SG generator, continuing the RCS inventory loss.

Further cooldown and depressurization of the RCS down to RHR SDC temperature and pressure limits using the intact SG following ruptured SG overfill ultimately allows initiation of RHR shutdown cooling, terminating further inventory loss from the RCS and successfully providing long term inventory control and heat removal (heading EC3). Approximately six hours are available to the operator to successfully terminate the event in this manner before RWST depletion occurs according to MAAP analysis.

Should safety injection fail during a steam generator tube rupture, it is still possible to prevent core damage by isolating the ruptured steam generator, and cooling and depressurizing the RCS to reach RHR shutdown cooling operating conditions before RWST depletion occurs. Since SI makeup is unavailable, the ruptured steam generator fills more slowly allowing the operator approximately two hours to accomplish this action.

Should secondary cooling become unavailable, the operators would initiate bleed and feed cooling according to the EOPs for loss of heat sink. This operation was conservatively not credited in the Prairie Island IPE as a SGTR followed by failure of secondary cooling was a low probability event.

Main Steam (Feedwater) Line Break - This event is initiated by a rapid cooldown of the primary system as a result of steam flow from a break in the secondary side of the plant. For this event tree, only breaks upstream of the MSIV were considered, with breaks downstream of the MSIV not being considered. The functions required for adequate core cooling are the same as those for transient initiators except for some differences which result from the large initial cooldown. The main steam/feedwater line break event tree is presented in Figure 3.1-8.

A heading is included early in the event tree for isolation of the faulted steam generator and maintaining RCS pressure control with the intact steam generator (heading B). Successfully controlling RCS pressure in this manner allows the event to proceed similar to a transient initiated event, with the difference that only one steam generator is available for decay heat removal as feedwater has been isolated to the faulted SG.

If the faulted SG cannot be isolated, reheating of the primary system will occur after blowdown is complete. Because additional inventory will have been injected into the RCS from SI during initial depressurization, expansion of the water in the primary system will result in relief from the pressurizer PORV's or safeties. Failure of the PORV's or the safety valves to close is considered as a part of the consequential LOCA heading under these conditions (heading RCP). The need for SI and long term injection with recirculation is modeled, even after successful makeup to the steam generators for these sequences.

Anticipated Transient Without SCRAM - The ATWS event tree differs from the transient and LOCA event trees as it is directed at the plant accommodating a failure of the reactivity control function as opposed to heat sink or inventory control. The ATWS event tree is provided in Figure 3.1-9. The Prairie Island event tree for ATWS focuses on providing early RCS pressure control and long term reactivity shutdown, given a failure to trip the reactor and insert control rods.

For transients and small LOCA initiated from power levels less than 40% (heading PL), the peak pressure attained in the primary system is not predicted to exceed allowable stress levels of reactor coolant system components provided heat removal is available with the steam generators (WCAP-11993, Assessment of Compliance With ATWS Rule Basis for Westinghouse PWRs). This heat removal can be accomplished with auxiliary feedwater alone. Eventual long term shutdown of the reactor is achieved by local operator actions to trip the reactor trip breakers, trip the turbine and by boric acid addition through the charging system (heading OA5).

For events greater than 40% power, reactor pressure can be controlled provided at least one main feedwater pump is available to supply feedwater at rates sufficient to remove heat from the steam generators associated with the power level in the reactor (heading MFA). Again, long term reactivity shutdown is provided as described above for heading OA5. Should main feedwater not be available, early trip of the turbine and initiation of auxiliary feedwater initiation is provided by AMSAC.

Prevention of reactor overpressure depends on auxiliary feedwater flow rate to the steam generators, the moderator temperature coefficient and the pressurizer pressure relief capacity. Favorable negative reactivity feedback conditions exist over the majority of the cycle. Only during the early portion of the cycle is the moderator temperature coefficient positive or not sufficiently negative to limit peak pressure in the primary system with auxiliary feedwater available. The fraction of time that reactivity feedback is insufficient to limit peak pressure in the reactor in conjunction with the availability of pressurizer relief valve capacity is quantified as a part of the primary pressure relief heading of the event tree (heading PR). Event tree heading PR is dependent on the number of auxiliary feedwater pumps that are providing makeup to the steam generators (headings AF2 and AF) and whether manual rod insertion was successful within the first minute following the need for reactor trip (heading OA4). For heading AF2, both auxiliary feedwater pumps are available, while for heading AF, only a single AFW pump is available. The amount of AFW pumps available directly affects the amount of unfavorable exposure time, with less AFW flow, more pressurizer pressure relief is required. Manual rod insertion by an operator after an ATWS has occurred, reduces the amount of negative reactivity feedback necessary to mitigate an ATWS event.

3.1.2.3 Assumptions

Assumptions about plant behavior for event tree development follow:

1. The event trees were based on plant design, operational practices, and procedures. Prairie Island plant specific emergency operating procedures are based on the Westinghouse Owners Group Emergency Procedure Guidelines and were used to evaluate operator actions expected during transient and accident events.

2. The plant evaluation and model quantification did not take credit for nonproceduralized operator actions.

3. The Prairie Island plant is conservatively assumed to be operating at 100% power at the beginning of all transients considered in this evaluation, unless otherwise noted in the event tree headings.

4. A mission time of 24 hours was used for time dependent component failure rates. Six hour mission times were used for the EDGs as after 6 hours the probability of offsite power recovery is approximately 0.9. Time frames for recovery were considered assuming that system failures occurred at T=0, maximizing decay heat rates in determining available recovery time.

5. The end state of any sequence in the Level I event trees was either a safe stable condition with the core cooled and the containment intact - designated "success" on the event tree diagrams, or a damaged core is reached. Sequences leading to core damage are designated with one of the accident class identifiers defined in Section 3.1.5.

6. The effects of spatially dependent external events such as fires, seismic events, tornados, etc. are not included in the Prairie Island IPE models, but internal flooding was evaluated.

7. Repair and recovery actions were not included in fault tree models but were considered on a sequence by sequence basis depending upon the sequence significance in relation to the overall CDF.

8. The time available to recover main feedwater, crosstie the auxiliary feedwater pump from the second unit, or start bleed and feed is based on

the time available until steam generator dryout plus 15 minutes has occurred. After this time, it is assumed that secondary cooling or bleed and feed have failed. Typical time to dryout for transient events with no secondary makeup is approximately 40 minutes based on MAAP analysis (see section 7.1).

9. Core uncovery and core damage were assumed to occur when core exit thermocouple temperatures exceed 1200°F for 30 minutes or whenever they reached 2000°F. Timing associated with this condition was based on MAAP analysis of sequences in the various accident classes. Typical time frames for this condition range from 2 hours for transients following loss of secondary cooling to 30 minutes for the large LOCA without RHR injection.

10. The time at which it is necessary for the operator to initiate recirculation is based on the rate of depletion of the RWST for the various accident classes (see section 7.1). For transients with bleed and feed, small LOCAs and SGTR events, depletion of the RWST principally depends on the flow from the SI system as the CS pumps may not actuate. For this reason, six to eight hours are available prior to RWST depletion for these events. For these events, excluding SGTR, if a fan coil unit is in operation, containment pressure does not rise to the point that containment spray will be initiated (23 psig), limiting the rate of RWST depletion. For medium and large LOCAs, RHR injection will occur in addition to SI injection. Further, containment spray operation is expected as a result of the initial pressure rise following the pipe break. The time at which it is necessary to switch to recirculation for these events is assumed to be approximately 30 minutes based on MAAP analysis.

11. Decay heat removal from containment is included in two event tree headings: LTI and Containment. Long term injection to the RCS is assumed to require heat removal through the RHR heat exchangers to the CC system in order to maintain RHR pump operation for reasons such as falling below required NPSH during recirculation. Containment heat removal is assumed to require operation of fan coils unit or containment spray. This function prevents long term overpressurization of containment. As RHR heat exchangers effectively remove decay heat in the long term recirculation mode, and as they are also required for containment spray in the recirculation mode, successful RHR recirculation for the LTI heading effectively assures the success of the containment control heading.

12. Quantification of the loss of offsite power event trees (with successful operation of one diesel generator) does not credit the repair of a diesel or restoration of offsite power for the 24 hour mission time of the event.

These recovery events may reduce the failure rate for secondary cooling, short term and long term RCS injection.

13. Quantification of AC power recovery in the SBO event tree includes the potential for repair of a diesel generator or restoration of offsite power during the interval available to prevent core damage. However, quantification of headings following the recovery of AC power assume only one emergency AC power train has been restored.

14. The success criteria for the instrument air system assumes two of three air compressors are required. Partial operation of the system (one compressor) may provide adequate pressure or extend the period for recovery of the system beyond that assumed in the analysis. Furthermore, some air operated equipment is provided with accumulators (such as the pressure PORVs). While these accumulators will eventually depressurize, temporary operation of this equipment may be possible but is not credited.

15. Loss of a DC train initiator affects the pneumatic supply to the pressurizer PORVs in bleed and feed operation. Quantification of this initiator effectively assumed the PORVs are lost instantly at the time of the initiating event. In fact, a potentially significant amount of time may be available for bleed and feed operation with the air remaining in the accumulator to the operable PORV, allowing time for recovery not credited in the analysis.

16. Cooling to feedwater, condensate, instrument air and component cooling is assumed to be lost at the time of the initiator. For some accident sequences, partial operation of the system (i.e., one pump instead of the two assumed to be required) may provide at least partial cooling to the systems supported by cooling water. Further, loss of systems supported by component cooling is not instantaneous in the event of complete cooling water system failure. Heatup of the inventory in component cooling and attached systems provide time for recovery not credited in the analysis.

17. The interfacing LOCA evaluation used the following assumptions:

    a. On exposure of low pressure piping to reactor pressure, it is recognized that the ultimate rupture strength of the piping is many times design. While leaking through the interfacing system may occur, there was only limited potential for gross rupture of the piping. A conditional pipe rupture probability of 4E-3 was used on exposure of low pressure piping to full RCS pressure as calculated from NUREG/CR-5102.

b. RHR Cold leg injection, RHR low head SI to the reactor vessel and RHR suction from the hot legs are considered as the most likely sources of Interfacing LOCA. Core damage is assumed on the rupture of any of these piping systems outside containment.

c. No credit is given for the operator to locally isolate the ISLOCA pathway due to the harsh environment that will be encountered.

d. It is assumed that the low pressure piping will break in the CS pump room which is assumed to fail the CS, SI and RHR pumps causing core damage due to loss of short term RCS inventory.

e. It is assumed that if the low pressure RHR piping does not instantaneously rupture, the RHR pump seals will fail when exposed to RCS pressure causing loss of both RHR pumps. Operator action to isolate the RHR pumps is not credited as the isolation valves are located in the RHR pit. Operator action to cooldown and depressurize the RCS to minimize the flow out the RHR pump seals and preserve RWST inventory is credited.

3.1.3 Success Criteria for Frontline Systems

Table 3.1-2 summarizes key frontline system success criteria for a representative group of accident initiators. The safety functions presented in this table are those associated with the general categories Secondary Heat Removal, RCS Inventory, and Containment Heat Removal. Additional headings are discussed that do not fall under the above listed categories such as emergency diesel generator and RCS cooldown success criteria.

The frontline system success criteria shown in Table 3.1-2 were derived from plant specific Prairie Island analysis of system response to transient and LOCA initiating events. The basis for the success criteria was a combination of realistic calculations using MAAP, USAR and operations manual descriptions. A summary of transient analyses performed for the Level 1 portion of the Prairie Island PRA is provided in Section 7.1.

Each of the safety functions were successfully accomplished when any of their corresponding frontline systems successfully operated. Successful operation of these systems was defined in terms of the physical alignment of specific portions of the system. While successful operation of coolant injection systems has been defined previously as providing enough water to the reactor core to prevent core exit thermocouple temperature from exceeding 1200°F for 30 minutes or 2000°F at any time, the minimum flow rate requirements which meet this criteria can be expressed as the flow provided by a certain pump or a number of pumps from a given system.

The basis for using the core exit thermocouple temperatures greater than 1200°F for 30 minutes as an indication for core damage comes from studies that were documented in NUREG-1228 "Source Term Estimation During Incident Response to Severe Nuclear Power Plant Accidents". The studies found that at a core temperature up to 1400°F, there are no changes in the structural integrity of the fuel rods in the core. At core temperatures between 1400° and 2000°F, the zirconium cladding begins to lose some of its structural integrity and some ballooning of the cladding and bowing of the fuel rods may occur. At temperatures greater than 2000°F, zirconium undergoes an exothermic reaction with steam in the RCS forming zirconium oxide which results in widespread cracks in the fuel cladding. For these reasons, Prairie Island chose 1200°F as the core will always be in a coolable geometry and there is no point just beyond 1200°F where fuel conditions change dramatically. Also, when 1200°F is read by the core exit thermocouples, the temperatures being read are steam temperatures which could vary 200 to 300°F depending on the accident initiator. MAAP analysis indicates that if the hottest core temperature remains less than 2000°F and does not exceed 1600°F for longer than 30 minutes, less than 1% of the total fuel rods will experience a temperature in excess of 1200°F. The second core damage criteria of 2000°F core exit thermocouples at any time, is discussed above and is the point at which zirc-water reactions begin to occur.

The criteria for operational success of each frontline system may vary with the type of initiator that results in the need for frontline system operation. For example, the RCS inventory makeup requirements to prevent core uncovery for a small break in the RPV pressure boundary are less than for larger breaks. Also, if a system serves more than one function, it's success criteria may be different for each function.

The frontline system success criteria for ATWS sequences are summarized in Table 3.1-3.

3.1.4 Support System Modeling

Fault tree linking was used to account explicitly for support system interdependencies in the IPE. Fault trees for all support systems were developed. The support system fault trees were then linked to the frontline and other support systems where required. The frontline systems were then combined with other frontline systems as dictated by the event trees using HPSETS. No specific support states were developed for the Prairie Island IPE. However, the fault trees were quantified retaining results of the solution to support system top events. This produced insights in the ways support systems interact with frontline systems and each other.

3.1.5 Accident Sequence Classification

This section discusses the method used to group core damage sequences into categories based upon characteristics of the accident sequences. These core damage sequence categories are called accident classes and serve as input to the Level 2 evaluation.

The potential types and frequencies of accident sequences at a nuclear power plant cover a broad spectrum. In order to limit these sequences to a manageable number, sequences with similar characteristics (e.g., similar initiating events, primary system conditions, and timing) were grouped together. Table 3.1-4 provides the definitions of the accident classes used in the Prairie Island IPE to classify Level 1 results.

Grouping of similar core damage sequences into classes was performed based upon the following criteria:

- Integrity of the containment
- Initiator type
- Relative timing of the core melt with respect to the initiator
- Primary system pressure.

The distribution of sequences among these classes provides insights as to the functional failures which may dominate the risk leading to a core damage event.

In summary, the event tree sequence end states are either a safe shutdown condition or one in which core damage has occurred. As noted, a wide spectrum of possible core damage states exists. The core damage sequences are categorized into accident classes to provide a discrete representation of this spectrum. The core damage classes provide the entry conditions to the containment event trees and source term evaluation. They also establish the boundary conditions for quantifying the radionuclide releases.

Table 3.1-1
Initiating Events

CATEGORY	INITIATING EVENT	DESIGNATOR	FREQUENCY (PER RX. YEAR)	SOURCE[2]
ANTICIPATED TRANSIENTS	RX TRIP (OTHER THAN BELOW)	TR1	1.68	Plant Data
	SG HI-HI LVL	TR2	9.00E-2	Plant Data
	INADVERTENT SI-SIGNAL	TR3	2.30E-1	Plant Data
	LOSS OF FEEDWATER	TR4	9.00E-2	Plant Data
SPECIAL TRANSIENTS	LOSS OF COOLING WATER	LOCL	1.82E-5	Fault Tree
	LOSS OF COMP. COOLING WATER	LOCC	3.46E-3	Fault Tree
	LOSS OF TRAIN A DC POWER	LODCA	8.69E-3	Fault Tree
	LOSS OF TRAIN B DC POWER	LODCB	8.69E-3	Fault Tree
	LOSS OF INSTRUMENT AIR	INSTAIR	1.17E-2	Fault Tree
LOSS OF OFFSITE POWER	LOSS OF OFFSITE POWER	LOOP	6.50E-2	NUREG-1032, NUMARC-8700
UNANTICIPATED TRANSIENTS	MAIN FEEDWATER LINE BREAK	MFLB	2.50E-5	WASH-1400
	MAIN STEAM LINE BREAK	MSLB	3.90E-4	WASH-1400
INTERNAL FLOODING	AUX. BLDG. ZONE 7 (695' EL)	AB7FLD	5.05E-3	EPRI TR-102266
	AUX. BLDG. ZONE 8 (ABOVE 695')	AB8FLD	1.34E-4	EPRI TR-102266
	TB. BLDG. ZONE 1 (AFWP RM)	T1FLD	1.04E-5	EPRI TR-102266
	TB. BLDG. ZONE 13 (RELAY RM)	T13FLD	2.68E-5	EPRI TR-102266
	SCRNHSE ZONE 1 (SG CL AREA)	SH1FLD	6.09E-6	EPRI TR-102266
	SCRNHSE ZONE 2 (NON-SG AREA)	SH2FLD	2.54E-3	EPRI TR-102266
LOCA's	SMALL LOCA	SLOCA	3.00E-3	PWR IPEM Methodology
	MEDIUM LOCA	MLOCA	8.00E-4	PWR IPEM Methodology
	LARGE LOCA	LLOCA	3.00E-4	PWR IPEM Methodology
LOCA's OUTSIDE CONTAINMENT	INTERSYSTEM LOCA	ISLOCA	2.27E-7	Fault Tree, NUREG-5102
	STEAM GENERATOR TUBE RUPTURE	SGTR	1.50E-2	Plant Data
FAILURE TO TRIP (ATWS)	RX TRIP (OTHER THAN BELOW)	ATWS-TR1	2.52E-5[1]	
	SG HI-HI LEVEL	ATWS-TR2	1.35E-6[1]	
	INADVERTENT SI SIGNAL	ATWS-TR3	3.45E-6[1]	
	LOSS OF FEEDWATER	ATWS-TR4	1.35E-6[1]	
	LOSS OF COOLING WATER	ATWS-LOCL	2.73E-10[1]	
	LOSS OF COMP. COOLING WATER	ATWS-LOCC	5.19E-8[1]	
	LOSS OF TRAIN A DC POWER	ATWS-LODCA	1.30E-7[1]	
	LOSS OF TRAIN B DC POWER	ATWS-LODCB	1.30E-7[1]	
	LOSS OF INSTRUMENT AIR	ATWS-INSTAIR	1.76E-7[1]	
	LOSS OF OFFSITE POWER	ATWS-LOOP	9.75E-7[1]	
	MAIN FEEDWATER LINE BREAK	ATWS-MFLB	3.75E-10[1]	
	MAIN STEAM LINE BREAK	ATWS-MSLB	5.89E-9[1]	
	INT. FLD. AB ZONE 7 (695' EL)	ATWS-AB7	7.58E-8[1]	
	INT. FLD. AB ZONE 8 (ABOVE 695)	ATWS-AB8	2.01E-9[1]	
	INT. FLD. TB ZONE 1 (AFWP RM)	ATWS-TB1	2.55E-10[1]	
	INT. FLD. TB ZONE 13 (RLY RM)	ATWS-T13	4.02E-10[1]	
	INT. FLD. SH ZONE 1 (SG AREA)	ATWS-SH1	9.14E-11[1]	
	INT. FLD. SH ZONE 2 (NON-SG)	ATWS-SH2	3.81E-8[1]	
	SMALL LOCA	ATWS-SLOCA	4.50E-8[1]	
	MEDIUM LOCA	ATWS-MLOCA	1.20E-8[1]	
	STEAM GENERATOR TUBE RUPTURE	ATWS-SGTR	4.50E-7[1]	

Initiating Events Notes:

[1] All frequencies are multiplied by the failure to trip demand rate (1.5E-5/d) to determine ATWS frequency.

[2] Sources: "Plant Data" indicates plant-specific operating experience data. "Fault Tree" indicates that a plant-specific fault tree was constructed and quantified for this system to determine the initiating event frequency. Reference to an NRC or industry document indicates that a plant-specific analysis was performed to determine the initiating event frequency using the methodology provided in that document.

Table 3.1-2
Level 1 Frontline System Success Criteria for Anticipated Transients

Initiating Event	Secondary Cooling	RCP Seal LOCA	RCS Inventory		EDG Operation	RCS Cooldown and Depress.	Containment Heat Removal
			Short Term	Long Term			
Large LOCA	N/A	N/A	1 RHR pump supplied from RWST	1 RHR pump on recirc. with operable RHR HX	N/A	N/A	2 FCU or 1 CS pump on recirc
Medium LOCA	N/A	N/A	1 SI pump or 1 RHR pump supplied from RWST	1 SI pump or 1 RHR pump on recirc. with operable RHR HX	N/A	N/A	2 FCU or 1 CS pump on recirc.
Small LOCA	1 AFW pump or 1 MFW pump supplying 1 SG	N/A	1 SI pump supplied from RWST	1 SI pump on recirc. with operable RHR HX	N/A	2 charging pumps and one pzr PORV or aux. spray and one SG PORV and 1 train of RHR SDC	2 FCU or 1 CS pump on recirc.
Transient	1 AFW pump or 1 MFW pump supplying 1 SG	1 charging pump supplying seal injection or 1 CC pump supplying CC to thermal barriers	1 SI pump supplied from the RWST and 1 pzr PORV	1 SI pump on recirc. with operable RHR HX	N/A	N/A	2 FCU or 1 CS pump on recirc.
LOOP	1 AFW pump supplying 1 SG	1 charging pump supplying seal injection or 1 CC pump supplying CC to thermal barriers	1 SI pump supplied from the RWST and 1 pzr PORV	1 SI pump on recirc. with operable RHR HX	D1, D2 or operator action to cross-tie to unit 2 DGs and D5 or D6 success	N/A	2 FCU or 1 CS pump on recirc.
SBO	Turbine driven AFW pump supplying 1 SG	N/A	1 SI pump supplied from the RWST and 1 pzr PORV	1 SI pump on recirc. with operable RHR HX	restoration of onsite or offsite power within 2, 4 or 5 hrs after SBO	Operator locally opens 1 SG PORV	2 FCU or 1 CS pump on recirc.
SGTR	1 AFW pump or 1 MFW pump supplying 1 SG	N/A	1 SI pump supplied from the RWST	N/A	N/A	2 charging pumps and one pzr PORV or aux. spray and one SG PORV and 1 train of RHR SDC	N/A

Table 3.1-2 (continued)
Frontline System Success Criteria for Anticipated Transients

Initiating Event	Secondary Cooling	RCP Seal LOCA	RCS Inventory		EDG Operation	RCS Cooldown and Depress.	Containment Heat Removal
			Short Term	Long Term			
Main steam/feedwater line break	1 AFW pump or 1 MFW pump supplying 1 SG	1 charging pump supplying seal injection or 1 CC pump supplying CC to thermal barriers	1 SI pump supplied from the RWST and 1 pzr PORV	1 SI pump on recirc. with operable RHR HX	N/A	N/A	2 FCU or 1 CS pump on recirc.

Table 3.1-3
Level 1 Success Criteria for Transient Initiators With Failure to Trip (ATWS)

ATWS power level	MFW	OA4	Full AFW	Partial AFW	RCS Pressure Relief Capacity	OA5	Containment Heat Removal
< 40%	N/A	N/A	N/A	1 AFW pump supplying 1 SG	N/A	Operator performs normal or emergency RCS boration	2 FCU or 1 CS pump on recirc
> 40%	1 MFW pump supplying 1 SG	operator manually inserts control rods for 1 min. following ATWS	2 AFW pumps supplying 1 SG (cross-tie to unit 2 not credited)	1 AFW pump supplying 1 SG	1 pzr PORV and 2 PZR safety relief valves	Operator performs normal or emergency RCS boration	2 FCU or 1 CS pump on recirc.

Table 3.1-4

Level 1 Accident Class Definition for Prairie Island IPE

ACCIDENT CLASS[1]	DESCRIPTION
TEH (NUMARC IA)[2]	Transient initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor pressure is high at the time of core damage.
TLH (NUMARC IB)	Transient initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.
BEH	Station blackout in which core damage occurs prior to recovery of AC power or bleed and feed fails upon recovery of AC power. Reactor pressure is high at the time of core damage.
SEH (NUMARC IIIA)	LOCA initiated events in which high head safety injection is not capable of preventing core damage. Reactor pressure is high at the time of core damage.
SLH (NUMARC IIIB)	LOCA initiated events in which high head safety injection is successful but high head recirculation is not. Reactor pressure is high at the time of core damage.
SEL (NUMARC IIIC)	LOCA initiated events in which high head and low head safety injection do not prevent core damage. Reactor pressure is low at the time of core damage.
SLL (NUMARC IIID)	LOCA initiated events in which safety injection was effective but high and low head recirculation is not. Reactor pressure is low at the time of core damage.
FEH	Internal flood initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor pressure is high at the time of core damage.
FLH	Internal flood initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.
REP (NUMARC IV)	ATWS events in which reactor vessel overpressure occurs.
RLO (NUMARC IV)	ATWS events in which long term negative reactivity insertion is not successful.
GLH (NUMARC VA)	Steam Generator Tube rupture sequences leading to core damage as a result of failure to depressurize the RCS before RWST depletion. Reactor pressure is high at the time of core damage.
GEH	Steam generator tube rupture sequences with failure of high head injection or failure of secondary heat removal. Reactor pressure is high at the time of core damage.
V (NUMARC VB)	Interfacing LOCA sequences between the reactor and low pressure piping systems in the auxiliary building.

(1) Key

1st Character (Initiator)	2nd Character (Timing)	3rd Character (Reactor Conditions)
T - Transient B - Station Blackout S - LOCA G - Steam Generator Tube Rupture V - Interfacing LOCA R - ATWS F - Internal Flooding	E - Early (prior to recirculation) L - Late (after recirculation)	H - High pressure (above shutoff of low pressure pumps) L - Low pressure

(2) NUMARC Accident Class designator from NUMARC Severe Accident Issue Closure Guidelines.

Figure 3.1-1
Anticipated Transients Event Tree

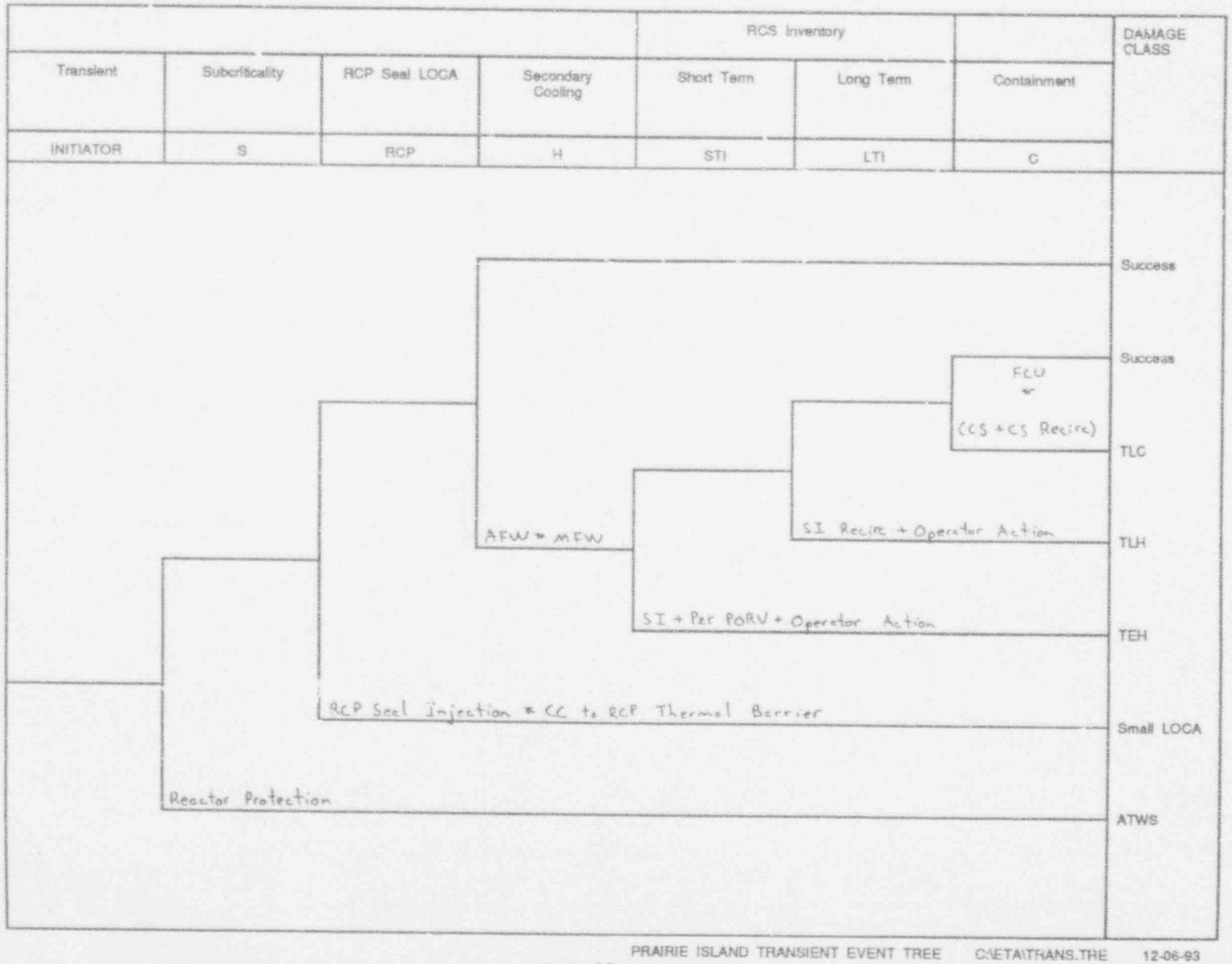


Figure 3.1-2
LOOP Event Tree

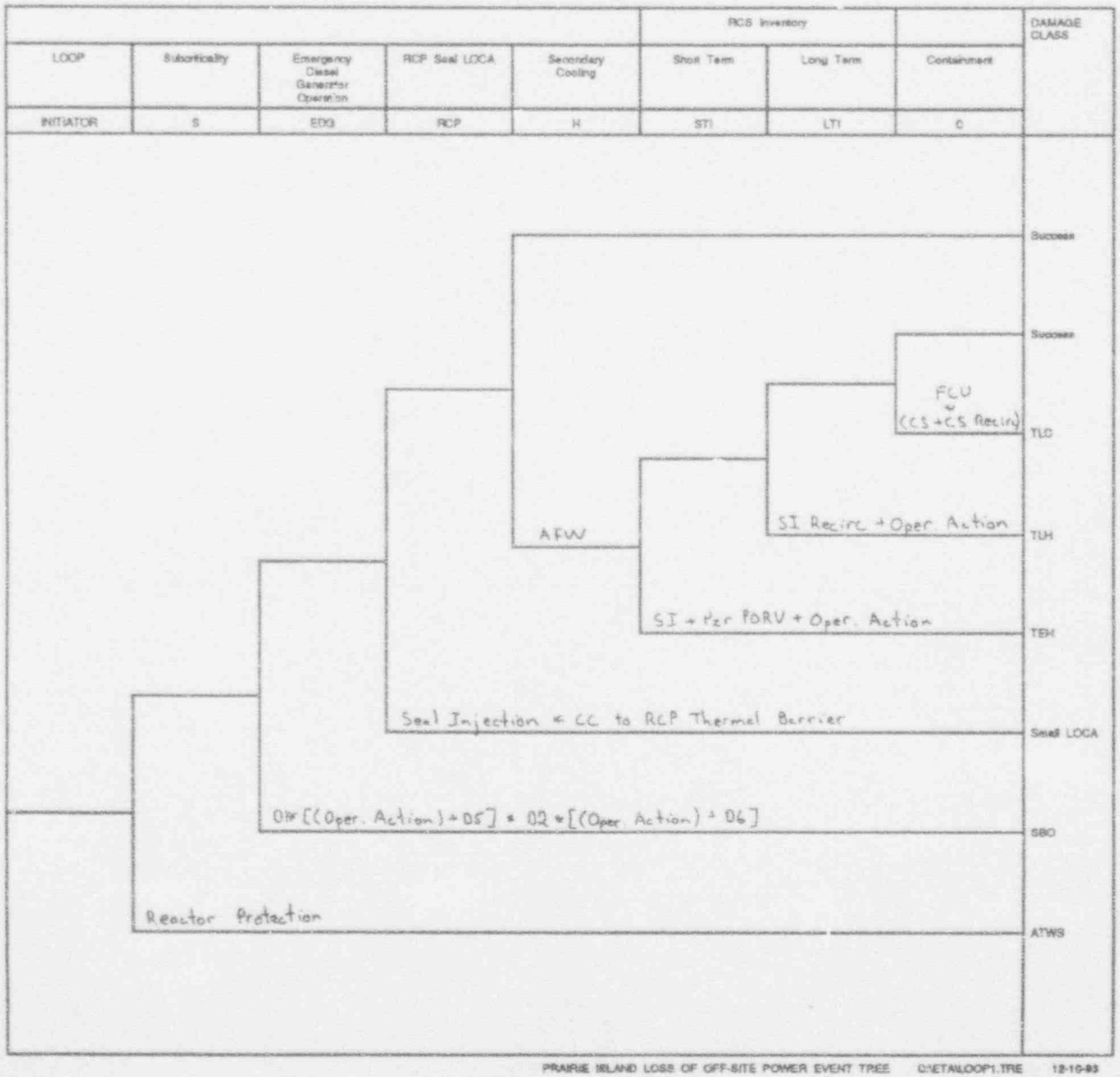


Figure 3.1-3
SBO Event Tree

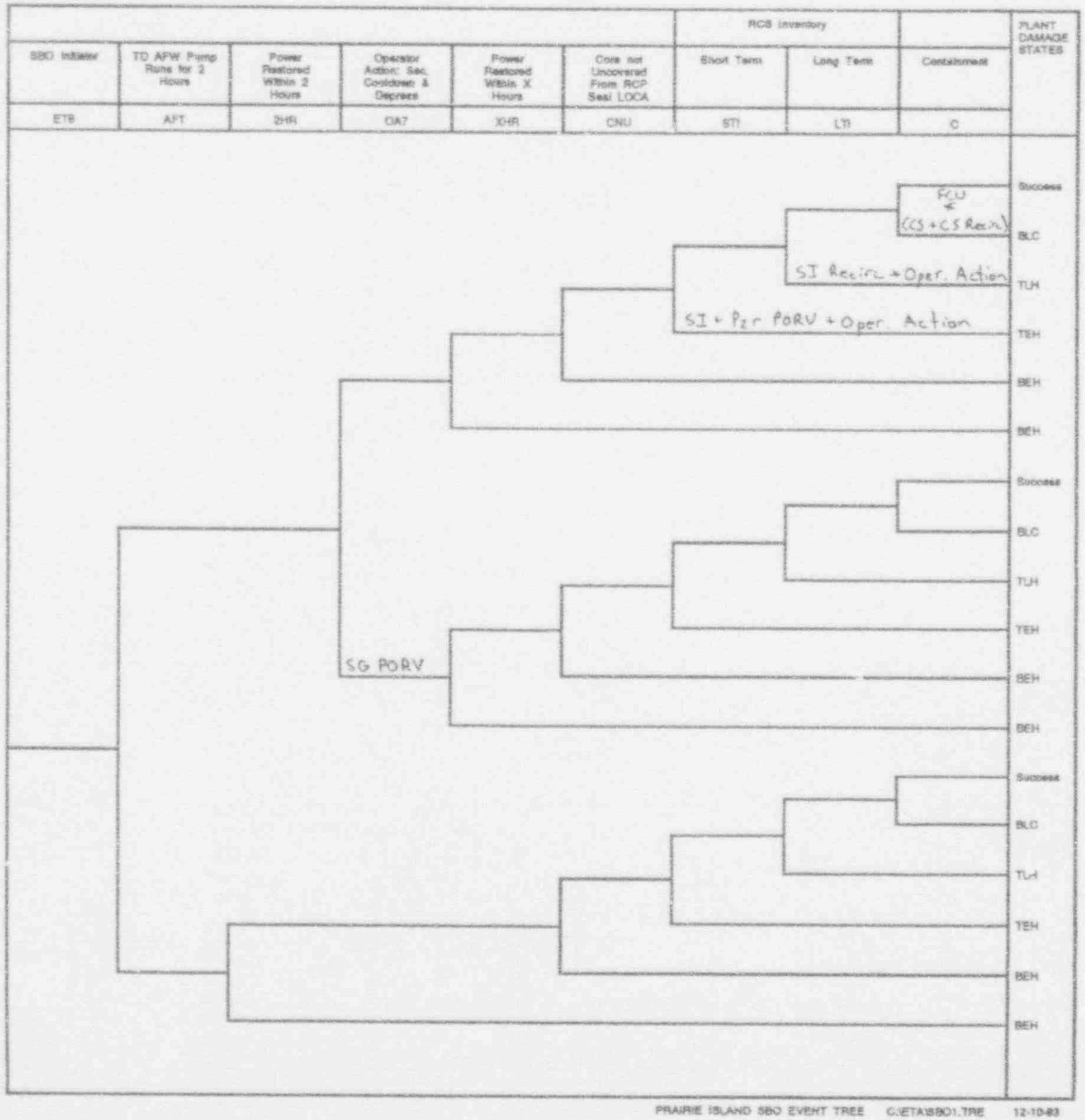


Figure 3.1-4
Small LOCA Event Tree

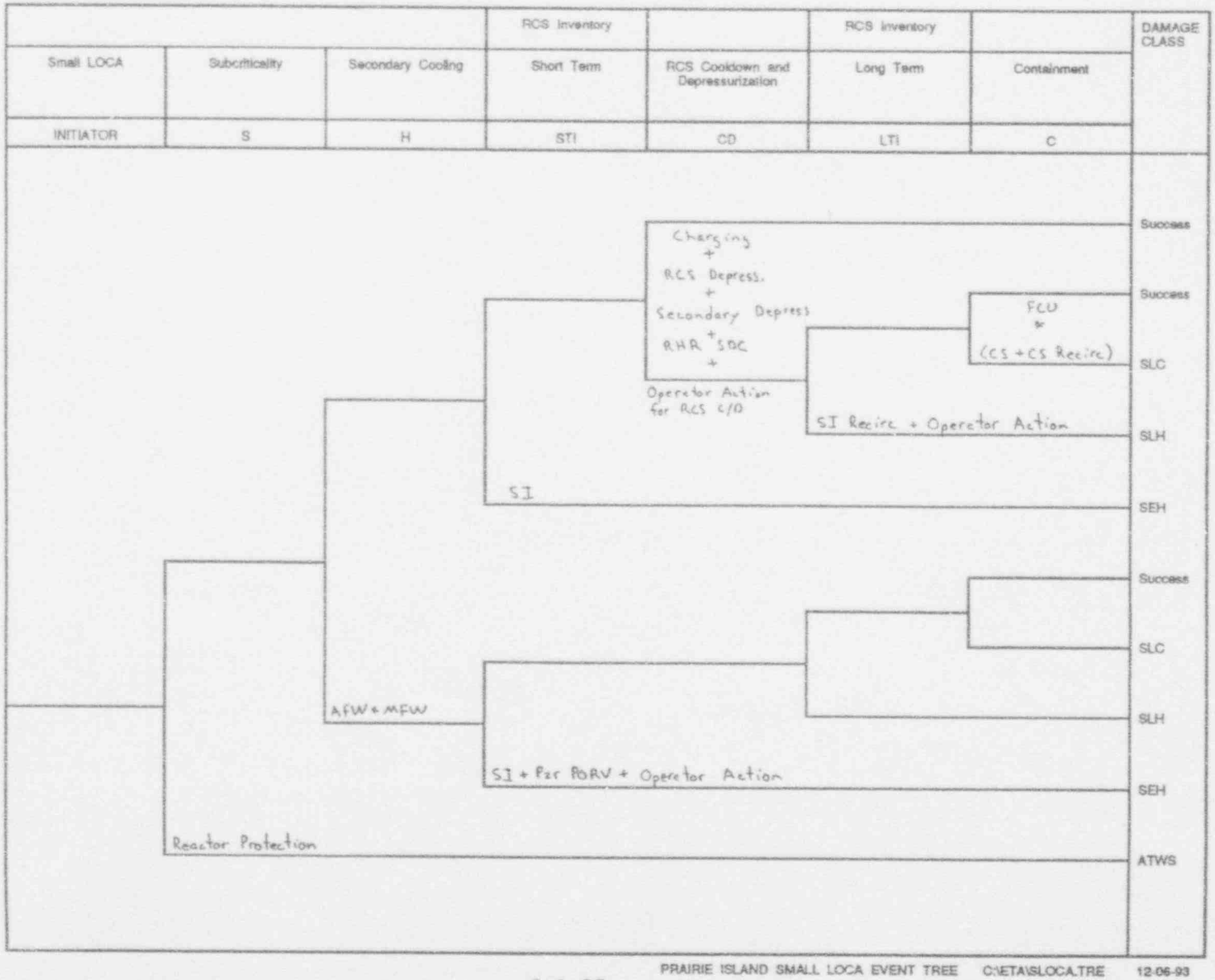
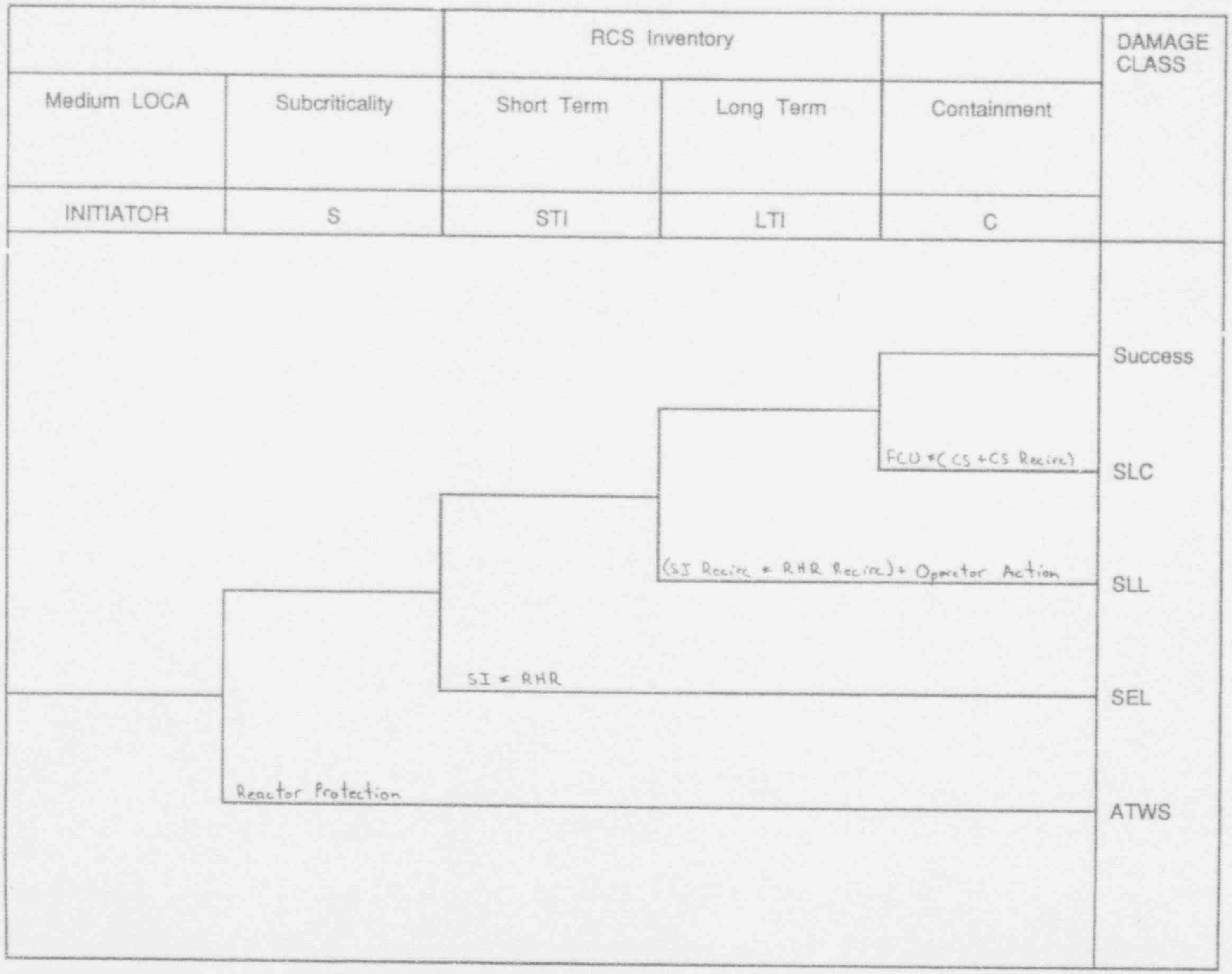
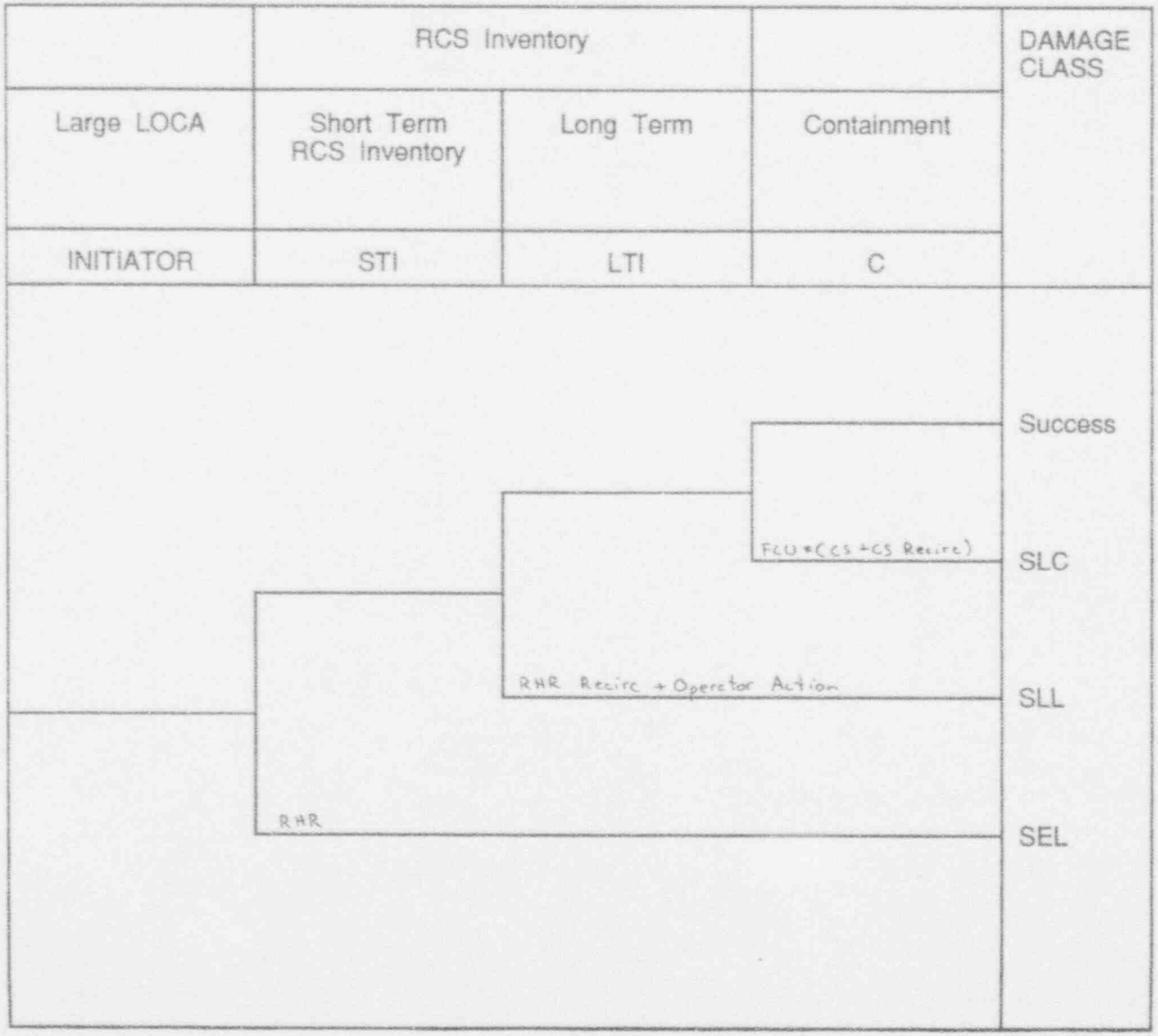


Figure 3.1-5
Medium LOCA Event Tree



PRAIRIE ISLAND MEDIUM LOCA EVENT TREE C:\ETA\MLOCA.TRE 12-06-93

Figure 3.1-6
Large LOCA Event Tree



PRAIRIE ISLAND LARGE LOCA EVENT TREE C:\ETA\LLOCA.TRE 12-06-93

Figure 3.1-7
SGTR Event Tree

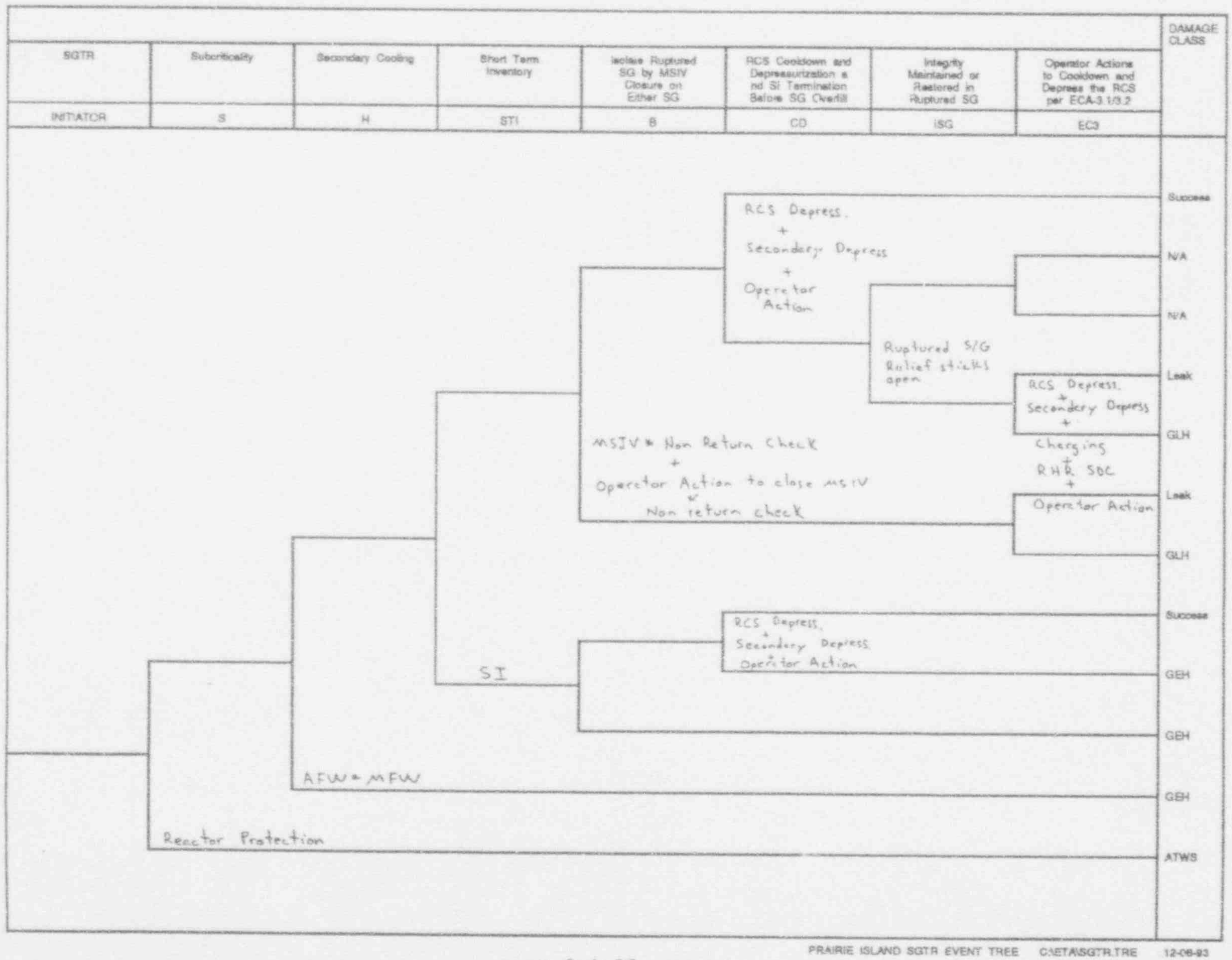


Figure 3.1-8
Main Steam/Feedwater Line Break Event Tree

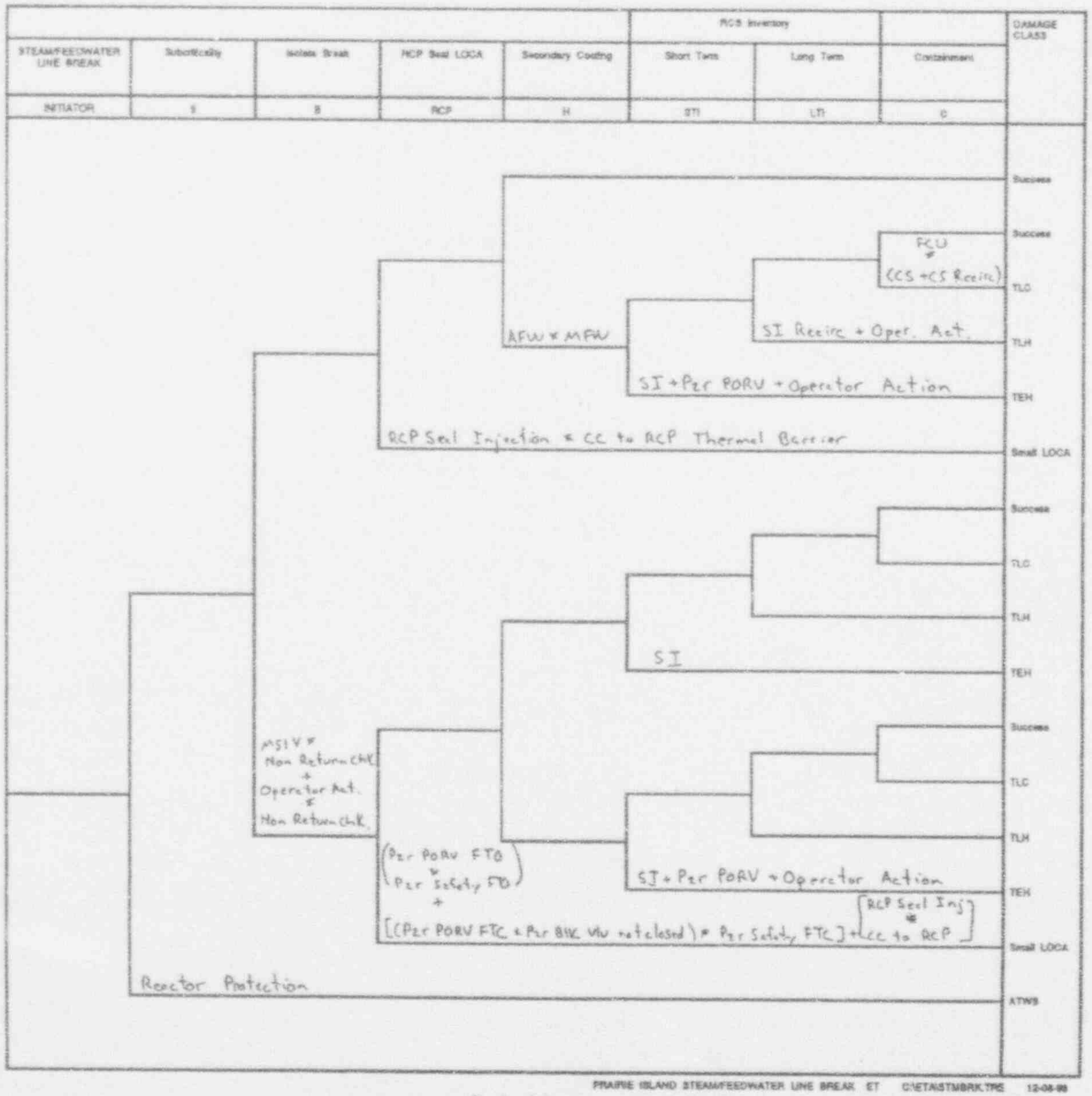
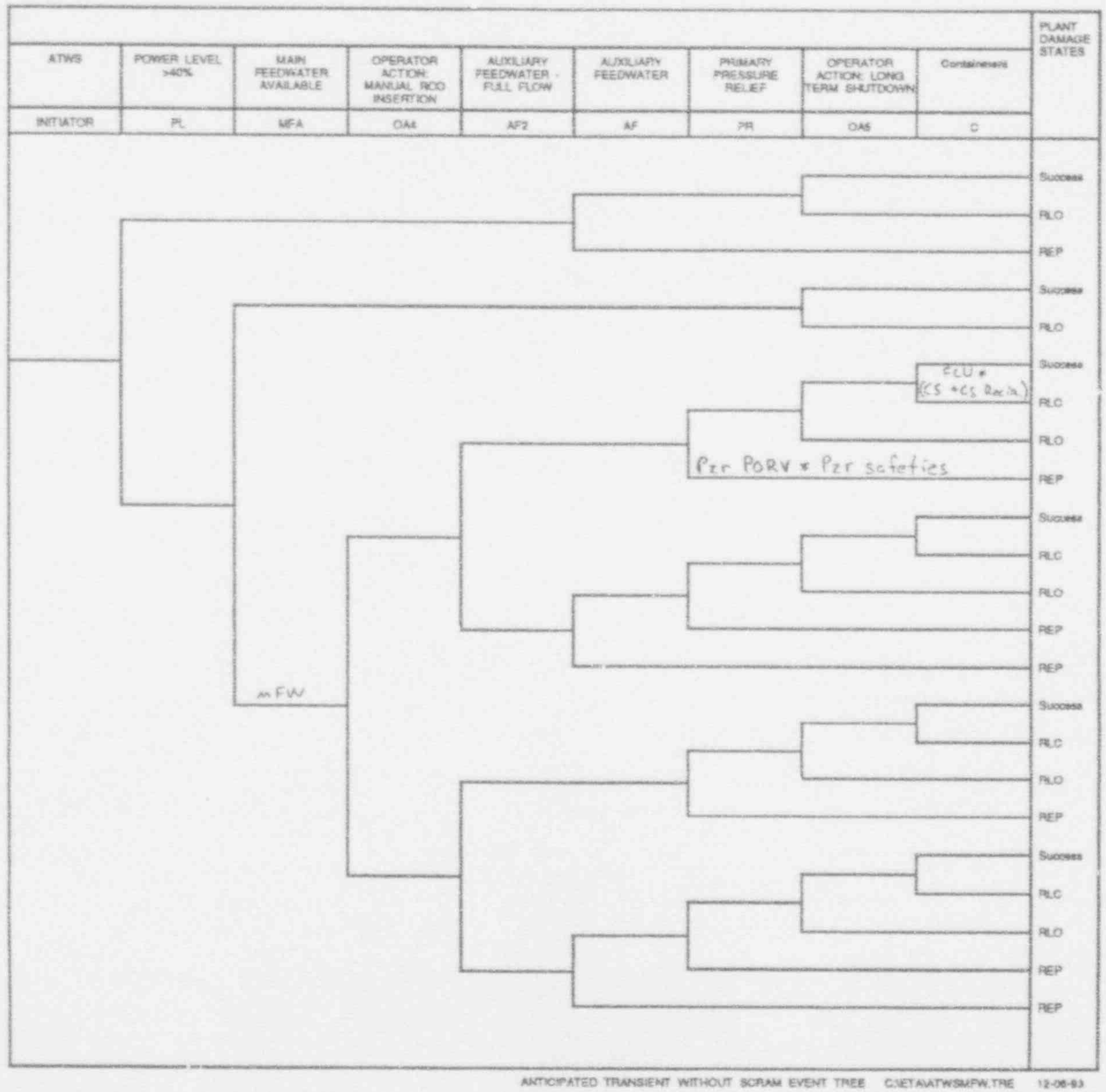


Figure 3.1-9
ATWS Event Tree



3.2 System Analysis

3.2.1 System Descriptions

This section provides a brief description of frontline and support systems considered in the IPE. The dependencies of one system on another are shown in the dependencies matrices found in Section 3.2.3.

3.2.1.1 Reactor Protection System (RPS)

Instrumentation associated with the reactor protection system (RPS) monitors key plant parameters to determine whether the plant processes are within the bounds of important operating parameters associated with normal operation. A simplified drawing of the system is shown in Figures 3.2-1 and 3.2-2.

The RPS is designed to prevent, in conjunction with the primary containment, containment isolation, and ECCS systems, the release of radioactive materials in excess of the guidelines of 10CFR100, and to prevent fuel damage as a consequence of single operator error or single equipment failure. When specified limits have been exceeded, the RPS initiates a reactor trip.

When an off-normal condition is sensed, the RPS logic sends a trip signal to the reactor trip breakers which open, causing the control rods to drop into the core, shutting down the plant and annunciating the off-normal condition in the control room. The RPS is arranged as two separately powered trip systems. The trip system has trip logic which produces an automatic reactor trip signal in a 2 out of 3 or 2 out of 4 configuration.

3.2.1.2 ATWS Mitigation System Actuation Circuitry (AMSAC)

AMSAC is a means of control rod insertion which is triggered by separate and diverse logic from the RPS. Its purpose is to provide a redundant mechanism for reactor trip in the unlikely event a common mode failure in the RPS were to fail to initiate AFW or cause a turbine trip in addition to prohibiting a reactor trip. AMSAC is initiated if the initial power level is greater than 40% and low feedwater flow is sensed, after a time delay. AMSAC initiation causes a turbine trip and AFW actuation.

3.2.1.3 Chemical and Volume Control System (CVCS)

There are 3 functions of the CVCS system that were considered in the IPE. These functions are normal RCS makeup, RCP seal injection, and auxiliary spray for the pressurizer. Figure 3.2-3 is a line diagram of the CVCS.

The CVCS System consists of 3 variable speed positive displacement pumps that take a suction from the Volume Control Tank (VCT) or the RWST as a backup. The normal line up is to have the pump discharge flow split with most flow going through the Regenerative Heat Exchanger to the RCS to provide the makeup needed to balance the Letdown flow. The rest of the discharge flow passes through the Seal Injection Filters and then to the RCP seals to provide cooling and lubrication. When necessary the flow through the regenerative heat exchanger can be diverted to the pressurizer spray nozzle to provide RCS pressure control.

Return flow from the RCS to the Volume Control Tank is from the Letdown System. This flow is through the Regenerative Heat exchanger, the Letdown Heat Exchanger and then into the VCT. Any makeup water needed for the VCT comes via the Blender from the Reactor Makeup Water, the BAST, or both.

The success criteria for the seal injection function of the CVCS system is for one pump to be taking a suction from either the VCT or RWST and supplying flow via one seal injection filter to the RCP seals. A return path is also necessary through either the seal return heat exchanger to the VCT or through the seal return relief valve. For the auxiliary spray function, the success criteria is for one pump to be supplying flow to the pressurizer spray nozzle.

3.2.1.4 Safety Injection (SI)

The primary function of the Safety Injection (SI) system is to remove stored energy and fission product decay heat from the reactor core following a loss of primary or secondary coolant. The SI system is modeled for 2 modes of operation. These modes are high head injection and high head recirculation. A drawing of the SI System is included as Figure 3.2-4.

The SI system consists of two independent trains. Each train consists of a pump with associated suction and discharge valves. The pumps are motor driven centrifugal pumps which have a capacity of 700 gpm at 1300 psig and a shutoff head of approximately 2170 psig. The trains initially take suction from the highly concentrated boric acid storage (BAST) tanks, then automatically switch to the Refueling Water Storage Tank (RWST) when the BAST reach low level. As the RWST empties, the suctions of the SI pumps can be manually transferred to containment sump B via the RHR pump discharge. During this recirculation phase, the water spilled onto the containment floor from a LOCA is the source of water for sump B. The Residual Heat Removal (RHR) pumps take a suction from sump B, cool the water through the associated RHR heat exchanger then supply the water to the suction of their associated SI pump.

Each SI pump train is normally aligned to discharge to the RCS cold legs. Either pump can discharge to either cold leg through normally open cross over line at the discharge of each pump. The pumps can also be manually aligned to discharge into the reactor vessel through the low head SI injection lines.

The success criteria for the injection phase is one train of SI taking suction from the RWST supplying sufficient flow to one of two RCS cold legs. In the recirculation phase of operation, the success criteria is one train of SI being supplied from sump B through the associated RHR pump and heat exchanger and discharging to one of two RCS cold legs. The heat exchanger must be supplied with CC cooling.

3.2.1.5 Residual Heat Removal (RHR)

The Residual Heat Removal (RHR) system is modeled in 3 modes of operation. These modes are low head injection, low head recirculation, and shutdown cooling. Also the RHR system is used to provide suction for the SI and CS systems when they are in a recirculation mode. Figure 3.2-5 is a line drawing of the RHR system.

The RHR system is divided into two trains. Each train contains one pump and one heat exchanger. Each RHR pump has a rated capacity of approximately 2000 gpm at 120 psig and a shutoff head of 140 psig. For the injection mode, the RHR pumps take an initial suction from the RWST and discharge the water through their associated heat exchanger into the RCS via the reactor vessel injection nozzles. The two pumps have a common suction line from the RWST and each loop has a dedicated injection path to the reactor vessel. The suction source for the RHR system is the RWST when in the injection mode and from containment Sump B in the recirculation mode when the RWST is depleted and the spilled RCS coolant is on the containment floor.

The shutdown cooling mode of the RHR system is used to provide decay heat removal for SLOCA events and SGTR events. In this mode the RHR pumps take a suction on the RCS hot legs and discharge through the associated heat exchanger back into the RCS at the loop B cold leg. The RHR heat exchangers are cooled by the Component Cooling System.

The success criteria for the initial injection phase of the RHR system is one train of pumps taking suction from the RWST and discharging into its associated reactor vessel injection nozzle. In the recirculation mode, the success criteria is one RHR train taking suction from containment sump B through the associated heat exchanger and discharging the cooled water into the associated reactor vessel injection nozzle. The success criteria for the shutdown cooling mode of the RHR system is for one train to take a suction from the RCS hot legs, transfer heat to the CC system in the associated heat exchangers and return the water to the RCS through the loop B cold leg.

3.2.1.6 Auxiliary Feedwater (AFW) System

The normal function of the auxiliary feedwater system is to supply steam generator makeup for normal transients such as heatup and cooldown when the water demands are low or main feedwater is not available. The system also provides high pressure makeup to the steam generators under emergency conditions to assure a reactor coolant system heat sink is always available. A simplified flow diagram of the Auxiliary Feedwater System is shown in Figure 3.2-6.

The auxiliary feedwater system consists of two independent full capacity parallel trains. Each train consists of a pump and its associated piping and valves each capable of discharging approximately 220 gpm at 1300 psig. Normally, each pump supplies water to both steam generators but can be isolated from either steam generator if desired. One train is equipped with a motor driven pump while the other is equipped with a steam turbine driven pump. The steam supply for the turbine pump can be extracted from either steam generator. The motor driven pump discharge can be cross tied to the opposite unit's motor driven pump discharge to provide additional redundancy in abnormal emergency conditions.

Both pumps can take suction from either the condensate storage tanks or the cooling water system. The pumps are normally lined up to take suction from the condensate storage tanks. Each of the three tanks contains approximately 150,000 gallons of demineralized water. In the event the condensate tanks are unavailable, the pumps can be lined up to take suction from the unlimited supply of cooling water from the Mississippi River.

The success criteria for adequate auxiliary feedwater flow is one of the two pump trains for each unit taking suction from the condensate storage tanks or from cooling water and supplying design capacity flow to either one of the two steam generators.

3.2.1.7 Main Feedwater (MFW) and Condensate

The MFW system is used to supply makeup water to the steam generators during transients, SLOCA, or SGTR events when the AFW system is unavailable. A simplified one line drawing of the MFW system and the condensate system are shown in Figure 3.2-7a and 3.2-7b.

The Condensate System consists of three 50% capacity motor driven pumps which take a suction from the bottom of the condenser hotwell. Normally two pumps are running discharging to a common header which directs flow through the air ejector condenser and the gland steam condenser. Flow leaving the gland steam condenser is divided into two parallel trains, each consisting of a drain cooler and three low pressure heaters. Downstream of #3 heater the headers are combined and then split again at the inlet to the #4 heater. The flow combines at the outlet of the #4 heater and flows to the suction of the main feedwater pumps.

The main feedwater system consists of two 60% capacity motor driven pumps that take a suction from the condensate pump discharge header and discharge to a common header which directs the feedwater flow, to the high pressure feedwater heaters. The common header splits into two trains at the inlet of the #5 high pressure heater. The outlets of the two #5 heaters combine into a common header which again divides into two parallel headers which direct the feedwater flow to the steam generators (SG). Each SG header contains a flow meter, a main feedwater regulating valve, a bypass valve, and an isolation valve.

The main feedwater header is isolated by a feedwater isolation signal that closes the feedwater regulating valve and it's bypass valve. Main feedwater is isolated on the following signals:

- Hi Hi steam generator level
- Reactor trip and low RCS average temperature
- Safety Injection (SI) signal

3.2.1.8 Pressurizer PORV

There are two pressurizer PORV trains per unit. These valves when open allow flow from the top of the Pressurizer to the Pressurizer Pressure Relief Tank. Each train consists of a motor operated block valve and an air operated relief valve. The block valve is used to isolate a PORV that is leaking excessively or will not close. Each PORV is an air operated fail closed valve. The incoming air supply line to each PORV is equipped with an air accumulator and a check valve to allow approximately 15 valve openings should instrument air be lost. The PORVs receive an open signal when 2/2 associated pressurizer pressure channels exceed 2335 psig and close if either channel falls below 2335 psig. The PORVs can also be opened manually from the Control Room as is done during Feed and Bleed operation.

3.2.1.9 Containment Fan Coil Units (FCU)

The normal function of the Fan Coil Units is to maintain containment temperature and humidity within a reasonable range for equipment purposes and human habitability. The system also provides for containment pressure suppression by condensing steam following a LOCA or containment steam line break.

The fan coil units consist of four condensing units designed into two independent trains. Each train consists of two condensing units, two circulating fans and the associated ductwork and dampers. One fan coil unit in each train is normally operated in fast speed and moves approximately 61,500 SCFM of air to the reactor vessel gap area. The other fan coil in the train is normally running in slow speed discharging to the containment dome. During warm weather, the cooling medium to the coils is normally a non-safety related chilled water system, with cooling water being used during cool weather. In this configuration, two of the fans discharge in fast speed (61,500 SCFM of air) to the reactor vessel area while the other two discharge to the containment dome in slow speed (29,000 SCFM of air).

In emergency operations, each fan switches to slow speed and circulates approximately 29,000 SCFM of air. In addition, the cooling medium switches to the safety related cooling water system and the ductwork dampers switch to discharge to the containment dome. In this configuration, each fan coil unit can remove one half of the maximum postulated containment heat input. This system in conjunction with the two containment spray trains is capable of removing over twice the predicted accident heat input.

The success criteria for adequate containment air handling is two of the four fan coil units operating in slow fan speed, the cooling medium is switched to the cooling water system and the discharge dampers are aligned to the containment dome. A simplified flow diagram of the containment fan coil system is shown in Figure 3.2-8 and the cooling medium system is shown in Figure 3.2-9.

3.2.1.10 Containment Spray System (CS)

The containment spray system is normally on standby for actuation during emergency conditions. The function of the containment spray system during accident conditions is to supply a pressure suppressing spray to the containment dome following a LOCA or containment steamline break. The pumps are started by the "P" signal which is generated either manually or by containment pressure at 23 psig.

The containment spray system consists of two independent parallel trains. Each train consists of a motor driven pump, associated piping and valves and a spray header ring. The pumps take suction from both the borated refueling water storage tank and a caustic addition standpipe. Each pump is capable of discharging a borated caustic flow of 1300 gpm at 220 psig to an independent spray header located on the containment ceiling.

The success criteria for operation of the containment spray system is one spray pump taking suction from the refueling water storage tank and discharging at design capacity to the associated containment spray header. A simplified flow diagram of the containment spray system is shown in Figure 3.2-10.

3.2.1.11 Cooling Water (CL)

The primary functions of the Cooling Water (CL) system is to provide an adequate cooling water supply for plant equipment loads, to provide a cooling water supply to all the safeguards equipment during normal and emergency operating conditions and to provide an alternate feedwater supply to the steam generators.

The CL system is a safeguards system consisting of five pumps feeding a ring header shared by both units. The header can be automatically or manually separated into two redundant supply headers, A and B. The normal water supply for the CL system is from the circulating water (CW) pump bays in the screenhouse. Two horizontal motor driven CL pumps take a suction on the CW bays and discharge to a common header. Three vertical pumps, one motor driven and two diesel driven take a suction on an emergency bay and also discharge to the common CL header.

The cooling water supplied to all safeguards and non-safeguards equipment from supply header A is discharged through the Unit 1 CL return header to the Unit 1 CW return header. The cooling water supplied to all safeguards and non-safeguards equipment from supply header P is discharged through the Unit 2 CL return header to the Unit 2 CW return header.

The success criteria for the CL system varies depending on the initiating event. For transient initiating events, two pumps are required to meet the transient needs of one unit in hot shutdown and the 100% power needs of the unaffected unit. For the case of a LOOP (two unit LOOP assumed) a single CL pump is required while for a LOCA, a single pump is required assuming that at least one of the CL header isolation valves closes.

A simplified diagram of the Cooling Water System is shown in Figure 3.2-11.

3.2.1.12 Component Cooling Water (CC)

The Component Cooling (CC) Water system provides an intermediate cooling system between the heat exchangers in potentially radioactive systems and the Cooling Water System.

The CC system is a safeguards system consisting of two parallel loops each of which consists of a pump, heat exchanger and associated piping and instrumentation. Both loops are served by a single surge tank which accommodates the thermal expansion and contraction within the system.

The two loops are capable of being cross-connected at the suction and discharge of the pumps. Either loop also has the capability of being cross-connected with either loop in the opposite unit. CC water from either unit can be supplied to components shared by the two units.

The success criteria for the CC system is one pump and one heat exchanger per unit with a supply of cooling water to the heat exchanger. A simplified diagram of the Component Cooling Water System is shown in Figure 3.2-12.

3.2.1.13 Instrument Air

The Instrument Air system provides dry compressed air to various plant instruments and control. The system also provides compressed air to operate various control valves. A simplified drawing of the system is shown in figure 3.2-13.

The instrument air system consists of 3 motor driven compressors that draw air from the atmosphere around them and discharge into an air receiver. The 3 air receivers outlets are cross connected together and feed 2 air dryers. The air dryers are normally aligned such that one dryer feeds unit 1 air header and the other dryer supplies the unit 2 air header. The output of the air dryers can be cross connected to allow either dryer to supply both units.

The air supply to the containment has 2 air operated containment isolation valves arranged in series. These valves are air operated valves that are normally open and fail closed on a loss of air. They automatically close on a containment isolation signal in conjunction with a main steam isolation signal.

The success criteria for the Instrument Air system is for two of the three compressors to be running and supplying compressed air through the air dryers to each unit's instrument air header.

3.2.1.14 Onsite AC Power

The onsite AC power system supplies electric power at the required voltage to the electric loads within the plant. The system is divided into safeguards and non-safeguards portions. Each unit has two 4160V safeguards buses. Each of these buses supplies all of the electric power to one train of safeguards equipment. In the event of a LOOP the safeguards buses are powered by backup emergency diesel generators.

Each safeguards bus has it's own diesel generator. D1 and D2 power Unit 1 buses 15 and 16 respectively and D5 and D6 power Unit 2 buses 25 and 26 respectively. A manual cross-tie capability is available to supply power to a 4160V bus from the opposite unit's train-related diesel generator if all power supplies are lost to that bus.

The normal function of the safeguards diesel generators is to provide a standby source of AC power to the four 4160V safeguards buses on loss of all offsite AC power supplies. During normal operations, the diesel generators are on standby. Upon receiving a start signal, the diesels will load onto a safeguard bus after all other offsite sources are unsuccessfully attempted. In the event of an SBO condition, each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as the essential loads of the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. Adequate fuel oil is stored onsite to support one diesel generator in conjunction with one diesel cooling water pump for a minimum of 14 days.

The unit 1 diesel generators are different than the unit 2 diesels. They have different support system requirements such as the unit 2 diesels do not require cooling water for engine cooling. The success criteria for the diesels is a successful start and run for six hours by at least one of the dedicated diesel generators per unit, or successful start and run of at least one diesel in the opposite unit and successful manual cross-tie to its train-related 4160 V bus in the unit affected by the LOOP.

The 480V safeguards electrical system is supplied by the 4160V safeguards buses via a stepdown transformer. Unit 1 has two 480V safeguards busses; one powered from each of the 4160V safeguards buses. Unit 2 has four 480V safeguards buses; two from each 4160V bus. Each of these buses is supplied by a separate breaker and transformer.

The nonsafeguards 4160V buses are supplied by the main generator output while the plant is at greater than 15% power. When the unit trips, there is a fast transfer of the buses to an off-site power supply.

A simplified drawing of the onsite AC power system is shown in figure 3.2-14.

3.2.1.15 DC Power

The purpose of this system is to supply an adequate DC power supply for vital loads such as instrumentation, reactor protection, fire protection, 4160 V switchgear and EDG control power. During emergency situations, the station batteries and the DC distribution system are designed to provide power to instruments and controls needed to place the plant in a safe shutdown condition following a loss of all AC power.

Each unit has two complete and separate 125V DC distribution systems. Each unit has two battery trains and associated power distribution equipment. The combined output of the battery and the battery charger is supplied to the main distribution panel through a fuse panel. Individual loads and smaller distribution panels are serviced from the main distribution panel. Non-safeguard equipment is supplied by either battery as appropriate to balance the DC loading on each battery.

The success criteria for the DC power system is one train of DC supplied to plant components for two hours through the batteries. A simplified diagram of the DC power system is shown in Figure 3.2-15 and 3.2-16.

3.2.1.16 120V Instrument AC Power

The Instrument AC system supplies a highly regulated single phase AC power to plant instrumentation. The system consists of 4 static inverters which supply 4 distribution panels which each supply power to a separate channel of instrumentation.

The static inverters normally are supplied with 480V AC power from the safeguards 480V buses. This power supply is backed up by the plant batteries. The inverters then provide an uninterruptable, regulated 120V AC power supply to their corresponding instrument distribution panel.

The distribution panels, also called instrument buses, have 2 supply breakers which are mechanically interlocked such that only one can be shut at a time. The power supplies are either the associated inverter or panel 117 (217 for unit 2) which is an unregulated 120V source.

A simplified drawing showing the 120V AC system with it's 480V AC and DC power supplies is found in figure 3.2-17.

3.2.1.17 SI Signal

The safety injection signal ("S" signal) is sent when conditions indicative of a severe reactor accident exist. The purpose of the signal is to prevent core damage and/or mitigate the effects of the accident. The safety injection signal is initiated when any of the following conditions exist:

- Pressurizer pressure less than 1815 psig
- Containment pressure greater than 4 psig
- Main steamline pressure in either steam line less than 500 psig

- Manual actuation

The safety injection signal initiates many functions throughout the plant. Some of the more important functions are:

- Reactor trip signal
- Start signal to all ECCS pumps and various motor driven valves open or close signals to align ECCS for injection
- Start signal to both Emergency Diesel Generators
- FCUs shifted to slow speed and aligned to discharge to the containment dome
- FCUs cooling medium aligned to Cooling Water
- Condensate pumps and Main Feedwater pumps tripped and feedwater isolation signal generated
- Start signal to the Auxiliary Feedwater pumps
- Cooling water headers split and diesel cooling water pumps receive a start signal

3.2.1.18 Safeguards Chilled Water

The safeguards chilled water system consists of two independent trains. Each train is a closed loop chilled water system that consists of a centrifugal chiller, chilled water pump, and associated pipes, valves, and unit coolers.

Each train of chilled water supplies room cooling to it's associated safeguards equipment including 4160V and 480V switchgear, the relay room and computer room, control room air handler, and the RHR pits.

Supply and return header cross connect valves allow either chilled water pump and chiller to supply both trains. The cross connect valves are automatically shut on an "S" signal to ensure system reliability.

The success criteria for the system is for one chiller and chilled water pump in a train to be running and supplying chilled water to the RHR pit unit coolers and to the 480V safeguards switchgear room coolers. Recent analysis has shown that room cooling is no longer a requirement for RHR operation, but the requirement for room cooling was conservatively left in the RHR model. A drawing of the safeguards chilled water system is found at figure 3.2-18.

3.2.1.19 SG PORV

Each steam generator has one PORV connected to the main steam line upstream of the MSIV. The PORV is an air operated globe valve which can be operated from the control room or from the hot shutdown panel.

The PORV relieves a SG overpressure condition to the atmosphere minimizing the cycles on the code safety valves. They are also used in the event of a MSLB downstream of the MSIV or to perform secondary cooldown. The PORV will fail closed on a loss of air or DC power to the air supply solenoids.

A drawing of the main steam system showing the PORVs is found at figure 3.2-19.

3.2.1.20 MSIV

Each main steam line has one MSIV located in the line to isolate the header when necessary. The MSIV is located in the Auxiliary Building near the piping penetration into containment.

The MSIV consists of two swing check valves welded together. The MSIV is capable of stopping steam flow in either direction against full differential pressure. The upstream valve opens against normal flow. It is opened and held open by two pneumatic cylinders that are supplied by the station air system. The downstream valve is opened by normal steam flow.

The MSIVs are both tripped by a Hi-Hi containment pressure signal at 17 psig. Each MSIV is tripped individually by a Hi-Hi steam flow signal with an "S" signal or a Hi steam flow signal with "S" signal and Lo-Lo RCS average temperature signal.

A drawing of the main steam system showing the MSIVs is found at figure 3.2-19.

3.2.1.21 Room Cooling

Room cooling is provided to various rooms in the plant to remove ambient heat generated by operating equipment. This is necessary to prevent failure of the equipment from overheating. Room cooling is provided by unit coolers located in the rooms.

The unit coolers consist of fans that blow room air over cooling coils which are supplied with safeguards chilled water with the cooled air being returned to the room.

3.2.2 Fault Tree Methodology

Fault trees were used to model plant systems as part of the PRA. They were used to produce system failure equations which were then linked into core damage sequence equations as dictated by the event tree logic. Fault trees developed for the Prairie Island IPE are listed in Table 3.2-1.

Prior to development of the system fault tree models, various information sources were reviewed and summarized in system notebooks which were the basis for the development of the fault trees.

Front-line systems were generally characterized as providing safety functions relating to accident mitigation such as reactor vessel injection or decay heat removal. Support systems provided necessary functions to ensure operability of front-line systems. Separate system fault trees were developed using EPRI's CAFTA fault tree manager which were later linked together using Logic Analyst's HPSETS. The frontline system fault trees were developed to allow the support system fault trees to be linked directly into the logic when quantification was performed. Human errors were included in the fault trees, where an operator action was necessary in order for a system to operate, such as the operator action to switchover to recirculation. Operator actions in response to equipment failures were not included in the fault trees, but were later included after sequence quantification as recovery factors.

A consideration in developing the fault tree models was the level of detail to include. One criterion for determining the level of detail was the available data concerning components. For example, it was not necessary to model a pump down to the bearings and its control circuit down to the contacts, if all failures of the pump and control circuit were encompassed by one failure mode of interest, such as, pump fails to start, and no further insights would be gained by more detailed modeling.

Data was used to determine what to model based on its relative contribution. Faults associated with passive components such as pipes and manual valves were eliminated from further consideration if, for example, the system had a pump with a particular failure mode of 1E-3 compared to much lower values for pipe rupture or for the manual valve failing to remain open. If the passive failure modes would not contribute significantly to the top event when compared to the system pump failure, passive failures could be excluded from the model.

Transfers were used to connect different sections of a fault tree, and to connect one fault tree to another. Transfers also served to duplicate logic that appeared in two or more places. Any time a front-line system component required a support system to function, a transfer to that support system was required.

Component faults or basic events were not defined below the level of detail that the component failure data was available. For example, plant records are typically maintained for motor-operated valves failing to open or close, but rates for each of the specific causes of their failures are difficult to derive. Therefore, motor-operated valve sub components were not modeled in detail. Each basic event was assigned a failure probability before an estimate of the system failure probability could be determined.

Table 3.2-2 is a summary of components and failure modes for basic events that were generally included in the PRA fault tree models. The support system requirements shown in Table 3.2-2 include those systems and components which are directly necessary to support front-line system operation. The timing required to render the component inoperable is an important consideration. Failure of a support requirement such as motive or control power typically results in immediate component failure. However, failure of support requirements such as lubrication or seal faults may still allow the component to operate for some period of time and accomplish its required function.

Support systems often serve more than one component. In order to properly account for these commonalities among otherwise redundant components or independent systems, it was necessary to explicitly model these support requirements.

An I & C investigation was performed as part of the fault tree development process. From a general review of the I & C circuits for various systems, the following three groups of I & C were considered to be potentially important and were modeled. They are listed in order of priority:

1. I & C that affected more than one system (e.g., SI Logic/Sensors, or bus undervoltage relay affecting various loads on the same bus).
2. I & C that affected an entire system (e.g., one relay or sensor affecting both trains of a system)
3. I & C that affected one train or loop of a system (e.g., two pumps affected by a single relay in one RHR loop).

To assess the quantitative impact of failure of redundant I&C components on the total failure probability for the system, common cause failure of instruments was considered. The approach followed for modeling and quantifying common cause events is discussed in Section 3.3.4.

3.2.3 Dependency Matrices

Dependency matrices are shown in Tables 3.2-3 through 3.2-5. Table 3.2-3 shows which initiating events have an influence on a frontline system. Table 3.2-4 shows which frontline systems have an influence on other frontline systems. Table 3.2-5 shows which support systems have an influence on frontline systems.

Table 3.2-1

PRAIRIE ISLAND FAULT TREE

Frontline Systems	Support Systems
Reactivity Control	Station Power
Chemical Volume and Control System	Emergency AC Power
	DC Power
Secondary Heat Removal	Cooling Water
Auxiliary Feedwater	Component Cooling Water
Main Feedwater/Condensate	Instrument Air
Steam Generator PORVs	SI Actuation Signal
	Instrument Power
Short Term Injection	CS Actuation Signal
Safety Injection	
Pressurizer PORVs	
Low Head Injection (RHR)	
Long Term Injection	
High Head Recirculation (SI/RHR)	
Low Head Recirculation (RHR)	
Containment Control	
Containment Spray	
Containment Spray Recirculation	
Fan Coil Units	
RCS Cooldown and Depressurization	
Charging	
RHR Shutdown Cooling	
Auxiliary Spray	

Table 3.2-2

COMPONENTS/FAILURE MODES/TRANSFERS INCLUDED IN THE PRA FAULT TREES

Component	Failure Mode	Support System Transfer
Pump*, Fan*, Air Compressor*	FTS FTR	Pump/Motor/Engine Cooling AC Bus DC Panel (May be required for breaker operation)
Diesel Generator	FTS FTR	Engine Cooling DC Panel HVAC
Motor Operated Valve*	FTO FTC FTRO** FTRC**	AC Bus DC Panel
Air Operated Valve (Includes Solenoid Valve)	FTO FTC FTRO** FTRC**	AC or DC Panel (for Solenoid Operation) Instrument Air/Nitrogen
Check Valve	FTO FTC FTRC**	
Manual Valve	FTRO** FTRC**	
Filter/Screen/ Basket Strainer/ Heat Exchanger	Plug	
Bus, Batter, Inverter, Charger, Transformer	FTE FTRE	AC Bus DC Panel

Instrumentation and Control components should be modeled based on the criteria in Section 3.2.2.

Notes:

FTS - Fails to Start
FTR - Fails to Run
FTO - Fails to Open
FTC - Fails to Close
FTRO - Fails to Remain Open
FTRC - Fails to Remain Closed
FTE - Fails to Energize
FTRE - Fails to Remain Energized

*Circuit breaker faults were included with these components, i.e., circuit breakers were not be explicitly modeled for these components.

**FTRO and FTRC failure modes would not be included if an associated demand failure existed for the valve, or if the operating status of the valve was identified by a surveillance test on a quarterly basis or more frequently.

NOTES to Table 3.2-5a & 3.2-53b

1. MFW pumps 11 and 12 are supplied from offsite power through buses 11 and 12, respectively.

2. Aux. lube oil pumps 11 and 12 for the MFW pumps are required for maintaining pump operation if the pumps have been tripped and need to be restarted.

3. MFW pumps 11 and 12 breakers control power are supplied from 125VDC panel 11. The pumps are required to re-started following an SI signal or SG Hi-Hi level.

4. The control power for the MFW regulating and bypass valve solenoids is from 125VDC panel 151. Loss of power to the solenoids results in closure of the reg. valves and disables MFW and Condensate makeup to the SGs.

5. Loss of instrument air leads to MFW reg. bypass valves failing to remain open and therefore, leads to MFW failure.

6. Failure of one train of cooling water will not affect the instrument air system since either train of cooling water can provide cooling to the three compressors. Since instrument air is not affected by failure of one cooling water train, the MFW reg. valves are not completely affected. However, failure of the entire cooling water system would eventually result in failure of instrument air which in turn results in failure of the MFW reg. valves to remain open and therefore, failure of the MFW system.

7. 4KV emergency bus 16 supplies power to AFW motor driven pump 12 (train B). Makeup to unit 1 SGs can be supplied from the MD pump in the unit 2 AFW system through a system cross-tie line. Unit 2 AFW MD pump 21 motive power is supplied from unit 2 emergency bus 25. The 12 and 21 MD driven pump breakers control are supplied from unit 1 and 2 DC sources, respectively.

8. Failure of Bus 13 would fail 11 condensate pump. Failure of Bus 14 would fail the 12 and 13 pumps. It is assumed that during normal plant operation pumps 11 and 12 are running while 13 is in standby. Control power for pump 13 breaker is provided by 125VDC Panel 11.

9. Cooling water provides lube oil cooling to the MFW and condensate pumps through the unit 1 turbine building cooling water header via Train A of cooling water.

10. Loss of 120V Panel 112 (113) will fail the power supply to 1P-468 (1P-478) (11 (12) SG PORV pressure channel) such that CV-31084 (CV-31089) will not open automatically.

11. One train of SI, RHR, CS and CC will be lost upon failure of 4.16KV essential bus 15 or 16. However, if these failures are associated with components that supply power to the buses (i.e., DGs) and not the buses themselves, then buses 15 and 16 can be crosstied to the unit 2 4.16KV buses 25 and 26, respectively. One train of SI, RHR and CS is also loss if either of the 125VDC trains fail to supply control power to close the pump breakers to start the pumps. Local operation of the breakers is not credited.

12. The success criteria for the Reactor Protection (RP) system is successful unit trip (subcriticality). Loss of any support system either causes system success (trip) or provides a half-trip due to loss of one train of analog protection circuitry. Therefore, loss of the associated 125VDC trains or loss of power to the MG sets result in system success.

13. Loss of 125VDC or instrument air to 11 TD AFW pump steam inlet control

valve causes it to fail open, starting the pump.

14. deleted......

15. Cooling water provides the heat sink for the CC heat exchangers With failure of Train A CL, Train A CC is assumed to fail eventually causing failure of one train of SI & RHR, and vice versa for Train B CL. Loss of CC alone will have the same result.

16. 480VAC essential MCC 1K1 provides motive power to many of safeguards Train A loads. Power is provided to the bus from 4.16KV Switchgear 15 through 480VAC bus 110. The following are essential loads powered from MCC 1K1.

    - CS Train A suction valve from RHR pump 11 (MV-32096).
    - RHR Train A suction from containment sump B (MV-32075, MV-32077)
    - RHR heat exchanger valves (MV-32093).
    - CS pump 11 discharge valve (MV-32103).
    - SI test line A valve to the RWST (MV-32202).
    - SI Train A suction valve from RHR pump 11 (MV-32206).
    - SI RWST suction valve (MV-32079).
    - SI suction (MV-32081).
    - C[illegible] Cooling heat exchanger valves (MV-32120 MV-32145).
    - Co[illegible] water return header valves (MV-32038, MV-32322).
    - 12 charging pump.
    - Charging suction from RWST (MV-32060)

17. 480VAC essential MCC 1KA2 provides motive power to many of safeguards Train B loads. Power is provided to the bus from 4.16KV Switchgear 16 through 480VAC bus 120. The following are essential loads powered from MCC 1KA2.

    - Train B suction from containment sump B (MV-32076, MV-32078)
    - [illegible]est line B valve to the RWST (MV-32203).
    - C[illegible] pump 12 discharge valve (MV-32105).
    - SI Train B suction valve from RHR pump 12 (MV-32207).
    - SI RWST suction valve (MV-32080).
    - SI BAST suction valve (MV-32082).
    - Component Cooling heat exchanger valves (MV-32121, MV-32146).

18. 480VAC essential MCC 1LA1 and 1LA2 provides power to the RHR Trains A and B, respectively for the injection and SDC modes. Power to the bus is supplied to MCC 1LA1 and 1LA2 from 4.16KV switchgear 15 and 16 through buses 110 and 120, respectively.

    MCC-1LA1
    - RHR Train A low head injection valve (MV-32064).
    - SDC Loop A RCS suction valves (MV-32164, MV-32165).
    - RHR Loop B return valve (MV-32066).

    MCC-1LA2
    - RHR Train B low head injection valve (MV-32065).
    - SDC Loop B RCS suction valves (MV-32230, MV-32231).

19. Fan Coil Units 11 and 13 (Train A) remove heat from the containment though Cooling Water Train A. Power to Train A units is supplied from MCC 1X1. Fan Coil Units 12 and 14 (Train B) remove heat from the containment though Cooling Water Train B. Power to Train B units is supplied from MCC 1X2. Heat is removed from the FCUs through the cooling water system.

20. Steam to the AFW turbine for pump 11 is provided from MS loops A and B. Failure of either Main Steam loop does not necessarily leads to loss of AFW Train A.

NOTES to Table 3.2-5a & 3.2-5b - (Continued)

21. Cooling water provides a backup suction source for the AFW system for long term secondary cooling. Failure of cooling water will not have an immediate impact on the AFW system since the primary suction source is from the CSTs.

22. Both the Pzr PORVs and SG PORVs have accumulators available which are intended to allow a limited number of valve cycles on loss of instrument air. The Pzr PORV accumulators are sized to allow 15 open/close cycles of the valves. The SG PORV air accumulators exist but no documentation of their design basis information is available and pre operational tests did not include cycling of the valves without instrument air. Therefore, they are conservatively assumed to fail closed on loss of instrument air. Loss of cooling water would eventually result in loss of the PORVs since instrument air compressors required cooling from the Cooling Water system.

23. 480V essential MCC 1K2 provides motive power to many safeguards Train B loads. Power is provided from 4.16 KV Bus 15 through 480 AC Bus 120. The following are essential loads powered from MCC 1K2.

    11 & 13 charging pumps

24. Loss of Panel 113 causes the charging flow splitting valve CV-31198 to fail open causing RCP seal injection flow to be diverted to charging.

25. Loss of 480V essential MCC 1K1 causes failure of the charging pump suction valve from the RWST (MV-32060) causing loss of this suction path. VCT normal makeup is not affected. Local operation of the manual bypass valve is not credited.

26. Loss of MCC 1D1 causes failure of 11 RMW pump while failure of MCC 1D2 fails 12 RMW pump. These two pumps supply RMW for normal VCT makeup.

27. Loss of 120V Panel 111 causes failure of VCT normal makeup instruments such that normal makeup fails.

28. Loss of 125V DC Panel 151 causes failure of the RMW supply valves to the blender failing VCT normal makeup.

29. Loss of instrument air causes the charging flow splitting valve CV-31198 to fail open diverting seal injection flow to charging. All charging pumps go to minimum speed. It was assumed the operator must start a second charging pump in order to restore RCP seal injection.

30. Loss of Train A or Train B CL fails the associated train of safeguards chilled water resulting in loss of room cooling to the associated 480V bus transformer. Without operator action, it is assumed the bus will fail causing loss of all associated equipment. Loss of the associated train of chilled water has the same effect.

31. Failure of 480V MCC 1U1 causes failure as is of MV-32323, 11 MFW pump discharge valve. This only becomes a factor if 11 MFW pump has tripped and must be re-started, in which case MV-32323 would not open.

32. Failure of 480V MCC 1U2 causes failure as is of MV-32324, 12 MFW pump discharge valve. This only becomes a factor if 12 MFW pump has tripped and must be re-started, in which case MV-32324 would not open.

33. Loss of 480V MCC 1A1 causes failure of 11 AFW pump CL suction valve MV-32025. Since CL is a backup suction source, this is a delayed dependence.

34. Loss of 480V MCC 1A2 causes failure of 12 AFW pump CL suction valve MV-32027. Since CL is a backup suction source, this is a delayed dependence.

NOTES to Table 3.2-5a & 3.2-5b - (Continued)

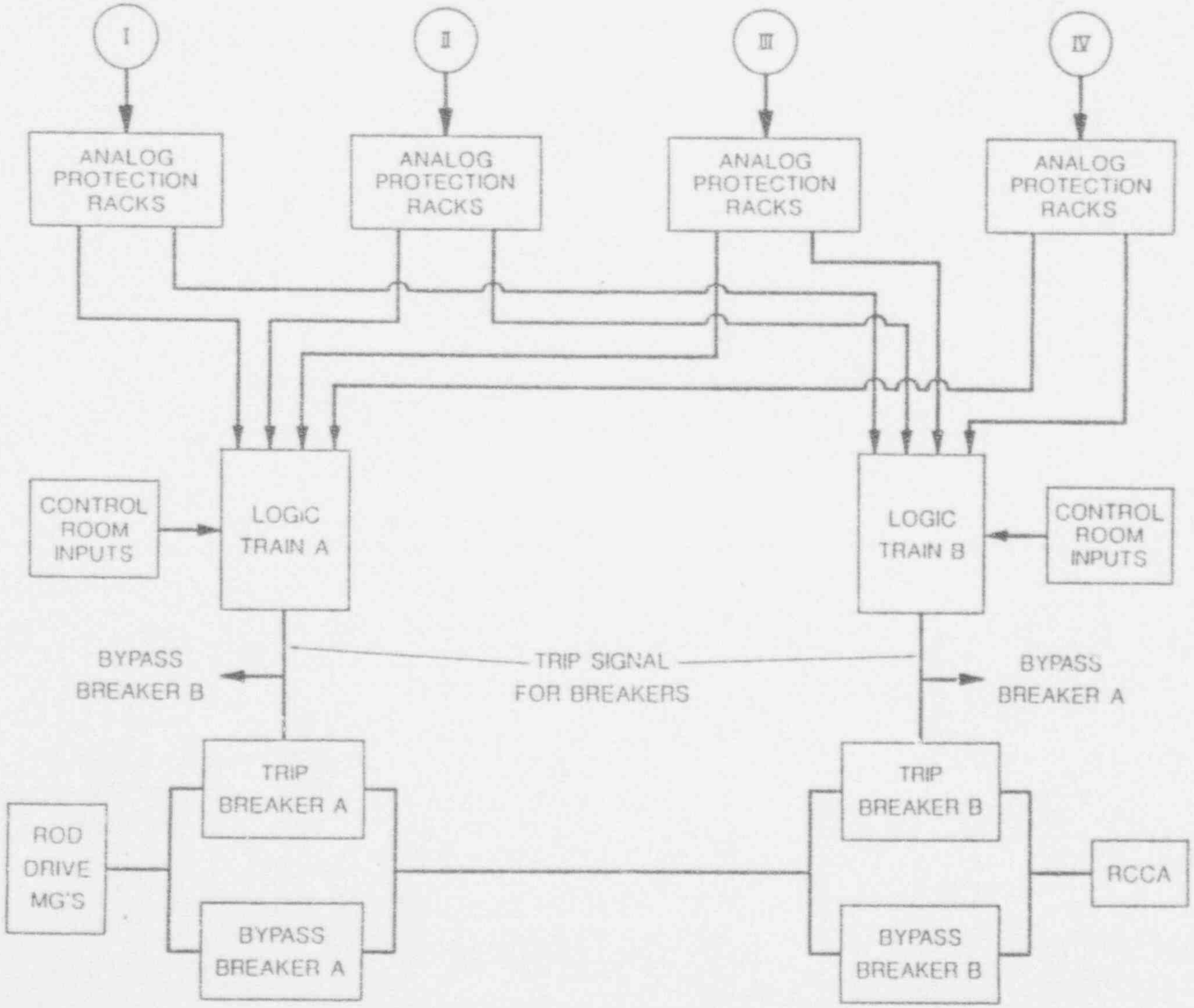
35. Loss of 120V Panel 114 (111) will fail the power supply to 1HC-468(1HC-478) (11 (12) SG PORV hand controller) such that manual operation of CV-31084 (CV-31089) will not be possible.

36. Deleted......

37. It was conservatively assumed that on loss of the associated chilled water train the RHR pits will overheat failing the pumps. Loss of IA will cause loss of all chilled water along with failure of the associated CL train.

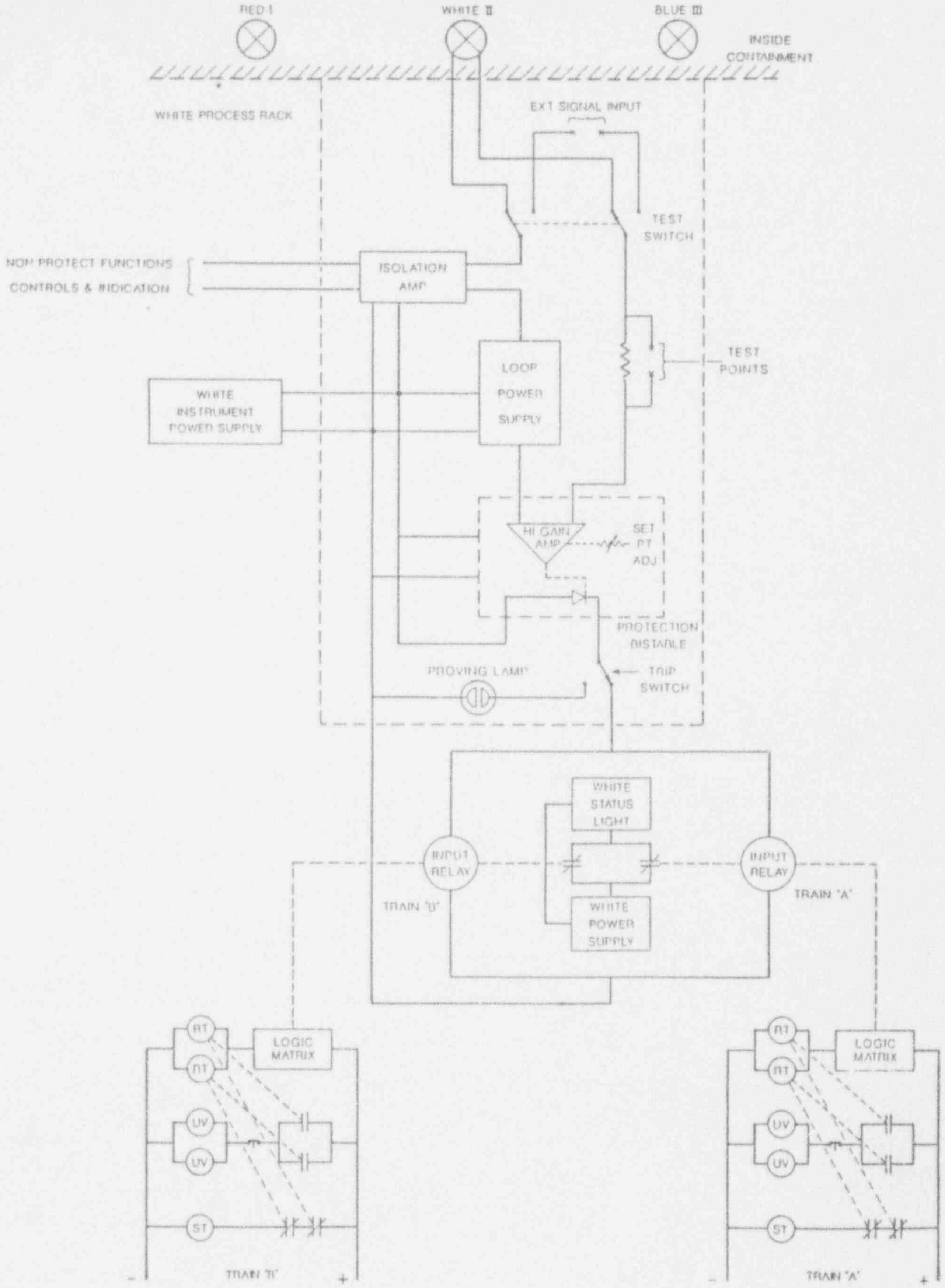
38. Failure of 125V DC Panels 12, 16 and 162 causes closure of CV-31741 (Train B IA Containment Isolation) which fails all IA to containment failing both PORVs. Panel 162 also fails power to CV-31231 (Train B PORV) causing failure of CV-31231.

39. Failure of 125V DC Panels 11, 15 or 191 cause closure of CV-31740 (Train A IA Containment Isolation) which fails all air to containment failing both PORVs. Panel 191 also fails power to CV-31232 (Train A PORV) causing failure of CV-31232.



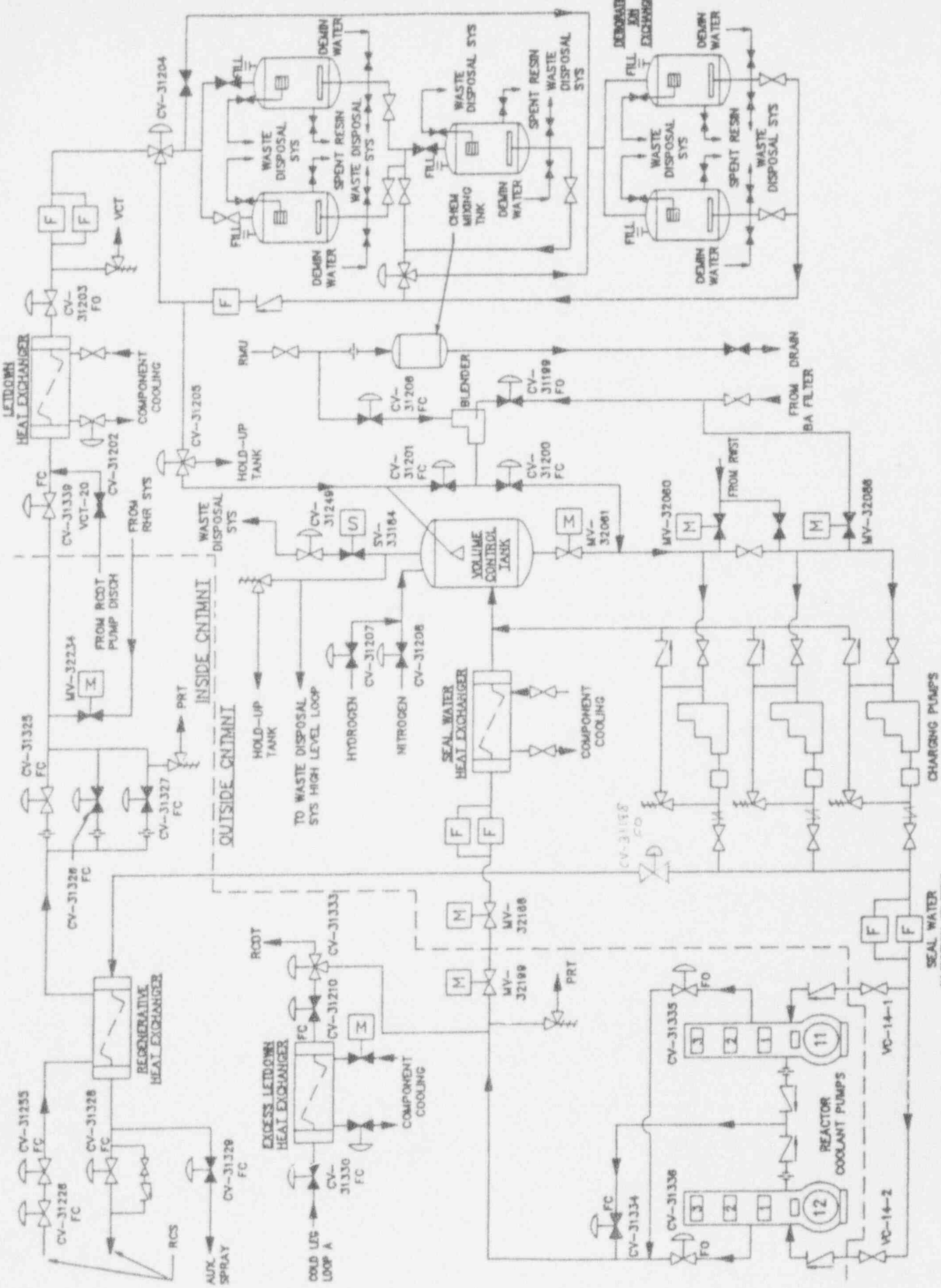
SIMPLIFIED REACTOR PROTECTION SYSTEM

FIGURE 3.2-1



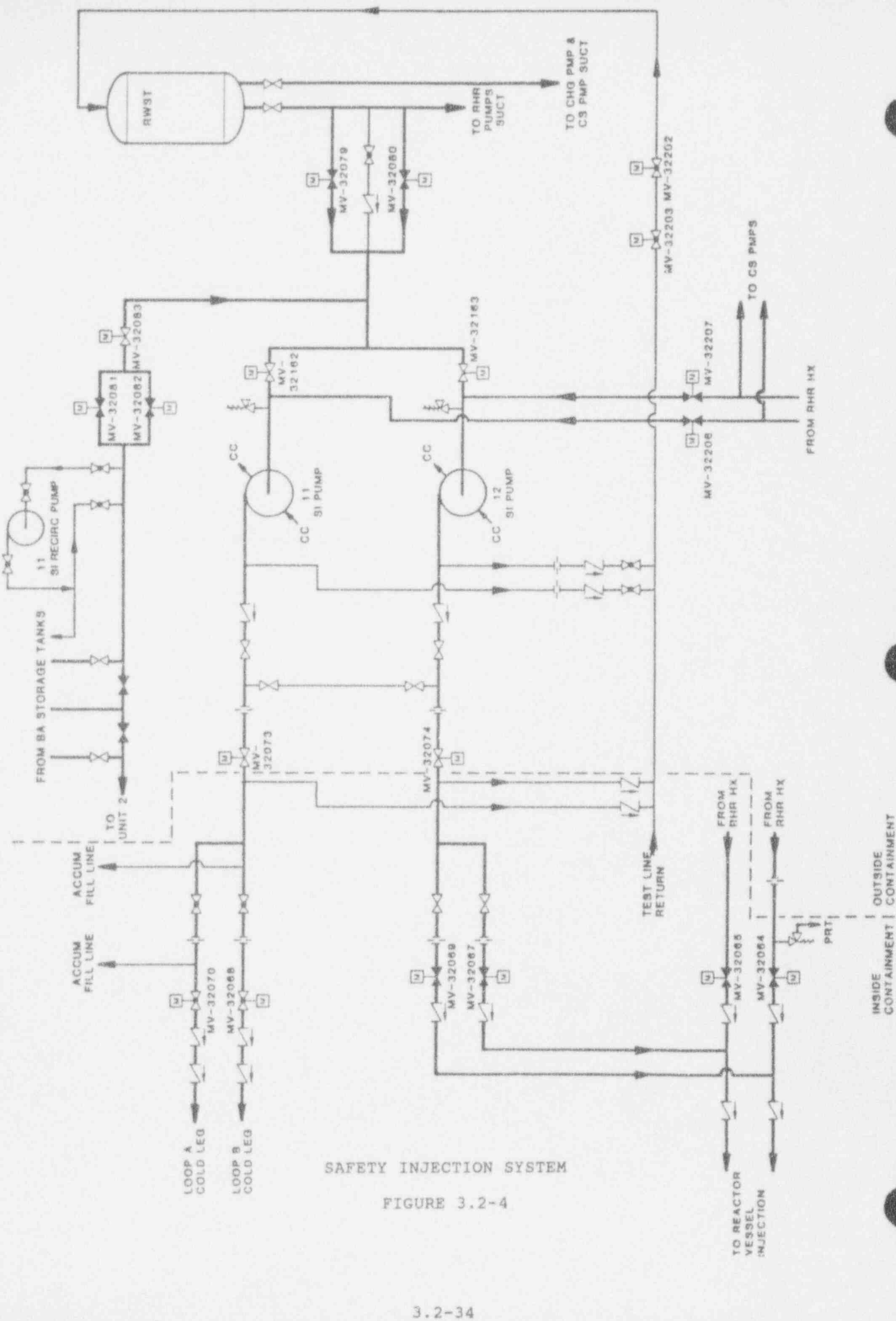
TYPICAL REACTOR PROTECTION CHANNEL (USING THREE REDUNDANT CHANNELS)

FIGURE 3.2-2



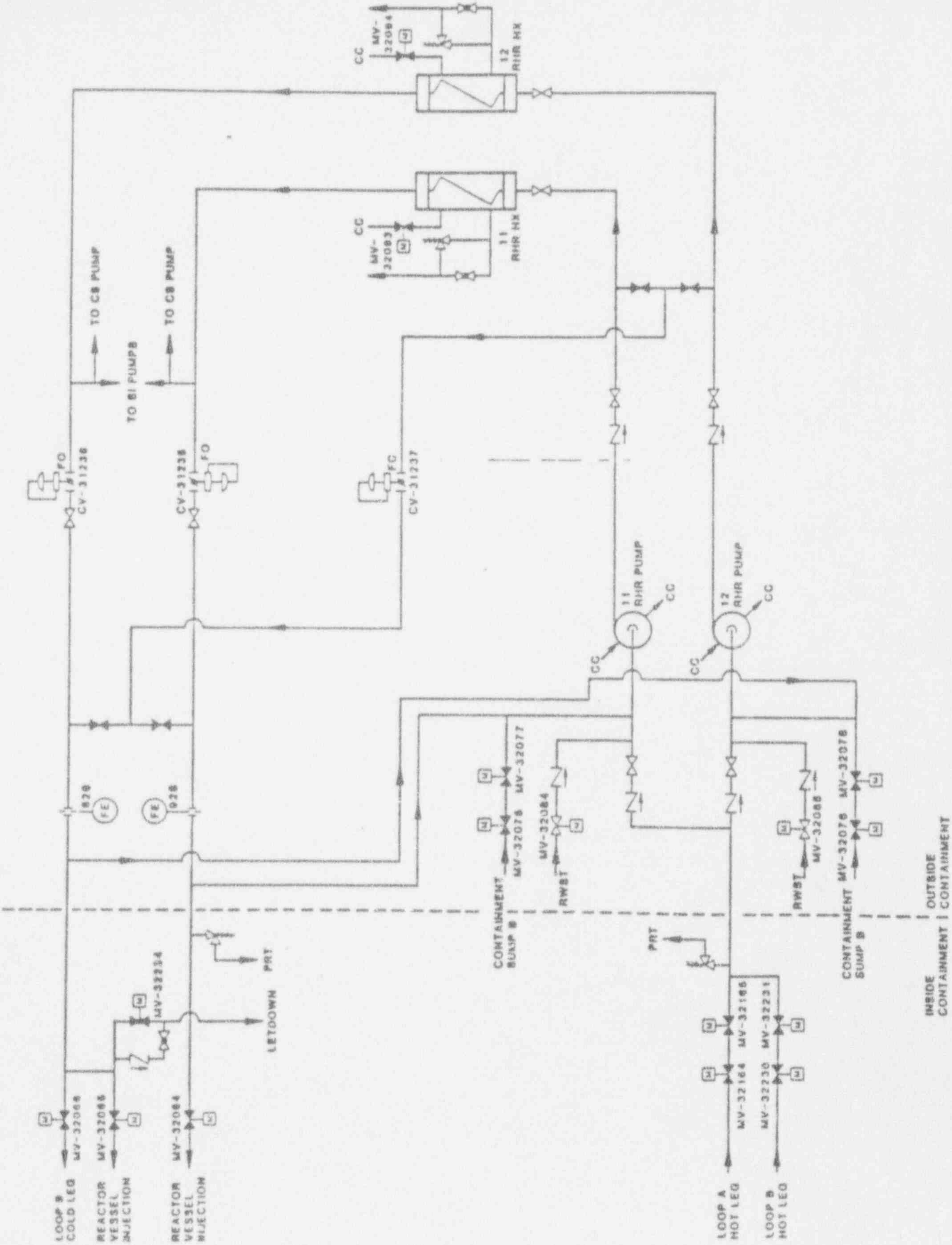
CHARGING, LETDOWN AND SEAL WATER SIMPLIFIED FLOW

FIGURE 3.2-3



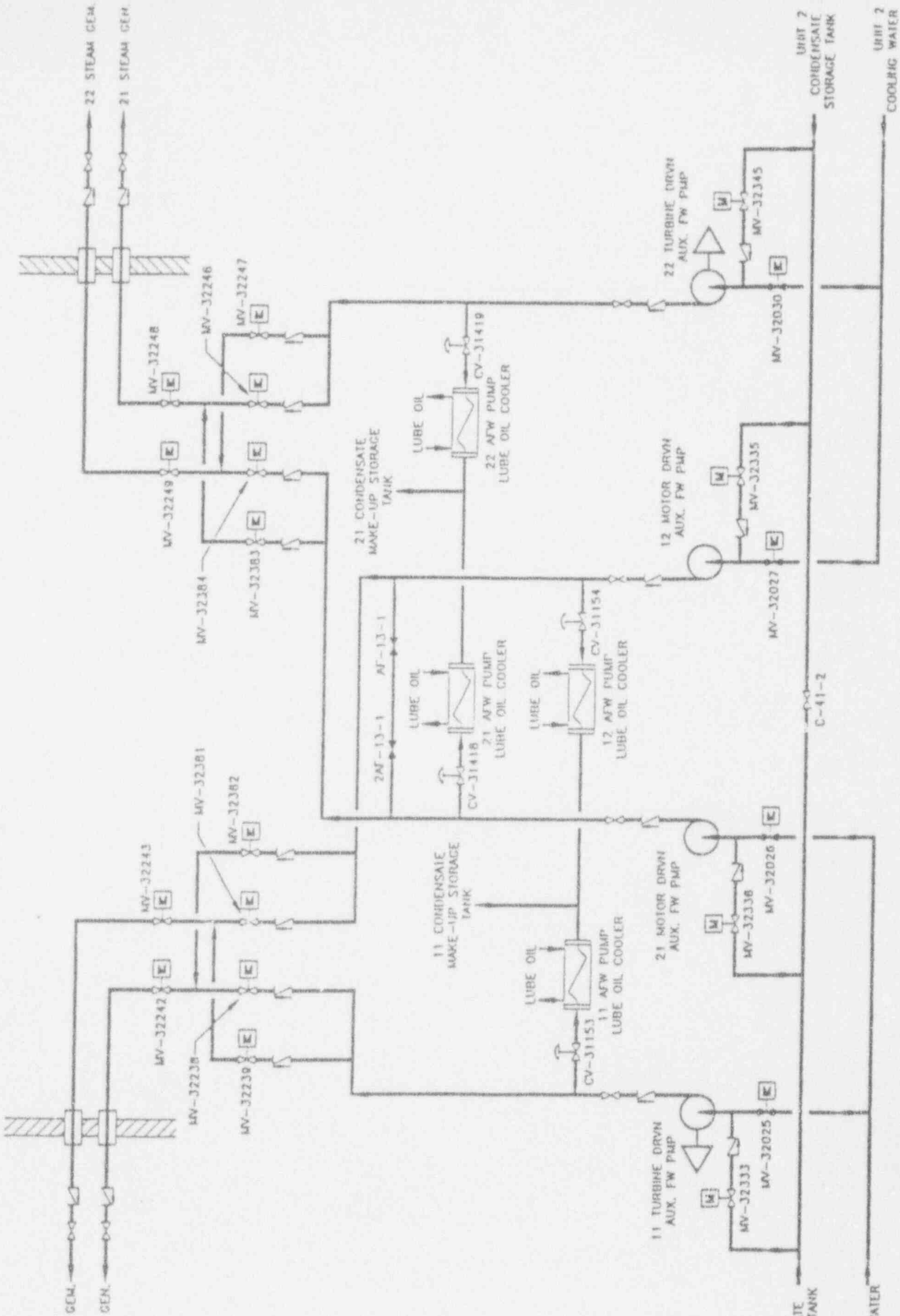
SAFETY INJECTION SYSTEM

FIGURE 3.2-4



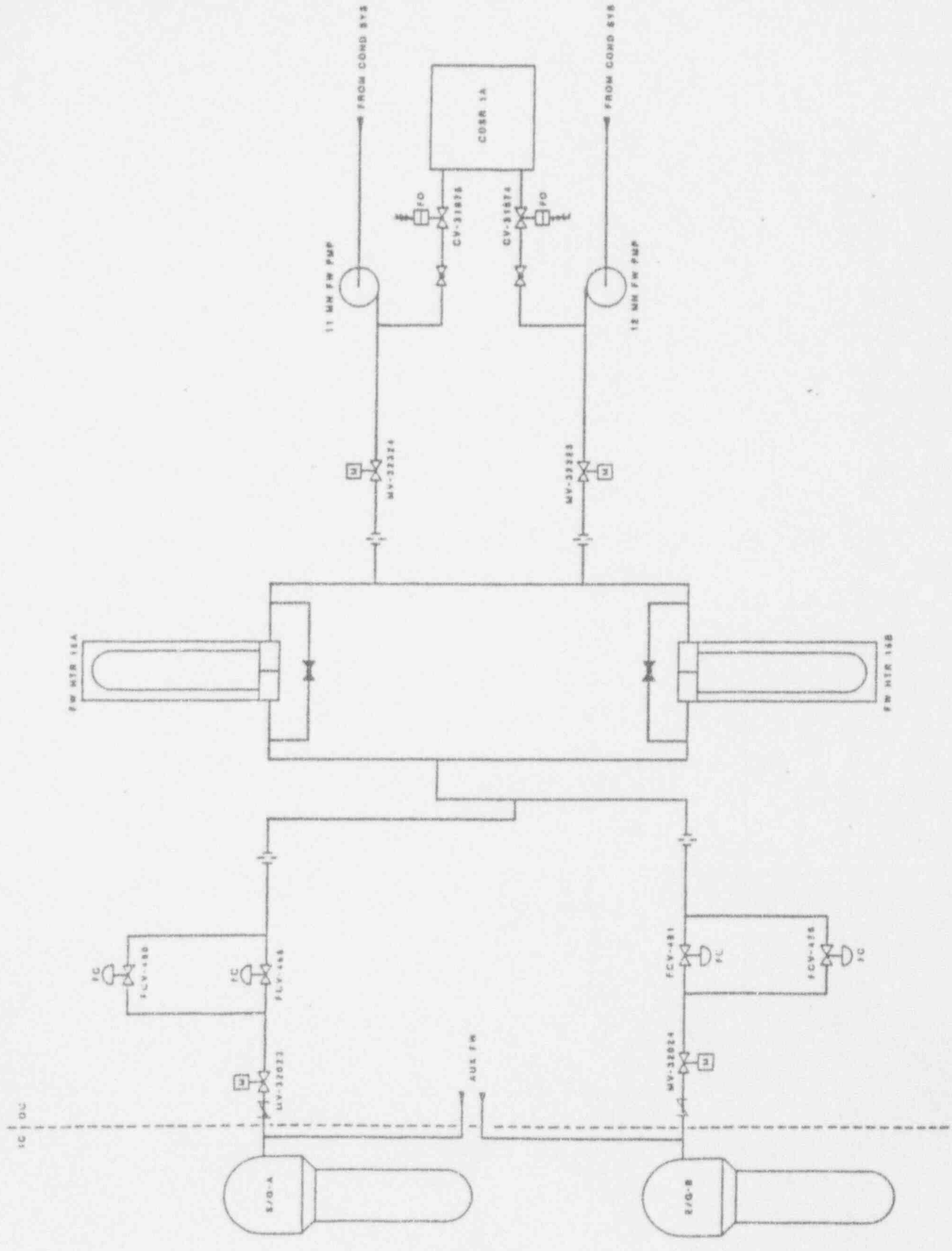
RESIDUAL HEAT REMOVAL SYSTEM

FIGURE 3.2-5



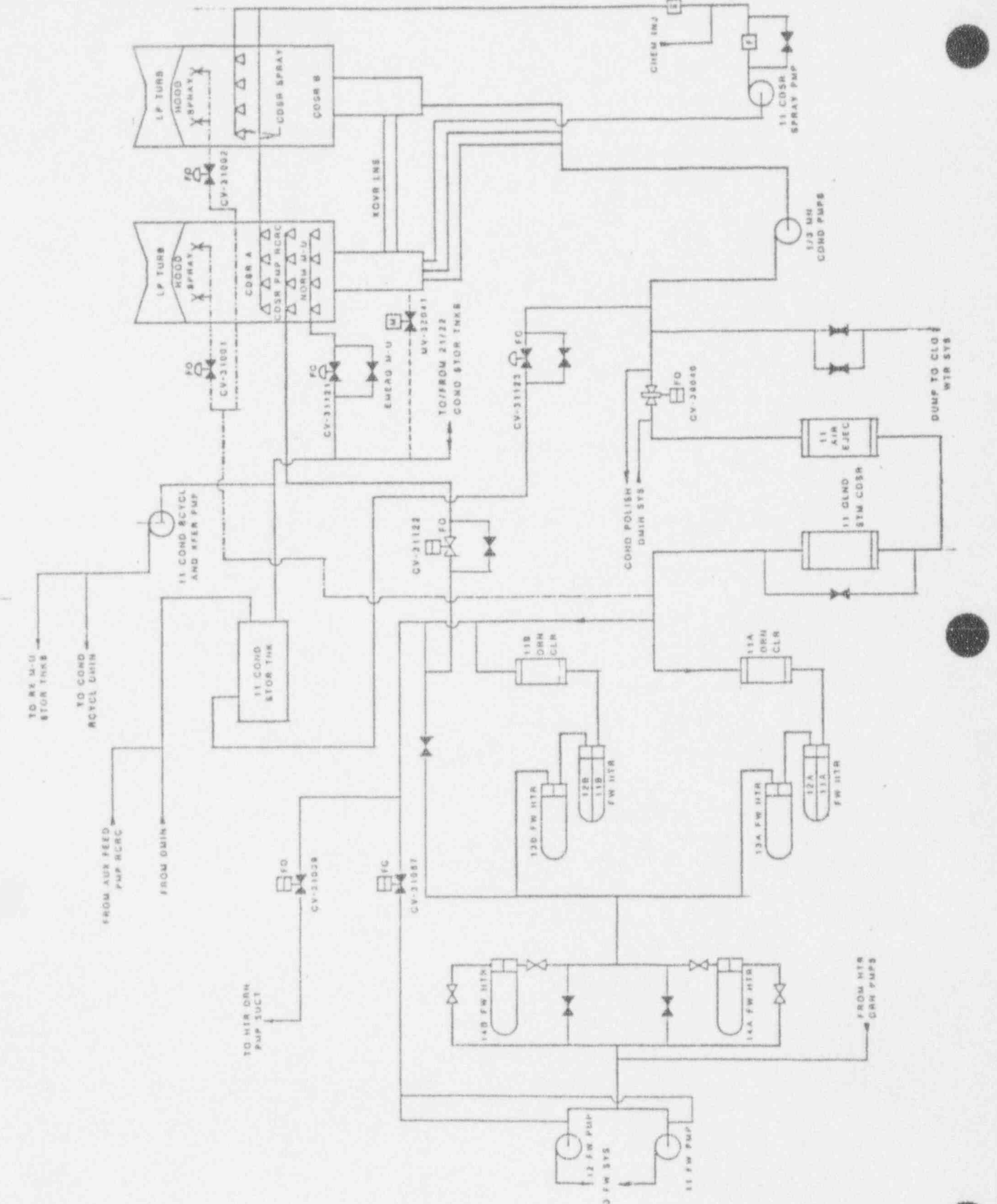
AUXILIARY FEEDWATER SYSTEM

FIGURE 3.2-6



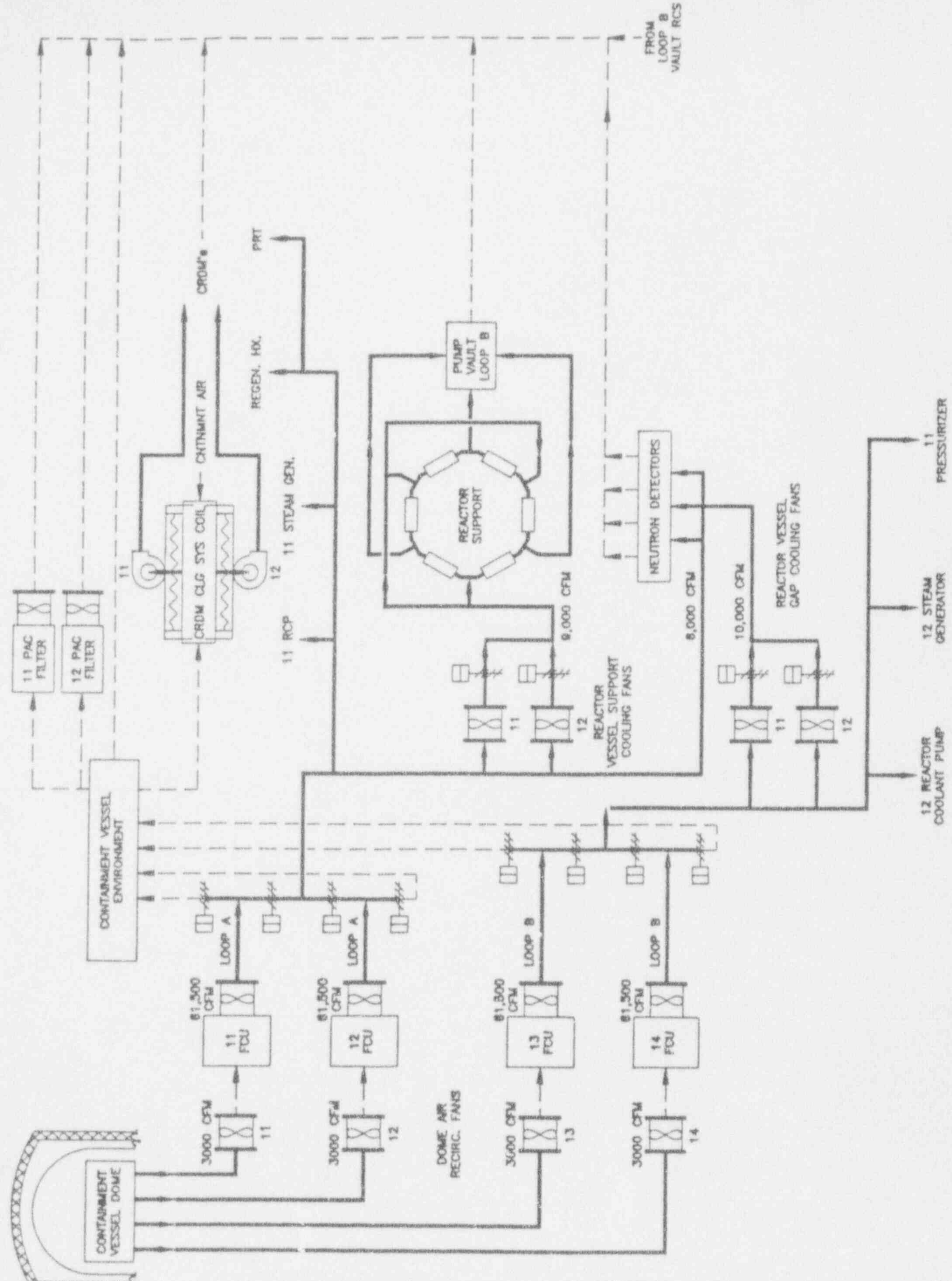
MAIN FEEDWATER SYSTEM

FIGURE 3.2-7a



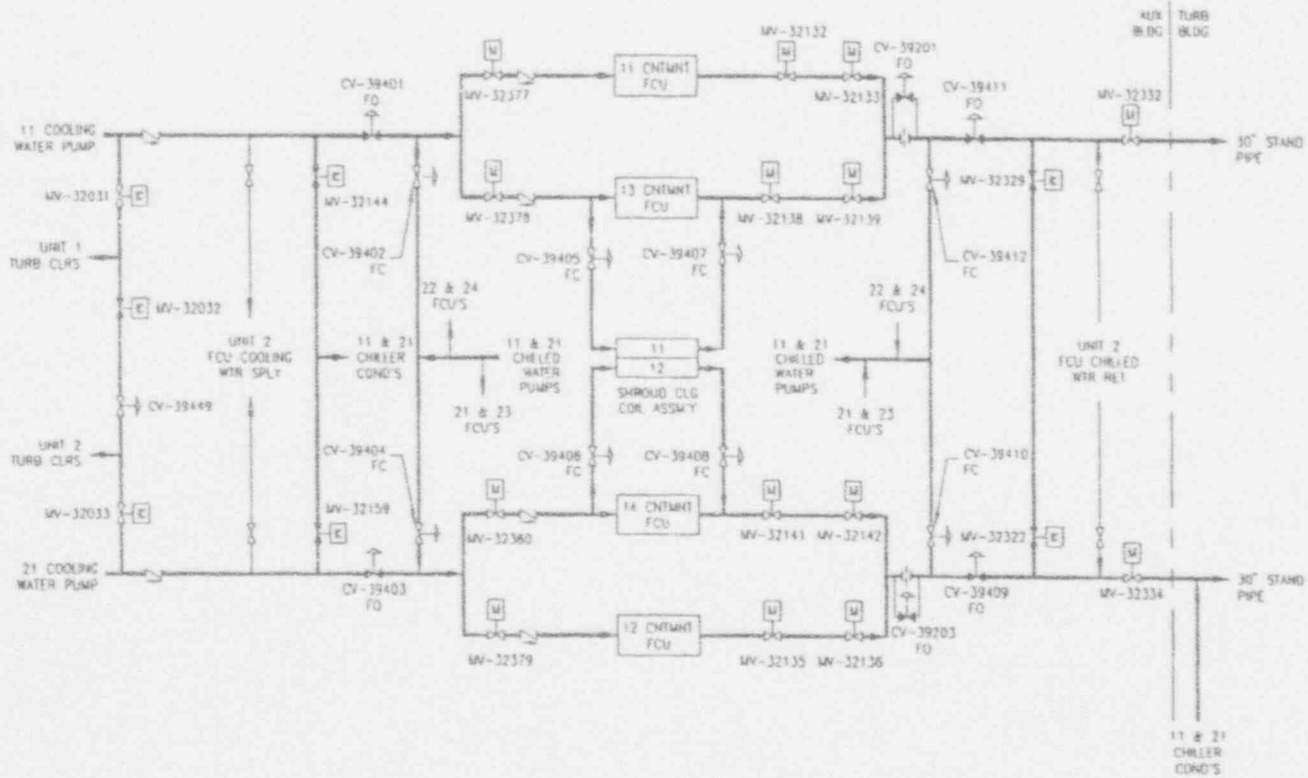
CONDENSATE SYSTEM

FIGURE 3.2-7b



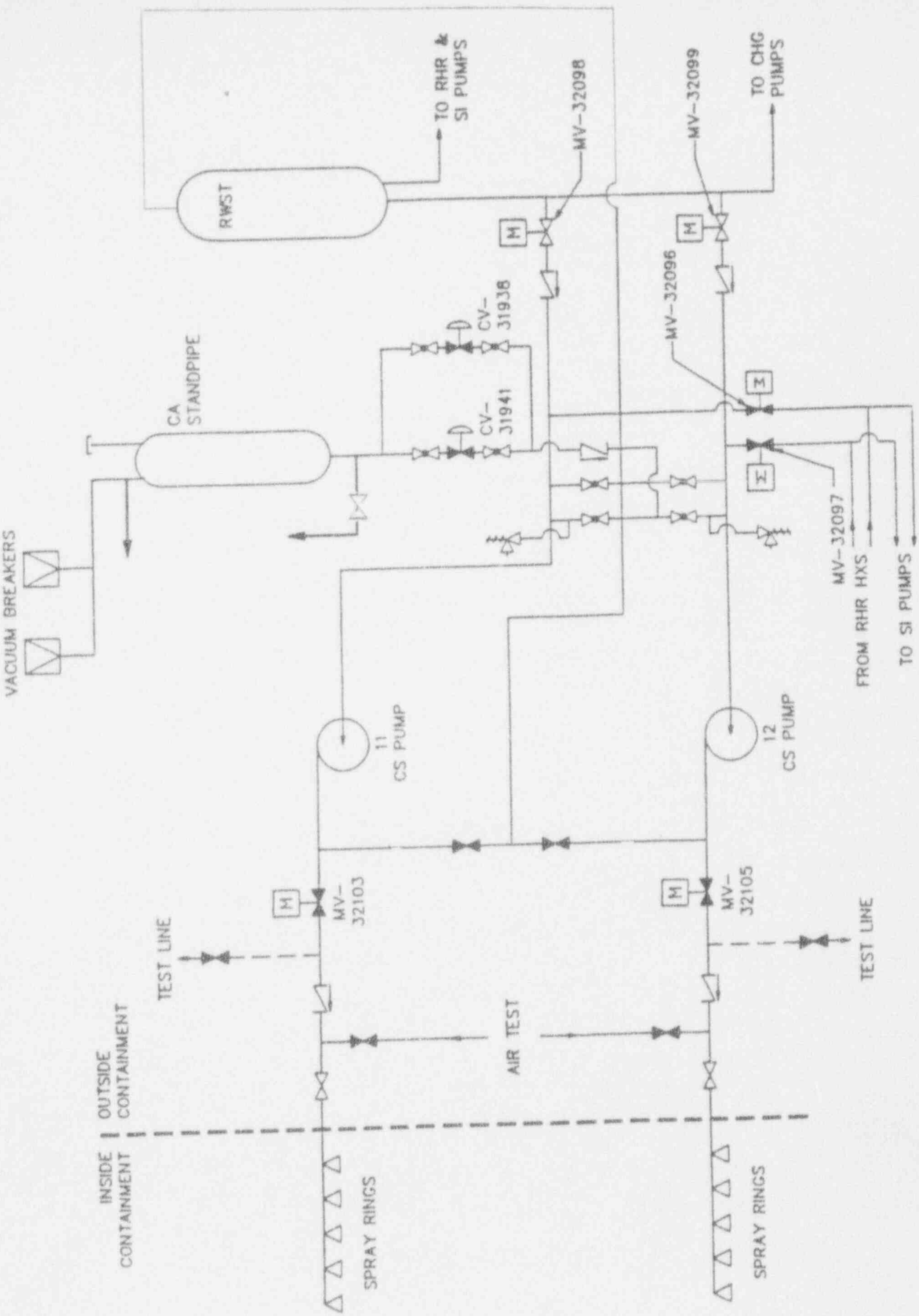
CONTAINMENT VESSEL AIR HANDLING SYSTEM

FIGURE 3.2-8



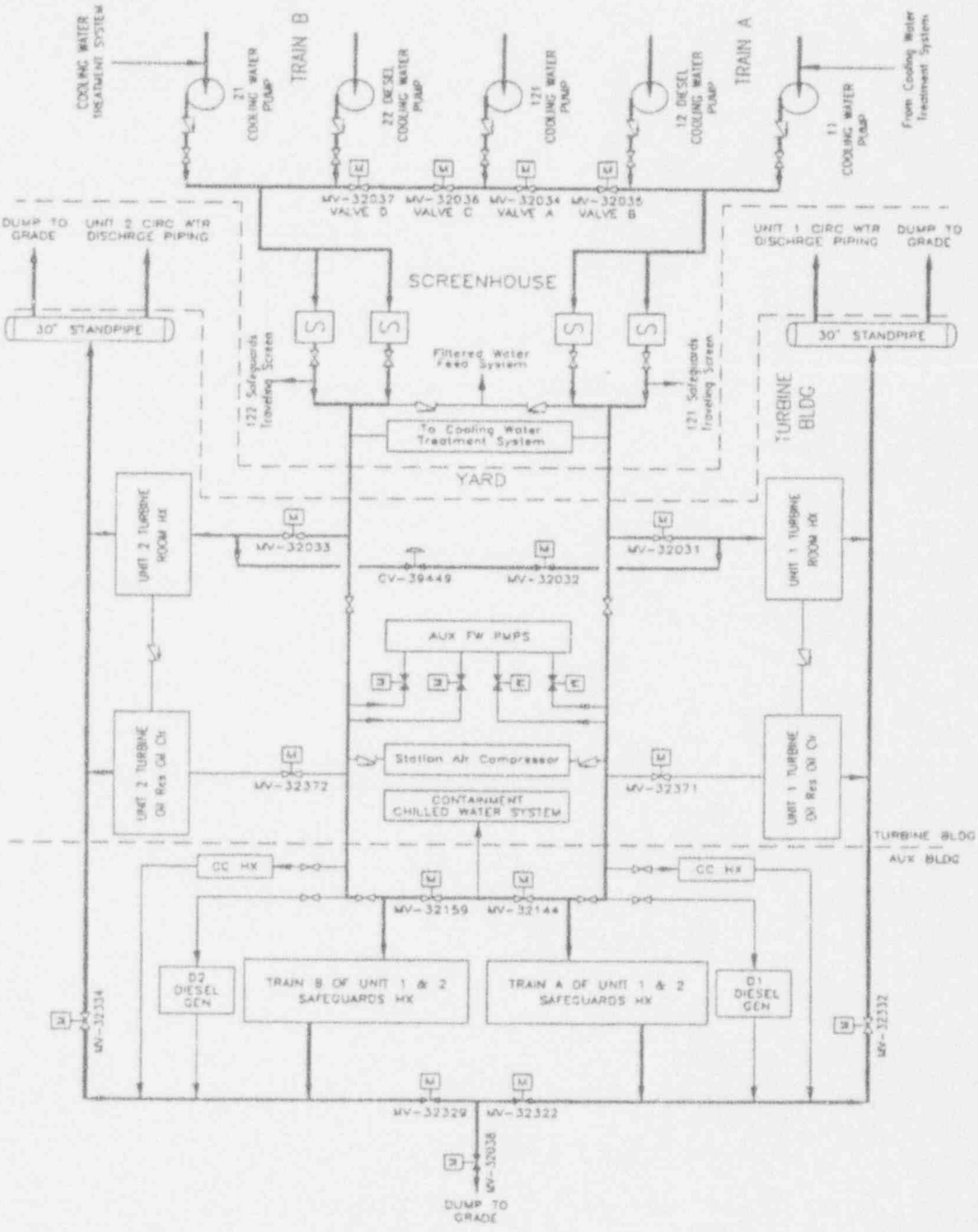
FAN COIL UNIT CHILLED WATER SUPPLY

FIGURE 3.2-9



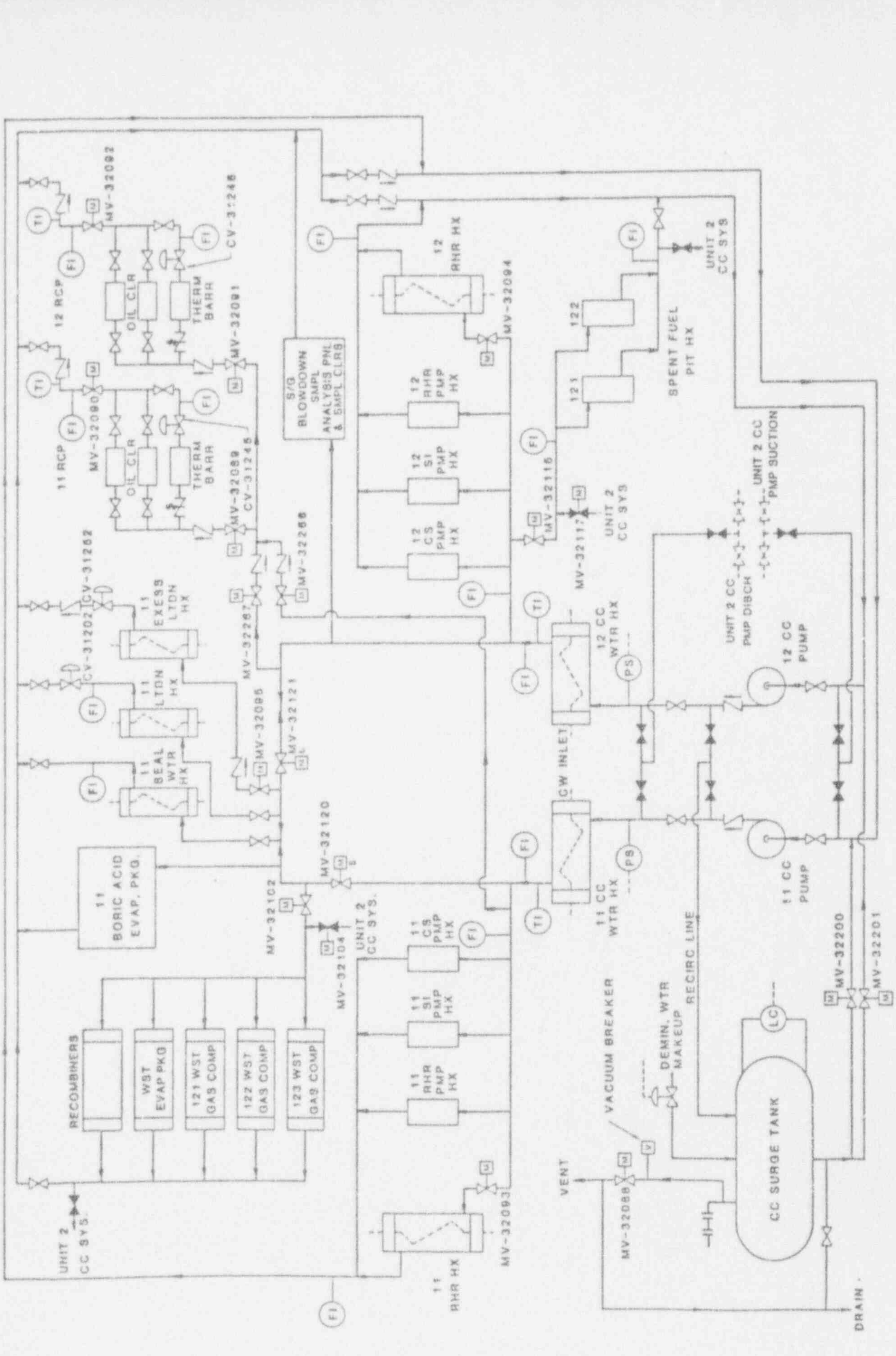
CONTAINMENT SPRAY SYSTEM

FIGURE 3.2-10



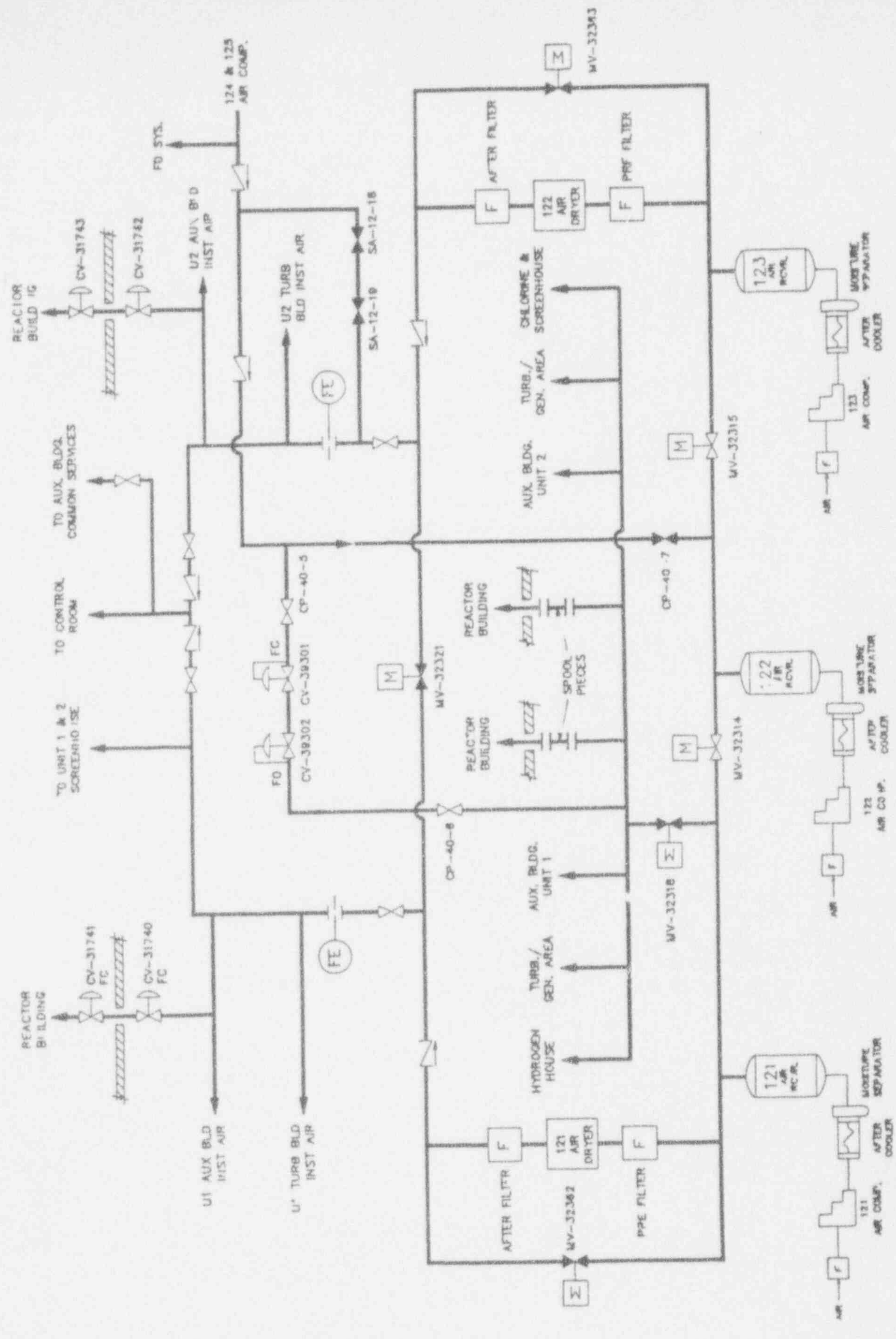
COOLING WATER SYSTEM

FIGURE 3.2-11



UNIT 1 COMPONENT COOLING WATER SYSTEM

FIGURE 3.2-12



INSTRUMENT AND STATION AIR SYSTEM

FIGURE 3.2-13

Tabl

INITIATING EVENT TO FRONTI

Initiating Event	Criticality	RCP Seal Cooling		Secondary Cooling		
	RPS	CC	CVCS	MFW	AFW	COND
Normal Transient				(1)		(1)
Transient - S/G Hi-Hi Level				(1)		(1)
Transient - Inadvertent SI				(2)		(2)
Transient Loss of FW				X		X
MFW Line Break				P(3)(2)		P(3)(2)
MS Line Break				P(3)(2)		P(3)(2)
S/G Tube Rupture				P(3)(2)		P(3)(2)
Large LOCA				(2)		(2)
Medium LOCA				(2)		(2)
Small LOCA				(2)		(2)
ISLOCA				(2)		(2)
Loss of Instrument Air			X(6)	X(4)		X(4)
Loss of Cooling Water		D(19)	D(15)	(5)	D(16)	(5)
Loss of Component Cooling Water		X				
Loss of Offsite Power	(21)			X(7)		X(7)
Loss of DC Train A				X(8)		X(8)
Loss of DC Train B		P(11)			P(17)	

NOTES:
X = Complete Dependence. Frontline system not available following initiator.
P = Partial Dependence. Frontline system partially unavailable following initiator (e.g., one l
D = Delayed Dependence. Delayed impact on frontline system unavailability (e.g., loss of compon

e 3.2-3

.INE SYSTEM DEPENDENCY MATRIX

		Short Term RCS Inventory			Long Term RCS Inventory			Containment Heat Removal		
	SG PORVs	SI	RHR	Pzr PORVs	RHR	RHR Recirc	SI Recirc	CS	FCU	CS Recirc
		X	X		X	X	X	X		
	X(9)			X(9)	D(20)	D(20)				
	D(9)	D(10)		D(9)	X(12)	X(12)	X(12)		X	X(13)
		D(10)			X(12)	X(12)	X(12)			X(13)
		P(11)	P(11)	X(18)	P(11)	P(11)	P(11)	P(11)		P(11)
		P(11)	P(11)	X(18)	P(11)	P(11)	P(11)	P(11)		P(11)

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NOTES to Table 3.2-3

1. Feedwater isolation occurs on reactor trip. Operator action to open feedwater valves is required to reestablish flow.

2. A safety injection signal results in MFW and condensate pump trip in addition to feedwater and containment isolation. Operator action to restart the pumps, reset the "S" signal and open valves is required in order to inject to the SGs.

3. A break in the feedwater line to one of the two SGs will disable MFW system ability to makeup to the affected loop. However, makeup to the other SG is not affected provided the affected loop is isolated from the unaffected one. The effect on the MFW system is assumed to be similar for a MSLB and a SG tube rupture event as the affected steam generator is required to be isolated.

4. SG 11 and 12 regulating and bypass valves fail closed on a loss of instrument air to the control valves or loss of Train A DC to their associated valve solenoids, thereby leading to failure of the MFW system. Since makeup to the SGs from the condensate system is through the MFW lines, this has the same effect on the condensate system.

5. Loss of cooling water is assumed to result in failure of feedwater and condensate pumps on the order of 20 minutes due to the unavailability of lube oil and bearing cooling.

6. Loss of instrument air causes the charging pumps (3) to shift to slow speed operation. If the operator starts a second, there is enough flow to supply RCP seal injection.

7. Offsite power is required to operate the MFW and condensate pumps.

8. Loss of DC Train A would result in closure of the MFW regulating and bypass valves. See note 4. Makeup from MFW or Condensate will be disabled.

9. Loss of instrument air to the pressurizer and SG PORVs would result in their failure to operate. Although the pressurizer PORVs are equipped with air accumulators which allows the valves to be cycled, they are conservatively assumed to fail when instrument air is lost. Loss of cooling water would have a delayed effect on the instrument air compressors and therefore, on maintaining PORV operation.

10. Loss of cooling to the SI lube oil coolers from the Component Cooling Water (CC) system would eventually result in failure of the pumps to continue to run. Failure to remove heat from the CC system to the Cooling Water system would fail the CC system ability to perform its function and therefore, result in failure of SI pumps.

11. Loss of one DC train would affect one train of SI, RHR, CS, and CC systems. The pump breakers are supplied from separate DC trains.

12. Loss of CC to the RHR heat exchangers would result in failure of SI, RHR system to remove heat from the primary system on recirculation. Failure to remove heat from the CC heat exchanger to the CL system would eventually lead to failure of the CC to provide cooling to its heat loads (i.e, RHR heat exchangers, pump oil and seal cooler units, and etc..). Therefore, loss of cooling water has a indirect effect on SI and RHR recirc. operation.

13. Containment Spray (CS) in the recirculation mode removes heat from the containment via the RHR heat exchanger. A loss of component cooling water to the RHR heat exchanger would result in failure of the CS system to perform this function. A loss of cooling water to the CC heat exchanger would indirectly affect the ability of the CS system to perform this

function.

14. Loss of one train of 125VDC would result in failure of the CVCS to function in the boron injection mode.

15. Loss of CL causes loss of safeguards chilled water. Without operator intervention, the safeguards 480V Bus 110/120 rooms are assumed to heat up failing Bus 110 & 120 transformers causing loss of all equipment supplied by these buses.

16. Loss of CL causes loss of the CL suction to the AFW pumps. When the condensate storage tanks are empty the suction of the AFW pumps is shifted to CL. If CL is unavailable the AFW pumps are lost.

17. Loss of Train B DC causes loss of control power to 12 AFW pump. Local operator action is required to use pump.

18. Loss of Train A or B DC causes closure of one of the instrument air to containment isolation valves failing instrument air to containment. Although pressurizer PORV's have air accumulators that allow ~15 valve cycles, they are conservatively assumed to be unavailable.

19. Loss of CL causes loss of the heat sink for the CC heat exchangers which would eventually lead to failure of CC to provide cooling to the RCP thermal barriers.

20. Loss of instrument air results in closure of the control room chiller outlet CL valves resulting in failure of safeguard chilled water causing loss of RHR pit cooling. Without operator action, this would eventually cause failure of the RHR pumps. Recent analysis has shown that RHR pit cooling is not required.

21. LOOP causes loss of power to both MG sets causing the rods to fall into the core causing system success.

Tab[illegible]

FRONTLINE TO FRONTLIN[illegible]

Frontline System	Criticality	RCP Seal Cooling		Secondar[illegible] Cooling	
	RPS	CC	CVCS	MFW	AFW
RPS				(5)	
CC					
CVCS Seal Cooling					
MFW					
AFW					
COND				X(1)	
SG PORVs					
SI					
RHR					
Pzr PORVs					
RHR Recirc					
SI Recirc					
SDC					
CS					
FCU					
CS Recirc					

NOTES:
X = Complete Dependence. Frontline system not available as a direct result of other frontline s[illegible]
P = Partial Dependence. Frontline system partially unavailable following failure of other fronl[illegible]

e 3.2-4

SYSTEM DEPENDENCY MATRIX

		Short Term RCS Inventory			Long Term RCS Inventory			Containment Heat Removal		
COND	SG PORVs	SI	RHR	Pzr PORVs	SDC	RHR Recirc	SI Recirc	CS	FCU	CS Recirc
(5)										
P(2)		(6)								
		(6)								
					(7)					
		(4)			(7)		(4)			
							X(3)			X(3)

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NOTES to Table 3.2-4

1. The main feedwater pumps will trip on low suction pressure following a failure of the Condensate system.

2. Failure of the MFW regulating and bypass valves would prevent SG makeup from the condensate system.

3. Component failures in the RHR containment sump suction path would result in the failure of SI, CS and RHR in the recirculation mode.

4. Failure of pressurizer PORVs to function would result in failure to remove heat from the primary system via bleed and feed operation. This indirectly affect availability of the successful operation of SI.

5. Main feedwater isolates on a reactor trip signal with low average RCS temperature.

6. Secondary cooling is assumed to be required for successful SI during small LOCA (other than bleed and feed) and SGTR.

7. Cooldown and depressurization of the RCS is required to initiate shutdown cooling for small LOCA and SGTR sequences.

Tabl

SUPPORT TO FRONTLINE

Support System	Criticality		RCP Seal Cooling				
	RPS		CVCS			CC	
	A	B	11	12	13	A	B
Bus 11 (4160VAC)							
Bus 12 (4160VAC)							
Bus 13 (4160VAC)	(12)	(12)					
Bus 14 (4160VAC)	(12)	(12)					
Bus 15 (4160VAC)				X(16)		X(11)	
Bus 16 (4160VAC)			X(23)		X(23)		X(11)
Bus 25 (4160VAC)							
MCC1K1 (480VAC)			P(25)	X(16)	P(25)	X(17)	
MCC1A1 (480VAC)							
MCC1LA1 (480VAC)							
MCC1X1 (480VAC)							
MCC1A2 (480VAC)							
MCC1K2 (480VAC)			X(23)		X(23)		
MCC1KA2 (480VAC)							X(17)
MCC1LA2 (480VAC)							
MCC1X2 (480VAC)							
MCC1D1 (480VAC)			P(26)	P(26)	P(26)		
MCC1D2 (480VAC)			P(26)	P(26)	P(26)		
MCC1U1 (480VAC)							
MCC1U2 (480VAC)							
Panel 111 (120VAC)			P(27)	P(27)	P(27)		
Panel 112 (120VAC)							
Panel 113 (120VAC)			X(24)	X(24)	X(24)		
Panel 114 (120VAC)							
DP 11 (125VDC)	(12)					X(11)	
DP 12 (125VDC)		(12)					X(11)
DP 13 (125VDC)							

e 3.2-5a

SYSTEM DEPENDENCY MATRIX

Secondary Cooling								
MFW		AFW		COND			SG PORVs	
,	B	A	B	11	12	13	CV-31084	CV-31089
X(.)								
	X(1)							
				X(8)				
					X(8)	X(8)		
			P(7)					
			P(7)					
		D(33)						
			D(34)					
X(2)								
	X(2)							
X(31)								
	X(32)							
								X(35)
							P(10)	
								P(10)
							X(35)	
X(3)(4)	X(3)(4)					X(8)		
			P(7)					

Support System	Criticality		RCP Seal Cooling					
	RPS		CVCS			CC		
	A	B	11	12	13	A	B	A
DP 15 (125VDC)	(12)							X(4)
DP 16 (125VDC)		(12)						
DP 162 (125VDC)								
DP 191 (125VDC)								
DP 151 (125VDC)			P(28)	P(28)	P(28)			X(4)
DP 21 (125VDC)								
IA			X(29)	X(29)	X(29)			X(5)
CL (both trains)								D(6)
Cooling Water Train A				D(30)		X(15)		X(9)
Cooling Water Train B			D(30)		D(30)		X(15)	
Component Cooling Water Train A								
Component Cooling Water Train B								
Chilled Water Train A				D(30)				
Chilled Water Train B			D(30)		D(30)			
Main Steam Loop A								
Main Steam Loop B								

NOTES:
X = Complete Dependence. Frontline system not available following failure of support system.
P = Partial Dependence. Frontline system partially unavailable following failure of support system.
D = Delayed Dependence. Delayed impact on frontline system unavailability.

3.2-5a - *(Continued)*
'LINE SYSTEM DEPENDENCY MATRIX

	Secondary Cooling								
	MFW		AFW		COND			SG PORVs	
B	A	B	A	B	11	12	13	CV-31084	CV-31089
	X(4)	X(4)			X(4)	X(4)	X(4)		
			(13)						
	X(4)	X(4)			X(4)	X(4)	X(4)		
				P(7)					
	X(5)	X(5)	(13)					X(22)	X(22)
	D(6)	D(6)						D(22)	D(22)
	X(9)	X(9)	D(21)		X(9)	X(9)	X(9)		
(15)				D(21)					
			P(20)						
			P(20)						

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Tabl

SUPPORT TO FRONTLINE

Support System	Short Term Cooling						RHR S
	SI		RHR		Pzr PORVs		
	A	B	A	B	A	B	A
Bus 11 (4160VAC)							
Bus 12 (4160VAC)							
Bus 13 (4160VAC)							
Bus 14 (4160VAC)							
Bus 15 (4160VAC)	X(11)		X(11)				X(11)
Bus 16 (4160VAC)		X(11)		X(11)			
Bus 25 (4160VAC)							
MCC1K1 (480VAC)	P(16)	P(16)					
MCC1A1 (480VAC)							
MCC1LA1 (480VAC)							X(18)
MCC1X1 (480VAC)							
MCC1A2 (480VAC)							
MCC1K2 (480VAC)							
MCC1KA2 (480VAC)	P(17)	P(17)					
MCC1LA2 (480VAC)							
MCC1X2 (480VAC)							
MCC1D1 (480VAC)							
MCC1D2 (480VAC)							
Panel 111 (120VAC)							
Panel 112 (120VAC)							
Panel 113 (120VAC)							
Panel 114 (120VAC)							
DP 11 (125VDC)	X(11)		X(11)		X(39)	X(39)	X(11)
DP 12 (125VDC)		X(11)		X(11)	X(38)	X(38)	
DP 13 (125VDC)							
DP 15 (125VDC)					X(39)	X(39)	
DP 16 (125VDC)					X(38)	X(38)	

e 3.2-5b

SYSTEM DEPENDENCY MATRIX

Long Term Cooling					Containment Heat Removal					
ͻC	RHR Recirc		SI Recirc		CS		FCU		CS Recirc	
B	A	B	A	B	A	B	A	B	A	B
	X(11)		X(11)		X(11)		X(19)		X(11)	
X(11)		X(11)		X(11)		X(11)		X(19)		X(11)
	X(16)		X(16)		X(16)				X(16)	
							X(19)			
		X(17)		X(17)		X(17)				X(17)
X(18)										
								X(19)		
	X(11)		X(11)		X(11)				X(11)	
X(11)		X(11)		X(11)		X(11)				X(11)

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Support System	Short Term Cooling							
	SI		RHR		Pzr PORVs		RHR SDC	
	A	B	A	B	A	B	A	B
DP 162 (125VDC)					X(38)	X(38)		
DP 191 (125VDC)					X(39)	X(39)		
DP 21 (125VDC)								
IA					X(22)	X(22)	D(37)	D(37)
CL (both trains)					D(22)	D(22)		
Cooling Water Train A	D(15)						D(15)	
Cooling Water Train B		D(15)						D(15)
Component Cooling Water Train A	D(15)						D(15)	
Component Cooling Water Train B		D(15)						D(15)
Chilled Water Train A							D(37)	
Chilled Water Train B								D(37)
Main Steam (11)								
Main Steam (12)								

NOTES:
X =Complete Dependence. Frontline system not available following failure of support system.
P =Partial Dependence. Frontline system partially unavailable following failure of support system
D =Delayed Dependence. Delayed impact on frontline system unavailability.

.2-5b - *(Continued)*
LINE SYSTEM DEPENDENCY MATRIX

Long Term Cooling						Containment Heat Removal					
RHR SDC		RHR Recirc		SI Recirc		CS		FCU		CS Recirc	
	B	A	B	A	B	A	B	A	B	A	B
7)	D(37)	D(37)	D(37)	D(37)	D(37)					D(37)	D(37)
5)		D(15)		D(15)				D(19)		D(15)	
	D(15)		D(15)		D(15)				D(19)		D(15)
5)		D(15)		D(15)						D(15)	
	D(15)		D(15)		D(15)						D(15)
7)		D(37)		D(37)						D(37)	
	D(37)		D(37)		D(37)						D(37)

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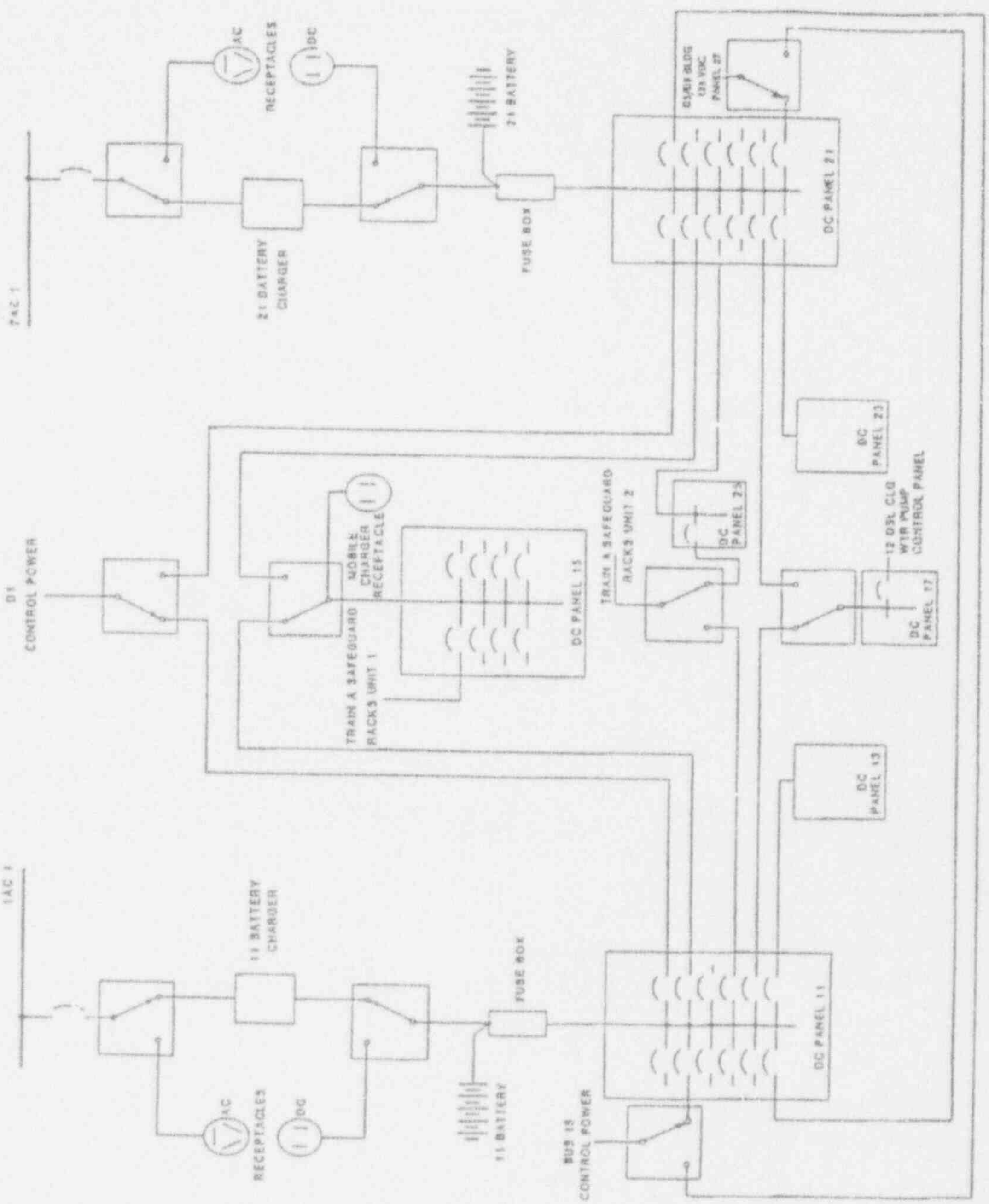
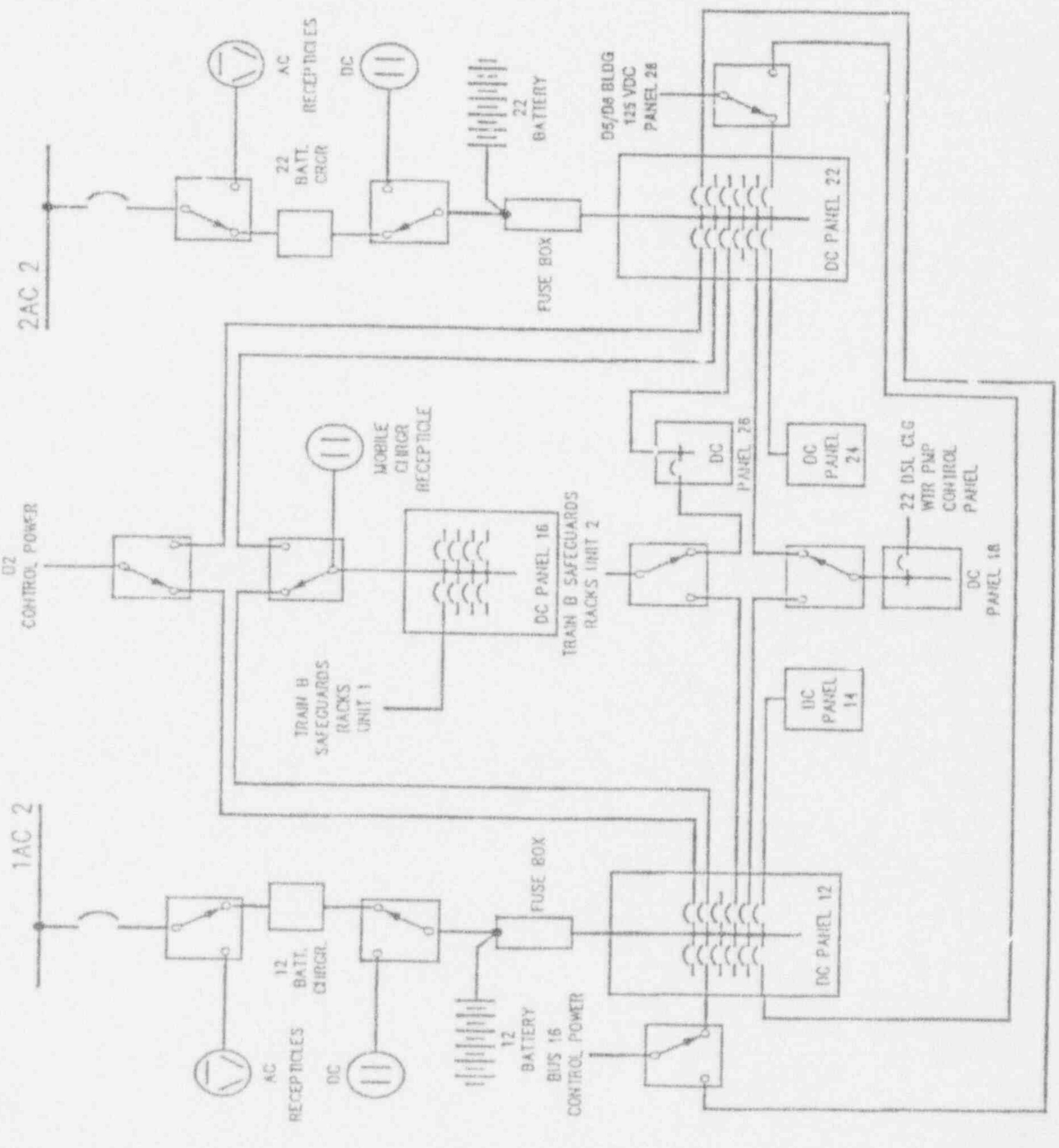


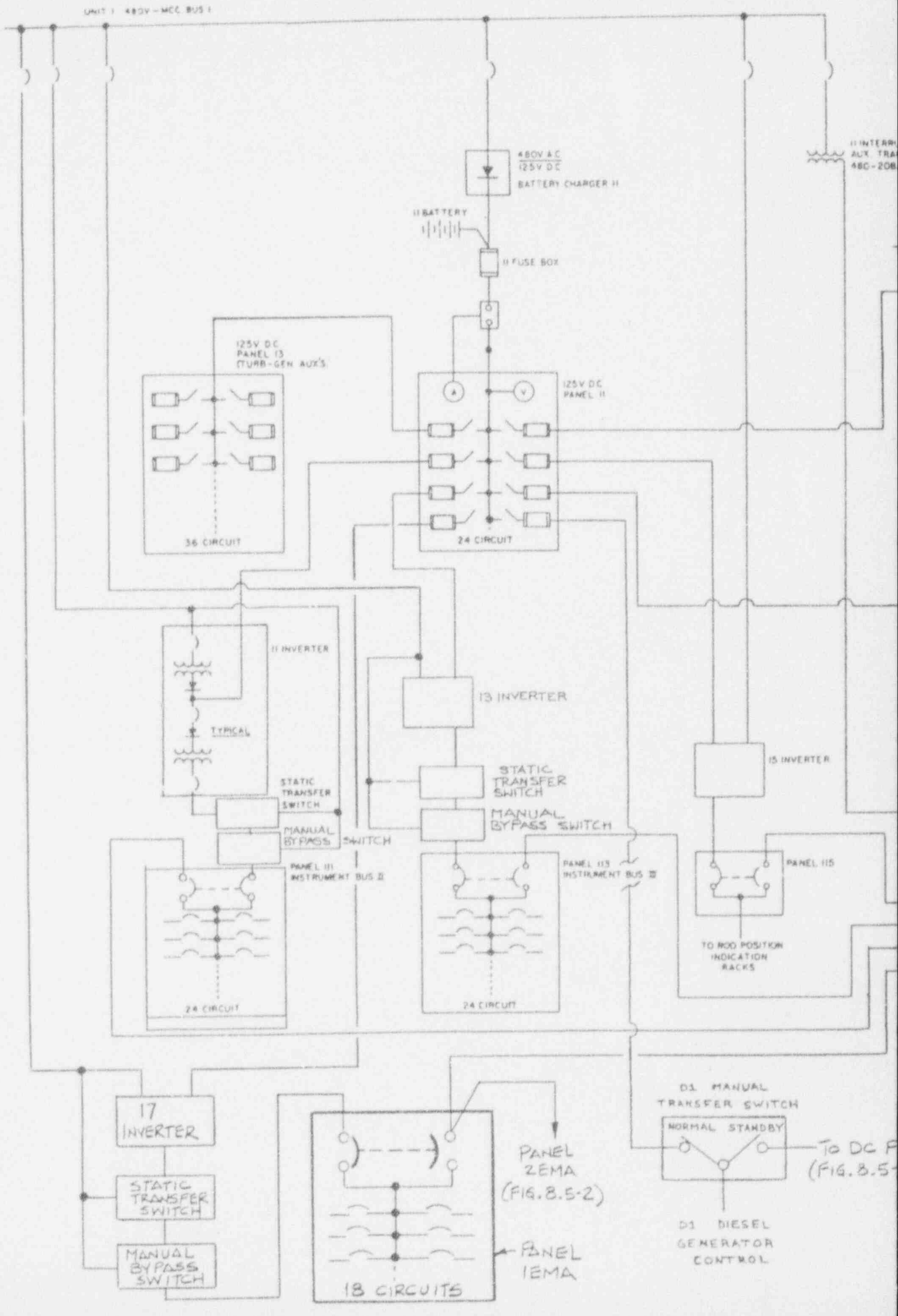
TRAIN A DC POWER

FIGURE 3.2-15



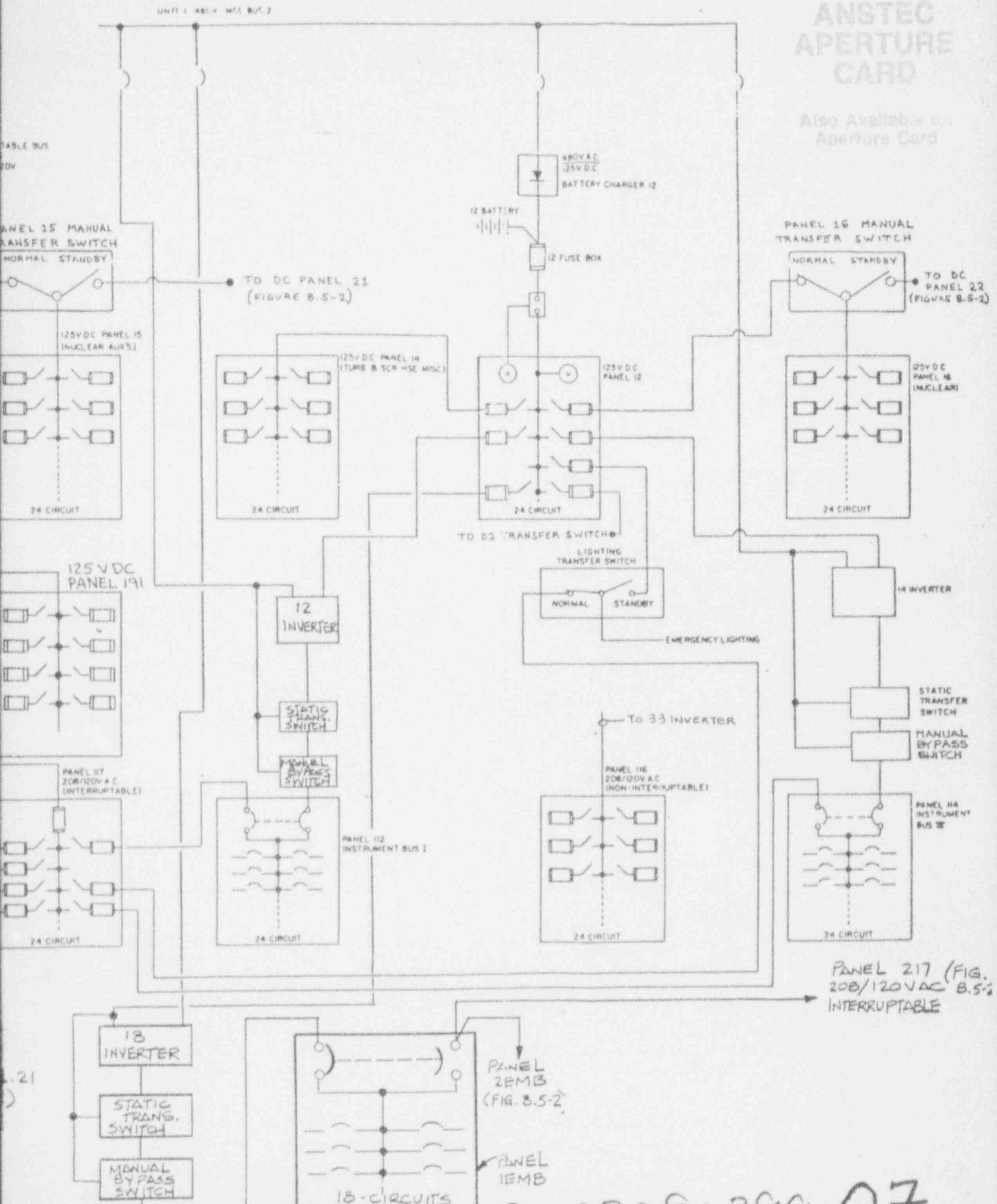
TRAIN B DC POWER

FIGURE 3.2-16



125V DC 120 V AC INSTRUMENT SUPPLY - UNIT 1

FIGURE 3.2-17



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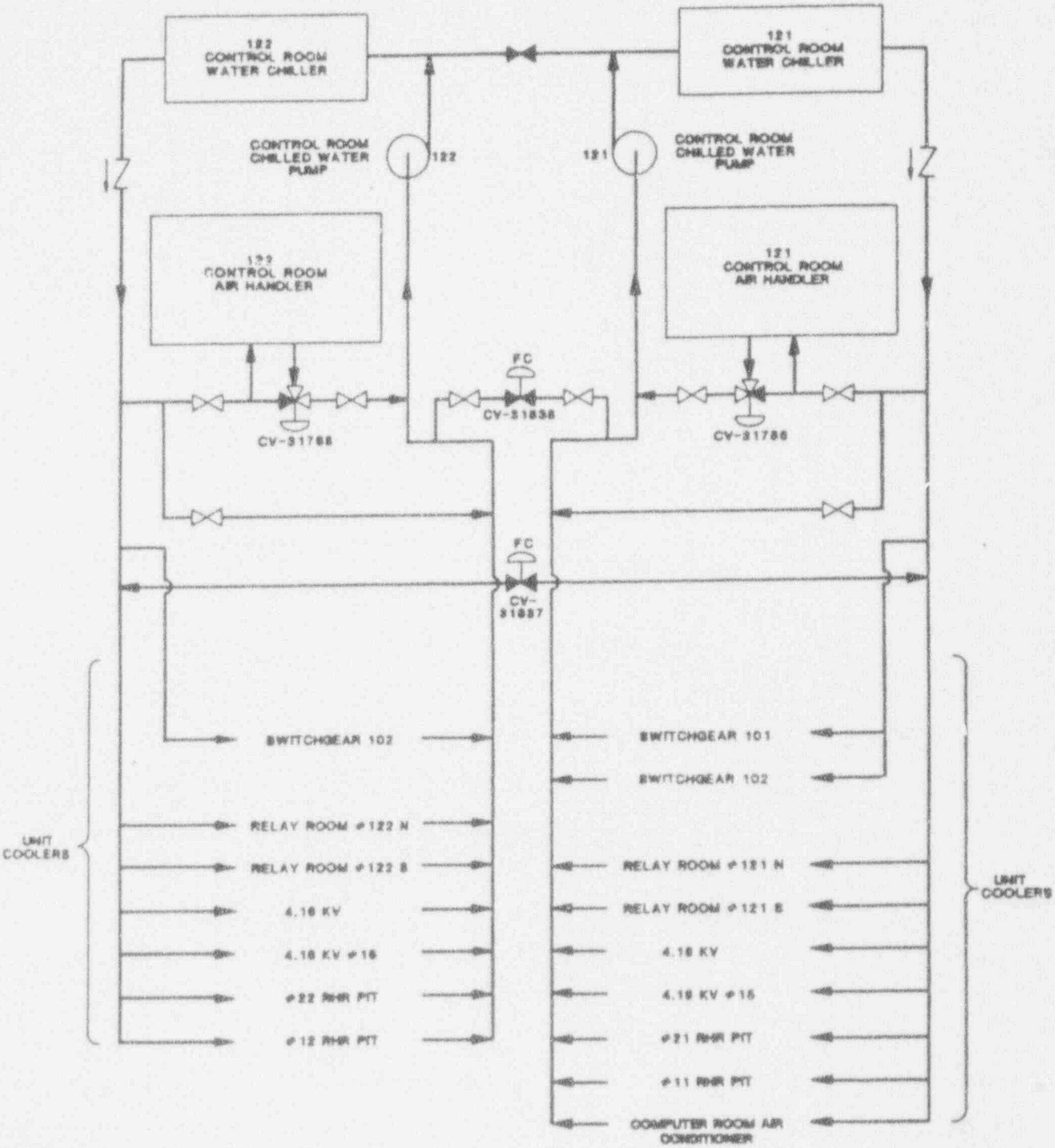
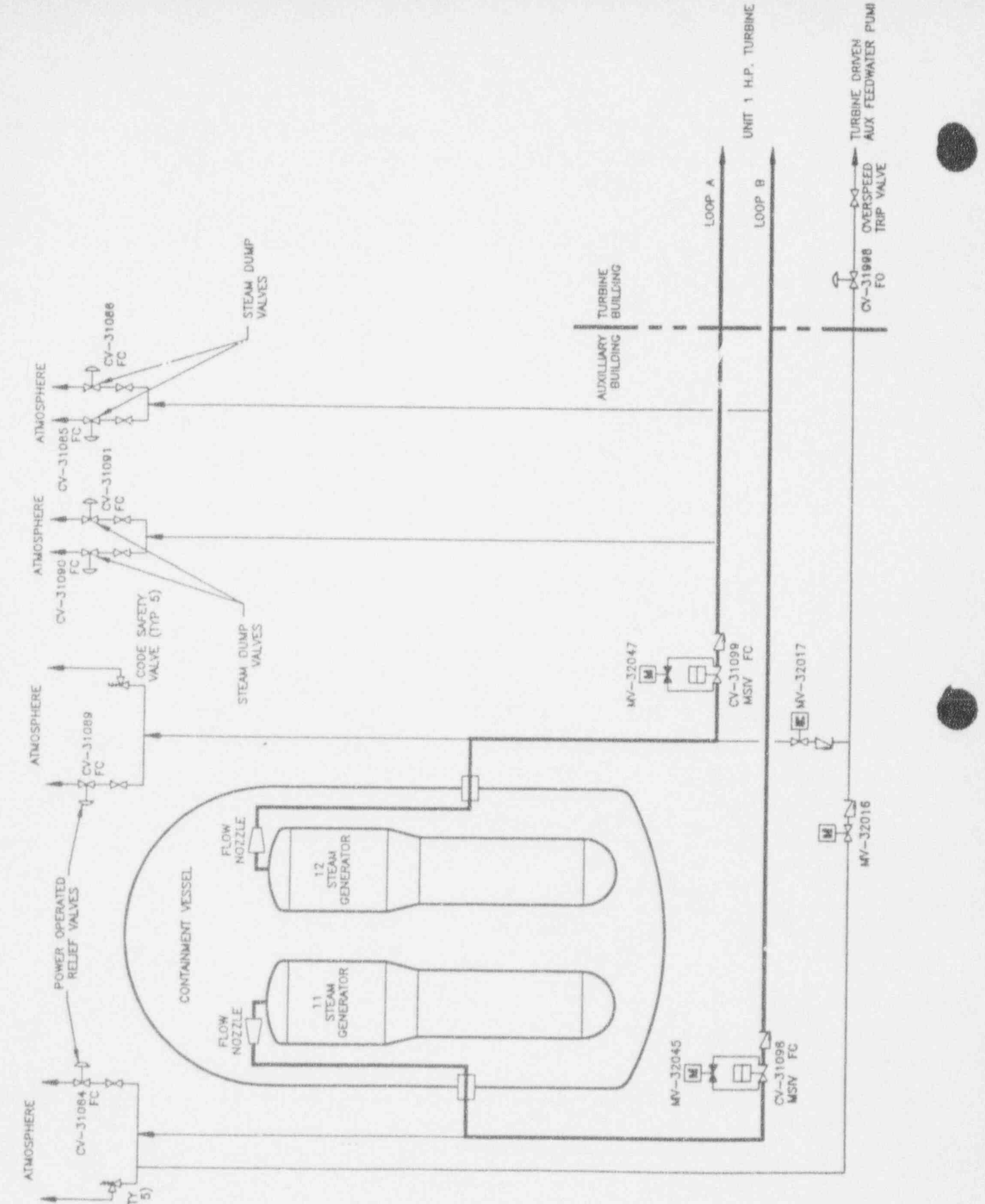


SAFEGUARDS CHILLED WATER SYSTEM

FIGURE 3.2-18



MAIN AND AUXILIARY STEAM SYSTEM

FIGURE 3.2-19

3.3 Sequence Quantification

3.3.1 Introduction

The process of quantifying fault trees involved calculating a probability for each basic event on each fault tree. These calculations were based on either historical failure and demand data for Prairie Island, or on an acceptable source of generic data. Plant specific data were preferred, because they provided a greater potential to gain plant-specific insights than generic data sources.

The plant-specific or generic failure rates fell into one of three categories.

1. Demand-type failures (such as pump failure to start or valve failure to open).

2. Failure during standby (in which case the failure probability was the failure rate times one half the interval of the test which will detect the failure).

3. Random failure of the component to perform its function during the course of the transient (the failure probability is the failure rate times the mission time of the component, typically 24 hours).

The mission time of components was needed to calculate the probability of failures of operating equipment which occurred randomly subsequent to the initiating event. It is a common practice in the nuclear power industry to use a mission time of 24 hours for PRA activities unless specific considerations dictate otherwise. Successful operation for 24 hours of the equipment required to respond to accident conditions would place the plant in a condition where decay heat levels are very low and long times are available for mobilization of people and equipment for recovery of failures occurring beyond this point in time. Successful 24 hour operation of plant equipment leaves the plant in a state where if subsequent failures occur, they would have a very low contribution to the Core Damage Frequency.

3.3.2 List of Generic Data

When plant-specific failure rates could not be calculated, several sources of generic data were available. They were:

1) NUREG/CR-2815, Probabilistic Safety Analysis Procedures Guide
2) NUREG/CR-4550, Analysis of Core Damage Frequency
3) IEEE Standard 500 data
4) EPRI TR-100320, Vol. 2, Reliability Centered Maintenance (RCM)

Technical Manual
5) WASH-1400, Reactor Safety Study (NUREG 75/014)

The generic failure rates from these sources were frequently expressed as failures per hour. When a failure rate estimate for a demand failure was given in generic data as failures per hour, the failure rate was converted to failures per demand by treating it as a random failure during standby. The failure rate per hour was multiplied by one-half the test interval to get the probability of failure on demand. This method was considered appropriate because demand failures can be viewed as failures to function on demand due to some preexisting fault which actually developed during the idle period since the last use of the equipment. Table 3.3-1 provides a summary of events which used generic data and the source of that data.

Generic initiating events were used when no plant data was available to estimate an initiating event frequency. The generic initiating events are discussed in more detail in Section 3.1.1. The following generic initiating events were used for the Prairie Island IPE:

LOCAs

3.3.3 Plant Specific Data and Analysis

Plant specific data were collected primarily for major mechanical components. Classical statistical methods of estimating component failure rates were used. Plant specific data sources were exhausted before generic data sources were used for any component failure rate. This extensive use of plant specific data means that in general, all major and significant mechanical component failure rates and initiating events were generated using plant specific data.

During the data collection process component boundaries were established which were used for data collection and system fault tree modeling. In general for pumps, the instrument air compressors, and the FCUs any failure that effected the pump, it's driver, it's supply breaker, or the breaker control or motor control circuitry was considered a failure of the pump. The auxiliary feedwater pumps and vertical cooling water pumps were treated differently. In both cases, different types of drivers are used on identical pumps. In these two cases the pumps and drivers were accounted for separately to allow for common cause analysis on the pumps and drivers independently. Components that receive an "S" signal did not include the "S" signal circuitry within the component boundary. The emergency diesel generators boundaries included the engine with it's support systems (except for cooling water on D1 and D2), the governor, the generator, the output breaker, and all control circuitry.

The plant specific demand failure rate of a given component was estimated by dividing the failures of that component during a specified time interval by the demands for that component to act or operate during the same period of time. Time dependent standby failures were calculated by multiplying the failure rate per hour by one-half the test interval. Time dependent operating failures were derived by dividing the total number of failures by the total number of hours the component had run. This was done for each failure mode of interest to produce rates for several failure modes of each component. The result was expressed either as a rate per demand, if the failure mode is a demand-type failure, or a rate per hour if the failure mode was standby or operating. This process was also used for pools of similar components which were coalesced to obtain statistically broader based results. Examples of component types that were pooled are motor-operated valves, etc.

The sample period for which plant specific data was collected was ten years, between January 1, 1978 and December 31, 1987. This time span was the period when failure, maintenance, and demand data were readily accessible using electronic data retrieval techniques. The data collected was considered to be significant and provides meaningful failure rates.

The hours of actual plant operation during the sample period were compiled. Random and demand failures were counted during the entire sample period, whether or not the plant was in an outage. These were divided by all the demands during the sample period in order to obtain a failure rate estimate.

The plant specific failure rates were compared to the generic sources to check for reasonableness. When a discrepancy occurred the calculation was checked to find the reason for the discrepancy. If there was sufficient plant data to make a good estimate of the failure rate the plant value was used since it will correctly model the plant equipment.

Some components and failure modes experienced no failures recorded in the plant data. In order to use the component data to derive a non-zero failure rate estimate in these cases, a value of 0.5 was used to represent the number of "failures" in deriving the estimate. This treatment (which is similar to a Bayesian update of a non-informative prior) allowed derivation of a conservative non-zero estimate while giving some credit to the component for not failing. Sometimes, however, this treatment resulted in an estimate that was much higher than generic estimates for the same type of component and failure mode. In such cases, generic estimates were used because using the conservative estimated derived from plant data would penalize the component for having experienced no failures. These cases were indicative of insufficient plant data on which to base an estimate, so generic estimates were considered more appropriate.

Table 3.3-2 provides a summary of components which used plant specific data.

3.3.4 Human Actions

Human actions modeled in the PRA include errors in restoring systems to normal operating status following test or maintenance activities, activities in progress at the time of the initiating event which influence its outcome such as maintenance or testing, and operator errors in responding to an accident.

3.3.4.1 Restoration Errors

In some cases, test or maintenance activities require a component to be temporarily removed from service such that it cannot perform its intended function. Failure to properly restore the component to the proper position or condition could result in the component being unavailable when required. To account for component unavailability due to restoration errors, several factors relating to each test and maintenance action were examined. Many tests and maintenance procedures require an operational test of a system or component following completion of work to verify that the system is operable. In some cases, even if a component were to be left in the wrong position or condition it would automatically return to the proper condition when required. An example of this would be a normally open isolation valve in an injection line which gets a signal to open even if it was inadvertently shut. Unless these factors were present, restoration failure modes were included in the fault tree models as a basic event.

Correcting restoration errors was credited if the operator could tell from the control room that the component was in the wrong position or condition and the operator was required to check the component status routinely (once per hour or once per shift). A reduction in the probability of failing to correctly restore a component to service was made in these cases.

3.3.4.2 Maintenance Activities

There were two general categories of maintenance actions of importance:

1. Routinely scheduled maintenance. These actions occurred periodically and were intended to ensure that a component operates at peak efficiency. Actions such as oil changes, bearing replacement, filter replacement, etc. are examples of this type of maintenance.

2. Unscheduled maintenance. These actions involve repair or replacement of a component due to failure during normal operation or upon detection during periodic testing. Generally speaking, unscheduled maintenance

actions require a longer time to complete than scheduled actions. The frequency of both scheduled and unscheduled maintenance can vary significantly from system to system depending on the operating philosophy (e.g., waiting until scheduled outages rather than taking components out of service during normal operations), as well as the reliability of a system or component.

Plant specific data was used to derive the fraction of time a given component or train of equipment could be expected to be out of service for maintenance. The period of time over which this data was collected was the same as that for which component data was collected (January 1978 through December 1987).

3.3.4.3 Testing Activities

Testing actions refer to those periodic operations or inspections of components to verify that they were operable. These acts were usually performed to satisfy requirements contained in the Technical Specifications for the plant. A system could be unavailable because of the test. Testing was only modeled if the testing resulted in a system or component unavailability during the test. Information used to derive component unavailability during testing was obtained from a review of plant surveillance procedures.

3.3.4.4 Human Error

In order to minimize the possibility of having multiple human error events in the same cutset, the number of human errors included on the fault trees was held to a minimum. Only those post-accident operator actions required to initiate systems and maintenance restoration errors were included in the fault trees. Operator actions in response to equipment failures were not included until sequence cutsets were generated. The cutsets were reviewed after sequence quantification and when more than one human error appeared in the same cutset, either independence of the human actions was confirmed, or a change was made to correctly model dependence between the human errors.

The only human actions credited in the PRA are those currently proceduralized or covered in operator training. In deriving the human error probability (HEP) for each of these actions, a conservative screening process was used. The screening process for determining the initial HEP values assumed human actions are influenced by several key performance shaping factors such as:

1. Time available to perform the action.

2. Degree of difficulty in performing the action (complexity of action or number of procedural steps).

3. Stress under which action must be taken.

Operator reliability was determined based on plant specific estimates of the time available to initiate and perform the action. Performance shaping factors associated with degree of difficulty and stress were applied to each failure rate. The screening values were obtained by following a flow chart and answering a series of questions. A value (or a time dependent table) was assigned to the variable based on the answers to the questions. The HEPs assigned to each operator action using this screening procedure are based on the following data sources: (1) NUREG/CR-1278, Handbook of Human Reliability Analysis [3.3-1], (2) Wash-1400, Reactor Safety Study [3.3-2], and (3) the data sources used in the BWR IPE Methodology [3.3-3]. Screening values for some of the typical operator actions are given in table 3.3-10.

Quantification of the fault trees and event trees was performed with the screening values and the most important operator actions were identified later to focus the detailed HEP development. Operator actions were identified as important if they contributed significantly to the baseline core damage probability or if a change in the failure rate could cause a significant increase in overall core damage probability. This method is similar to the approach suggested in NUREG-1335 [3.3-4] (page 2-8) for identifying important actions that have a significant effect on sequence frequency. The importance measures used to identify these operator actions are Fussell-Vesely and Birnbaum. The Fussell-Vesely importance measure gives the fraction of risk associated with a given component. The Birnbaum importance measure gives the increase in risk associated with a component, i.e., for this case it is the CDF when component failure probability equals one minus the CDF when the component failure probability equals zero. Operator and recovery actions which have a Fussell-Vesely greater than or equal to 1% and a Birnbaum greater than or equal to 1E-6 were considered for further evaluation. Each time the model logic or basic event values are changed and the model is requantified, the Fussell-Vesely and Birnbaum for each human error event also changes. Some of the HEPs that met the criteria for performing detailed HRA prior to fine tuning the model may no longer meet the criteria. For these cases, if a detailed HEP was calculated for previous iterations of the quantification process, we continued to use the value even if the human error event no longer met the criteria for performing detailed HRA.

The detailed HRA was performed using the EPRI SHARP framework for human reliability analysis. The quantification of the human error probabilities was performed using the method in NUREG/CR-4772 [3.3-5] (commonly known as the ASEP method), which provides a simplified version of the method in NUREG/CR-1278, The Handbook of Human Reliability Analysis. The ASEP method produces HEP estimates that are more conservative than would be realized from a full scope application of the THERP method, but usually less conservative than the screening estimates used in the initial sequence quantification.

Finally, a few of the key operator actions were analyzed using the methodology described in NUREG/CR-1278 [3.3-1]. The analysis is similar to the ASEP methodology described above except that more detailed analysis is performed for:

- The types of procedures used (with or without signoffs, etc.)
- Verification steps
- Crew size and expected crew response timing
- Errors of omission and errors of commission (based on the type of controls)
- Timing
- Expected Stress
- Conditional HEPs (dependence between operator actions)

The NUREG/CR-1278 methodology was used for the five operator actions identified in table 3.3-3 as HRECIRCSMY, HRECIRCXXY, RRECIRCXXY, SGTRXXXCDY and SGTRXXEC3Y. The five operator actions are associated with transferring to recirculation following a LOCA or cooling down and depressurizing following a Steam Generator Tube Rupture.

The HEP values from the detailed HRA were substituted for the screening values in the final results of the sequence quantification The HEP results from the detailed HRA were compared to the results from the screening analysis. In all cases, the detailed HRA produced HEPs at about the same value or lower than the screening analysis results. Therefore no information was missed during the quantification using the screening values, i.e., there would be no additional cut sets if the final quantification would have been performed using the HEPs obtained from the detailed HRA. The basic events for which detailed HRA was performed are described further in Table 3.3-3 and 3.3-5.

In addition to the quantification of operator actions, Table 3.3-4 provides a list of repair and recovery activities that were included in the PRA. Repair and recovery data was either derived from generic sources (such as offsite power recovery or repair of mechanical equipment).

The human factors review in support of the HRA included the following three task:

1) Review of the "Control Room Design Review" documents for factors not previously considered in the Prairie Island PRA HRA.

2) Walkdowns of selected local operator actions and control room panels to verify assumptions made during the HRA, and to look for factors not previously considered in the HRA.

3) Interviews with control room personnel to discuss roles and responsibilities during actions, timing of operator actions, and performance of specific actions important to the PRA.

3.3.5 Common Cause

This section outlines the steps for evaluation of common cause failure probabilities in the system models developed for the PRA. The discussion describes how common cause events were included in the fault trees. The PRA common cause failure analysis was part of a wider evaluation aimed at analyzing and estimating the potential effects of dependencies in and among plant systems. Important common cause dependencies were those that may compromise existing redundancy to prevent and mitigate a severe accident.

The common cause failure analysis treated those dependencies that were not explicitly modeled in other phases of the PRA. The list below gives dependencies that are explicitly treated in other phases of the PRA and their method of treatment:

Support System Dependencies: Transfers to support system fault trees were included at appropriate points in system fault trees. Linking of fault trees during fault tree reduction and cutset generation ensured such dependencies were expressed correctly in PRA results.

Shared Components Among Frontline Systems: As with shared support systems, this type of dependency was evaluated correctly by the linking of fault trees in the sequence quantification phase of the analysis.

Human Errors: Human errors, considered in the IPE, were discussed in the previous section. Human errors such as incorrect calibration of sensors or instruments were included as explicit events in system fault trees. Human errors such as failure to restore components to service after their isolation for maintenance were also explicitly included as explicit events in fault trees. Operator errors occurring subsequent to an accident initiator were explicitly treated in the system fault trees if the system was not automatic and required manual action for initiation. Events associated with operator response to initiate automatic systems or repair failed systems were included as recovery actions after sequence cutset results were generated.

Maintenance and Testing: Unavailability of multiple components due to maintenance, repair (unscheduled, corrective maintenance), and testing were included as explicit events in the system fault trees.

External Events: Dependencies among component failures due to the effects of spatially dependent or "external" events (earthquake, fire, external flood, tornado, and heavy wind) are not evaluated as a part of the PRA at this time. The effects of these events will be considered in response to the IPEEE. Common dependencies due to internal flooding were evaluated, however.

Inclusion of other common cause failure modes involved defining additional events representing common cause failures of components to be added to system fault trees. Common cause events were defined and their probabilities estimated to capture the dependence among component failures (both within a system and among separate systems) arising from causes other than those listed above. Some potential causes of dependent component failure other than those listed above included common design, manufacture, installation errors, adverse environment, internal physical similarities such as identical parts, and common human impacts during maintenance, testing, or operation.

The component groups for which common cause events were defined are largely those that have proved important in previous PRAs and reliability studies and are given in Table 3.3-6.

The common cause investigation examined equipment within individual systems and included some components with potential dependencies across both units. Some common cause groups which include components from both Unit 1 and Unit 2 include:

1. Motor and turbine driven auxiliary feedwater pumps
2. Emergency diesel generators
3. Batteries.

After common cause events were included in the system models, probability estimates were calculated for each event for fault tree quantification and cut set generation. This required selection of a common cause probability model, data analysis to derive parameter estimates for the model, and the evaluation of event probabilities according to the model and the data.

The common cause failure (CCF) analysis estimated CCF probabilities in the framework of the Multiple Greek Letter (MGL) model. This model's parameters (the Greek letters beta, gamma, delta, etc.) are defined as conditional probabilities of the failure of additional components in a common cause group, given the failure of a certain number of components. Thus, for example, the MGL model parameter "beta" is defined as the probability of common cause failure of two or more components in a common cause group, given that at least one has failed; the parameter "gamma" is defined as the CCF probability of three or more components, given the failure of at least two. The basic event probabilities of the common cause events were simply the product of the single-component failure probability (estimated from plant data or generic sources) and the MGL parameter estimates.

The primary data for the common cause factor estimates were found in published studies [3.3-6, 7, 8, 9], which have sorted and classified events as individual or common cause component failures. The multiple greek letter results for the CCF analysis are presented in Table 3.3-7.

3.3.6 Support States

Fault trees were developed for the support systems required by the front line systems. The support system fault trees were prepared and quantified in the same manner as the frontline system fault trees. The effects of support system component failure on frontline systems and sequences was accomplished by linking the support system fault trees directly into the frontline and other support systems they affect. Using the linking process there is no need to produce a support state event tree model to account for the effects of support systems.

3.3.7 Sequence Quantification

After all of the system fault trees were completed, minimal cutset equations for the top events of the fault trees were produced. Equations for the functional headings of the fault trees were then derived where combinations of more than one fault tree top event for a given safety function were required. The functional equations representing the headings for the Level I Event Trees were then combined with the various initiating events as defined by the event trees to produce core damage sequences.

The computer programs CAFTA (EPRI) and HPSETS (Logic Analysts, Inc.) were used for this work. Cutsets for all systems, functions and sequences were retained down to the 10^{9} level.

3.3.8 Internal Flooding Evaluation

Generic Letter 88-20 requires an internal flooding analysis as part of the IPE process. A number of internal flooding PRAs to date have been scoping analyses which have concluded that internal flooding will not lead to core damage. The Oconee 3 PRA, however, concluded flooding was a dominant contributor to the total core damage frequency and subsequently made plant modifications as a result. Other plants have experienced maintenance events which have resulted in flooding of equipment. All of these factors provide the basis for performing the Prairie Island internal flooding analysis.

The purpose of the Prairie Island IPE internal flooding analysis was to determine potential vulnerabilities due to flooding from sources such as tank overfilling, hose and pipe ruptures, and pump seal leaks. The analysis used bounding and conservative assumptions to simplify the analysis. Qualitative and quantitative analyses were performed to identify potentially important vulnerabilities. Attention was focused on the major flood sources in the plant which could affect multiple systems and propagate to other areas. Low capacity systems which had limited impact on other systems and flood initiators which were bounded by other flooding events were qualitatively screened from further consideration.

The total core damage frequency for internal flooding events is estimated to be 1.04E-5/year. This was dominated by a single flood that accounted for almost all of the CDF due to flooding. This flood is in zone TB1 which is the Auxiliary Feedwater Pump/ Instrument Air Compressor Room. This room has the main cooling water supply headers to the Auxiliary Building running through the overhead. This flood consists of a single sequence in which a significant break occurs in the Loop A or B cooling water line above the auxiliary feedwater pump room in the turbine building. The resultant flood causes loss of all auxiliary feedwater pumps, loss of all instrument air compressors and loss of main feedwater due to loss of instrument air and loss of lube oil cooling. Reactor trip is successful along with RCP seal cooling. Secondary cooling fails due to failure of AFW and MFW. Short term RCS inventory fails due to loss of pressurizer PORVs which fail closed on loss of instrument air. No other flood had a significant impact on core damage.

Figure 3.3-1 shows the floor layout of the Auxiliary Feedwater Pump room. If the fire door in the room is closed, the impact of this flood is significantly reduced since the zone is divided into two smaller zones which means that fewer components are exposed to the flood water. Only one train of Auxiliary feedwater pump per unit is affected by a break in either of the new zones. On a Loop A break, 121 and 122 Instrument Air Compressors are exposed while on a Loop B break, only 123 Compressor is effected. Sensitivity studies for this flood with the fire door closed were performed to determine the impact of closing the door. The results of this study are discussed in section 6.

The assumptions, methodology, and mitigative factors of the Prairie Island internal flooding IPE are discussed in this section. The results of the flooding quantification are discussed in section 3.4.

3.3.8.1 Background

Considerable review of the Prairie Island plant design and operating procedures has been performed in the past with respect to the potential and effects of internal flooding. In performing the internal flooding evaluation, various documents were reviewed which discussed the possibility of internal flood such as the IE Bulletin 80-24 and SOER 85-05.

SOER-85-05 issued by INPO, required an assessment of the vulnerability of operating facilities to the loss of safe shutdown functions due to internal plant flooding. Analyses performed in response to this SOER identified no safe shutdown functions which could be compromised as a result of various flood initiators. The response to SOER 85-05 identified that maintenance events were the primary cause of flooding events based on industry experience. An extensive part of the plant evaluation of the SOER involved reviewing procedures to see if they adequately addressed flooding and to identify the need for training in this area. Identified as a part of this review, was the fact that procedural controls are in place assuring safety related isolations require independent verification. Emergency procedures were also reviewed as a part of the SOER and were found to be adequate in this respect. Administrative procedures specifically address flooding as a consideration in the plant modification process. The response to the SOER also involved training plant personnel on internal flooding and the need to ensure adequate isolation of equipment. A review of the training needs identified in the original SOER evaluation was performed in 1989 to verify them to be in place. SOER 85-05 was a nonprobabilistic assessment of the potential for flooding and its consequences. The results of the PRA were found to be consistent with this evaluation.

3.3.8.2 Process

For the purpose of performing the Prairie Island IPE flooding analysis, flood zones within various buildings of the plant were determined. A flood zone was defined as an area in which systems and equipment included in the level 1 PRA were located that could be potentially affected by flooding from one or more sources. A deterministic screening process of each potential flood zone to eliminate areas where no equipment considered in the IPE is located as well as areas where no flood source of sufficient volume is available was performed. Table 3.3-8 presents the definition of the six flood locations after completion of the screening process. Table 3.3-9 provides a summary of the systems and components that would be unavailable if flooding of a particular zone occurred. Internal flood initiating event frequencies were calculated by zone and were based on the combined frequency of each relevant flooding sources' contribution to the zone.

Plant walkdowns were conducted for each potential zone and each potential flooding source as a part of the deterministic review to obtain various factors such as the length and diameter of water piping system, number of valves, tanks, room drains, room sumps, presence of equipment for systems considered in the PRA, propagation to and from other areas, door arrangement, curbs, and more. Generic pipe, valve, and tank rupture frequencies were used to estimate the initiating event frequency due to pipe break. Realizing there was a great deal of uncertainty in the pipe and valve rupture frequencies, a detailed analysis to account for every foot of pipe in the plant was unnecessary because important insights would be apparent regardless of the exact initiating event frequency. The primary objective of the walkdown was to determine potential flooding sources and equipment affected, with a secondary objective to account for the amount of equipment to be considered in the initiating event frequency. In deriving the initiating event frequency only normally running systems, systems with auto start features or systems that could drain by gravity were included. Systems that auto start only after an initiating event, such as SI, RHR, or CS, were not included due to the low probability of the initiating event and the pipe failure together. Systems which are normally not running and do not have an automatic start capability were not included as a potential flooding source. Further, low pressure piping is assumed to contribute to the potential for flooding at the same rate as pressurized piping. No credit for leak-before-break concepts was taken in this evaluation.

An estimate of the potential for maintenance or surveillance activities to contribute to the flooding in each zone was also made. Contribution from such activities was considered irrespective of the administrative and procedural controls associated with tagging equipment and verifying its return to service, no particular maintenance or surveillance activity could be assumed to predominate the risk associated with internal flooding. The potential for this type of flooding initiator was estimated simply by assuming that there was a 50% chance that a flooding event should have occurred due to maintenance activities over the life of the plant so far (or 2.5E-2/yr). The maintenance initiating event frequency used in the quantification was distributed among the various areas as a weighted average in proportion to the amount of maintenance done in an area which could cause a flood.

For each flood zone for which drainage was credited, analyses were performed to estimate the flooding rate an area could tolerate considering factors such as floor drains, sump capacity, and door leakage. Prior to elimination of potential flooding sources for a particular flood zone, it was confirmed that the drainage capacity for the room exceeded the rate at which flooding was expected to occur. For the systems that remained, calculations were also performed to establish the size of the piping above which those systems needed to be considered further. For flood sources associated with a limited volume of water (such as that contained within specific tanks) derivation of room volumes was performed. These were used to determine what level the room would reach for a given volume of water. Where multiple systems contribute to the potential for flooding of a particular zone, the system with the highest flooding rate or most significant effects was considered in the analysis of the zone (for example, the lower capacity fire system was often considered to be bounded by the cooling water system). Once the low or limited capacity systems were identified, attention was focused on the higher capacity systems, particularly those which would affect multiple systems.

On completion of the initiating events analysis and the FMEA, sequence quantification was performed using the internal events event trees and fault trees. Failures postulated to occur as a result of the flood were related to components represented by basic events within the fault trees.

3.3.8.3 Assumptions

Having identified important flooding zones within Prairie Island structures and source of the potential flood initiators, a number of assumptions must be made about the effects of each of the postulated floods. Assumptions regarding systems and equipment that may be disabled as a result of the flood are presented in Table 3.3-9. In this section, other assumptions regarding the magnitude and effects in each of the flood areas are presented. Assumptions which were applied generically to all flood areas are presented below. It should be noted that care was taken to use conservation or bounding assumptions in many cases to minimize detailed evaluations of minor factors which may not provide significant insights regarding potential vulnerabilities associated with internal flooding.

Generic Assumptions

Doors which open away from the flood are assumed to fail before the water rises significantly above the floor (less than 2 feet) allowing water to flow into and affect equipment in adjacent areas.

Doors which open into the region of the flood are assumed to remain closed. Leakage around the door into adjacent areas and consideration of its effect are still estimated, however.

Pump run out or pump overcurrent breaker trips are conservatively assumed not to occur when a pipe break occurs.

The minimum time allowed for a zone to flood was based on the indications that the operators would receive to alert them to the flood. The operators were assumed to find and isolate the source of flooding within 20 minutes if an alarm or other indicator would tell them exactly where the flooding is occurring. If the operators have an indication that there is a flood but the indication does not lead them directly to the source it is assumed that they will find and isolate the leak within 60 minutes. If there is no indication that there is a flood occurring it was assumed that the flood will be found and isolated within 3 hours by the operators doing their normal rounds.

Motor control centers and electrical buses were assumed to fail at 6 inches of water.

Cable insulation was assumed to be water resistant. A visual check was performed of several cable trays to assure no notable degradation of cable insulation was observable.

Water removal from a zone via floor drains was considered but found to be insignificant as compared to other water removal mechanisms and flood sources.

Water spray on equipment was considered. If water spray from piping located near equipment that could only affect one component or one train of equipment was not considered to have a significant effect and was not considered since failure of the equipment caused by spray has a lower probability than random failure. Therefore the failure of the equipment from a pipe break was assumed to not contribute significantly to the overall system failure rate. Failure of multiple systems or components by water spray was included in the analysis. Spray from a high capacity pipe was included because breaks large enough to flood a zone were conservatively assumed to fail all equipment in that zone.

3.3.8.4 Transient Analysis

In quantifying each of the flood initiated accident sequences, examination of reactor response established key timing for reactor conditions and operator response. Each of the accident sequences were assigned to an accident class:

FEH - Flood initiated core damage early at high reactor pressure

FLH - Flood initiated core damage early at low reactor pressure

No new transient analyses were considered necessary to quantify flooding initiators. The timing of each of these classes was essentially the same as their counterpart in the internal events PRA. FEH corresponds to TEH accident class and FLH corresponds to TLH. A description of these transient accident classes can be found in section 3.4.2.

References

3.3-1 NUREG/CR-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications", USNRC, August, 1983.

3.3-2 WASH-1400 (NUREG-75/014), "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants", USNRC, October, 1975.

3.3-3 IDCOR BWR Individual Plant Evaluation Methodology, Rev 1, December 1986.

3.3-4 NUREG-1335, "Individual Plant Examination: Submittal Guidance", USNRC, August, 1989.

3.3-5 NUREG/CR-4772, "Accident Sequence Evaluation Program Human Reliability Analysis Procedure", USNRC, February, 1987.

3.3-6 NP-3967, "Classification and Analysis of Reactor Operating Experience Involving Dependent Events", EPRI, June 1985.

3.3-7 NUREG/CR-3289, "Common Cause Fault Rates for Instrumentation and Control Assemblies", USNRC, May, 1983.

3.3-8 NUREG/CR-2770, "Common Cause Fault Rates for Valves", USNRC, February, 1983.

3.3-9 Nuclear Plant Reliability Data System, INPO

Table 3.3-1
Generic Failure Rates Used in this Study

Component	Failure	Value	Reference
Motor Operated Valve	F	2.00 E-7/hr	NUREG/CR-2815
	L	2.00 E-7/hr	NUREG/CR-2815
Air Operated Valve	F	1.00 E-7/hr	NUREG/CR-4550
	L	5.00 E-7/hr	NUREG/CR-4550
Solenoid Valve	N	9.40 E-7/d	IEEE 500
	F	1.10 E-7/hr	IEEE 500
Manual Valve	N	2.00 E-7/hr	NUREG/CR-2815
Relief Valve	L	2.37 E-6/hr	IEEE 500
	N	3.20 E-3/d	IEEE 500
Damper	F	1.37 E-6/hr	IEEE 500
	N	1.20 E-4/d	NUREG/CR-2815
Air operated damper	F	1.37 E-6/hr	IEEE 500
	N	1.20 E-4/d	NUREG/CR-2815
	C	1.20 E-4/d	NUREG/CR-2815
Bus	E	3.00 E-8/hr	NUREG/CR-2815
MCC	E	3.00 E-8/hr	NUREG/CR-2815
Ckt Bkr	F	1.00 E-7/hr	IEEE 500
Ckt Bkr (480V)	C	9.95 E-5/d	IEEE 500
	L	1.00 E-8/hr	IEEE 500
	N	4.29 E-5/d	IEEE 500
Ckt Bkr (4160V)	C	9.95 E-5/d	IEEE 500
	L	1.00 E-8/hr	IEEE 500
	N	4.29 E-5/d	IEEE 500
Fuse Failure	E	2.30 E-7/hr	WCAP-10271
Transformer	E	6.00 E-7/hr	NUREG/CR-2815
Breaker position indicator	E	1.00 E-4/d	WASH 1400
Battery charger	E	4.10 E-7/hr	IEEE 500
	S	4.90 E-7/hr	IEEE 500
Battery	E	2.00 E-6/hr	NUREG/CR-2815
Inverter	E	6.00 E-5/hr	NUREG/CR-2815
DC Panel	E	3.00 E-8/hr	NUREG/CR-2815
Relay	E	3.00 E-6/hr	NUREG/CR-2815
	P	3.00 E-6/hr	NUREG/CR-2815
	W	1.00 E-7/hr	IEEE 500
Solid State Logic Module	E	3.00 E-6/hr	NUREG/CR-2815
Bistable	E	1.01 E-6/d	IEEE 500
Flow Transmitter	E	2.60 E-7/hr	IEEE 500
Level Transmitter	E	4.60 E-7/hr	IEEE 500
Pressure Transmitter	E	3.80 E-7/hr	IEEE 500
Pressure Controller	E	3.00 E-6/hr	NUREG/CR-2815
SI Pumps	R	3.00 E-5/hr	NUREG/CR-4550
CS Pumps	R	3.00 E-5/hr	NUREG/CR-4550
BATP	R	9.60 E-4/hr	NUREG/CR-2815
	S	1.00 E-4/d	NUREG/CR-2815
Pressurizer PORV	N	1.00 E-5/d	NUREG/CR-4550
	C	3.00 E-2/d	NUREG/CR-4550
Flow orifice	F	6.00 E-7/hr	NUREG/CR-2815
Filter	F	3.00 E-5/hr	NUREG/CR-2815
Strainer	F	3.00 E-5/hr	NUREG/CR-2815
Screen House Trav. Screens	F	3.00 E-5/hr	NUREG/CR-2815

Table 3.3-1 (continued)
Generic Failure Rates Used in this Study

Component	Failure*	Value	Reference
Circ. Water Traveling Screen	F	3.00 E-5/hr	NUREG/CR-2815
Heat exchanger	F	5.70 E-6/hr	NUREG/CR-4550
	L	3.00 E-6/hr	NUREG/CR-4550
Pipe	F	1.00 E-9/hr	WASH 1400
Tank	L	2.70 E-7/hr	Seabrook PRA
Chiller	S	5.00 E-3/d	RCM Handbook
	R	1.00 E-4/hr	RCM Handbook
Unit cooler	S	6.00 E-6/hr	NUREG/CR-2815
	R	6.00 E-6/hr	NUREG/CR-2815
Fan	S	4.00 E-3/d	NUREG/CR-4550
	R	7.00 E-6/hr	NUREG/CR-4550
Motor operated pump	S	3.60 E-3/d	NUREG/CR-2815
	R	1.00 E-4/hr	NUREG/CR-2815
Press. switch	W	7.00 E-8/hr	IEEE 500
	E	1.01 E-6/d	IEEE 500
Static switch	E	2.48 E-4/d	IEEE 500
Flow switch	W	8.60 E-7/hr	IEEE 500
Limit switch	E	6.00 E-6/hr	NUREG/CR-2815
Manual switch	L	3.00 E-8/hr	WASH 1400
	C	1.00 E-5/d	WASH 1400
	E	1.00 E-5/d	WASH 1400
Level switch	E	1.01 E-6/d	IEEE 500
	W	1.57 E-6/hr	IEEE 500

* Failure codes on this chart: L = Fail to remain closed / Leak
F = Fail to remain open / Plugged
N = Fail to open
C = Fail to close
E = Fail to function
S = Battery charge failure
P = Short to power
W = Spurious operation
S = Fail to start
R = Fail to run
M = Corrective maintenance unavailability

Table 3.3-2
Equipment Which Used Plant Specific Data

Component	Failure	Value
Component Cooling Pumps	R	2.70E-6/hr
	S	2.74E-4/d
	M	1.12E-3
	T	2.47E-3
RHR Pumps	R	2.61E-5/hr
	S	4.55E-4/d
	M	1.59E-4
	T	9.56E-4
D1 and D2	R	1.13E-2/hr
	S	3.37E-3/d
	M	7.96E-3
	T	1.04E-2
AFW Pumps	R	1.33E-4/hr
	S	6.11E-4/d
AFW Pump Motors	R	1.39E-4/hr
	S	7.58E-4/d
	M	5.87E-4
	T	3.76E-4
AFW Pump Turbines	R	6.13E-3/hr
	S	9.43E-3/d
	M	1.88E-4
	T	3.56E-4
SI Pumps	S	1.10E-3/d
	M	2.36E-4
CS Pumps	S	1.09E-3/d
	M	4.00E-4
FCU	R	1.44E-6/hr
	S	9.88E-5/d
	M	3.56E-3
Inst Air Compressors	R	6.90E-6/hr
	S	2.04E-4/d
	M	1.14E-3

Table 3.3-2 (continued)
Equipment Which Used Plant Specific Data

Component	Failure	Value
	T	2.86E-2
11/21 CL Pumps	R	1.16E-5/hr
	S	4.83E-4/d
Vertical CL Pumps	R	3.07E-5/hr
	S	5.88E-4/d
CL Pump Diesels	R	4.85E-3/hr
	S	4.46E-3/d
	M	3.30E-3
	T	4.66E-3
121 CL Pump Motor	R	1.55E-5/hr
	S	1.24E-3/d
	M	1.69E-4
	T	8.22E-4
Condensate Pumps	R	1.63E-6/hr
	S	1.36E-3/d
	M	2.19E-4
Charging Pumps	R	1.17E-4/hr
	S	7.96E-4/d
	M	2.16E-2
	T	6.33E-4
BATP	M	3.51E-3
	T	2.28E-5
SG PORV	N	1.04E-3/d
	C	1.04E-3/d
MOV	N	4.72E-3/d
	C	1.55E-3/d
AOV	N	2.64E-3/d
	C	1.71E-3/d
Check Valve	N	1.77E-5/d
	C	1.80E-5/d
Dampers	N or C	1.17E-3/d
MFW Pumps	R	9.85E-6/hr

Table 3.3-2 (continued)
Equipment Which Used Plant Specific Data

Component	Failure	Value
	S	6.02E-3/d
	M	2.92E-3

Notes:

1. Failure Modes
   R - fail to run
   S - fail to start
   N - fail to open
   C - fail to close
   M - Corrective maintenance unavailability
   T - Preventive maintenance unavailability

2. The T failure mode includes both preventive maintenance unavailability and test unavailability.

3. Some components had no preventive maintenance or test done while at power, therefore no T mode is used.

4. Generic values were used for some failure modes on some components due to low demands or operating hours which did not produce reliable plant specific failure values.

5. The motor operated valves and air operated valves used plant-specific data only for failure to open and failure to close.

Table 3.3-3

Human Actions for which
Detailed HEPs were Developed

Operator Action	Fail. Prob	Discussion
Transfer unit 2 ac to unit 1 during unit 1 SBO	.0032	AMNVLTRXXY - During a station blackout of unit 1, with power still available to unit 2, the operators will cross tie unit 2 power to unit 1. The need for the action is easily recognized (unit 1 control room lights out & unit 2 lights on) and is proceduralized.
Cool down & depressurize RCS to stop tube leak before SG overfill	.011	SGTRXXXCDY - When a steam generator tube rupture occurs the faulted steam generator is isolated. Then the operators must depressurize the RCS to stop leakage to the secondary before the isolated steam generator goes solid with water and the SG PORV opens to relieve pressure. Following water relief, the SG PORV is likely to fail open.
Cool down and depressurize RCS to stop leak after SG overfill	.0065	SGTRXXEC3Y - If a steam generator tube rupture occurs and the PORV fails open on the ruptured steam generator, then the RCS must be depressurized to stop leakage from the RCS to the secondary. This action should be completed before the RWST runs dry because it is the source of makeup for the lost water.
Open doors on loss of room cooling	.067	ABSC3711XV - On loss of chilled water the operators are directed to provide temporary ventilation to bus 120 room. The room cooling is provided by opening the doors to the room and setting up portable fans.
Transfer to recirc. during small LOCA	.0012	HRECIRCSMY - On a small LOCA the ECCS automatically injects to the RCS taking suction from the RWSTs. When the RWST drains down to 33% level the operators manually switch ECCS to the recirculation mode of operation.
Transfer to recirc during medium LOCA	.0027	HRECIRCXXY - On a medium LOCA the ECCS automatically lines up and injects to the RCS taking suction from the RWSTs. When the RWST drains down to 33% level the operators manually switch ECCS to the recirculation mode of operation.

Table 3.3-3 (continued)

Human Actions for which
Detailed HEPs were Developed

Operator Action	Fail. Prob	Discussion
Transfer to recirc during large LOCA	.0084	RRECIRCXXY - On a large LOCA the ECCS automatically lines up and injects to the RCS taking suction from the RWSTs. When the RWST drains down to 33% level the operators manually switch ECCS to the recirculation mode of operation.
Cross tie to unit 2 motor driven AFW pump	.032	EOPHXCONXY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If they are unable to establish flow from unit 1 sources, they will cross connect the unit 2 motor driven AFW pump to unit 1. For this case unit 1 flow is not available due to mechanical reasons, and unit 2 AFW is available.
Cross tie to unit 2 motor driven AFW pump - conditional to restore MFW (no "S" signal present)	.22	EOPHXCONTY - This action is identical to that given for EOPHXCONXY except that it assumes that unit 1 flow was not available due to operator error. For this situation the dependency between this action and the unit 1 flow restoration actions are accounted for. This action is different from EOPHXCONSY in that no "S" signal is present.
Cross tie to unit 2 motor driven AFW pump - conditional to restore MFW ("S" signal is present)	.048	EOPHXCONSY - This action is identical to that given for EOPHXCONXY except that it assumes that unit 1 flow was not available due to operator error. For this situation the dependency between this action and the unit 1 flow restoration actions are accounted for. This action is different from EOPHXCONTY in that a "s" signal is present.
Restore MFW (no "S" signal)	.004	FOPFWTRANY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW flow is unavailable they will restore flow to the steam generators by opening the MFW bypass valves. This action is different from FOPFWSIXXY in that no "S" signal is present.

Table 3.3-3 (continued)

Human Actions for which
Detailed HEPs were Developed

Operator Action	Fail. Prob	Discussion
Restore MFW ("S" signal is present)	.027	FOPFWSIXXY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW flow is unavailable they will restore flow to the steam generators by opening the MFW bypass valves. This action is different from FOPFWTRANY in that a "s" signal is present.
Bleed & Feed (no "S" signal) - for single operator action cut sets	.039	FDBLDOPACY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW and MFW flow are unavailable and steam generator level drops below 7%, the operators are directed to initiate bleed and feed. This action is different from VFEEDBLDXY in that no "S" signal is present. This event is applicable to those cases where AFW and MFW were not restored for mechanical reasons.
Bleed & Feed (no "S" signal) - for multiple operator action cut sets	.071	FDBLDOPATY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW and MFW flow are unavailable and steam generator level drops below 7%, the operators are directed to initiate bleed and feed. This action is different from FDBLDOPACY in that the failure probability was calculated in such a way that this event is independent from operator actions to restore MFW or AFW. This action is different from VFEEDBLDSY in that no "S" signal is present.
Bleed & Feed ("S" signal is present) - for single operator action cut sets	.045	VFEEDBLDXY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW and MFW flow are unavailable and steam generator level drops below 7%, the operators are directed to initiate bleed and feed. This action is different from FDBLDOPACY in that a "s" signal is present. This event is applicable to those cases where AFW and MFW were not restored for mechanical reasons.

Table 3.3-3 (continued)

Human Actions for which
Detailed HEPs were Developed

Operator Action	Fail. Prob	Discussion
Bleed & Feed ("S" signal present) - for multiple operator action cut sets	.40	VFEEDBLDSY - Following a reactor trip the operators will verify that either MFW or AFW flow is being provided to the steam generators. If AFW and MFW flow are unavailable and steam generator level drops below 7%, the operators are directed to initiate bleed and feed. This action is different from VFEEDBLDXY in that the failure probability was calculated in such a way that this event is independent from operator actions to restore MFW or AFW. This action is different from FDBLDOPATY in that a "s" signal is present.

Table 3.3-4
Repair and Recovery Actions

Operator Action	Failure Probability	Discussion
Local recovery of MV-32120 or MV-32121 if both valves fail to close (basic event BMC2021RCV)	0.25	Applied to sequences in which both of these valves failed to close which is assumed to fail the CC system as these valves isolated non essential loads from the CC system and divide the CC system into two trains. Recovery data from NSAC-161 was used with a mean time to recover of 1 hour.
Local recovery of either MV-32093 or MV-32094 if both valves fail to open (basic event BMC93XXRCV)	0.25	Added to small LOCA sequences involving loss of recirculation as both valves failing to open fails CC to the RHR heat exchangers. These valves failing to open would be noticed early in the event. Recovery data from NSAC-161 was used with a mean recovery time of 2 hours.
Local start of 12 AFW pump at breaker cubicle after loss of DC control power (basic event E12AFWLOCV)	5E-2	Added to loss of train B DC sequences in which 11 AFW pump has failed and the operator has failed to restore MFW and cross-tie 21 AFW pump to unit 1. This is a screening value that is based on a recovery time of 58 minutes as determined by MAAP.
Local recovery of MV-32079 or MV-32080 after MV-32081 and MV-32082 have both failed to open (basic event H8182XXRCV).	5E-3	Added to cutset in which a small LOCA has occurred and the BAST suction valves to the SI pumps have both failed to open. In this case, the RWST suction valves to the SI pumps will not receive an open signal. The SI pumps will receive adequate suction from a passive RWST suction line. MV-32081 and MV-32082 failing to open will be noticed early in the event. This is a screening value based on a recovery time of 30 minutes.
Local recovery of MV-32079 or MV-32080 after both valves have failed to open (basic event HMC7980RCV).	0.25	Added to cutset in which a small LOCA has occurred and the two suction valves to the SI pumps from the RWST have failed to open. The SI pumps will receive adequate suction from a passive RWST suction line. Recovery data from NSAC-161 was used with a mean recovery time of one hour.

Table 3.3-4 (continued)
Repair and Recovery Actions

Operator Action	Failure Probability	Discussion
Recovery of loss of instrument air (basic event INSTAIRRCV)	0.58	Used to reduce the loss of instrument air initiating event frequency. Recovery data from NSAC-161 was used with a mean recovery time of 58 minutes.
Recovery of loss of component cooling (basic event LOCCRECXXV)	0.52	Used to reduce the loss of component cooling water initiating event frequency. Recovery data from NSAC-161 was used with a mean recovery time of two hours.
Recovery of loss of cooling water (basic event LOCLRECXXV)	0.52	Used to reduce the loss of cooling water initiating event frequency. Recovery data from NSAC-161 was used with a mean recovery time of two hours.
Local start of 12 CL pump on loss of DC control power (basic event SPD12MNSTY)	5E-2	Applied to cutsets in which a loss of train A DC has occurred followed by failure of 22 and 121 CL pumps causing a loss of cooling water. This is a screening value based on a recovery time of 45 minutes
Recovery of offsite power at: 2 hrs (FAILROSP2Y) 4 hrs (FAILROSP4Y) 5 hrs (FAILROSP5Y)	 0.265 0.122 0.109	Station blackout sequences are quantified by breaking up the transient into time phases. The phases at Prairie Island are selected representing the capacities of systems to cope with a total loss of AC power. (eg. 2 hrs to core damage following loss of AFW, 4 hrs to core damage following successful AFW for 2 hrs but failure of RCS cooldown). Power recovery was obtained from Westinghouse RCP seal model.
Recovery of a diesel generator at: 2 hrs (FAILREDG2Y) 4 hrs (FAILREDG4Y)	 0.66 0.47	The repair activities are considered to be independent of off-site power recovery and utilize the same time phases. Repair failure rates are taken from NUREG-CR/1362.

Table 3.3-5

Importance of Human Actions

Operator Action	Diagnosis Time (minutes)	Fussell-Vesely (%)	Birnbaum (x E-6)
Transfer unit 1 ac to unit 2 during unit 1 SBO	95	1.3	195
Cool down & depressurize RCS to stop tube leak before SG overfill	49	6.7	305
Cool down and depressurize RCS to stop leak after SG overfill	146	2.2	165
Open doors on loss of room cooling	15	3.4	25
Transfer to recirc during small LOCA	NA	.42	176
Transfer to recirc during medium LOCA	NA	4.3	800
Transfer to recir during large LOCA	NA	5.0	300
Cross tie to unit 2 motor driven AFW pump	24	3.2	51
Cross tie to unit 2 motor driven AFW pump - conditional to restore MFW (no "S" signal present)	24	.62	1.4
Cross tie to unit 2 motor driven AFW pump - conditional to restore MFW ("S" signal is present)	24	.37	3.8
Restore MFW (no "S" signal)	39	.78	98
Restore MFW ("S" signal is present)	39	.59	11
Bleed & Feed (no "S" signal) - for single operator action cut sets	22	7.2	92
Bleed & Feed (no "S" signal) - for multiple operator action cut sets	8	1.7	12
Bleed & Feed ("S" signal is present) - for single operator action cut sets	22	-[1]	-[1]
Bleed & Feed ("S" signal present) - for multiple operator action cut sets	8	.51	.64

Fussell-Vesely importance is a measure of risk reduction potential and represents that fraction of core damage frequency to which operator actions in the table contribute.

Birnbaum importance is a measure of risk increase potential and in this table is roughly equivalent to the increase in core damage frequency if the operator were not able to perform each of these actions.

[1] The Fussell-Vesely and Birnbaum are not given for the action because the event was truncated out of the results during sequence quantification.

[2] Diagnosis time not applicable here. The annunciator response model (Table 8-4 of NUREG/CR-4772) was used to determine operator diagnosis error.

Table 3.3-6

COMMON CAUSE COMPONENT GROUPS MODELED IN IPE

1. Diesel Generators (failure to start and run)
2. Pumps (failure to start and run)
3. Motor-Operated Valves (failure to open or close on demand)
4. Batteries (fail to operate on demand)
5. Air-Operated Valves (failure to open or close on demand)
6. Power Operated Relief Valves (failure to open or reclose on demand)
7. Check Valves (failure to open on demand; failure to remain closed)
8. Instrumentation and Control Components (failure to send signal or actuate equipment)

Table 3.3-7
Multiple Greek Letter Common Cause

COMPONENT/MODE	NUMBER OF COMPONENTS	BETA	GAMMA	DELTA
AFW Pumps FTS	3	.035	.17	
	4	.035	.17	.5
AFW Pumps FTR	3	.085	.14	
	4	.087	.16	.53
AFW Pump Motor Drivers FTS	2	.15		
AFW Pump Motor Drivers FTR	2	.013		
AFW Pump Turb Drivers FTS	2	.17		
AFW Pump Turb Drivers FTR	2	.040		
SI Pump FTS	2	.16		
SI Pump FTR	2	.17		
RHR Pump FTS	2	.16		
RHR Pump FTR	2	.18		
Cont Spray Pump FTS	2	.38		
Cont Spray Pump FTR	2	.081		
Cont Cooling Fans FTS	4	.071	.14	.385
Cont Cooling Fans FTR	4	.19	.51	.12
Cont Cooling Damper FTO	2	.24		
CC Water Pumps FTS	2	.14		
CC Water Pumps FTR	2	.058		
Cooling Water Diesel Driver FTS	2	.12		
Cooling Water Diesel Driver FTR	2	.12		
Diesel Generators FTS	4	.027	.21	.23
Diesel Generators FTR	4	.075	.14	.19
Fuel Oil Transfer Pumps FTS	2	.21		
	4	.32	.9	.9
Fuel Oil Transfer Pumps FTR	2	.18		
	4	.18	.5	.5
Motor Operated Valve FTO/FTC	2	.078		
	3	.082	.16	
	4	.085	.20	.75
Air Operated Valve FTO/FTC	2	.046		

Table 3.3-7 (continued)
Multiple Greek Letter Common Cause

COMPONENT/MODE	NUMBER OF COMPONENTS	BETA	GAMMA	DELTA
Check Valves FTO/FTC	2	.125		
	3	.125	.50	
	4	.125	.50	.50
PORVs FTO	2	.048		
Transmitters/Sensors	2	.17		
	3	.19	.46	
	4	.19	.47	.20
Batteries	2	.26		
	3	.27	.20	
	4	.27	.20	.38
Air Compressor FTS	3	.14	.071	
Air Compressor FTR	3	.069	.55	
Charging Pump FTS	2	.16		
	3	.21	.93	
Charging Pump FTR	2	.17		
	3	.17	.045	
Cooling Water - Pump Only FTS	2	.018		
	3	.018	.50	
Cooling Water - Pump Only FTR	2	.084		
	3	.099	.551	
Horiz CL Water Pumps FTR	2	.058		
Feed Water Pump FTS	2	.10		
Feed Water Pump FTR	2	.10		
Condensate Pump FTS	2	.10		
	3	.10	.55	
Condensate Pump FTR	2	.10		
	3	.10	.55	
Chiller FTS	2	.11		
Chiller FTR	2	.11		
Chilled Water Pump FTS	2	.10		
Chilled Water Pump FTR	2	.10		

Table 3.3-8

Flood Initiator Area Definition

FLOOD DESIGNATOR	AREA
SH1	Safeguards area of the Screen House
SH2	Nonsafeguards ares of the Screen House
AB7	695 foot level of the Auxiliary Building
AB8	715 foot level and above in the Auxiliary Building except for the Control Room Chiller Rooms
TB1	Auxiliary Feedwater Pump Room in the Turbine Building
T13	Cable Spreading Room

Table 3.3-9

Effects of Flood Initiators

FLOOD DESIGNATOR	AFFECTED PLANT AREA	FLOOD FREQUENCY	AFFECTED SYSTEMS	REMAINING SAFEGUARDS SYSTEMS
SH1	Screen House Safeguards Areas	6.09E-6/yr	Break in CL piping in the Screen House safeguards area fails the two diesel driven and single motor driven CL pumps. Room doors break, allowing flood to spread to lower level which fails the remaining two horizontal CL pumps. Operators must open safeguards 480V room door to provide room cooling and prevent loss of 480V power to the charging pumps to prevent an RCP seal LOCA which the SI system is not available to mitigate due to the loss of all CL.	AFW is available to provide secondary cooling with suction from condensate storage tanks. Charging pumps are available for RCS makeup and RCP seal cooling providing the local operator actions to restore safeguards 480V bus room cooling are successful.
SH2	Screen House Nonsafeguards Areas	2.54E-3/yr	Break in CL or circulating water piping in the Screen House lower level results in failure of both horizontal CL Pumps. Safeguards CL pumps are unaffected meaning that CL is available. No other equipment is affected by this flood. No automatic reactor trip is assumed to occur.	Safeguards CL pumps will start on low pressure after failure of the horizontal CL pumps. All other systems function normally.
AB7	Auxiliary Building 695 level	5.05E-3/yr	Break in Aux. Bldg CL header floods 695' elevation of the bldg to 6 inches. This is assumed to fail the 480V MCCs that supply power to the charging pumps. Operators are assumed to able to stop the flooding before the flood level can rise enough to fail other equipment due to the presence of level alarms in the area of the flood. No automatic reactor trip is assumed to occur.	Seal injection to the RCP seals is lost and one train of CC is lost due to loss of heat removal but loads (except RHR heat removal) are cooled by the other train leaving both trains of injection and one train of recirculation available.
AB8	Auxiliary Building 715 level and above	1.34E-4/yr	Break in fire protection line floods the 715' elevation of the Aux. bldg which is assumed to fails 480V Safeguards MCCs in the area. No automatic reactor trip is assumed to occur and the break is not large enough to spread to lower level via back flow through floor drains.	Flood is assumed to fail some safeguards MCCs but they do not supply any important loads. There is no major equipment affected by the flood and all systems are available for their normal functions.

Table 3.3-9 (continued)
Effects of Flood Initiators

FLOOD DESIGNATOR	AFFECTED PLANT AREA	FLOOD FREQUENCY	AFFECTED SYSTEMS	REMAINING SAFEGUARDS SYSTEMS
TB1	Auxiliary Feedwater Pump Room	1.04E-5/yr	Break in the CL header to the Aux. bldg occurs in the AFW/Inst. Air compressor room. The flood is assumed to fail all instrument air compressors and all AFW pumps. Loss of instrument air causes the feedwater regulating valves on both units to trip shut resulting in a reactor trip on both units due to low SG water level. MFW on one unit is assumed to fail due to loss of lube oil cooling. Bleed and feed capability is also lost for both units.	CL header break is assumed to cause loss of one CC heat exchanger but as the CC header is normally open, heat loads (except RHR heat removal) can be supplied by the other train leaving both trains of SI and RHR injection available and one train of recirculation. Loss of instrument air causes loss of MFW and pzr PORVs. This, along with loss of AFW pumps means failure of secondary cooling which leads to core damage.
T13	Cable Spreading Room	2.68E-5/yr	Break in the chilled water piping sprays down on DC Panel 15, DC Panel 16, AC Panel 111, and AC Panel 113 which is assumed to fail all these panels. Spray on these panels causes an automatic reactor trip and failure of MFW due to closure of the MFW regulating and bypass valves. Bleed and feed is lost due to closure of the instrument air valves causing failure of the pzr PORVs. AFW is still available to provide secondary cooling.	Spray is assumed to cause loss of normal makeup to the VCT, pzr PORV operation, and MFW. All ECCS equipment and CL operate normally.

Table 3.3-10

Human Errors Which Used Screening Values

Basic Event Name	Probability	Description
ABUS27RESY	1.00E-2	Operator fails to align Bus 25 to Bus 27 when required.
ESGLVLCONY	1.00E-2	Operator fails to control level in both SG's after SBO.
APNL17XXXY	1.00E-4	Operator fails to transfer power to panel 117 when required.
APNL217XXY	1.00E-4	Operator fails to transfer power to panel 217 when required.
CRECIRCXXY	1.00E-3	Operator fails to initiate CS recirculation when required.
LFL11XXXXY	1.00E-3	Operator fails to align filter train 11.
LVA31198XY	1.00E-3	Operator fails to close CV-31198.
J11RMWOPSY	5.00E-2	Operator fails to provide adequate makeup to 11 RMW tank.
J12RMWOPSY	5.00E-2	Operator fails to provide adequate makeup to 12 RMW tank.
SOPCLTOAFY	1.00E-3	Operator fails to align cooling water to the AFW pumps (condensate supply lost).
LPMCHGPMPY	1.00E-3	Operator fails to start a charging pump.
LVCTRMWOPY	1.00E-3	Operator fails to manually control RMW flow when required.
SMVALTRETY	1.00E-3	Operators fails to manually align alt. return path for CL train A and/or B.
SECOOLDEPY	5.00E-2	Operator fails to cooldown and depressurize the SG when required.
SGTRXXCD1Y	5.00E-3	Operator fails to cooldown & depressurize the RCS following SI failure for a SGTR.
SLOCAXXCDY	1.60E-2	Operator fails to C/D and depressurize the RCS for a small LOCA.
ZOPCRMCHLY	1.00E-3	Operator fails to start 122 Control Room Chiller after 121 trips.

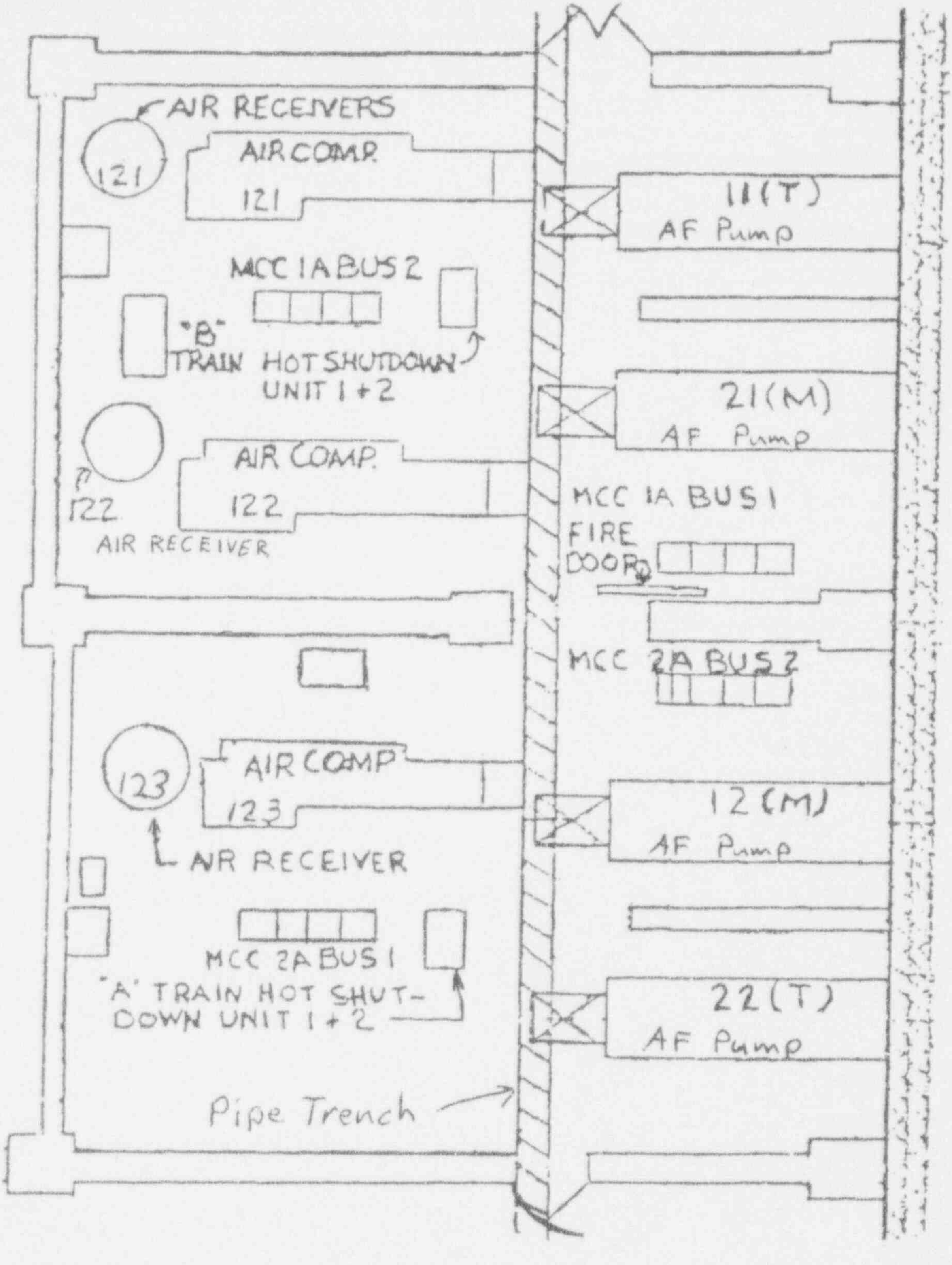


Figure 3.3-1

Floor Layout of the Auxiliary Feedwater Pump Room

3.4 Results and Screening Process

3.4.1 Introduction

The purpose of this section is to summarize the overall findings resulting from the quantification of the Prairie Island front end analysis (level 1 PRA). Internal events and internal flooding are discussed together. The IPE quantification focused on plant design features and operating characteristics that are most important to preventing core melt. Detailed descriptions of all of the dominant functional accident sequences are provided in this section. The specific items discussed for each sequence are:

1. Description of accident progression, event timing and containment failure mode if applicable.

2. Specific assumptions to which the results are sensitive. Efforts were made to make assumptions consistent with best-estimate information.

3. Significant initiating events, human actions and sensitive parameters.

The results provided below are for the Unit 1 portion of the IPE. However, the event descriptions also apply to the Unit 2 analysis, since the majority of the systems modeled for the two units are identical and symmetric. Refer to section 3.5 for a description of the unit 2 analysis and results.

The total CDF for Prairie Island unit 1 internal events was 5E-05/yr. Core damage was conservatively defined as thirty minutes with the core exit thermocouple temperatures over 1200°F or whenever the core exit temperatures reached 2000°F.

3.4.2 Application of Generic Letter Screening Criteria

Appendix 2 to Generic Letter 88-20 identifies the screening criteria for reporting potentially important sequences that might lead to core damage or unusually poor containment performance. The criteria applicable to Prairie Island are listed below:

1. Any functional sequence that contributes 1E-6 or more per reactor year to core damage.

2. Any functional sequence that contributes 5% or more to the total core damage frequency.

3. Any functional sequence that has a core damage frequency greater than or equal to 1E-6 per reactor year and that leads to containment failure which

can result in a radioactive release magnitude greater than or equal to the PWR-4 release categories of WASH-1400.

4. Functional sequences that contribute to a containment bypass frequency in excess of 1E-7 per reactor year.

5. Any functional sequences that the utility determines from previous applicable PRAs or by utility engineering judgement to be important contributors to core damage frequency or poor containment performance.

Prairie Island elected to use the functional sequence reporting criteria as the event trees described in section 3.1.2 were developed around a set of safety functions based on the EOPs. Each safety function consists of a set of frontline and support systems that can be used to perform the specified safety function. By using functional event trees, the core damage sequences that emerge, are sets of components and initiating events that fail the safety functions, thereby the choice of the functional reporting criteria from Generic letter 88-20. In addition, Prairie Island went one step further in reporting requirements by equating accident classes with functional sequences. In this case, core damage sequences are grouped together as to their similarity in regard to initiators, timing of core melt and affect on containment pressure at the time of core melt. The accident classes that meet this reporting criteria are listed in Table 3.4-1 with a description of the accident class together with a representative sequence from each accident class. Some accident classes that do not meet the reporting criteria are also included in Table 3.4-1 for completeness.

The results that follow, are reported by accident class from largest to lowest contributor with characterizations for each accident class. Significant equipment failures, operator actions and a representative sequence for each accident class are also provided. The contributions to the specific class CDF from component failures, initiating events or operator actions are the percentage of the risk associated with the failure of the applicable component, initiator or operator action. A description of the accident class designators can be found in section 3.1.5.

3.4.2.1 Class FEH-TB1

In the Prairie Island IPE, Class FEH-TB1 has a total CDF of approximately 1E-5 which accounts for 21% of the total CDF. This class consists of a single sequence in which a large break occurs in either the Loop A or Loop B cooling water line above the auxiliary feedwater pump room in the turbine building. The resultant flood is assumed to cause loss of all auxiliary feedwater pumps for both units, loss of all instrument air compressors for both units and loss of main feedwater for one unit due to loss of instrument air and loss of lube oil cooling to the affected pumps. Reactor trip is successful along with RCP seal cooling. Secondary cooling fails due to failure of AFW and MFW. Short term RCS inventory fails due to loss of pressurizer PORVs which fail closed on loss of instrument air. Core damage occurs early and at high pressure. The class FEH-TB1 sequence results can be found in Table 3.4-1.

Assumptions which may impact the class FEH-TB1 results include:

1. Crosstie from station air to instrument air is not credited as the crosstie valves required to be opened are located in the flooded auxiliary feedwater pump room. It is true that after the break has been isolated, operators could enter the room and perform the crosstie, but cross tying from station air to instrument air is not proceduralized. Station air would not be available for crosstie if the break was in the Loop B cooling water header.

2. Crosstie from Loop B cooling water to Loop A cooling water header in order to restore lube oil cooling to the main feedwater pumps is not credited as one of the valves in the crosstie line is air operated and fails closed on loss of air. The valve is located in the overhead and is not referenced in procedures as failing closed on loss of air.

3. No credit is taken for the water that is already in the steam generators. It has been shown that steam generator dryout occurs approximately 45 minutes after loss of main feedwater with core damage occurring approximately 2 hours after loss of main feedwater. It was assumed that no recovery actions were performed to restore secondary cooling during this time.

4. It is assumed that the pressurizer PORVs cannot operate after instrument air has been lost. There are air accumulators on each PORV that are designed to allow approximately 15 cycles of valve operation after loss of instrument air. Bleed and feed requires sustained open times for the PORVs. It is not known how long the PORVs may remain open while on the air accumulators so it was conservatively assumed they are inoperable on loss of air.

There are no important component failures or operator actions for this class as the core damage sequence consists principally of failures resulting from conditions associated with the flood.

3.4.2.2 Class TEH

The sequences within this class are characterized by transients where MFW becomes unavailable followed by a failure of AFW. Bleed and feed cooling of the RCS fails causing core uncovery at high RCS pressures approximately two hours after the transient occurs.

In the Prairie Island IPE, class TEH sequences have a total CDF of approximately 1E-5 per year or 20% of the overall CDF from all classes. The class TEH sequences are characterized by a transient where main feedwater is lost either through loss of instrument air or through LOOP. AFW subsequently fails leaving bleed and feed cooling as the only remaining means of RCS heat removal. Bleed and feed cooling fails due to operator action causing RCS core uncovery. SBO sequences where power has been restored before core damage has occurred are also classified as Class TEH. In these cases, an SBO causes a loss of MFW and AFW with the exception of the turbine driven pump. Power is restored before core damage occurs, but RCS short term inventory using bleed and feed fails causing core damage. The top sequence for class TEH can be found in Table 3.4-1.

Assumptions which may impact the class TEH results include:

1. It has been shown through MAAP analysis that only one pressurizer PORV is required for successful bleed and feed cooling.

2. The fault tree for AFW was constructed such that if a dual unit initiating event occurred (LOOP, loss of instrument air or loss of cooling water) and the unit 2 turbine driven auxiliary feedwater pump failed, the unit 2 motor driven auxiliary feedwater pump could not be crosstied to unit 1 as it would be required on unit 2.

3. It is assumed that the pressurizer PORVs cannot operate after instrument air has been lost. There are air accumulators on each PORV that are designed to allow approximately 15 cycles of valve operation after loss of instrument air. Bleed and feed requires sustained open times for the PORVs. It is not known how long the PORVs may remain open while on the air accumulators so it was conservatively assumed they are inoperable on loss of air.

4. Feedwater addition through the condensate pumps is not credited in the IPE as the majority of the failures for feedwater also fail condensate so it was felt that this method of feedwater addition would not significantly reduce the potential for loss of secondary cooling.

5. Cross-tie from station air to instrument air was not credited as it is not proceduralized.

Important initiating events identified were:

1. Loss of offsite power was a significant contributor in that it caused loss of main feedwater and, if the safeguards diesel generators were to fail, all of AFW with the exception of the turbine driven pump. LOOP was responsible for 50% of the Class TEH CDF.

2. Loss of instrument air caused loss of main feedwater through closure of the main feedwater regulating and bypass valves and also caused failure of bleed and feed cooling through failure of the pressurizer PORVs (see assumption 3 above). Loss of instrument air accounted for 30% of the Class TEH CDF.

Important human actions identified were:

1. Failure to initiate bleed and feed cooling on loss of all feedwater accounted for 47% of the Class TEH CDF.

2. Failure to crosstie 21 auxiliary feedwater pump to unit 1 on failure of 11 and 12 auxiliary feedwater pumps accounted for 20% of the Class TEH CDF.

3. Failure to locally restore main feedwater after it was lost as a result of the initiating event accounted for 16% of the Class TEH CDF.

The most significant equipment failures were:

1. Random failures to run of the turbine driven auxiliary feedwater pumps appeared in a large portion of the class TEH results. The turbine driven auxiliary feedwater pump was an important contributor as even though it is not dependant on AC or DC power, turbine driven pumps are not as reliable as the motor driven pumps. Failure of 11 AFW pump accounted for 59% of the Class TEH CDF.

2. Random failures to run for 22 AFW pump accounted for 27% of the Class TEH CDF. If a dual unit initiating event such as loss of CL or instrument air or LOOP occurs, failure of 22 AFW pump fails the crosstie from 21 AFW pump as 21 AFW pump is required for secondary cooling on unit 2.

3. Random failures to run for 12 AFW pump accounted for 20% of the Class TEH CDF. Since LOOP and loss of instrument air are the dominant initiating events for this damage class and also cause loss of MFW, greater reliance

is placed on the AFW system for secondary cooling.

3.4.2.3 Class SLL

The sequences within this class are characterized by a medium (5 to 12 inch equivalent pipe diameter break) or a large LOCA (12 inch to design basis equivalent diameter pipe break) followed by failure of high or low head recirculation. Core damage occurs approximately two hours after the initiation of the accident and at low reactor pressures due to the size of the break which depressurizes the RCS below RHR injection pressure.

In the Prairie Island IPE, Class SLL sequences have a total CDF of 8.3E-6 which accounts for approximately 17% of the total CDF. This class is characterized by a large or medium LOCA in which short term RCS inventory using SI or RHR injection is successful but the operators fail to switch to recirculation before the RWST is depleted causing injection to fail and subsequent core uncovery followed by core damage. The class SLL results can be found in Table 3.4-1.

Assumptions which could impact the class SLL result include:

1. SI injection by itself is not credited as a viable injection source for the large LOCA case due to its limited injection flow.

2. RHR injection is credited for the medium LOCA. As determined through MAAP analysis, the size of the break spectrum is such that upon SI injection failure, the RCS will depressurize below the RHR pump shutoff head before any core damage has occurred without any operator action required.

3. MAAP analysis shows that for large and medium LOCAs, SI accumulators are not required for prevention of core damage.

4. It is assumed that the reactor protection system is not required to bring the reactor subcritical for a large LOCA because the voiding that occurs in the core after the LOCA is assumed to add enough negative reactivity to bring the reactor subcritical.

5. It is assumed that auxiliary feedwater is not required for heat removal for medium and large LOCAs as the decay heat is removed through the break.

6. We do not take credit for procedurally stopping the CS pumps when containment pressure drops below 18 psig in order to obtain the shortest time to RWST depletion for switchover to recirculation timing as the human error analysis used is not detailed enough to account for this.

7. It is conservatively assumed that the RHR pump motors require room cooling for continued operation. Recent room heatup calculations have shown that the motors do not require room cooling.

Important human actions identified were:

1. Failure to switchover to low head recirculation following a large LOCA accounted for 30% of the Class SLL CDF as the switchover must be manually performed from the control room when the RWST reaches the low alarm setpoint.

2. Failure to switchover to high head recirculation following a medium LOCA accounted 26% of the Class SLL CDF.

Important component failure events identified were:

1. Common cause failures of the control room chilled water pumps which cause loss of room cooling in the RHR pump pits and are assumed to cause loss of RHR due to RHR motor failure. These failures together accounted for 8% of the Class SLL CDF.

2. Failure of both of the component cooling water inlet valves to the RHR heat exchangers to open due to common cause. This failure is assumed loss of the RHR heat exchangers as a heat sink and is assumed to fail recirculation. This failure accounted for 6% of the Class SLL CDF.

3.4.2.4 Class SEH

The sequences within this class are characterized by either a small LOCA (0.375 to 5 inches equivalent pipe diameter) or an RCP seal LOCA in which short term RCS inventory fails causing core damage early in the accident and at high RCS pressures.

In the Prairie Island IPE, class SEH sequences have a total CDF of 8.2E-6 per year or approximately 16% of the overall CDF from all classes. RCP seal LOCAs account for 79% of the Class SEH CDF. The class SEH sequences are dominated by an RCP seal LOCA caused by a LOOP or loss of train A DC power. Secondary cooling using either main or auxiliary feedwater is successful but short term RCS inventory fails due to failure of the SI system. The top sequence for class SEH can be found in Table 3.4-1.

Assumptions which may impact the class SEH results include:

1. MAAP analysis has shown that for the break sizes considered for a small LOCA, there is not time enough for the operator to cooldown and depressurize the RCS below the RHR pump shutoff head before core damage occurs. This results in the SI system being the sole injection source for a small LOCA.

2. MAAP analysis has shown that charging pumps alone cannot supply enough flow to prevent core damage in the event of SI system failure for the range of breaks that were considered small LOCAs.

3. It is conservatively assumed that the SI pumps fail immediately on loss of component cooling as component cooling provides cooling for lube oil and seal cooling. In reality, the pump may continue to operate for a length of time and the operator could cycle pumps to prevent lube oil overheating, however this is not proceduralized.

4. MAAP analysis has shown that SI accumulators are not required to prevent core damage for the small LOCA spectrum of break sizes.

Important initiating events identified were:

1. A small LOCA which accounted for 32% of the Class SEH CDF.

2. A LOOP is a significant contributor to an RCP seal LOCA in that if D1 and D5 diesel generators fail, instrument air is lost. Loss of instrument air causes closure of the control room chiller outlet cooling water valves, failing safeguards chilled water. Failure of safeguards chilled water causes failure of cooling to the bus 110/120 room which is assumed to result in failure of both buses due to transformer overheat. Failure of bus 110 and 120 results in failure of all charging pumps and both cooling water inlet valves for the component cooling water heat exchangers failing component cooling water and subsequently SI injection. Recovery factors were applied to some of the top cutsets as room heatup does not occur immediately and the CL inlet valves to the CC heat exchangers will open before the room heatup occurs. Since recovery was not applied to all cutsets, LOOP is a significant contributor to class SEH accounting for 25% of the Class SEH CDF.

3. A loss of train A DC is a significant contributor to an RCP seal LOCA as this initiator causes a reactor trip and subsequent loss of 11 and 12 cooling water pumps. If the remaining cooling water pumps fail, cooling water is lost which fails chilled water creating the same scenario as was

described in 2 above. Local start of 12 cooling water pump was applied to some of the top cutsets. Since recovery was not applied to all of the cutsets, loss of train A DC remains a significant contributor to class SEH accounting for 17% of the Class SEH CDF.

Important human actions identified were:

1. Local restoration of bus 110/120 room cooling by opening doors and using portable fans on loss of instrument air or cooling water. This accounts for 14% of the Class SEH CDF.

2. Local recovery of the cooling water system following the loss of cooling water initiator accounts for 8% of the Class SEH CDF.

3. Local recovery of the SI suction valves from the RWST when both valves fail to open accounts for 4% of the Class SEH CDF.

The most significant equipment failures were:

1. Random failure of D5 diesel generator to run accounts for 13% of the Class SEH CDF while D1 diesel generator failure to run accounts for 12%. Failure of these two diesel generators following a LOOP fails 21 AFW pump and two out of three instrument air compressors, failing instrument air.

3. Random failure of 11 AFW pump to run accounted for 13% of the Class SEH CDF as 11 AFW pump does not require diesel generator support following a LOOP as do 12 and 21 AFW pumps.

3.4.2.5 Class GLH

Sequences within this class are characterized by a steam generator tube rupture with failure to cooldown and depressurize the RCS and terminate SI before the ruptured steam generator overfills. A relief on the ruptured steam generator is assumed to stick open and then RCS cooldown and depressurization before RWST depletion occurs fails, causing core uncovery and subsequent core damage. Core damage is expected to occur approximately nine hours after the tube rupture has occurred and at high RCS pressures.

Class GLH sequences make up 12% of the total CDF at Prairie Island with a CDF from all class GLH sequences of 6E-6 per year. This class is characterized by a steam generator tube rupture in which reactor trip, secondary cooling, short term RCS inventory and ruptured steam generator isolation are successful. The operator then fails to cooldown and depressurize the RCS before the ruptured steam generator overfills. A ruptured steam generator relief sticks open and the operator then fails to cooldown and depressurize the RCS to RHR shutdown cooling temperature and pressure before RWST depletion occurs which causes loss of SI injection and subsequent core damage. The top class GLH sequence can be seen in Table 3.4-1.

Assumptions which could impact the class GLH results include:

1. It is assumed that if the ruptured steam generator is overfilled, a relief valve will stick open with a probability of 1.0. The relief valves are designed for steam relief (not water relief) so it was assumed they will stick open when relieving water.

2. It is assumed that the operator must have two charging pumps running in order to terminate SI after steam generator overfill and subsequent RCS cooldown and depressurization as there was no analysis to support successful SI termination without charging.

3. The steam dump system was not modeled for use in RCS cooldown in order to simplify the plant model. It is assumed that the steam generator PORVs are the only means for RCS cooldown through the secondary system. In reality, the steam dump system is the preferred method to use with the steam generator PORVs as the backup.

4. The normal pressurizer spray system is not modeled for use in RCS depressurization in order to simplify the plant model. It is assumed that the pressurizer PORVs and auxiliary spray are the only means of RCS depressurization.

5. It is assumed that the pressurizer PORVs cannot operate after instrument air has been lost. There are air accumulators on each PORV that are designed to allow approximately 15 cycles of valve operation after loss of instrument air. Bleed and feed requires sustained open times for the PORVs. It is not known how long the PORVs may remain open while on the air accumulators so it was conservatively assumed they are inoperable on loss of air.

6. It is assumed that two instrument air compressors are required for instrument air system success. Crosstie from the station air system to the instrument air system when an instrument air compressor is in maintenance was not credited as the procedure does not specifically require this action.

7. Local recovery actions to replace blown fuses are not credited.

8. It was conservatively assumed that the RHR loop return valve was the only means to return water from the RHR heat exchangers back to the RCS loops when on RHR shutdown cooling. In reality, either of the RHR injection valves could be opened to allow a return path back to the RCS.

Important human actions identified were:

1. Failure to cooldown and depressurize the RCS in order to terminate SI before the ruptured steam generator overfills accounted for 59% of the class GLH CDF.

2. Failure to cooldown and depressurize the RCS after the ruptured steam generator overfills in order to get the RCS down to RHR shutdown cooling temperature and pressure before the RWST is depleted. This operator action accounted for 18% of the class GLH CDF.

3. Failure to recover either SG PORV after both PORVs have failed to open due to common cause which would fail RCS cooldown and depressurization. This recovery action accounted for 8% of the Class GLH CDF.

Important component failures identified were:

1. Failure of the RHR loop return valve to open which is assumed to fail RHR shutdown cooling accounted for 13% of the class GLH CDF. See assumption 8.

2. Failure of both steam generator PORVs to open due to common cause accounted for 3.5% of the class GLH CDF.

3.4.2.6 Class BEH-NOPWR

Sequences within this class are characterized by a loss of offsite power with failure of onsite AC power and failure to recover a power supply prior to core damage. Core damage is expected several hours after the SBO occurs if the turbine driven auxiliary feedwater pump fails and 6-8 hours if the turbine driven AFW pump is successful but fails due to battery depletion. Core damage is expected to occur at elevated RCS pressures for SBO events.

Class BEH-NOPWR sequences make up approximately 6% of the total CDF at Prairie Island with a CDF from all class BEH-NOPWR sequences of 2.8E-6 per year. This class can be characterized by a station blackout with successful turbine driven AFW pump operation. The operator is successful in cooling down and depressurizing the RCS with the steam generator PORVs to minimize RCP seal leakage. The operator then fails to restore to restore offsite and onsite AC power before core uncovery and subsequent core damage. The top sequence for this class is listed in Table

3.4-1.

Assumptions which could impact the class BEH-NOPWR results include:

1. The batteries are conservatively assumed to last for an average time of 2 hours. This is the approximate average depletion time for all four batteries. Through load shedding, the batteries may be able to last for a longer time period.

2. No credit is taken for battery replacement. If AC power is not available for the battery chargers, the station batteries will eventually drain. In the IPE models there is no credit taken for replacing the batteries with other, charged, batteries.

3. If the batteries became unavailable, it was assumed that the turbine driven auxiliary feedwater pump will fail as all SG level instrumentation would be lost causing the operator to operate the pump without knowledge of possible overfill of the steam generators causing flooding of the steam lines to the turbine driven pump.

4. The RCP seal LOCA model used for SBO is a Westinghouse model that models the magnitude of the seal LOCA that the RCS can take as a function of time: e.g. the more time that passes before recovery of SI, the greater the potential of core uncovery. The model also distinguishes whether or not the RCS has been cooled down in accordance with the emergency procedures.

5. Credit is taken for the operator to cooldown and depressurize the RCS by local operation of the steam generator PORVs as specified in procedures for station blackout.

6. The mission time for 12 and 22 diesel driven cooling water pumps is conservatively assumed to be 24 hours which results in a high failure to run probability for these pumps. In reality a six hour mission time should have been used as after six hours, there is a 90% chance of power recovery.

Important human actions identified were:

1. Conditional failure to recover a diesel generator within four hours after an SBO has occurred assuming the operator successfully cools and depressurizes the RCS accounts for 93% of the Class BEH-NOPWR CDF.

2. Conditional failure to restore offsite power within five hours after an SBO has occurred assuming the operator successfully cools and depressurizes the RCS accounts for 89% of the Class BEH-NOPWR CDF.

3. Failure to restore offsite or onsite power within two hours after an SBO has occurred assuming the turbine driven AFW pump has failed accounts for 7% of the Class BEH-NOPWR CDF.

4. Failure to cross-tie Unit 2 buses to Unit 1 AC buses when Unit 1 is experiencing the SBO accounts for 6% of the Class BEH-NOPWR CDF.

Important component failure events were:

1. Random failures to run of D5 or D6 diesel generators account for 37% of the Class BEH-NOPWR CDF as these diesels can supply power to unit 1 and also to 121 cooling water pump.

2. Common cause failure to run of 12 and 22 cooling water pumps accounts for 26% of the Class BEH-NOPWR CDF. Failure of both of these pumps after an SBO is assumed to fail D1 and D2 diesel generators as these diesels require cooling water for operation.

3. Random failures to run of 12 or 22 cooling water pumps accounts for 21% of the Class BEH-NOPWR CDF.

4. Random failures to run of D1 or D2 diesel generators account for 15% of the Class BEH-NOPWR CDF.

3.4.2.7 Class SLH

The sequences within this class are characterized by a small LOCA (0.375 to 5 inches equivalent pipe diameter) followed by failure of high head recirculation. Core damage occurs approximately ten hours after the initiation of the accident at high reactor pressures.

In the Prairie Island IPE, class SLH sequences have a total CDF of 2.4E-6 which accounts for approximately 5% of the total CDF. This class can be characterized by a small LOCA in which secondary cooling and short term RCS inventory using SI pumps is successful. The operator then fails to cooldown and depressurize the RCS to allow use of RHR shutdown cooling before RWST depletion occurs. High head recirculation is then required but it fails due to operator action or equipment failure. The core uncovers and is then damaged due to loss of makeup capability. The top sequence for this class is listed in Table 3.4-1.

Assumptions which may impact the class SLH results include:

1. MAAP analysis has shown that SI accumulators are not required to prevent core damage for the small LOCA spectrum of break sizes.

2. No credit is given for efforts to replenish the RWST should recirculation from the containment sump fail as the flow rates attainable for RWST refill were considered too small to be of benefit to prevent core damage.

3. It is assumed that all systems actuated automatically from an "S" signal fail if the "S" signal should fail to be generated.

4. It is assumed that two charging pumps are required in order for RCS cooldown and depressurization to succeed as maximum charging is established in EOP ES-1.1, rev 9, "Post LOCA Cooldown and Depressurization" to provide sufficient makeup to enable the SI pumps to later be stopped.

Important operator actions identified were:

1. Local recovery of the CC supply valves to the RHR heat exchangers after they have failed closed account for 15% of the Class SLH CDF.

2. Failure to cooldown and depressurize the RCS to allow RHR shutdown cooling to be put in service before RWST depletion occurs accounts for 10% of the Class SLH CDF.

3. Failure to lineup high head recirculation before RWST depletion occurs accounts for approximately 6% of the Class SLH CDF.

Important components identified for class SLH sequences were:

1. Random failures of 121 control room chiller and chilled water pump account for 55% of the Class SLH CDF. 121 control room chiller is isolated from 122 chiller after receipt of an "S" signal as the chiller crossover valves close. If 121 chiller or chilled water pump fail, train A chilled water fails which causes loss of room cooling to the Bus 110 room which is then assumed to result in failure of bus 110 due to transformer overheating. Bus 110 ultimately powers 11 and 13 charging pumps which fails post LOCA cooldown and depressurization as it is assumed that two charging pumps are required for success.

2. Failure of both CC inlet valves to 11 and 12 RHR heat exchangers to open due to common cause accounts for 15% of the Class SLH CDF as they cause loss of CC to the heat exchangers which is assumed to fail recirculation.

3.4.2.8 Class TLH

The sequences within this class are characterized by transients where secondary cooling becomes unavailable or where an SBO has occurred but AC power has been restored. Primary bleed and feed cooling is successful but high head recirculation fails. Core damage is expected to occur approximately 11 hours after the accident and at high RCS pressures.

In the Prairie Island IPE, Class TLH sequences have a total CDF of 8E-7 per year or 1.6% of the overall CDF from all classes. The top sequence for this class is listed in Table 3.4-1.

Assumptions are the same as for Class TEH (see section 3.4.2.1).

Important initiating events identified were:

1. Loss of offsite power. This event was significant because it causes a loss of main feedwater and reduced reliability of 12 AFW pump as the power supply is solely from the diesel generators. There were also LOOP sequences coupled with diesel generator failures which lead to an SBO in which power was restored, bleed and feed was successful but recirculation fails. This initiator accounted for 99% of the Class TLH CDF.

Important operator actions identified were:

1. Failure of the operator to initiate high head recirculation before RWST depletion accounts for approximately 10% of the Class TLH CDF as high head recirculation must be established through local and control room actions at Prairie Island.

2. Failure of the operator to crosstie 21 motor driven auxiliary feedwater pump to unit 1 on failure of both unit 1 auxiliary feedwater pumps accounted for 7% of the Class TLH CDF. This action was a large contributor as LOOP is the most important initiating event and LOOP causes loss of main feedwater creating greater reliance on AFW for secondary cooling.

Important component failures identified included:

1. Random failures of D2 or D6 diesel generators to run account for 60% of the Class TLH CDF. Failure of these two diesel generators following a LOOP fails 12 AFW pump.

2. Random failures to run of 11 AFW pump accounted for 55% of the Class TLH CDF as 11 AFW pump has no AC power requirements so that when a LOOP occurs, it is unaffected while the motor driven AFW pumps must rely on the diesel generators for support.

3. Random failures to run for 22 AFW pump accounted for 46% of the Class TLH CDF. If a dual unit initiating event such as loss of CL, instrument air or LOOP occurs, failure of 22 AFW pump fails use of the crosstie from unit 2 as 21 AFW pump would be required for unit 2 secondary cooling.

3.4.2.9 Class GEH

Sequences within this class are characterized by a steam generator tube rupture together with the following three scenarios: 1) failure of secondary cooling 2) failure of short term RCS inventory and failure to isolate the ruptured steam generator and 3) short term RCS inventory failure followed by failure to cooldown and depressurize the RCS before core damage. Core damage is expected to occur approximately four hours after the tube rupture and at high RCS pressures.

Class GEH sequences make up 1.2% of the total CDF at Prairie Island with a CDF from all class GEH sequences of approximately 6E-7 per year. This class is characterized by sequences in which a steam generator tube rupture occurs followed by successful reactor trip and secondary heat removal. Short term RCS inventory using SI fails but the operator is successful in isolating the ruptured steam generator. The operator then fails to cooldown and depressurize the RCS before core damage occurs. The top class GEH sequence can be seen in Table 3.4-1.

Assumptions which could impact the class GEH results include:

1. Credit is taken for the operator to cooldown and depressurize the RCS to stop primary to secondary leakage following SI failure as MAAP analysis has shown that core damage does not occur following SI failure for approximately 2 hours.

2. Bleed and feed cooling following failure of secondary cooling was conservatively not credited as a SGTR followed by failure of secondary cooling was not a large contributor to class GEH. In reality, the operators would use bleed and feed cooling following failure of secondary cooling.

3. Credit is taken for the main steamline non-return check valve for ruptured steam generator isolation. If the MSIV on the intact steam generator fails to close, isolation from the ruptured steam generator can be accomplished by lowering the pressure in the intact steam generator with its PORV to less than the ruptured steam generator thereby closing the non-return valve on the intact steam generator. This is a proceduralized operator action.

Important operator actions identified were:

1. Local restoration of bus 110/120 room cooling by opening doors and using portable fans when room cooling is lost through loss of chilled water. Failure of this action accounts for 63% of the class GEH CDF.

2. Failure to cooldown and depressurize the RCS to stop primary to secondary leakage after SI system failure and before core damage occurs accounts for 24% of the Class GEH CDF.

Important component failures identified include:

1. Failures of 121 and 122 control room chilled water pumps to start due to common cause account for 60% of the Class GEH CDF. If 121 and 122 chilled water pumps fail, chilled water fails which causes loss of room cooling to the Bus 110/120 rooms which is then assumed to result in failure of bus 110 and 120 due to transformer overheating. Failure of bus 110 and 120 cause failure of all instrument air compressors which fails RCS depressurization causing core damage as the RCS cannot be depressurized before RWST depletion.

2. Failure of both of the RWST to SI pumps suction valves to open due to common cause fails the long term injection source for the SI pumps and accounts for 6% of the Class GEH CDF.

3.4.2.10 Class BEH

Sequences within this class are characterized by a loss of offsite power with failure of onsite AC power. Offsite or onsite AC power is restored within 4-5 hours but the core is uncovered and damaged due to an RCP seal LOCA prior to returning AC power supplies to service. Core damage is expected within several hours after the SBO occurs depending on the rate of RCP seal leakage and at elevated RCS pressures.

Class BEH sequences make up approximately 0.5% of the total CDF at Prairie Island with a CDF from all class BEH sequences of 2.6E-7 per year. This class can be characterized by a station blackout with successful turbine driven AFW pump operation. The operator is successful in cooling down and depressurizing the RCS using steam generator PORVs to minimize RCP seal leakage. Onsite AC power is restored but an RCP seal LOCA has caused core uncovery and subsequent core damage. The top sequence for this class is listed in Table 3.4-1.

Assumptions are the same as were reported in section 3.4.2.6 for damage class BEH-NOPWR.

Important operator actions identified were:

1. Failure to cross-tie Unit 2 buses to Unit 1 AC buses when Unit 1 is experiencing the SBO accounts for 5.5% of the Class BEH CDF.

2. Failure to cooldown the RCS using the SG PORVs to reduce RCP seal leakage and to inject the SI accumulators accounts for 5% of the Class BEH CDF.

Important component failures identified were the same as were reported in section 3.4.2.6 for damage class BEH-NOPWR.

3.4.2.11 Class V

This class consists of LOCAs with a bypassed containment which includes interfacing systems LOCAs. The break location can bypass the source term mitigation features associated with the containment. This class of sequences represented approximately 0.5% of the total core damage frequency. The potential ISLOCA pathways quantified for Class V were:

1. The RHR to loop B return line which is isolated from RCS operating pressures by two check valves and a normally closed motor operated valve.

2. The RHR suction from loops A and B which is isolated from the RCS by two normally closed motor operated valves.

3. Reactor vessel low head injection line which is isolated from the RCS by two check valves.

Important assumptions include:

1. The exposure of low pressure piping outside of containment to primary system pressure was considered to be a result of interfacing isolation valve failures.

   On exposure of low pressure piping to reactor pressure, it is recognized that the ultimate rupture strength of the piping is many times design. While leaking through the interfacing system may occur, there was only limited potential for gross rupture of the piping. A conditional pipe rupture probability of 4E-3 was used on exposure of low pressure piping to full RCS pressure as calculated from NUREG/CR-5102, "Interfacing Systems LOCA - Pressurized Water Reactors".

2. No credit is given for the operator to locally isolate the ISLOCA pathway due to the harsh environment that will be encountered.

3. It is assumed that the low pressure piping will break in the auxiliary building which is assumed to fail the CS, SI and RHR pumps causing core damage due to loss of short term RCS inventory. In the absence of auxiliary building environmental analysis for these events, no credit was given for operator diagnosis and isolation of the ISLOCA from the control room via MOVs prior to auxiliary building equipment failure.

4. It is assumed that if the low pressure RHR piping does not instantaneously rupture, the RHR pump seals will fail when exposed to RCS pressure causing loss of both RHR pumps. Operator action to isolate the RHR pumps is not credited as the isolation valves are located in the RHR pit. Operator action to cooldown and depressurize the RCS to minimize the flow out the RHR pump seals and preserve RWST inventory is credited.

3.4.2.12 ATWS Damage Classes

The ATWS damage classes are grouped together as none of them are significant contributors to the overall core damage frequency due to the ability to ride out the event effectively by heat removal through the steam generators and because of the reliable reactor protection system. ATWS has also not been shown to be significant at other PWRs. These damage classes can be characterized by accident sequences involving an ATWS event where local actions taken by the operator to ensure the reactor is subcritical have failed (Class RLO) or when all feedwater has failed or inadequate RCS pressure relief exists (Class REP). Core damage is expected late after the ATWS has occurred for class RLO and early after the ATWS for class REP. All core damage is expected to occur at high RCS pressures due to the critical reactor. Class RLO sequences make up 0.3% and class REP sequences

0.3% of the total CDF at Prairie Island. The top sequence for each damage class can be found in Table 3.4-1.

3.4.2.13 Class SEL

The sequences within this class are characterized by a medium or large LOCA followed by failure of short term RCS inventory using SI or RHR injection. Core damage occurs relatively soon after the initiation of the accident and at low reactor pressures.

In the Prairie Island IPE, Class SEL sequences have a total CDF of 7.6E-8 which accounts for approximately 0.2% of the total CDF. This class is dominated by a large LOCA followed by failure of RHR injection. Assumptions are the same as those for Class SLL in section 3.4.2.4 above. The top sequence for this class can be found in Table 3.4-1. The large LOCA initiating event frequency combined with a relatively reliable RHR system results in the low contribution from this initiator. Medium LOCA events are assumed to be greater in frequency but are lower in risk because the SI system is capable of providing adequate core cooling in addition to the RHR system.

3.4.2.14 Class FEH

The sequences within this class are characterized by a flood which causes a reactor trip and disables equipment necessary to provide secondary cooling or bleed and feed cooling causing early core damage at high RCS pressures. Assumptions are the same as for class TEH which can be found in section 3.4.2.1. The top sequence for this damage class can be found in Table 3.4-1.

3.4.2.15 Class FLH

The sequences within this class are characterized by a flood which causes a reactor trip and disables some equipment required for secondary cooling and long term RCS inventory. This damage class is the smallest contributor to the overall plant CDF as the class FLH sequences were truncated out of the results when using a truncation limit of 1E-11. Assumptions are the same as for class TLH which can be found in section 3.4.2.8.

Core damage frequency for each initiating event considered in the Prairie Island IPE can be found in Table 3.4-2.

3.4.2.16 Functional Sequences Due to Recovery Actions

The NRC guidance document for preparing the IPE submittal (NUREG 1335) provides screening criteria for accident sequence reportability. The document also requests that licensees identify and report any sequence the drops below the applicable reporting criteria because the frequency has been reduced by more than an order of magnitude by credit taken for human recovery actions. The NRC also request information on the timing and complexity of the postulated recovery actions.

NSP defines a recovery action as those actions that the operators perform as a result of a system or component not performing as expected in response to plant emergency conditions. Generally, recovery actions are performed outside of the control room. Actions addressed in EOPs or normal operating procedures are not considered recovery actions (eg. ATWS, restoration of MFW after AFW failure, SI recirculation). Some examples of recovery actions are:

1. Recovering offsite or onsite AC power

2. Repairing local electrical or mechanical faults associated with plant systems or components

3. Local manual operation of failed remotely operated valves

4. Local operation of pumps on failure of control power

To determine which sequences would fall above the reporting criteria, all actions identified as recovery actions were set to true one at a time in the plant core damage sequences. Those sequences that increased by an order of magnitude were reported in Table 3.4-3. Table 3.4-4 presents the timing and complexity associated with the recovery actions that changed core damage sequences by at least an order of magnitude. Table 3.3-4 contains all repair and recovery actions that were used in the Prairie Island IPE.

3.4.3 Vulnerability Screening

No vulnerabilities were identified as part of the IPE process at Prairie Island. The criteria used to determine if any vulnerabilities existed were:

1. Are there any new or unusual means by which core damage or containment failure occur as compared to those identified in other PRAs?

2. Is there adequate assurance of no undue risk to public health and safety?

Neither of these criteria lead to the identification of potential vulnerabilities for the Prairie Island plant. The accident classes that contribute to the potential for core damage are similar to those identified in PRAs of comparable facilities such as those evaluated in NUREG 1150 and similar plants such as Point

Beach and Kewaunee. With an overall CDF being an acceptably low level of 5E-5/yr, NSP believes that there is adequate assurance of no undue risk to public health and safety.

Another term frequently used in this report is "significant insight". Many insight were generated as part of this study. In general, a significant insight was a system, component, or action which influenced the results of this study more than other events evaluated. A significant insight may involve:

1. A unique safety feature which significantly drove risk either by limiting the potential for or contributing to core damage.

2. A system interaction affect which had a relatively important impact on the overall results of the study.

3. A component failure mode or operator action which had a significant impact on the results of an accident class or the overall results.

4. A failure or operator action worthy of consideration of a recommendation.

5. A critical operator action which had limited procedural guidance.

Detailed discussions of insights derived from the Prairie Island IPE are presented in Section 6.0.

3.4.4 Loss of Decay Heat Removal

Generic Letter 88-20, section 5, discusses resolution of USI A-45 "Shutdown Decay Heat Removal Requirements." This section outlines the analysis of the Prairie Island decay heat removal (DHR) capability, as required by the generic letter.

The Prairie Island IPE is an integrated look at core damage risk from all internal events including loss of decay heat removal. The IPE used a systematic approach to evaluate plant systems and components looking for vulnerabilities to severe accidents. Inherent to this approach is an evaluation of the potential for loss of decay heat removal capability.

NUREG-1289 "Unresolved Safety Issue A-45, Shutdown Decay Heat Removal Requirements" Section 1.1, lists 2 criteria that must be met by the systems that are used to remove decay heat. These criteria are (1) to maintain sufficient water inventory in the RCS to ensue adequate cooling of the fuel and (2) to provide the means for transferring decay heat from the RCS to an ultimate heat sink. With this definition in mind, NSP chose to define DHR as decay heat removal from the reactor core.

As part of the Prairie Island IPE, the following topics related to DHR were analyzed and will be discussed:

1. The issues discussed in USI A-45.
2. Systems available at Prairie Island for DHR.
3. Proposed modifications.
4. Conclusions.

3.4.4.1 Relevant USI A-45 Issues

The various analyses performed to resolve the DHR issue were based on NUREG-1289, "Unresolved Safety Issue A-45, Shutdown Decay Heat Removal Requirements". The six specific discussed to resolve A-45 are:

1. No corrective action.

2. Perform detailed risk assessment.

3. Install various modifications.

4. Enhance bleed and feed capabilities.

5. Install a dedicated hot shutdown DHR system.

6. Install a dedicated cold shutdown DHR system.

The focus of this study was on item 2 from the list above. Item 1 was not considered because actions to identify and address DHR risk were performed as part of this evaluation. Item 3 was not considered as Prairie Island is not susceptible to the vulnerabilities listed in NUREG-1289. Alternative 4 was not considered as the bleed and feed capability at Prairie Island is adequate for core cooling. Alternatives 5 and 6 are not cost beneficial based on the Prairie Island CDF.

3.4.4.2 Systems Available for DHR

There are four possible methods by which decay heat can be removed from the reactor core:

1. Secondary cooling through the steam generators with main feedwater and auxiliary feedwater providing the steam generator makeup.

2. Bleed and feed cooling utilizing the SI pumps and pressurizer PORVs.

3. RCS injection and recirculation as provided by the SI and RHR systems during medium and large LOCAs.

4. Shutdown cooling mode of RHR operation after the RCS has been cooled down and depressurized to RHR SDC conditions.

3.4.4.2.1 Steam Generators

Heat removal through the steam generators is the primary and preferred method of removing decay heat until the RHR SDC system is placed in service. Effective heat removal using the steam generators requires circulation of primary coolant through the core with energy removal in the steam generators by use of steam relief to the condenser or atmosphere and steam generator makeup. Steam relief was not modeled for the Prairie Island IPE because of the many diverse means of steam removal. Following a reactor trip, steam is relieved to the condenser through a single air operated relief valve or to the atmosphere through four air operated valves. If the MSIVs should fail closed, steam relief is possible through an air operated PORV for each steam generator or through five safety relief valves on each steam generator, all of which are upstream of the MSIVs. In the event of loss of air, DC control power or instrument power, steam relief is assured through the five safety valves for each steam generator as they are not dependant on any support systems. With those many and diverse means of steam relief, it was assumed that the main reason for loss of steam generator cooling would be through loss of makeup capability. There are two means of makeup to the SGs that were modeled in the Prairie Island IPE; auxiliary feedwater (AFW) and main feedwater (MFW). A description of both of these systems follow.

Auxiliary Feedwater System

The AFW system consists of 2 completely redundant trains per unit, each capable of feeding both Steam Generators in that unit. One train consists of a turbine driven pump and the other consists of a motor driven pump. In addition, the motor driven pump from one unit can be cross connected to supply the Steam Generators of the other unit. Any one of the three pumps can supply adequate flow to meet a unit's decay heat removal needs following any transient event. The normal water supply to the AFW system is the Condensate Storage Tanks. These are backed up by the Cooling Water system.

Measures have been taken to prevent a single failure from failing the entire AFW system. The containment isolation motor valves that isolate AFW flow to the Steam Generators are open with their associated breaker locked open. This prevents an inadvertent isolation of all AFW flow to a Steam Generator due to a common cause failure of these valves to open. In addition, manual valves in the

AFW flow path that have the potential to reduce AFW flow have their positions administratively controlled to prevent inadvertent valve misaligmments after system maintenance.

Failure of the AFW pumps to start or run is minimized by ensuring the reliability of the pump driver. The power supplies to the motor driven pumps are backed up by safeguards diesel generators to ensure reliability of the power supply. The steam supply to the turbine driven pump is from the main steam system upstream of the MSIVs. The motor valves on the steam supply lines are normally open and have indication in the control room that would alert the operators if the valves were misaligned. The steam supply valve that isolates steam from the turbine driven AFW pump is an air operated valve that will fail open on loss of air or DC control power, starting the AFW pump.

NSP performed a reliability study to identify potential improvements to the Auxiliary Feedwater System. The report, NSPNAD 8606P Rev. 0, had several recommendations which were implemented that significantly increased the reliability of the system. Some of the recommendations involved modifications to the system, while others were administrative changes such as new procedures or training recommendations for operations personnel. Some of the most risk significant recommendations which were implemented are discussed below:

1. The AFW pump discharge recirculation flow now provides lube oil cooling, removing a previous dependance on cooling water.

2. Cross-tie of the motor driven AFW pumps between units is now proceduralized.

3. Operators have been trained on how to reset the turbine trip throttle valve and on how to locally start the turbine driven pump.

Dominant contributors to the AFW system reliability will be discussed in this section as derived from the AFW system fault tree.

Effects of Significant Initiating Events On the AFW System:

Initiating Event	AFW Failure Probability
Transients	8.8E-5
LOOP	8.1E-4
SBO	3.6E-2

The failure probability of the AFW system can vary for the spectrum of initiating events. Its support systems include only AC and DC power with cooling water providing a backup suction source in the event the condensate storage tanks are depleted. The increase in failure probability for LOOP events noted above reflects the additional dependance of the AFW system on the emergency diesel generators. In the event the diesel generators fail, an SBO occurs causing loss of the motor driven AFW pumps, leaving the turbine driven pump as the only means for feedwater addition to the steam generators. The turbine driven AFW pump is not dependant on AC or DC power, as the steam admission valve to the pump fails open on loss of DC power.

Important Hardware Failures on the AFW System:

Failure	Contribution to AFW Failure Probability
Random failure of unit 1 turbine driven AFW pump to run	79%
Random failure of unit 1 motor driven AFW pump to run	27%
Unit 1 train B AFW misaligned after T&M	24%
Motor driven AFW pump motors fail to start due to common cause	22%

Random failures to run of the turbine driven auxiliary feedwater pumps appeared in a large portion of the results. The turbine driven auxiliary feedwater pump was an important contributor as even though it is not dependant on AC or DC power, turbine driven pumps are not as reliable as the motor driven pumps. Failure of 11 AFW pump accounted for 80% of AFW system failure probability. Common cause events between the AFW pumps are not large contributors because of the diversity of the AFW pump drivers with two turbine driven and two motor driven pumps and to the redundancy provided by three pumps, all of which must fail to disable the AFW system.

Valve failures are not large contributors to the AFW system failure as the only valves required to change state are the steam admission valves to the turbine driven AFW pumps. All other valves required for system operation are in their required positions or fail open on loss of support system.

Important Operator Actions:

Failure to crosstie the motor driven pump from unit 2

The ability to crosstie the two motor driven AFW pumps between units contributes 51% to the system failure probability. The crosstie must be performed locally outside of the control room but the action is proceduralized and the valves required to be opened are easily accessed.

Main Feedwater System

The Main Feedwater System is the primary source of makeup to the steam generators during normal operation. Following a reactor trip, feedwater is automatically isolated to the steam generators in order to prevent a rapid RCS cooldown. Feedwater can be easily recovered from the control room for initiating events that do not generate an "S" signal by resetting the feedwater isolation signal and opening the feedwater regulating bypass valves. If an SI signal has been generated, MFW restoration is somewhat more complicated in that the condensate and MFW pumps must be restarted, the "S" signal and containment isolation signals must be reset, the MFW containment isolation valves must be opened and the MFW bypass valves must then be opened.

The Main Feedwater System consists of 2 redundant pumps which can supply feedwater to both Steam Generators. Each pump is capable of supplying all of the necessary flow to remove decay heat after any transient event. The pump suction is supplied from the Condensate System. The discharge of the pumps are cross-connected and then flow through 2 feedwater heater trains which are arranged in parallel. The flow is again combined before it is split to flow through the Feedwater Regulating Valves to the Steam Generators.

The MFW system is not a safeguards system and therefore the pump motor power supply is not from a safeguards bus and is not backed up by a diesel.

Dominant contributors to the MFW system reliability will be discussed in this section as derived from the MFW system fault tree.

Effects of Significant Initiating Events on the MFW System:

Initiating Event	AFW Failure Probability
LOOP, Loss of CL, Loss of Train A DC Loss of MFW	1.0
Loss of instrument air	0.58
Transient with no "S" signal present	6.6E-3
Initiating event causing an "S" signal	3.9E-2

Since MFW is not a safeguards system, the pumps are not powered from a diesel backed bus and therefore are unavailable on LOOP. Loss of CL causes loss of lube oil cooling to the MFW and condensate pumps causing eventual failure of the pumps. Since the feedwater regulating and bypass valves are air operated fail closed valves, loss of train A DC power and loss of instrument air both cause closure of all of the feedwater valves, failing feedwater. Local operation of the main feedwater valves is proceduralized in the EOP for loss of heat sink. A recovery factor obtained from generic data for feedwater recovery was applied to cutsets in which instrument air was lost. The same recovery factor was conservatively not applied to cutsets where loss of train A DC was the cause for feedwater failure. The different MFW system failures probabilities for initiating events which did not fail feedwater and those initiating events which caused an "S" signal to be generated is the difference in recoveries that the control room operators must perform to recover MFW as explained above.

Important Hardware Failures on the MFW System:

Failure	Contribution to AFW Failure Probability
Bus 110 unit cooler unavailable due to maintenance	15%
Control room chillers fail to run due to common cause	4%
Control room chilled water pumps fail to run due to common cause	4%

Hardware failures are not significant contributors to MFW system unavailability as the large portion of MFW system failure are due to the initiating events as described above. All of the hardware failures listed above cause eventual loss of DC power through loss of room cooling to the safeguards 480V bus rooms. It is assumed that if room cooling is lost to the safeguards 480V bus rooms, the transformers will heat up and eventually fail causing loss of all loads supplied by the affected buses. In the cases above, this results in loss of the battery chargers causing DC power to fail after the batteries have depleted. In reality, the batteries will provide DC power for at least two hours allowing the operator to restore local cooling of the safeguards bus rooms through opening door, and use of portable fans. The local restoration of room cooling to the safeguards bus rooms following loss of room cooling is a proceduralized action that was conservatively not credited in this case as the contribution to MFW failure from loss of room cooling was small.

Important operator actions:

The important operator action is the restoration of MFW for events in which it lost as a result of the initiating event but is otherwise available. Restoration of MFW accounts for approximately 60% of the MFW failure probability. The actions associated with MFW restoration for those initiating events that do and do not generate an "S" signal has been described above. Restoration of MFW is a relatively simple proceduralized action that can be performed from the control room.

3.4.4.2.2 Bleed and Feed

Transients resulting in reactor trip employ secondary cooling as the primary mechanism for core heat removal. For accident scenarios in which secondary cooling cannot be established or maintained, decay heat is absorbed by the primary system causing RCS temperature and pressure to rise. In these accidents, the emergency procedures direct the operator to initiate bleed and feed cooling.

To perform decay heat removal via bleed and feed, the operators inject cool water to the RCS with the SI system and remove hot water from the RCS through the Pressurizer PORVs. In this cooling mode, primary coolant is released through the PORVs into containment resulting in RCS pressure reduction and decay heat removal. SI injection in this mode maintains adequate RCS inventory as well as providing decay heat removal. A short description of the pressurizer PORVs and SI system follows.

The Pressurizer PORVs are air operated fail closed valves that are used to prevent over pressure in the RCS. For bleed and feed operation they are manually opened from the control room to allow water to flow from the Pressurizer to the Pressurizer Relief Tank.

Since the PORVs are air operated valves they are dependent on Instrument Air and DC power to operate. The Instrument Air supply to containment passes through two air operated fail closed containment isolation valves that are arranged in series. A failure of either valve or the associated control circuit for either valve will cause the valve to close and isolate instrument air to containment which will result in the loss of bleed and feed capability.

The PORVs do have air accumulators to allow valve operation in the event of a loss of instrument air, but they have not be shown to have sufficient capacity to allow valve operation for the duration of the bleed and feed operation. Therefore the PORVs are assumed to fail on a loss of instrument air.

<u>Safety Injection System</u>

The Safety Injection (SI) System is used to inject water from the Refueling Water Storage Tank (RWST) into the RCS when the RCS pressure is greater than the shutoff head of the RHR pumps. The SI system consists of 2 redundant trains containing a pump and it's associated valves. Each train is capable of providing adequate flow to prevent fuel damage during a small or medium break LOCA, main steam line break, or a main feed line break event.

The SI pump motors are powered from safeguards buses which are backed up by diesel generators for reliability. The motor operated valves which must operate to align the system for injection are also powered from safeguards power supplies. Motor operated valves in the injection lines to the RCS cold legs are normally open with the motor operator breaker locked open to prevent inadvertent valve misalignment. The SI pump discharges are cross connected such that either pump can supply cold leg injection or reactor vessel injection.

The SI pumps draw a suction off of the BASTs for the first few minutes of the injection phase of an event and then switch to the RWST when the Lo-Lo level alarm is reached on the BASTs. When the RWST low level alarm setpoint is reached, the operators are instructed to transfer from injection to recirculation mode.

Effects of Significant Initiating Events on Bleed and Feed:

Initiating Event	Bleed & Feed Failure Probability
Loss of Train A DC Loss of Train B DC	1.0
Loss of IA	0.58
Loss of CC Loss of CL	0.52
Transient with no "S" signal present	4.1E-2
Initiating event causing an "S" signal	4.7E-2
LOOP	5.1E-2

As shown above, the availability of bleed and feed cooling is highly dependant on the initiating event. During normal transient events, bleed and feed is relatively reliable and its operation is principally dependant on operator action to initiate bleed and feed. For events involving loss of train A or B DC power, the instrument air containment isolation valves fail closed cutting off instrument air to the pressurizer PORVs, failing bleed and feed.

Loss of CC is assumed to fail the SI system as the SI pumps rely on CC for lube oil cooling. The failure probability of bleed and feed for this initiating event reflects the recovery factor applied from generic data for recovery of a CC system. Loss of CL has the same effect as loss of CC as loss of CL is assumed to result in loss of CC. The failure probability of bleed and feed for loss of CL reflects the recovery factor applied from generic data for recovery of a CL system.

The remaining initiating events differ only in the failure probability for the operator initiating bleed and feed or the reliance of the SI system on the diesel generators following a LOOP.

Hardware failures are insignificant contributors to the bleed and feed failure probability as almost 95% of the failure probability is from human error. The operator actions to initiate bleed and feed differ as to whether an "S" signal has been generated by the initiating event. If an "S" signal has not been generated, the operator must manually start the SI pumps and open the pressurizer PORVs, while if an "S" signal has been generated, he must only verify an SI pump is running and then open the pressurizer PORVs.

3.4.4.2.3 RCS Injection and Recirculation

During medium and large LOCAs, decay heat is removed from the RCS by the ECCS. The two systems from the ECCS that are utilized to provide RCS inventory control are the SI and RHR systems. Each system has two modes of operation. During the initial phase of injection, both systems inject into the RCS from the RWST. The SI pumps are high head low capacity pumps that are used to inject into the RCS when the RCS pressure remains above the shutoff head of the RHR pumps. The RHR pumps are low head high capacity pumps that are used to prevent core damage for a design basis LOCA.

When low level in the RWST is reached, the operators are instructed to switch to the recirculation mode of ECCS. In recirculation, the RHR pump suction is shifted to the containment sump. Water is drawn from the containment, cooled in the RHR heat exchangers and discharged either back into the RCS or to the suction of the SI pumps depending on whether RCS pressure is above or below the shutoff head of the RHR pumps.

For high head recirculation, when RCS pressure is above RHR pump shutoff head, the RHR pump discharge is directed to the SI pump suction. The SI pumps then pump the water back into the RCS at high pressure. For low head recirculation, when the RCS pressure is below the RHR pump shutoff head, the RHR pumps discharge directly into the RCS. Since the SI system has been discussed previously, it will not be discussed again.

<u>SI Injection and Recirculation</u>

Effect of Significant Initiating Events on SI Injection:

Initiating Event	AFW Failure Probability
SGTR or LOCAs	1.9E-3

The failure probability of the SI system does not vary for the spectrum of initiating events considered as only LOCAs and SGTR utilize SI injection as SI operation for bleed and feed was covered under section 3.4.4.2.2. Since the initiating events considered do not impact the SI system, the system failure probability is independent of the initiating event.

Important Hardware Failures for SI Injection:

Failure	Contribution to AFW Failure Probability
BAST suction valves failing to open due to common cause	25%
RWST suction valves failing to open due to common cause	25%
Control room chilled water pumps fail to start due to common cause	19%
Both SI pumps fail to start due to common cause	9%

The two largest contributors to the SI system failure probabilities are the suction valves from the BAST and RWST failing to open due to common cause. At Prairie Island, the SI pumps first draw a suction from the BAST and then switchover to the RWST on low BAST level. If the BAST or RWST suction valves fail to open, a small 2 inch passive suction line from the RWST will provide adequate suction to the SI pumps until the operator discovers the suction valve failures through control board review or through a checklist that is part of the EOPs. This recovery action was applied to the BAST suction valves failing to open. A separate recovery action was applied to the RWST valve failures as local recovery of the RWST valves would be required in this case as there is no alternate suction as there was when the BAST valves failed to open.

Chilled water failures appear in a large portion of the SI system failures as failure of chilled water to the unit 1 safeguards 480V bus rooms is assumed to result in failure of the transformers causing failure of all loads supplied by the safeguards buses. In the case of the SI system this would result in failure of the suction valves from the BAST and the RWST as they are the only valves required to change state for successful system operation. Recovery factors have been applied as loss of chilled water is a proceduralized recovery action whereby the operator opens the doors to the safeguard bus rooms and provides portable fans for cooling. There are no operator actions as the actuation of the SI system is automatic. If the "S" signal failed, credit was not taken to manually start equipment that would have received an "S" signal.

Effect of Significant Initiating Events on High Head Recirculation:

Initiating Event	AFW Failure Probability
Loss of CC Loss of CL	0.58
Transients	6.5E-3
LOOP	1.6E-2
SGTR and LOCAs	5.9E-3

Loss of CC is assumed to fail high head recirculation as the SI pumps rely on CC for lube oil cooling and the RHR heat exchangers use CC for their heat sink. The failure probability of high head recirculation for this initiating event reflects the recovery factor applied from generic data for recovery of a CC system. Loss of CL has the same effect as loss of CC as loss of CL is assumed to result in loss of CC. The failure probability of high head recirculation for loss of CL reflects the recovery factor applied from generic data for recovery of a CL system. The increase in failure probability for LOOP initiating events reflects the additional dependance of the SI, RHR and CC pumps on the emergency diesel generators.

Important Hardware Failures for High Head Recirculation:

Failure	Contribution to AFW Failure Probability
Both CC supply valves to the RHR heat exchangers failing to open due to common cause	7%
Both RHR to SI crossover supply valves failing to open due to common cause	7%
Both control room chilled water pumps fail to start due to common cause	4%
Both control room chillers fail to start due to common cause	4%

The largest hardware failure that contributes to high head recirculation failure is the common cause failure to open of the CC supply valves to the RHR heat exchangers. This failure causes loss of heat sink for the RHR heat exchangers which is assumed to cause failure of recirculation as heat cannot be removed from the RCS. Common cause failures of the RHR to SI crossover valves fail high head recirculation as only the RHR pumps can draw a suction from the containment sump, so to initiate high head recirculation, the RHR to SI crossover valves must be opened. Chilled water failures contribute to high head recirculation failure as it has been assumed that the RHR pumps require room cooling during the recirculation mode of operation. Recent analysis has however shown that the pumps do not require room cooling for operation.

The single most important operator action for high head recirculation is the failure of the operator to initiate high head recirculation. This operator action contributes 41% to the high head recirculation failure. At Prairie Island, lineup for high head recirculation cannot be performed from the control room as the breakers for the RHR to SI crossover valves are locked in the off position. Local operator actions outside the control room are required to restore power to these valves. The motor control centers for the crossover valves are located in easily accessible locations, the breaker cubicles are clearly marked and the keys required to open the locks on the breaker cubicles are located close to the motor control centers.

Residual Heat Removal System

The RHR System is used to inject water from the RWST or the containment sump into the RCS when the RCS pressure is low. The RHR system consists of 2 redundant trains each containing a pump and heat exchanger. The heat load from the heat exchangers is transferred to the CC system. Each RHR train is capable of providing the necessary injection flow to prevent core damage for a design basis LOCA.

The RHR pump motors are powered from safeguards buses which are backed up by diesel generators for reliability. The motor operated valves which must operate to align the system for injection are also powered from safeguards power supplies. The RHR flow control valves downstream of the heat exchangers are air operated and are dependent on Instrument Air, but they fail open on a loss of air and therefore will not fail their associated train. Since the RHR pumps are located in pits in the auxiliary building it has been assumed that room cooling is required for successful RHR pump operation. Recent analysis has shown that the RHR pumps do not require room cooling for successful pump operation.

The initiating events for which RHR injection is modeled, namely the medium and large LOCAs have no affect on the RHR system, therefore only hardware failures contribute to the system failure probability of 1.3E-4/yr.

Important Hardware Failures for RHR injection:

Failure	Contribution to AFW Failure Probability
Both RHR pumps failing to start due due to common cause	57%
Both RHR pumps failing to run due to common cause	29%
RWST rupture	5%

The largest contributors to RHR injection failure are common cause failures of the two RHR pumps to start or run. Since the only support systems that the RHR system requires during the injection mode of operation is AC and DC power, support system failures are not large contributors to system failure. Valve failures do not contribute to system failure as there are no valves required to change state for successful RHR injection as the RHR vessel injection valves are now left open because of hydraulic locking concerns.

Low Head Recirculation

The initiating events for which low head recirculation is modeled, namely the medium and large LOCAs have no affect on the RHR system, therefore only hardware failures and human failures contribute to the system failure probability of 1.2E-2/yr.

Important Hardware Failures for Low Head Recirculation:

Failure	Contribution to AFW Failure Probability
Both CC supply valves to the RHR heat exchangers failing to open due to common cause	4%
Both control room chilled water pumps failing to start due to common cause	3%
Both control room chillers failing to run due to common cause	2%

The largest hardware failure that contributes to low head recirculation failure is the common cause failure to open of the CC supply valves to the RHR heat exchangers. This failure causes loss of heat sink for the RHR heat exchangers which is assumed to cause failure of recirculation as heat cannot be removed from the RCS. Chilled water failures contribute to low head recirculation failure as it has been assumed that the RHR pumps require room cooling during the recirculation mode of operation. Recent analysis has however shown that the pumps do not require room cooling for operation.

The single most important operator action for low head recirculation is the failure of the operator to initiate low head recirculation. This operator action contributes 72% to the high head recirculation failure. Although switchover to low head recirculation can be performed from the control room, the time available to perform the action before RWST depletion is the limiting factor as the RWST level is expected to decrease rapidly during a large LOCA.

3.4.4.2.4 RHR Shutdown Cooling

The RHR system has been discussed previously in the injection and recirculation modes of operation. This section describes the RHR shutdown cooling (SDC) mode of operation. In this mode of operation, the RHR pumps draw a suction from the Loop A and B RCS hot legs and discharge the coolant through the RHR heat exchangers and back to RCS Loop B cold leg. The heat load of the coolant is transferred to the CC system from the RHR heat exchangers. The SDC mode of RHR operation can only be entered after the RCS has been cooled and depressurized to 350°F and 425 psig.

The initiating events for which RHR SDC is modeled, namely small LOCA and SGTR, have no affect on the RHR SDC system, therefore only hardware failures and human failures contribute to the system failure probability of 1.7E-2/yr.

Important Hardware Failures for RHR SDC:

Failure	Contribution to AFW Failure Probability
Failure of the RHR Loop B return valve to open	28%
Failure of Train A control room chilled water pump to start	19%
Failure of Train A control room chilled water pump to run	13%
Failure of Train A control room chiller to run	13%

The largest hardware contribution to RHR SDC failure is the failure of the single RHR loop return valve to open. Since this is the single return valve, failure of this valve to open fails both trains of RHR SDC. It was conservatively assumed that RHR SDC could not be established through the RHR injection valves to the reactor vessel. Train A chilled water failures are large contributors to RHR SDC failure as the lone loop return valve is powered from train A 480V AC power. It is assumed that if room cooling (chilled water) is lost to the safeguards 480V bus rooms, the transformers will heat up and eventually fail causing loss of all loads supplied by the affected buses. In the cases above, this results in loss of the motor control center that powers the loop return valve, failing RHR SDC. The local restoration of room cooling to the safeguards bus rooms following loss of room cooling is a proceduralized action that was conservatively not credited in this case as the contribution of RHR SDC failure to the overall CDF was small.

3.4.4.2.5 Containment Spray and FCU

There are 4 Fan Cooler Units (FCUs) inside the containment that draw air from around the unit and pass it through cooling coils to cool the air and condense any steam in the air, returning the condensate to a containment sump. They then discharge the cooled air to either the containment dome area or to the space around the reactor vessel. The fan motors are powered from a safeguards power supply that is backed up by a diesel. The normal cooling medium for the FCU cooling coils is from the non safeguards chilled water system. Upon receipt of an "S" signal, the cooling medium swaps over to the safeguards cooling water system.

The containment spray system consists of two pumps that are able to draw a suction from the RWST and a caustic standpipe to deliver a borated water-sodium hydroxide mixture to spray ring headers located in the containment dome. The CS system operation consists of two phases; an injection and a recirculation phase. During the injection phase, the pumps draw a suction from the RWST and the caustic standpipe and deliver the mixture to spray rings in the containment dome. During the recirculation phase of operation, water is supplied to the suction of the CS pumps from the RHR pumps drawing a suction from the containment sump.

In all of the Prairie Island event trees, success or failure of recirculation was asked before FCU or CS success or failure. If recirculation failed, it was assumed that core damage would occur. Credit was not taken for the FCUs removing decay heat from containment and condensing the water to return it to the containment sump, even though MAAP analysis has shown that they are fully capable of this. In the case of recirculation, failure of the RHR heat exchanger is assumed to result in failure of recirculation even though the RHR pumps could recirculate the water through containment where the heat could be removed by the FCUs.

3.4.4.3 Conclusions

In NUREG-1289, the two DHR requirements listed are:

1. Maintain sufficient water inventory in the reactor coolant system to ensure adequate cooling of the fuel.

2. Provide the means for transferring heat from the reactor coolant system to an ultimate heat sink.

With this definition in mind, loss of DHR becomes synonymous with core damage as there are no Level 1 core damage sequences that do not involve loss of either one or both of the two requirements listed above. As identified above, there are many redundant and diverse means for DHR at Prairie Island. Several of the DHR systems and operator actions would have to fail in combination to have an impact on the DHR capability at Prairie Island. With the performance of the level 1 IPE, and the overall CDF being an acceptably low level of 5E-5/yr, NSP considers it has fulfilled the requirements of USI A-45.

3.4.5 Sensitivity and Importance Analysis

Once the dominant accident sequences leading to core damage were screened to determine the important contributors to core damage, sensitivity studies were conducted. Sensitivity studies were conducted on initiating event frequencies, operator actions, common cause, test and maintenance and for certain system components. The evaluations were performed to determine the global effect of the parameters of interest. Failure rates were increased/reduced by a factor of 5 where a higher level of uncertainty and variability exists such as human reliability, common cause and test and maintenance unavailability. Failure rates for system components were increased/decreased by a factor of 2 since actual plant data was used and there was less uncertainty associated with these parameters.

The following subsections describe the various sensitivity evaluations which were performed for the Prairie Island IPE study.

3.4.5.1 Sensitivity Analysis for HRA

1. All Operator Actions Successful

   A sensitivity analysis was performed in which it was assumed that all operator actions were successful. The results show that some sequences are very sensitive to human reliability failure rates. It also shows that if all operator actions were successful, an improvement of 36% (3.2E-5/yr) in total CDF would be realized.

2. Operator Action Failure Rates

   A sensitivity analysis was performed in which all human error probabilities were increased by a factor of 5. The results show that the CDF increased by a factor of approximately four (2.1E-4/yr) and is a reasonable error factor for this parameter. This analysis had the greatest effect on transients in which MFW is not restored by the operator following reactor trip, followed by AFW system failure and failure of the operator to initiate bleed and feed.

3.4.5.2 Sensitivity for EDG Failure Rates

A sensitivity analysis was performed in which the EDG failure rates were increased to determine the overall effect on the CDF as well as the individual initiators. In this sensitivity case, the failure probabilities including common cause were increased by a factor of two. The total CDF increased by 44% (7.2E-5/yr). The LOOP and SBO initiators were the most sensitive initiators due to the dependance on the diesel generators for success.

3.4.5.3 Sensitivity for Test and Maintenance Unavailabilities

In this sensitivity case, the calculated test and maintenance unavailabilities were increased by a factor of five. The results show that the model is sensitive to this parameter as the CDF increased by 85% (9.3E-5/yr) due to the online maintenance performed on safeguards equipment such as diesel generators. Increasing the maintenance unavailability for the air compressors increases the failure probability for instrument air which directly affect SGTR events as they have a dependance on instrument air for RCS cooldown and depressurization.

3.4.5.4 Sensitivity for Internal Initiating Event Frequencies

Table 3.4-2 present the initiating event frequencies for the internal events selected for analysis. The frequencies for loss of instrument air, loss of a DC bus, loss of component cooling water and loss of cooling water were calculated using the results of fault tree analysis and would have a higher level of uncertainty associated with them. Examination of Table 3.4-2 shows that only the loss of instrument air and loss of train A DC initiating events have a significant affect on the CDF. If the loss of instrument air initiating event frequency were increased by a factor of five, then the overall CDF will increase to 6.3E-5/yr, a 25% increase. If the loss of train A DC initiating event frequency is likewise increased by a factor of five, the overall CDF increases to 5.9E-5/yr, a 17% increase.

3.4.5.5 Importance Analysis

The importance analysis was based on use of the Fussell-Vesely and Birnbaum algorithms. The Fussell-Vesely importance gives the risk associated with a given component or how much the component is contributing to system or overall failure. The Birnbaum importance gives the increase in risk associated with the failure of a specific component. The results that follow will be based on the discussion of the Fussell-Vesely results.

Table 3.4-5 presents the results of the importance calculation performed for the initiating events used in the IPE. The results show that the first five initiating events contribute approximately 65% to the overall CDF. The LOOP results also include core damage contribution from SBO.

Table 3.4-6 presents the results of the importance calculation performed for the major operator actions that were used in the IPE. The results show that the operator actions associated with bleed and feed, transfer to recirculation and RCS cooldown and depressurization following a SGTR are significant contributors to the overall CDF.

Figures 3.4-1 and 3.4-2 rank the systems considered in the IPE according to Fussell-Vesely and Birnbaum. As can be seen from the results, AFW is the largest contributor because of the LOOP, T1FLD, INSTAIR and LODCA initiating events causing loss of MFW and/or loss of bleed and feed which places a heavy reliance on the AFW system as it is the only remaining means of secondary cooling. AC power is a large contributor as a LOOP followed by EDG failures can fail 12 or 21 AFW pump and also cause loss of loss of MFW which places a heavy reliance on the turbine driven AFW pump. Room cooling is important as loss of instrument air and loss of cooling water both cause failure of chilled water which supplies room cooling to the unit 1 480V safeguards bus rooms. It is assumed that on loss of room cooling without local operator actions to restore cooling, the bus rooms heat up and fail the transformers causing loss of all 480V safeguards loads.

Figures 3.4-3 and 3.4-4 rank the corrective maintenance contributions to overall CDF. As can be seen, train B AFW is the largest contributor as it is the most reliable pump to supply AFW to unit 1 because of its lower failure rate compared to the turbine driven pump and to the motor driven pump from unit 2 which requires an operator action for use. The charging pumps are large contributors because of the conservative assumption that charging is a requirement for successful RCS cooldown and depressurization following a SGTR.

Figures 3.4-5 and 3.4-6 rank the preventive maintenance and test contributions to overall CDF. As can be seen, the instrument air compressors are the largest contributors due to the success criteria of the instrument air system. Success for the instrument air system requires two out of three compressors. With one compressor in PM, a failure of a second compressor causes failure of the instrument air system. The unavailability of the instrument air compressors due to preventive maintenance is large due to the large accumulation of operating hours on the compressors and the PMs that are performed according to operating hours.

Table 3.4-1
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
FEH-TB1	Flood with core damage early and at high RCS pressures.	1E-5	21	A flood occurs in the AFW pump room from the Loop A or B CL header. Reactor trip and RCP seal cooling are successful. All AFW pumps fail, along with all instrument air compressors due to the flood. MFW fails due to closure of the main feed regulating and bypass valves and loss of lube oil cooling to the MFW pumps. Bleed and feed cooling fails due to loss of instrument air.	1E-5	21
TEH	Transient with core damage early and at high RCS pressures	1E-5	20	Loss of instrument air causing rx trip due to loss of MFW. RCP seal cooling is successful but 11, 12 and 22 AFW pumps FTR so 21 AFW pump cannot be used for Unit 1. Bleed and feed fails due to loss of instrument air and local restoration of main feedwater is unsuccessful.	4.4E-7	0.9
SLL	Medium or large LOCA with core damage late and at low RCS pressures	8.3E-6	16.6	Large LOCA with successful short term RCS inventory but long term RCS inventory fails due to operator error in lining up for recirculation	2.5E-6	5
				Medium LOCA with successful reactor trip and short term RCS inventory but long term RCS inventory fails due to operator error in lining up for recirculation	2.2E-6	4.3
SEH	Small LOCA with early core damage at high RCS pressures	8.2E-6	16.4	Loss of cooling water causing eventual reactor trip due to loss of CC to the RCP motors. Loss of CL causes loss of chilled water which causes loss of room cooling to the 480V safeguards bus rooms. Loss of room cooling is assumed to result in the eventual 480V bus failure causing loss of all charging pumps leading to an RCP seal LOCA that cannot be mitigated by the SI pumps as they have lost CC cooling to their lube oil coolers. Local operator actions to restore cooling water and 480V bus room cooling also fail.	6.3E-7	1.3
GLH	SGTR with core damage late and at high RCS pressures	6E-6	12	SGTR with operator failing to C/D & depressurize the RCS before ruptured SG overfill. A Ruptured SG relief sticks open followed by the operator failing to C/D and depressurize the RCS to RHR SDC temperature and pressure before RWST depletion.	1.1E-6	2.1

Table 3.4-1 (continued)
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
BEH-NOPWR	SBO with early core damage at high RCS pressures	2.8E-6	5.6	LOOP with successful reactor trip followed by D1, D2, D5 and D6 diesel generators failing to run due to common cause. The TD AFW pump runs for 2 hours before batteries are depleted and SG level instrumentation is lost. The operator is successful in depressurizing the SGs with the SG PORVs to reduce RCP seal leakage but the operator fails to restore offsite and onsite AC power at 5 hours.	2.3E-7	0.5
SLH	Small LOCA with late core damage at high RCS pressures	2.4E-6	4.8	Small LOCA with successful Rx trip, secondary cooling and short term RCS inventory. RCS C/D and depressurization to RHR SDC conditions is successful but the CC valves to the RHR heat exchangers fail to open failing RHR SDC and recirculation. Local attempts at recovery are also unsuccessful.	3.5E-7	0.7
TLH	Transient with late core damage at high RCS pressures	8E-7	1.6	LOOP with successful reactor trip followed by failure of D2 and D6 diesel generators to run which fails all train B safeguards equipment. 11 and 22 AFW pumps then fail to run followed by failure of the CC supply valve to 11 RHR heat exchanger to open, failing recirculation.	2.4E-8	0.05
GEH	SGTR with early core damage high RCS pressures	6E-7	1.2	SGTR followed by successful reactor trip and secondary cooling. RCS short term injection fails because the SI suction valves from the RWST fail to open due to common cause. The operator then fails to cooldown and depressurize the RCS before core damage occurs.	3.5E-8	0.07
BEH	SBO with early core damage at high RCS pressures	2.6E-7	0.5	LOOP with successful reactor trip followed by D1, D2, D5 and D6 diesel generators failing to run due to common cause. The TD AFW pump runs for 2 hours before batteries are depleted. The operator is successful in depressurizing the SGs with the SG PORVs to reduce RCP seal leakage and the operator is successful in restoring offsite AC power at 5 hours but an RCP seal LOCA has caused core damage.	2.6E-8	0.05
V	Interfacing systems LOCA	2.3E-7	0.5	Catastrophic failure of both of the RHR series loop A suction isolation motor valves followed by failure of both of the RHR pump seals causing a small LOCA outside of containment and the operator is unsuccessful in cooling down and depressurizing the RCS before RWST depletion.	5.5E-8	0.1

Table 3.4-1 (continued)
Reportable Core Damage Sequences By Accident Class

Accident Class	Description	Total CDF for Class	% Total CDF	Dominant Sequence Description	Sequence Prob.	% Total CDF
RLO	ATWS with operator failing to perform local reactor shutdown actions	1.6E-7	0.3	Normal transient followed by failure of the reactor protection system. The reactor power level is greater than 40%, main feedwater is successful but the operator fails to perform local action to make the reactor subcritical.	8.3E-8	0.2
REP	ATWS without adequate RCS pressure relief capacity	1.6E-7	0.3	Loss of main feedwater transient followed by failure of the reactor protection system. The reactor power level is greater than 40% and the operator fails to manually drive rods in for 1 minute. Auxiliary feedwater is successful but there is not adequate RCS pressure relief to prevent RCS overpressure.	2.8E-8	0.06
SEL	Large or medium LOCA with early core damage at low RCS pressures	7.6E-8	0.2	Large LOCA followed by failure of both RHR pumps to start due to common cause.	2.1E-8	0.04
FEH	Flood with early core damage at low RCS pressures	7.2E-10	1E-3	Auxiliary building zone 7 flood with successful reactor trip and RCP seal cooling. 11 and 12 AFW pumps fail to run and the operator fails to restore main feedwater and also fails to crosstie 21 AFW pump to unit 1. The operator then fails to initiate bleed and feed cooling.	1.5E-10	3E-4

Table 3.4-2
Core Damage Frequency By Initiating Event

Initiating Event	Initiating Event Frequency (per reactor year)	CDF from Initiating Event (per reactor year)	% of Total CDF from Initiating Event
I-TR1	1.68	6.4E-7	1.3
I-TR2	9.00E-2	2.9E-8	0.06
I-TR3	0.23	1.2E-6	2.4
I-TR4	9.00E-2	5.2E-7	1.0
I-LOCC	3.46E-3	5.5E-7	1.1
I-LOCL	1.82E-5	6.4E-7	1.3
I-LODCA	8.69E-3	2.2E-6	4.4
I-LODCB	8.69E-3	4.6E-7	0.9
I-INSTAIR	1.17E-2	3.2E-6	6.3
I-LOOP	6.50E-2	1.1E-5	21.2
I-MSLB	3.90E-4	*	*
I-MFLB	2.50E-5	*	*
I-SLOCA	3.00E-3	4.1E-6	8.2
I-MLOCA	8.00E-4	4.6E-6	9.3
I-LLOCA	3.00E-4	3.7E-6	7.5
I-SGTR	1.50E-2	6.6E-6	13.2
I-T1FLD	1.04E-5	1E-5	21
I-T13FLD	2.68E-5	*	*
I-AB7FLD	5.05E-3	8.5E-10	2E-3
I-AB8FLD	1.34E-4	*	*
I-SH1FLD	6.09E-6	4.1E-7	0.8
I-SH2FLD	2.54E-3	4.3E-10	9E-4
V	2.3E-7	2.3E-7	0.5

Table 3.4-2 (continued)

Definitions of Initiators

I-TR1	Normal transients
I-TR2	SG Hi Hi level transient
I-TR3	Inadvertent "S" signal transient
I-TR4	Loss of main feedwater transient
I-LOCC	Loss of component cooling water
I-LOCL	Loss of cooling water
I-LODCA	Loss of train A DC
I-LODCB	Loss of train B DC
I-INSTAIR	Loss of instrument air
I-LOOP	Loss of offsite power
I-MSLB	Main steam line break
I-MFLB	Min feedwater line break
I-SLOCA	Small LOCA (3/8" to 5" equivalent pipe diameter)
I-MLOCA	Medium LOCA (5" to 12" equivalent pipe diameter)
I-LLOCA	Large LOCA (12" up to design basis pipe diameter)
I-SGTR	Steam generator tube rupture
I-T1FLD	Turbine building zone 1 flood
I-T13FLD	Turbine building zone 13 flood
I-SH1FLD	Screenhouse zone 1 flood
I-SH2FLD	Screenhouse zone 2 flood
I-AB7FLD	Auxiliary building zone 7 flood
I-AB8FLD	Auxiliary building zone 8 flood
V	Interfacing systems LOCA
*	These results were truncated out

Table 3.4-3
Reportable sequences as a Resul. of Recovery Actions

Accident Class	Sequence Description	Sequence Probability	% Tota' CDF
TEH	Loss of train B DC initiator causing a reactor trip with failure of 11 AFW pump to run. 12 AFW pump fails to start due to loss of control power. The operator fails to crosstie 21 AFW pump from unit 2 and also fails to restore MFW. Bleed and feed cooling fails because loss of train B DC causes closure of one of the instrument air isolation valves to containment, causing failure of the pressurizer PORVs. Local actions to start 12 AFW pump at the pump breaker cubicle are also unsuccessful.	5.4E-8	0.09
SEH	Loss of train A DC initiator causing a reactor trip. 11 and 12 CL pumps fail as a result of loss of train A DC. Random failures of 22 and 121 CL pumps together with failure of local start of 12 CL pump results in failure of cooling water which fails CC and safeguards chilled water. Loss of chilled water causes heatup of the safeguards 480V bus rooms and eventual failure of the buses causing failure of all charging pumps and causing an RCP seal LOCA due loss of seal injection and CC. RCS short term inventory fails as the SI pumps require CC for lube oil cooling.	5.5E-8	0.09

Table 3.4-4
Recovery Action Timing and Complexity

Identifier	Probability	Time Available	Actions Required
E12AFWLOCV	5E-2	58 minutes	Close pump breaker at 12 AFW breaker cubicle following loss of pump breaker control power
SPD12MNSTY	5E-2	240 minutes	Locally open one of two air start valves at 12 CL pump following loss of pump control power

Table 3.4-5
Initiating Event Importance Rankings

Initiating Event	Fussell-Vesely	Initiating Event	Birnbaum
I-LOOP	2.1E-1	I-T1FLD	1.00
I-T1FLD	2.1E-1	-SH1FLD	6.7E-2
I-SGTR	1.3E-1	I-LUCL	3.5E-2
I-MLOCA	9.3E-2	I-LLOCA	1.2E-2
I-SLOCA	8.2E-2	I-MLOCA	5.8E-3
I-LLOCA	7.5E-2	I-SLOCA	1.4E-3
I-INSTAIR	6.3E-2	I-SGTR	4.4E-4
I-LODCA	4.4E-2	I-INSTAIR	2.7E-4
I-TR3	2.4E-2	I-LODCA	2.5E-4
I-TR1	1.3E-2	I-LOOP	1.6E-4
I-LOCL	1.3E-2	I-LOCC	1.6E-4
I-LOCC	1.1E-2	I-LODCB	5.3E-5
I-TR4	1.01-2	I-TR4	5.8E-6
I-LODCB	9.3E-3	I-TR3	5.3E-6
I-SH1FLD	8.2E-3	I-TR1	3.8E-7
I-TR2	5.9E-4	I-TR2	3.3E-7
I-SH2FLD	8.6E-6	I-AB7FLD	1.7E-7
I-AB7FLD	1.7E-7	I-SH2FLD	1.7E-7

<u>Definitions of Initiators</u>

I-TR1	Normal transients
I-TR2	SG Hi Hi level transient
I-TR3	Inadvertent "S" signal transient
I-TR4	Loss of main feedwater transient
I-LOCC	Loss of component cooling water
I-LOCL	Loss of cooling water
I-LODCA	Loss of train A DC
I-LODCB	Loss of train B DC
I-INSTAIR	Loss of instrument air
I-LOOP	Loss of offsite power
I-MSLB	Main steam line break
I-MFLB	Min feedwater line break
I-SLOCA	Small LOCA (3/8" to 5" equivalent pipe diameter)
I-MLOCA	Medium LOCA (5" to 12" equivalent pipe diameter)
I-LLOCA	Large LOCA (12" up to design basis pipe diameter)
I-SGTR	Steam generator tube rupture
I-T1FLD	Turbine building zone 1 flood
I-T13FLD	Turbine building zone 13 flood
I-SH1FLD	Screenhouse zone 1 flood
I-SH2FLD	Screenhouse zone 2 flood
I-AB7FLD	Auxiliary building zone 7 flood

Table 3.4-6

Operator Action Importance Ranking

Operator Action	Diagnosis time	Fussell-Vesely[1]	Birnbaum[2]
Bleed and Feed	8 to 22min	0.09	1.0E-4/yr
Depressurize RCS before SG overfill following a SGTR	49 min	0.07	3.1E-4/yr
Transfer to Low Head Recirc following LOCA	Diagnosis time not applicable here. The annunciator response model (Table 8-4 of NUREG/CR-4772) was used to determine operator diagnosis error.	0.05	3.0E-4/yr
Transfer to High Head Recirc following LOCA	Diagnosis time not applicable here. The annunciator response model (Table 8-4 of NUREG/CR-4772) was used to determine operator diagnosis error.	0.05	9.8E-4/yr
Crosstie motor driven AFW pump from opposite unit	24 min	0.04	5.6E-5/yr
Open doors on loss of room cooling to 480v switchgear	15min	0.03	2.5E-5/yr
Depressurize RCS to RHR SDC before RWST depletion following ruptured SG overfill	146 min	0.02	1.7E-4/yr
Restore main feedwater after a reactor trip	39 min	0.01	1.1E-4/yr
Crosstie EDG to emergency bus in opposite unit	95 min	0.01	2.0E-4/yr

[1] Fussell-Vesely importance is a measure of risk reduction potential and represents that fraction of core damage frequency to which the operator actions in the table contribute.

[2] Birnbaum importance is a measure of risk increase potential and in this table is roughly equivalent to the increase in core damage frequency if the operator were not able to perform each of these actions.

System Importance Rankings

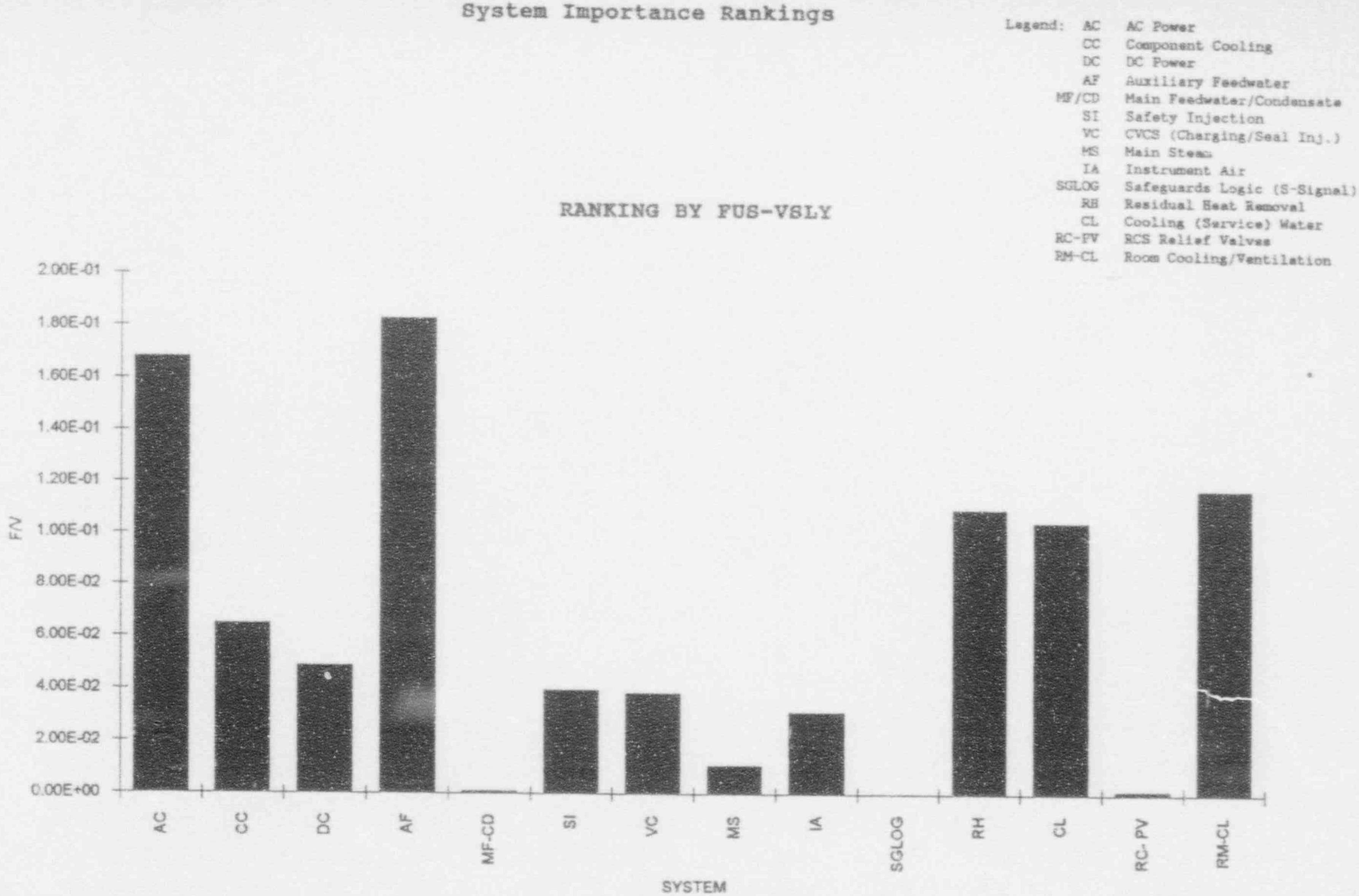


Figure 3.4-1

System Importance Rankings

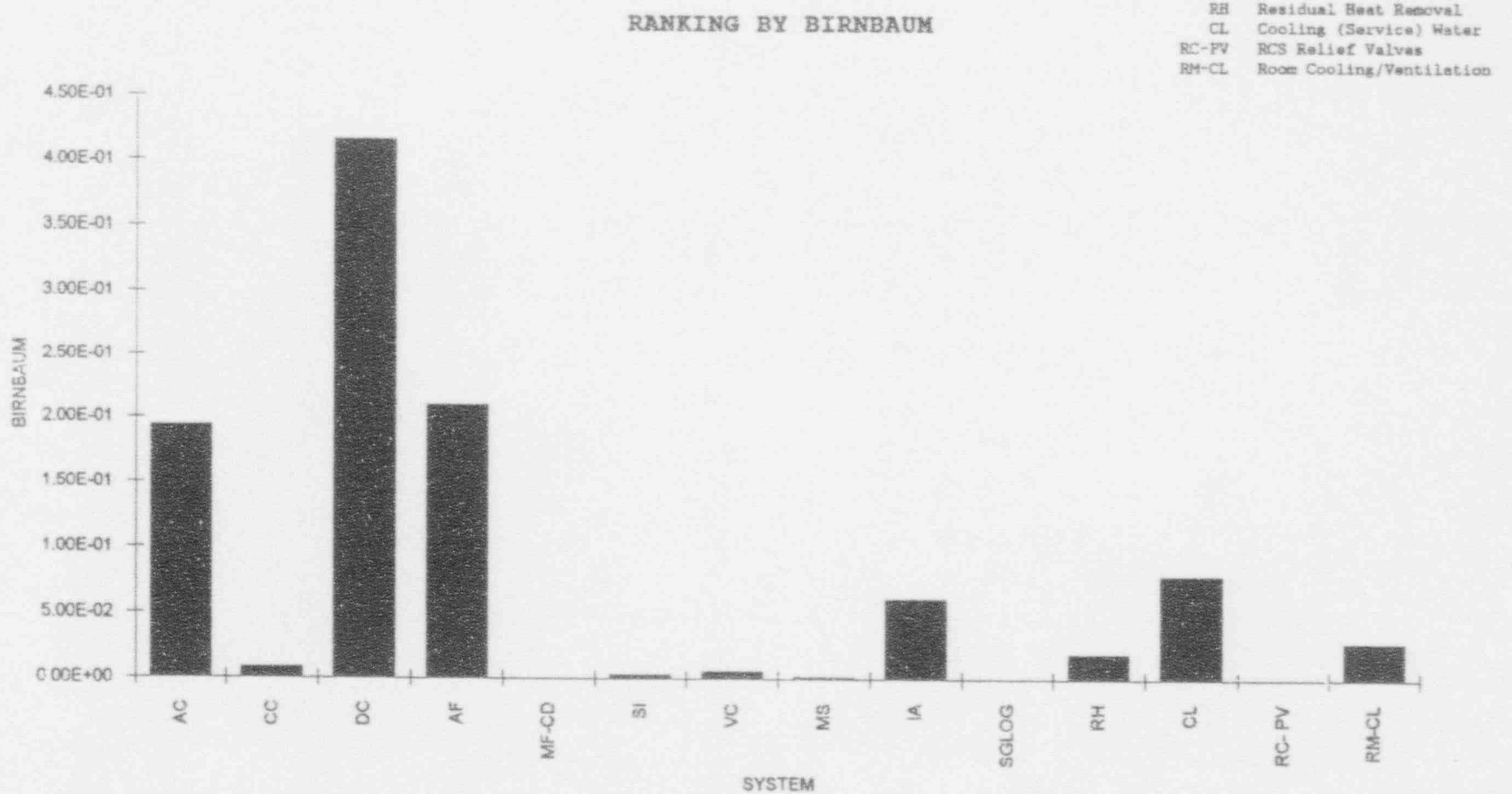


Figure 3.4-2

RANKING BY FUS-VSLY

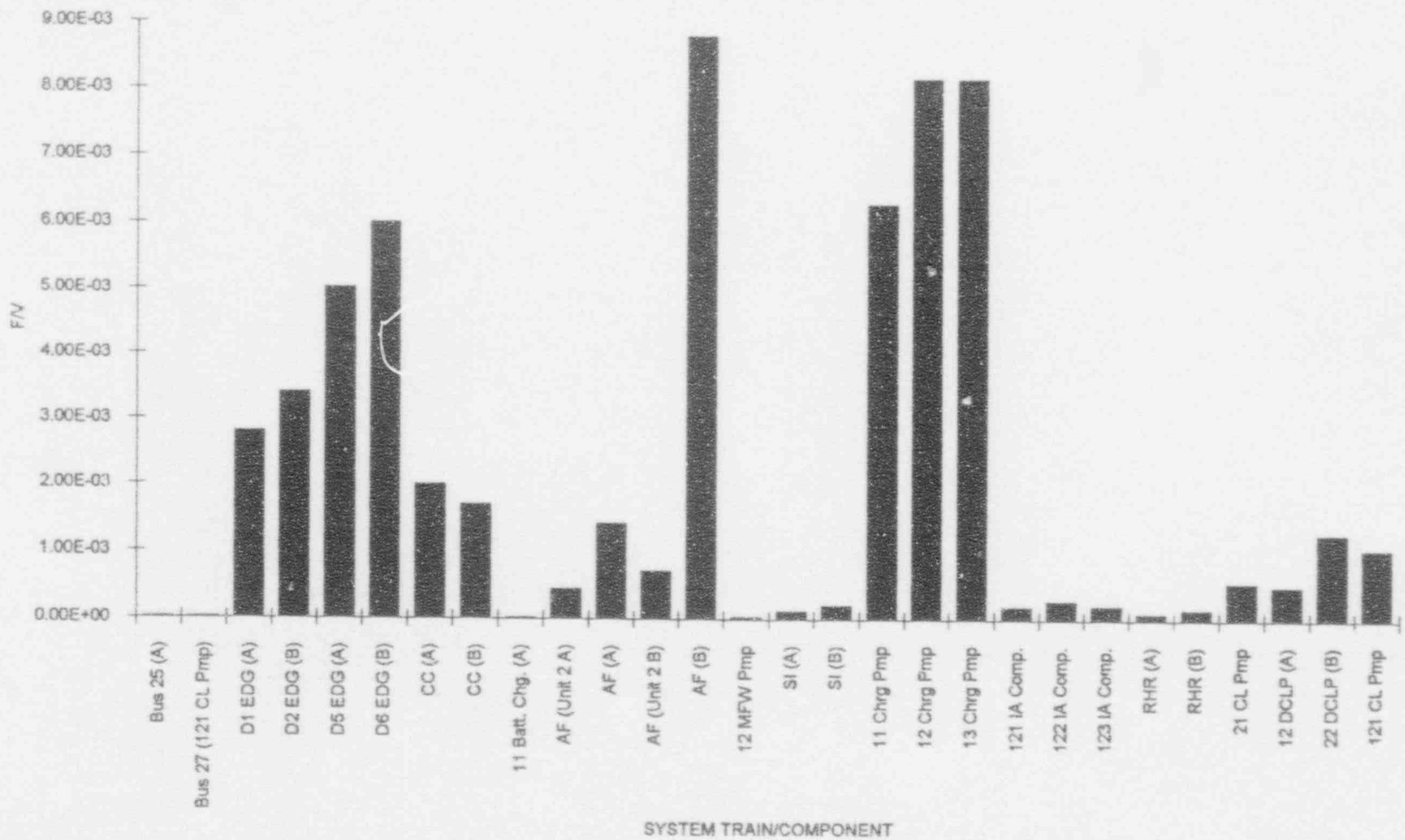


Figure 3.4-3

Corrective Maintenance Importance Rankings

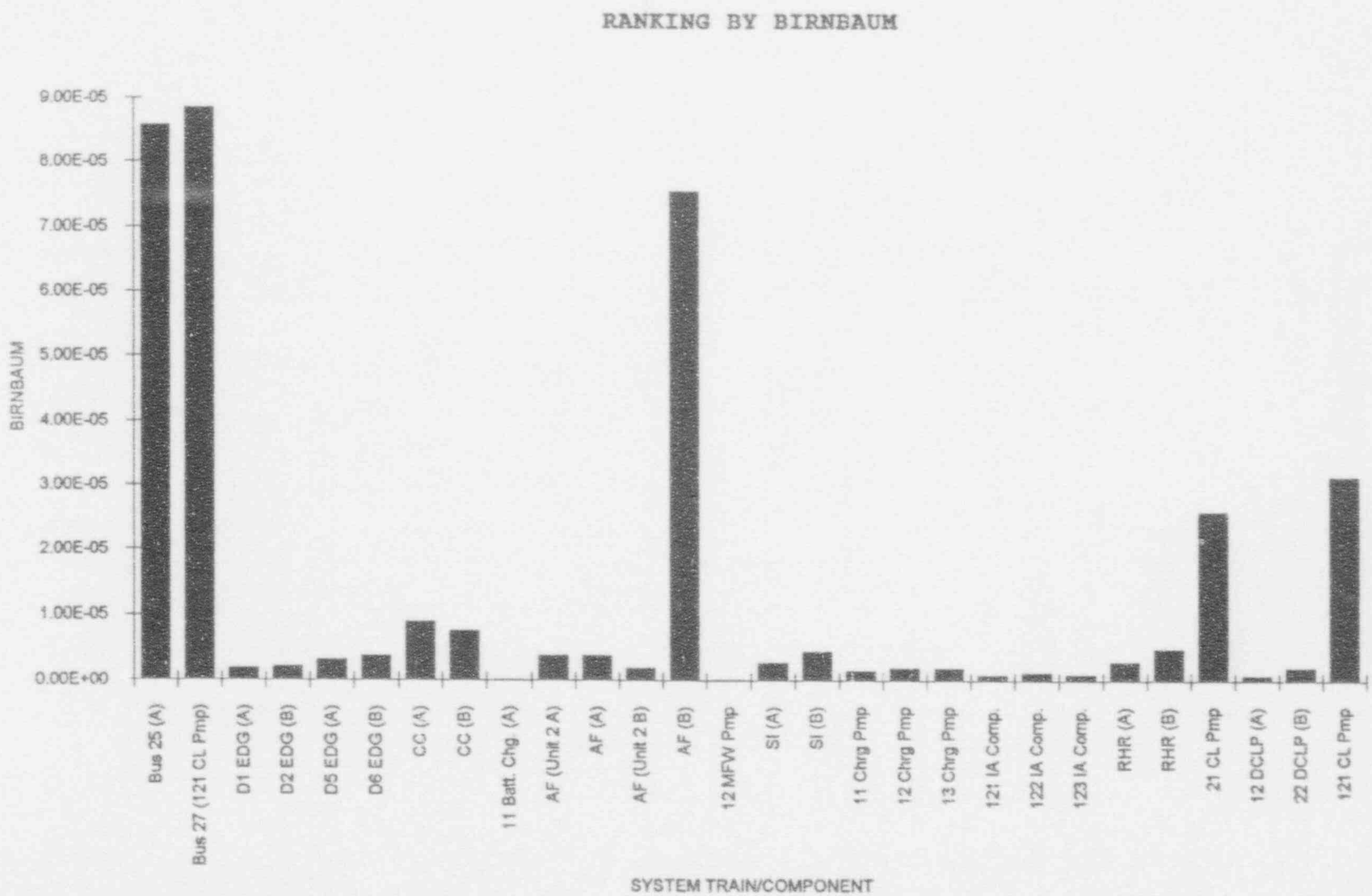


Figure 3.4-4

Preventive Maintenance/Test Importance Rankings

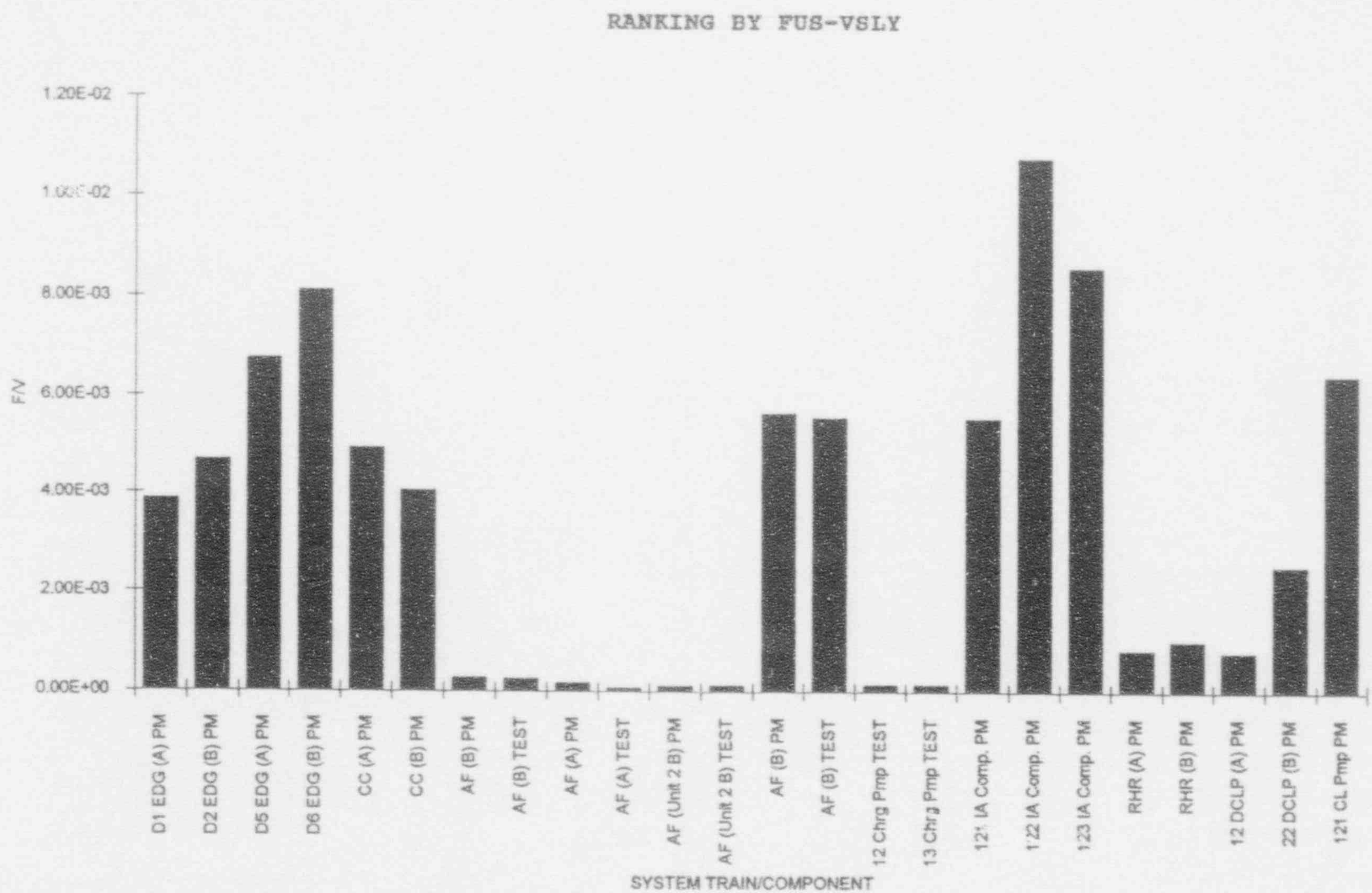


Figure 3.4-5

Preventive Maintenance/Test Importance Rankings

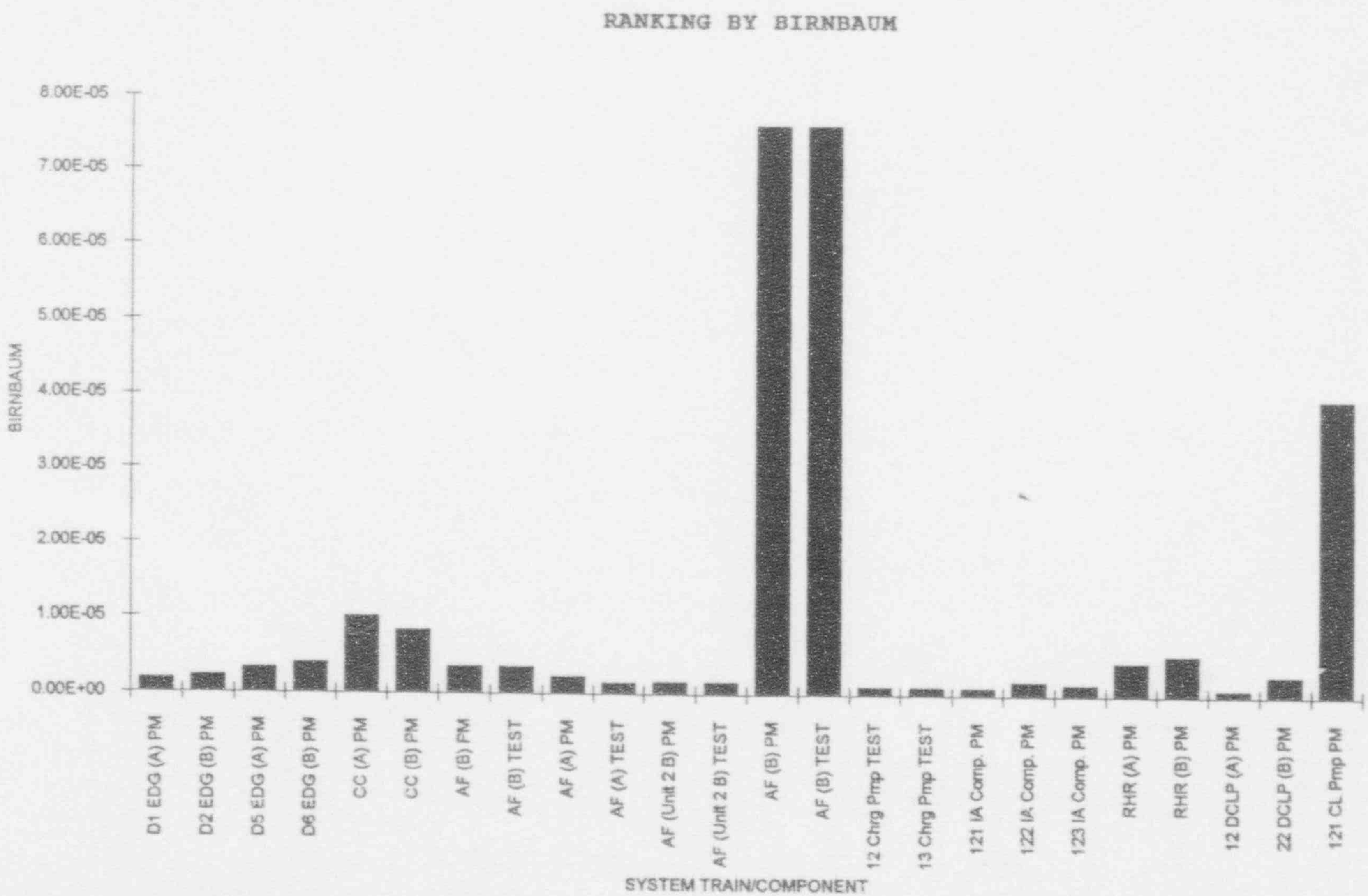


Figure 3.4-6

3.5 Unit 2 Considerations

3.5.1 Unit 2 Effects on Unit 1

Throughout the IPE analysis, consideration has been given to the affects of systems and equipment in both units on the frequency and outcome of a severe accident. Dual unit considerations explicitly modeled include the following:

1. Shared systems or systems capable of being crosstied between units such as:

   Instrument air
   Cooling water
   Auxiliary Feedwater
   Emergency AC power

Although component cooling water is capable of being crosstied between units, it was not modeled this way due to the low contribution to the overall CDF from CC.

2. Dual Unit initiators

   Loss of offsite power
   Loss of instrument air
   Loss of cooling water
   Flooding in the turbine building (T1FLD initiator)

If a dual unit initiating event occurred, equipment which could be crosstied from Unit 2 to Unit 1 was not credited until it was demonstrated that the equipment was not required for response to a Unit 2 transient or could support both units simultaneously. Fault tree modeling was used to account for use of shared components.

3. Common Cause modeling

For similar components within systems that are shared or could be crosstied, common cause analysis of the Unit 1 and Unit 2 systems as a whole was performed.

3.5.2 Unit 2 Level 1 Quantification

The Unit 1 results were used as input to determine the core damage frequency for Unit 2 . Using the Unit 1 results is appropriate for quantifying Unit 2 since all assumptions regarding system success criteria made in quantifying

Unit 1 results also apply to quantifying Unit 2 results. However, a few asymmetries exist between units. For differences between the two units, the Unit 1 results were modified to reflect Unit 2 design features.

3.5.2.1 Quantification Approach

The Unit 2 Level 1 results were obtained from requantifying the Unit 1 results and replacing appropriate Unit 1 component failures by their counterpart for Unit 2. In this process, Unit 1 component failures associated with systems that are symmetric (identical between the two units) were simply renamed to represent Unit 2 failure events. Unit 1 component failures associated with systems that are asymmetric between the two units were replaced with logic associated with Unit 2 counterparts. Failure events associated with systems that are shared between the two units were left as they were since these failures are valid for both Units 1 and 2. Finally, the failure events that apply for Unit 1 but do not apply for Unit 2 were deleted from the results to obtain the final Unit 2 core damage results.

Two major asymmetries were identified between Units 1 and 2:

1. Emergency AC power - The Unit 2 emergency diesel generators (D5 & D6) are air cooled and do not require cooling water for engine and lube oil cooling. Because of the dependency of Unit 1 DGs on cooling water, they consider equipment failures that do not contribute to the Unit 2 EDGs.

2. Room Cooling for 480V AC bus rooms - Unit 1 safeguards 480V AC buses are assumed to require room cooling. The Unit 2 480V AC buses are assumed to continue to operate during a plant transient without cooling to their rooms. Unit 2 480V AC bus rooms are comparatively larger than the Unit 1 bus rooms and are well ventilated. Therefore, if cooling is lost to the rooms, it is assumed that the room temperature will not reach a level to cause the buses to fail.

   Although a room heatup calculation has been performed that gives negative re ults for loss of Unit 2 480 V bus room cooling (TENERA Calculation 105206-2.2-001, Rev. 0), the calculation includes several conservative assumptions that are not applicable to a best estimate model of the room heatup. For example, the analysis assumes a main steam line break is occurring in the Auxiliary Building at the same time that room cooling is lost in the 480 V bus rooms. Also, all rooms are at their maximum expected operating temperatures, the outside air supply temperature is 96°F, and the buses are at their highest heat generation rate.

The 121 Cooling Water pump, a safeguards motor-driven pump, is powered from either Train A or Train B Unit 2 4160 V power (the operator can switch the power supply if the bus it is connected to becomes deenergized). It is assumed that the Unit 1 diesel generators cannot supply this pump in addition to their safeguards bus loads on a loss of offsite power (LOOP). However, this asymmetry between the units is not significant due to the availability of the diesel cooling water pumps on LOOP and due to the ability to connect the 121 pump to either Unit 2 bus. Also, the Unit 2 diesels themselves are not dependent on the cooling water system.

All other safety systems that are credited to mitigate core damage are symmetric between the two units in terms of their design and safety functions. Cooling water and Instrument Air systems are shared by Units 1 and 2 systems and therefore have minimum impact on the resulting difference in the core damage frequencies.

3.5.2.2 Results

The Unit 2 core damage frequency is calculated to be approximately 5.1E-5 per reactor year. A breakdown of Unit 2 core damage frequency by initiating events are tabulated in Table 3.5-1. As can be seen, the core damage distributions by initiating event for Unit 2 closely resemble the distribution in Unit 1. This is attributed to a large amount of symmetry among the safety systems between the two units. Because of this symmetry between the two units, the major contributors to core damage for Unit 2 are almost identical to their counterpart in Unit 1. The asymmetries identified above have little effect on the Unit 2 core damage frequencies when compared to the Unit 1 results for each initiating event. This is due to the redundancy and diversity of the systems in both the units to mitigate an accident event. The 4KV AC emergency buses can be crosstied between the two units. Therefore, for example, the key failure combinations associated with bus 15 and 25 in Unit 1 and 2, respectively can be written as:

```
Bus 15 =  ( D1 + CL) * ( X-tie + D5 ).
       =    D1 * X-tie
            D1 * D5
            CL * X-tie
            CL * D5

Bus 25 = ( D5 ) * ( X-tie + D1 + CL ).
       =    D5 * X-tie
            D1 * D5
            CL * D5
```

where, D1 represents Unit 1 diesel generator D1
D5 represents Unit 2 diesel generator D5
X-tie represents failure to cross-tie Unit 1 emergency buses to Unit 2 buses and vice-versa
CL represents cooling water system failure.

Notice that failure combinations representing (CL * X-tie) do not occur for Bus 25 but do for Bus 15 because D5 does not require cooling water to continue to run. Therefore, Bus 25 should be more reliable than Bus 15. However, the actual failure probability for the two buses are very similar. A closer examination shows that the (CL * X-tie) failure combinations make up an insignificant percentage of the bus 15 failure probability . Therefore, there is little change in the core damage frequencies between Unit 1 and 2 when bus 15 failures are replaced with bus 25 failures and likewise with buses 16 and 26.

Not crediting room cooling in the Unit 2 bus rooms has little effect on decreasing the Unit 2 core damage frequency when compared to Unit 1 frequency. There are two reasons for this:

1. Loss of Unit 1 bus room cooling has a negative effect on Unit 2 due to loss of 2 of the 3 available instrument air compressors for both units.

2. Unit 1 bus room cooling failures were not large contributors to the Unit 1 results due to ability of plant personnel to locally re-establish room cooling after it has failed. Because of the relatively low importance of bus room cooling, deleting these failure contributions for Unit 2 has little effect on the overall core damage frequency.

3.5.3 Conclusion

In summary, the Unit 2 results mirror that of Unit 1. Consistent with the Unit 1 results, there are no vulnerabilities that result in outliers with respect to Unit 2 core damage frequency. The similarity in the results is attributed to the fact that nearly all systems and functions accounted for in the Unit 1 analysis also apply to the Unit 2 analysis. Moreover, most of the safety systems credited in mitigating plant transients are symmetric between the two units. The asymmetries were determined to not be significant contributors to the difference between the two units' results as discussed above. Therefore, the major insight gained from the Unit 2 results when compared to Unit 1 results is that the units are almost identical in the way they respond to accident events.

Table 3.5-1
Core Damage Frequency By Initiating Event for Unit 2

Initiating Event	Initiating Event Frequency (per reactor year, Unit 2)	CDF from Initiating Event (per reactor year, Unit 2)	% of Total CDF from Initiating Event (Unit 2)	% of Total CDF from Initiating Event (Unit 1)
I-TR1	1.68	6.6E-07	1.3	1.3
I-TR2	9.00E-02	3.1-08	0.06	0.06
I-TR3	0.23	1.2E-06	2.4	2.4
I-TR4	9.00E-02	5.5E-07	1.1	1.0
I-LOCC	3.46E-03	5.5E-07	1.1	1.1
I-LOCL	1.82E-05	6.4E-07	1.3	1.3
I-LODCA	8.69F-03	2.2E-06	4.3	4.4
I-LODCB	8.69E-03	4.8E-07	0.9	0.9
I-INSTAIR	1.17E-02	3.2E-06	6.2	6.3
I-LOOP	6.5E-02	1.1E-05	22.4	21.2
I-MSLB	3.9E-04	*	*	*
I-MFLB	2.5E-05	*	*	*
I-SLOCA	3.00E-03	4.2E-06	8.2	8.2
I-MLOCA	8.00E-04	4.6E-06	9.1	9.3
I-LLOCA	3.00E-04	3.8E-06	7.3	7.5
I-SGTR	1.50E-02	6.6E-06	13.0	13.2
I-T1FLD	1.04E-05	1.04E-05	20.4	21
I-T13FLD	2.68E-05	*	*	*
I-AB7FLD	5.05E-03	1.5E-09	0.00	2E-3
I-AB8FLD	1.34E-04	*	*	*
I-SH1FLD	6.09E-06	4.1E-07	0.80	0.80
I-SH2FLD	2.54E-03	5.6E-10	0.00	9E-4
I-ISLOCA	2.27E-07	2.27E-07	0.5	0.5

* These results were truncated out

Table 3.5-1 (continued)

Core Damage Frequency By Initiating Event for Unit 2

Definitions of Initiators

I-TR1	Normal transients
I-TR2	SG Hi Hi level transient
I-TR3	Inadvertent "S" signal transient
I-TR4	Loss of main feedwater transient
I-LOCC	Loss of component cooling water
I-LOCL	Loss of cooling water
I-LODCA	Loss of train A DC
I-LODCB	Loss of train B DC
I-INSTAIR	Loss of instrument air
I-LOOP	Loss of offsite power
I-MSLB	Main steam line break
I-MFLB	Min feedwater line break
I-SLOCA	Small LOCA (3/8" to 5" equivalent pipe diameter)
I-MLOCA	Medium LOCA (5" to 12" equivalent pipe diameter)
I-LLOCA	Large LOCA (12" up to design basis pipe diameter)
I-SGTR	Steam generator tube rupture
I-T1FLD	Turbine building zone 1 flood
I-T13FLD	Turbine building zone 13 flood
I-SH1FLD	Screenhouse zone 1 flood
I-SH2FLD	Screenhouse zone 2 flood
I-AB7FLD	Auxiliary building zone 7 flood
I-AB8FLD	Auxiliary building zone 8 flood
V	Interfacing systems LOCA
*	These results were truncated out

4.0 BACK-END ANALYSIS

The purpose of the back-end analysis is to understand potential containment challenges, the impact of phenomena and plant features on the prevention and mitigation of containment challenges and limiting off-site releases, and the role of operator actions in dealing with containment challenges. This includes the calculation of source terms for the dominant accident sequences and recommendations which will allow for the evolution of an accident management program.

4.1 Plant Data and Plant Description

The Prairie Island containment is described below, along with the containment systems which are important to containment integrity, as well as the source term analysis. Detailed plant-specific data is used to model these containment features, so as to realistically evaluate the containment response to a core melt accident.

4.1.1 Containment Structure

The Prairie Island containment employs a 2-loop Westinghouse design with a freestanding steel shell containment. The Modular Accident Analysis Program (MAAP) is used in the Prairie Island IPE to model the plant and containment response to severe core melt accidents. Further discussion of the MAAP code and how MAAP is used in the Prairie Island IPE is contained in Section 4.2. For MAAP modeling and discussion purposes, the containment is sectioned into several compartments consisting of a total free volume of approximately 1,320,000 cubic feet. Figure 4.1-1 illustrates a vertical cross-section of the Prairie Island containment. MAAP sections the containment into four individual compartments: the upper compartment, annular compartment, lower compartment, and cavity. The upper compartment is defined as the large containment volume located above the refueling floor (Elev. 755'-0"). The annular compartment is defined as the area of containment below the refueling floor, but outside the secondary shield wall (i.e. missile barrier). The lower compartment is that portion of containment which is between the containment floor (Elev. 697'-6") and the refueling floor, but inside the secondary shield wall. The cavity includes the area in the reactor cavity and instrument tunnel. For the purpose of better modeling Prairie Island, these compartments were rearranged slightly. This arrangement had a minimal effect on the outcome of the Prairie Island Level II source term analyses.

Prairie Island's containment system consists of two separate structures: a reactor containment vessel and a shield building. The reactor containment vessel is a low-leakage steel shell, including penetrations, designed to confine radioactive material that could be released during a severe core melt accident. Nominal dimensions of the Prairie Island reactor containment vessel are as follows:

Inner Diameter (ft)	105
Interior Height (ft)	206
Cylinder Shell Thickness (in)	1-1/2
Dome Thickness (in)	3/4
Ellipsoidal Basemat Thickness (in)	1-1/2
Internal Free Volume (ft^3)	1,320,000

The reactor containment vessel is supported on grout base that was installed after the vessel was completed and tested. Both the reactor containment vessel and shield building are supported on a common foundation. Freedom of movement between the reactor containment vessel and the shield building is virtually unlimited. With the exception of the support grout placed underneath and near the knuckle sides of the vessel, there are no structural ties between the shield building and the reactor containment vessel above the foundation.

Completely enclosing the reactor containment vessel is the 2-1/2 foot thick concrete shield building. The shield building is a right circular cylinder with a shallow dome roof. A 4' - 10-1/2" annular gap is provided between the reactor containment vessel and the shield building. Prairie Island's shield building is a concrete structure designed to provide the following features:

- Biological shielding for design basis accident (DBA) conditions.
- Protection of the reactor containment vessel from adverse weather conditions and external missiles.
- A means of collecting and filtering fission product leakage from the reactor containment vessel.

The open design and significant venting areas for the sub-compartments within the Prairie Island containment help ensure a well-mixed atmosphere, a feature that inhibits combustible gas pocketing. Steel grating around the periphery of the operating deck provides a good flow path between the annular and upper compartments. This grating also provides an effective fission product removal mechanism in the form of impaction. The lower and upper compartments communicate through openings around the steam generators and their corresponding vaults.

Figure 4.1-2 illustrates the Prairie Island reactor cavity and instrument tunnel geometry. The free volume of the cavity and instrument tunnel is approximately

4930 ft^3 with a floor area of 292 ft^2. Geometry of the cavity and instrument tunnel, structures at the exit of the seal table, and openings in the instrument tunnel are important features of the Prairie Island containment because they:

- allow for a potentially wet cavity configuration if the RWST is injected, and

- act to limit the extent of debris dispersed from the cavity following a high pressure melt ejection (HPME).

The Prairie Island cavity has a total concrete basemat thickness of approximately 9.8 ft of basaltic concrete. Therefore, for sequences where the core debris is retained in the cavity, 9.8 feet of concrete must be ablated before the core debris will breach the containment boundary.

The Prairie Island containment facilitates flooding of the reactor cavity. Water can readily flow from the upper compartment to the annular containment floors and access the cavity. Access is in the form of two personnel entry hatches located on the instrument tunnel, approximately 18" off the floor of containment. These two hatches are left slightly ajar during normal plant operation. The base case assumption is that if the RWST is injected into containment, either by continuous containment spray operation, or by injection flow out of a break in the primary system, water will accumulate on the floor of containment. Once the containment water level exceeds 18", water will begin to overflow into the cavity through the two access hatches. Since the flow velocity going into the instrument tunnel may be sufficient enough to pull the doors closed, the issue of RPV lower coolability will be treated as a sensitivity. This feature of the Prairie Island containment has important implications for core-concrete interactions, ex-vessel steam explosions, hydrogen combustion, etc. Also, this feature allows for the possibility of cooling the reactor vessel lower head externally, thereby averting vessel failure altogether.

Personnel access into containment is normally provided through the main personnel airlock located on the 755'-0" elevation. The equipment hatch is located between the 711'-6" and 732'-6" elevations. An emergency personnel airlock is also located in annular compartment at the 733'-9" elevation. All three of these hatches employ non-metallic gaskets as part of their leakage barrier.

All containment penetrations are double-barrier assemblies consisting of a closed sleeve, in most cases, or a double gasketed closure for the fuel transfer tube. The mechanical penetrations are welded to the containment shell. Likewise, the electrical penetration assemblies (EPA's) are constructed to provide a leak-tight barrier. The EPAs employ a non-metallic seal and potting compound. There are no electric penetrations in the immediate vicinity of the seal table structure.

4.1.2 Containment Systems

The Prairie Island containment design includes the following three containment cooling systems:

1. Four Containment Fan Coil Units (FCUs)
2. Two Internal Containment Spray (CS) Trains
3. Two Low Pressure Residual Heat Removal (RHR) Pumps and Heat Exchangers

The residual heat removal (RHR) system, although not a containment system, also provides a means of long term containment heat removal. Brief descriptions of each of these systems listed above are provided below.

Containment Fan Coil Units

The containment air cooling system consists of four containment fan coil units (FCUs) each capable of removing approximately 14.5 MW from a saturated air-steam mixture at a flow rate of 29,000 cfm. At Prairie Island, the fan coolers are located throughout containment. One is located on the operating deck on the 755'-0" elevation. Another one is located on the 733'-9" elevation, and the two remaining fan coolers are located side by side on the 711'-6" elevation. The fan coolers take suction from the lower regions of containment and discharge to the upper compartment volumes.

During normal operation, most of the heat that is generated in containment is produced in the lower regions of the containment where the reactor coolant pumps are located. The operation of these pumps combined with all the RPV hot and cold legs causes the air in this region to heat up. Also, during an accident where there is a break in the RCS or the rupture disk on the PRT blows, most of the heat will be released into the lower regions of containment. To keep this area from overheating and degrading the performance of various components, air from the lower regions is drawn into the suction of the FCUs. The hot air is then forced through the FCUs where the air is drawn over a series of cooling coils which condense the steam and cool the air. The cooled air is then discharged back into the upper regions of containment. The cooling water for the FCUs is supplied by the Cooling Water System. Therefore, loss of cooling water results in the loss of containment heat removal via the containment fan coolers.

Internal Containment Spray System

The containment spray (CS) system sprays cool, borated water mixed with sodium hydroxide (NaOH) into the containment atmosphere following a severe core damage event to ensure that the containment pressure does not exceed the design pressure. The CS system consists of two separate trains, each with one, single-staged, horizontal centrifugal pump capable of delivering 1300 gpm. The CS system not only provides a potential pressure reduction mechanism, but also serves to maintain proper Ph of fluids within containment and provides an excellent means of removing fission products, especially aerosols, from the containment atmosphere.

The two containment spray trains initially take suction from the refueling water storage tank (RWST) and deliver the borated water-sodium hydroxide mixture to the associated spray ring headers in the containment dome. When the RWST level reaches a predetermined level (33% when both trains are operating and 28% when only one train is in operation), one train of pumps (where a train refers to one RHR pump and one CS pump) is turned off, the RHR pump is aligned to take suction from the containment sump, and the containment spray pump is aligned to take suction from the discharge of the RHR heat exchanger. Meanwhile, the other train continues taking suction from the RWST until the RWST empty alarm is reached. When the RWST water level drops below the empty alarm (8% level), the other RHR and containment spray pump are turned off and aligned for recirculation in the same manner as the first train. Prior to aligning the second train, the first train of pumps will already be operating in the recirculation mode. Therefore, when the CS pumps are in recirculation mode, the operating spray pump(s) are taking suction from the discharge of the RHR heat exchangers. Conversely, if the RHR pumps fail to switch to recirc., the containment spray pumps will not be available in recirculation.

Residual Heat Removal System

The residual heat removal (RHR) system consists of two separate trains, each consisting of one vertical, single-staged, centrifugal pump capable of delivering 2000 gpm at a primary system pressure below 140 psi. The main purpose of the RHR system during an accident is to provide low head emergency core cooling. In recirculation mode, the RHR pumps are aligned to take suction from the lower containment sumps and discharge to either: 1) the suction of the high head Safety Injection Pumps, 2) the suction of the Containment Spray Pumps, or 3) the RCS via the injection nozzles. The water is cooled via the RHR heat exchanger before it is delivered to the one of the three discharge locations listed above.

Containment cooling through the use of the RHR pumps is achieved through continuous injection through the failed RPV onto the debris located in the cavity. For cases where no injection occurred prior to vessel failure, the RHR pumps and heat exchangers can be used to cool the debris in the cavity and, after a period of time, the containment gas temperatures will begin to cool as well. Since the RHR pumps and heat exchangers rely on the component cooling water (CC) system and the cooling water system for cooling, loss of either one of these two systems will negate the containment heat removal capabilities of the RHR system, as well as the CS system which is dependent upon the RHR system in the recirculation mode.

4.1.3 Containment Data

The Modular Accident Analysis Program (MAAP) is used in the Prairie Island IPE to provide an integrated approach to the modeling of plant and containment thermal-hydraulic response and fission product behavior during severe core damage accidents. MAAP requires plant-specific input data which is compiled into a MAAP parameter file. The Prairie Island MAAP parameter file provides a complete, realistic description of the Prairie Island containment for a MAAP simulation. The parameter file is identical for all accident sequences. Table 4.1-1 correlates some important plant data to the parameter file section in which they are tabulated.

Table 4.1-1

Examples of Important Plant Data and Their Location In the Prairie Island Parameter File

Plant Data	Parameter File Section
Reactor Core (full power, UO_2 mass, Zr mass, mass of lower core plate and core support plate, fuel enrichment, fuel geometry)	•Core
Reactor Vessel (vessel mass, volume, wall thickness, mass of core barrel upper plenum internals, geometry	•Primary System
Primary System (hot and cold legs, volumes, elevations, reactor trip set points)	•Primary System
Primary System (initial water level, P,T)	•Initial Conditions
Pressurizer	•Pressurizer
Pressurizer Relief Tank	•Quench Tank
Steam Generator	•Steam Generator
Accumulators (water mass, temperature)	•Engineered Safeguards
Containment Structure (volumes, areas and thicknesses, elevations, equipment mass, heat sinks liner thickness, failure pressure)	•Upper Compartment (ACOMPT) •Lower Compartment (BCOMPT) •Annular Compartment (DCOMPT)
Containment Structure (cavity volume, floor area, basemat thickness)	•Cavity (CCOMPT)
Containment Structure (concrete properties, composition, rebar density)	•Concrete and Containment Shell
Containment Normal Conditions (T,P)	•Initial Conditions
Containment Systems (fan coolers, sprays)	•Generalized Engineered Safeguards
ECCS Injection/Recirculation (RWST water mass and temperature, charging, high-pressure and low-pressure injection, RHR HX details, pump curves, set points)	•Generalized Engineered Safeguards

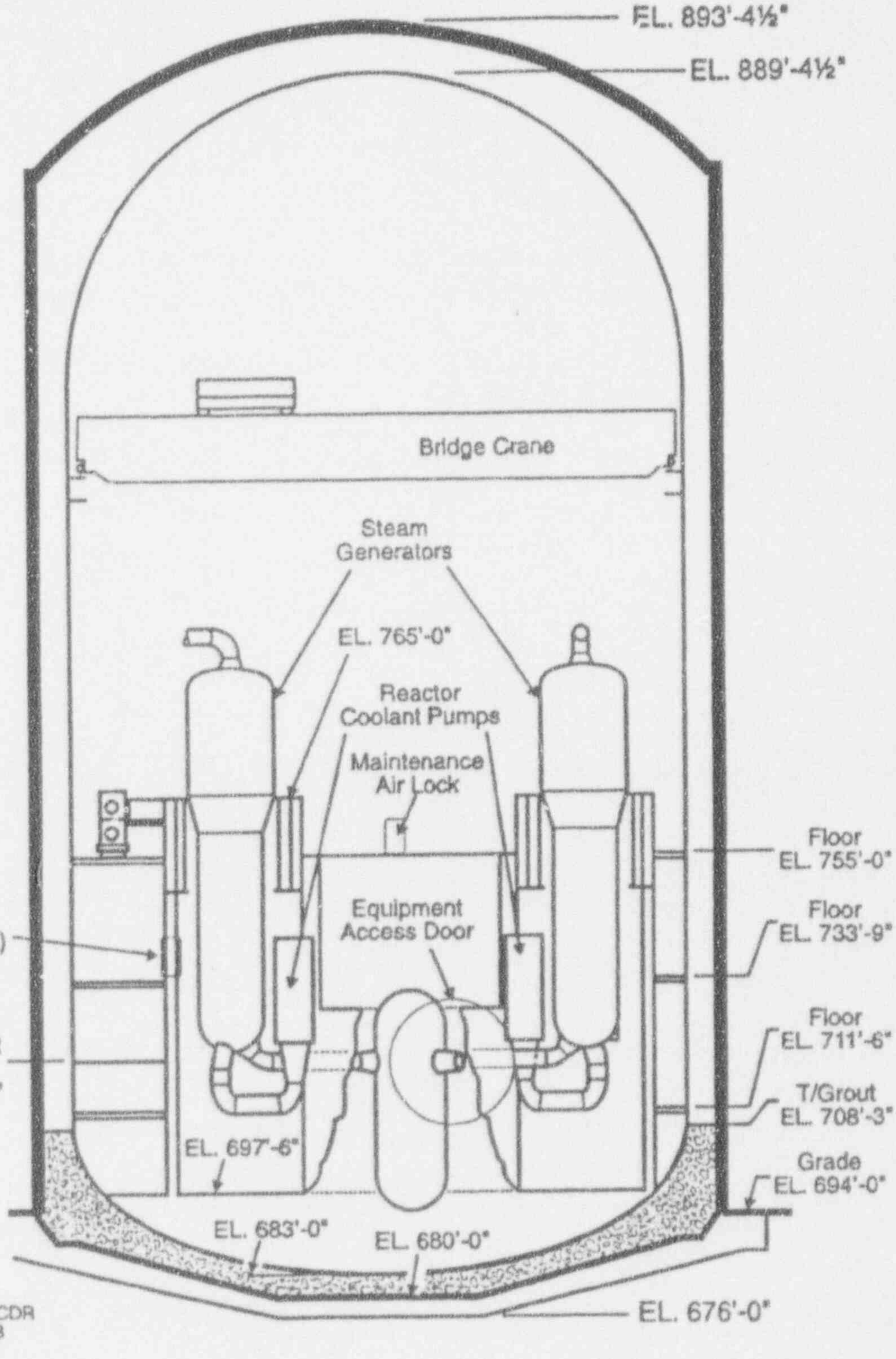


Figure 4.1-1 Vertical cross-sectional view of the Prairie Island Containment

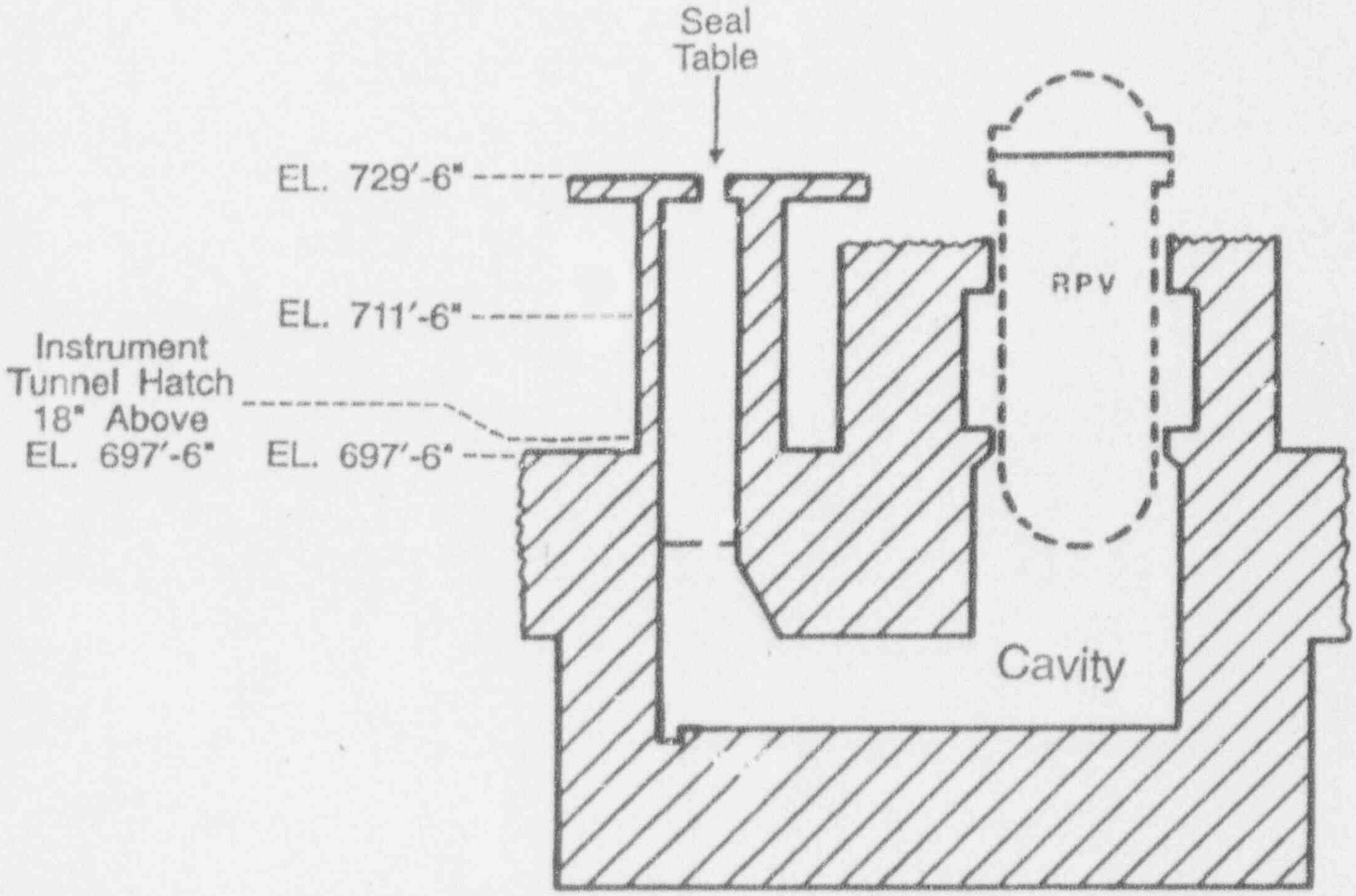


Figure 4.1-2 Geometry of the Prairie Island cavity and instrument tunnel

4.2 Plant Models and Methods for Physical Processes

This section contains documentation of all analytical models used in the severe accident progression analyses. General assumptions made throughout the Level 2 portion of the Prairie Island IPE are also described in this section.

4.2.1 Plant Models and Methods

The Prairie Island containment and source term analyses are part of the traditional Level 2 analysis. It includes plant models and physical processes which reflect the overall plant behavior following core damage. This is accomplished by coupling a probabilistic assessment of containment response to postulated accident scenarios with a physical model to examine plant response. This process also incorporates the impact of phenomenological uncertainties.

The probabilistic models are embodied in the containment event trees (CETs) which consider all the systems and operator actions, including functional events, that respond to a core damage event to prevent or mitigate the release of radioactive fission products from the containment. The plant physical model is defined in the MAAP parameter file as discussed in Section 4.1.3. This parameter file provides MAAP with information required by the code to perform calculations of plant-specific fission product transport and thermal hydraulic response to postulated accident sequences. It is also used to study the sensitivity of the source term to phenomenological uncertainties. The MAAP analyses are supplemented with phenomenological evaluation summaries (as discussed in section 4.4) to provide a complete physical representation of Prairie Island.

Results obtained with the probabilistic and physical plant models are closely linked. For instance, the CET structure depends on MAAP analyses to 1) define CET model success criteria, 2) establish timing of key events for human reliability analyses, 3) understand sequence progression, and 4) determine accident sequence outcome. Furthermore, sequences found to be either dominant contributors to the overall radionuclide release frequency or of structural interest became the basis for MAAP calculations in support of the source term analysis. Finally, MAAP analyses (section 4.8-2) and phenomenological evaluation summaries (section 4.4) are used to investigate the effect of phenomenological uncertainties on the source term assessment. The use of MAAP as suggested above provides the necessary deterministic complement to the probabilistic assessment. A detailed discussion of the containment event tree models is provided in Section 4.3, while a clearer examination of the MAAP models and the treatment of key phenomenological issues is presented here.

The Prairie Island IPE project utilized the MAAP 3.0B PWR Revisions 18 and 19 to perform the containment and source term analysis.

Source term analyses were performed following accident sequence quantification and designation of CET end states. CET end states that are representative of containment performance had their source terms quantified by Prairie Island MAAP analyses. The purpose of the source term analysis was to define and quantify the radionuclide release characteristics for a given accident sequence, which include specification of containment failure timing and fission product release magnitude. MAAP calculations provided release magnitudes for selected fission product groups, release locations, release timing data, and associated energy rates.

Since assumptions regarding key severe accident phenomena may dictate the analysis outcome, due consideration of phenomenological uncertainties is essential to the containment and source term analysis. The Prairie Island IPE methodology addresses the phenomenological issues in the following manner: 1) plant-specific phenomenological evaluations, 2) MAAP sensitivity studies, and 3) experimental studies of key phenomena. This three-pronged approach provides a bounding assessment of source term release timing and magnitude.

Prairie Island phenomenological evaluation summaries are the principle means of addressing the impact of phenomenological uncertainties on plant response. These evaluations address a wide range of phenomenological issues and provide an in-depth review of plant-specific features that influence the uncertainty or act to mitigate the consequences of such phenomena. The phenomenological evaluation summaries investigate both the likelihood of occurrence and the probable consequences of key severe accident phenomena. The phenomenological evaluation summaries are discussed in Section 4.4.

The phenomenological evaluation summaries are supported by available experimental information from open literature as well as information developed using the Fauske & Associates, Incorporated (FAI) experimental test facilities. Results of the FAI experimental efforts are incorporated into the appropriate phenomenological evaluation summaries.

The purpose of sensitivity studies is to determine which remaining phenomenological uncertainties have a significant impact on the likelihood or timing of containment failure and the magnitude of the source term release. Uncertainties in the various physical processes were examined as recommended by the IDCOR/NRC issue resolution process. Generic Letter 88-20 and NUREG-1335 provide summaries of those parameters that have been judged to have a significant effect on containment failure timing and source term release magnitudes. Section 4.8 provides a detailed discussion of the Prairie Island Level II sensitivity analysis.

In summary, the integrated approach to the assessment of plant response adopted in the Prairie Island IPE program linked together probabilistic models in the CETs with physical plant models contained within MAAP. These models were supplemented through the use of Prairie Island phenomenological evaluation summaries to provide in-depth technical arguments that reduce phenomenological uncertainties and examine realistic plant response to severe accident phenomena.

4.2.2 Level 2 Assumptions

This section contains important assumptions made as part of the Prairie Island Level 2 Analysis. The assumptions are:

1.) The time over which the Level 2 phenomenological and source term analysis was performed is generally on the order of 48 hours. Even if not recovered, by 48 hours the accident has generally progressed to a point where the final containment conditions and source terms could be determined. In cases where this would not be true (e.g. slow containment pressurization) estimation of the timing of releases and their magnitude was made based on trends or, the analysis was extended beyond 48 hours.

2.) Systems that are unavailable prior to core damage are assumed unavailable after core damage. If a system is not queried prior to core damage, however, it may be queried after core damage.

3.) Low pressure and/or RHR recirculation could become available after high pressure vessel failure, since the RPV would then depressurize below the RHR shutoff head.

4.) Containment spray injection could initiate at RPV failure, since the containment pressure could exceed the spray setpoint. This assumes that containment sprays were not initiated prior to core damage.

5.) Core debris on the containment floor was assumed to be coolable if the debris depth was less than 25 cm (per GL 88-20) and there was an overlying pool of water. There are no sumps or other areas at Prairie Island where debris can collect in a deep, uncoolable configuration, so debris bed was always assumed to be coolable. This issue was examined with sensitivity studies described in section 4.8.2.4.

6.) There is a flowpath from the containment floor to the reactor cavity through openings in the in-core instrumentation tunnel. The openings are two personnel hatches which are secured partially open during normal plant operations. These openings are located approximately 18" off the floor of the containment.

7.) Credit was taken for hot leg creep rupture to depressurize the primary system prior to vessel failure, when conditions indicated it was likely.

8.) Credit was taken for ex-vessel cooling of the RPV lower head when there was a sufficient volume of water in the cavity to provide the necessary cooling.

9.) High pressure melt ejection sequences would disperse most of the debris into a dry area of containment, where it would form a thin debris layer. This is modelled in MAAP by dispersing the debris to the refueling cavity in the upper compartment and disabling containment spray flow to the refueling cavity.

10.) No credit was taken for fission product retention or pressure retaining capabilities of the containment shield building.

11.) RWST or CST refill were not considered.

12.) For Level 2 analyses, a safe stable state is defined as:

- the containment is isolated,
- containment pressure is well below the ultimate failure pressure, and is constant or decreasing,
- containment temperature is well below the level needed to threaten non-metallic seal materials, and is constant or decreasing, and
- debris temperature is not high enough to ablate concrete, and is constant or decreasing.

13.) A high pressure core melt sequence was defined as the primary system pressure being high enough to entrain the core debris out of the cavity upon vessel failure. A low pressure sequence was defined as the primary system pressure being low enough at vessel failure for the core debris to be retained in the cavity.

14.) For penetration thermal attack considerations, the elastomers in the containment penetrations were assumed to be at the same temperature as the gas in the containment. This assumption is conservative because the penetration materials would be cooled by heat conduction to areas outside the containment and there would be a "lag time" from when the atmosphere reached a certain temperature until thermal equilibrium with the containment penetrations would be achieved.

4.3 BINS AND DAMAGE STATES

This section covers the methodology and results of binning sequences from the front end analysis for evaluation in the back end analysis, and binning to the results of the Level 2 sequence quantification. The bins are organized by factors such as timing, reactor conditions and containment conditions. A discussion of the binning process is presented for the following Level 1 and Level 2 results:

- Accident Classes
- Containment Failure Modes
- Release Modes

4.3.1 Front-to-Back End Interfaces

As noted in Section 3.1.5, the Level 1 accident sequence results were categorized into a group of approximately 14 accident classes. The accident classes are presented in Table 4.3-1. The delineation of accident classes and subclasses is dependent on the functional failures that occur in the Level 1 sequences that are assumed to lead to core damage. These functional categories are convenient in characterizing the Level 1 results and identifying the plant design and operating characteristics that drive the potential for core damage.

These same categories are also useful in transferring the results of the Level 1 PRA to the Level 2 containment event trees. This transfer is accomplished simply by using the cutsets from the Level 1 sequences as the initiating events in the containment event trees. Fault tree linking allows dependencies and failures important to the Level 1 results to be carried directly into the Level 2 sequence analysis. Fault trees developed for the Level 2 event tree headings include frontline and support systems similar to the Level 1 allowing for these dependencies to be counted in the Level 2 sequence analysis. Because of the fault tree linking approach, an explicit check list accounting for the availability of frontline systems for Level 2 sequences following the Level 1 analysis is not necessary. However, Table 4.3-2 is provided to show where these dependencies occur.

4.3.2 Damage States

Damage states are identified for each sequence of the Level 2 CETs. A four letter code was used to identify the damage state, A BB C. These codes are defined in Table 4.3-3.

The first letter (A) defines the state of the reactor at the time of vessel penetration, whether the event was recovered within the vessel or vessel penetration was assumed to occur at either high or low pressure.

The second two letters (BB) are used to define the status of the containment at the end of each of the containment event tree sequences. Whether the containment is intact or failed as a result of any of a number of severe accident phenomena is identified. The containment failure modes identified by this two letter code are patterned after the phenomenological challenges identified in NUREG-2300 and discussed in Section 4.4. In this manner the CET sequences are categorized into functional causes for containment failure much the way the Level 1 sequences were classified with respect to functional challenges to core cooling.

The last letter in the plant damage state identifier represents the timing of the event. It is noted that the timing specified in this identifier is relative to emergency planning purposes, or the declaration of a General Emergency. The timing of the potential for containment failure with respect to core damage and vessel penetration is also important but is specified as a part of the release mode, which is covered in the next section.

4.3.3 Release Modes

On identification of release modes they were related to relevant CET end states. The Prairie Island release mode categories, the magnitude of release associated with each category, and relevant CET end states are found in Table 4.3-4.

Table 4.3-1

Accident Class Definition for the Prairie Island Level 1 IPE

ACCIDENT CLASS[1]	DESCRIPTION
TEH (NUMARC IA)[2]	Transient initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor pressure is high at the time of core damage.
TLH (NUMARC IB)	Transient initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.
BEH	Station blackout in which core damage occurs prior to recovery of AC power or bleed and feed fails upon recovery of AC power. Reactor pressure is high at the time of core damage.
SEH (NUMARC IIIA)	LOCA initiated events in which high head safety injection is not capable of preventing core damage. Reactor pressure is high at the time of core damage.
SLH (NUMARC IIIB)	LOCA initiated events in which high head safety injection is successful but high head recirculation is not. Reactor pressure is high at the time of core damage.
SEL (NUMARC IIIC)	LOCA initiated events in which high head and low head safety injection do not prevent core damage. Reactor pressure is low at the time of core damage.
SLL (NUMARC IIID)	LOCA initiated events in which safety injection was effective but high and low head recirculation is not. Reactor pressure is low at the time of core damage.
FEH	Internal flood-initiated events with loss of secondary heat removal and failure of bleed and feed. Reactor Pressure is high at the time of core damage.
FLH	Internal flood-initiated events with loss of secondary heat removal, successful bleed and feed but failure of recirculation. Reactor pressure is high at the time of core damage.

(1) Key

1st Character (Initiator)

T - Transient
B - Station Blackout
S - LOCA
G - Steam Generator Tube Rupture
V - Interfacing LOCA

R - ATWS

2nd Character (Timing)

E - Early (prior to recirculation)
L - Late (after recirculation)

3rd Character (Reactor Conditions)

H - High pressure (above shutoff of low pressure pumps)
L - Low pressure
O - High pressure, Failure of Long Term Shutdown
P - High pressure, RCS Overpressure

(2) NUMARC Accident Class designator from NUMARC Severe Accident Issue Closure Guidelines.

Table 4.3-1 (continued)

Accident Class Definition for the Level 1 Prairie Island IPE

ACCIDENT CLASS[1]	DESCRIPTION
REP (NUMARC IV)	ATWS events in which reactor vessel overpressure occurs.
RLO (NUMARC IV)	ATWS events in which long term negative reactivity insertion is not successful.
GLH (NUMARC VA)	Steam Generator Tube rupture sequences leading to core damage as a result of failure to depressurize the RCS before RWST depletion. Reactor pressure is high at the time of core damage.
GEH	Steam Generator Tube rupture sequences with failure of high head injection or failure of secondary heat removal. Reactor pressure is high at the time of core damage.
V (NUMARC VB)	Interfacing LOCA sequences between the reactor and low pressure piping systems in the auxiliary building.

(1) Key

1st Character (Initiator)	2nd Character (Timing)	3rd Character (Reactor Conditions)
T - Transient B - Station Blackout S - LOCA G - Steam Generator Tube Rupture V - Interfacing LOCA R - ATWS	E - Early (prior to recirculation) L - Late (after recirculation)	H - High pressure (above shutoff of low pressure pumps) L - Low pressure O - High pressure, Failure of Long Term Shutdown P - High pressure, RCS Overpressure

(2) NUMARC Accident Class designator from NUMARC Severe Accident Issue Closure Guidelines.

Table 4.3-2
Prairie Island Level 1 to Level 2 Dependencies

ACCIDENT CLASS	Secondary Heat Removal			Debris Cooling						Containment Control		
				Injection			Recirculation					
	AFW	MFW	SG[d] PORV	SI	Pzr[d] PORV	CS	SI Recirc	RHR Recirc	CS Recirc	RHR	FCU	CS
TEH	-	-	✓	✓		✓	✓	✓	✓	✓	✓	✓
BEH	✓[a]	-	✓[a]	✓[a]		✓[a]	✓[a]	✓[a]	✓[a]	✓[a]	✓[a]	✓[a]
SEH	✓[b]	✓[b]	✓	✓[e]		✓	✓[e]	✓	✓	✓	✓	✓
TLH	-	-	✓	(f)		(f)	✓[h]	✓[h]	✓[h]	✓	✓	✓
SLH	✓[b]	✓[b]	✓	(f)		(f)	✓[h]	✓[h]	✓[h]	✓	✓	✓
SEL	✓	✓	✓	✓[g]		✓	-	-	-	-	✓	-
SLL	✓	✓	✓	(f)		(f)	✓[h]	✓[h]	✓[h]	✓	✓	✓
GLH	✓	✓	✓[k]	(l)		-	(m)	(m)	(m)	(l)	(m)	(m)
GEH	✓[b]	✓[b]	✓	(m)		(m)	(m)	(m)	(m)	(m)	(m)	(m)
FLH	-	-	✓	(f)		(f)	✓[h]	✓[h]	✓[h]	✓	✓	✓[j]
FEH[c]	-	-	-	✓[l]		✓[l]	✓[l]	✓[l]	✓[l]	✓[l]	✓[l]	✓[l]
REP	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓
RLO	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓

a On AC power recovery
b Provided reason for core damage is not secondary heat removal failure
c Turbine Building Flood
d Reactor Depressurization by this method is given limited credit in Level 2 analysis
e Provided reason for core damage is not SI failure
f Function successfully performed as a part of Level 1
g Large LOCA only
h Requires recovery of recirc
i 1 train only
j 2 FCUs only
k Provided reason for core damage is not secondary depressurization failure
l Credited in the Level 1, but no credit in Level 2 because containment is bypassed (RHR is for shutdown cooling in Level 1)
m Not credited in Level 1 or Level 2 because containment is bypassed
✓ Credited in the Level 2 analysis
\- Failed as a part of Level 1

Table 4.3-3

Level 2 Damage States

PI CET End State Definitions

Code: A BB C

A: Reactor Status

- X = Arrest in vessel. Accident terminated prior to vessel penetration.
- H = Vessel penetration at high pressure.
- L = Vessel Penetration at low pressure.

BB: Containment Status

- XX = Intact. No containment failure.
- DH = Overpressure failure due to decay heat.
- CC = Containment failure principally due to basemat penetration from core concrete interaction.
- OT = Overtemperature/overpressure failure from failure to cool core debris in containment.
- H2 = Early containment failure modes such as hydrogen combustion, DCH, etc.
- CI = Containment isolation failure.
- SR = SG tube creep rupture.

C: Containment Failure Timing (w/ respect to General Emergency)

- X = No release (other than leakage).
- L = Late release (on the order of a day).
- I = Intermediate release (4-24hr).
- E = Early release (0-4 hr).

Table 4.3-4
Summary Source Term Categorization

Category	Description	Relevant CET End States
I	Releases limited to leakage	H-XX-X, L-XX-X, and X-XX-X
II	High Noble gas, low or low-low volatile and non-volatile releases	H-OT-L, H-DH-L, and L-DH-L, and "Puff" release
III	High Noble Gas, medium volatile, and low or low-low non-volatile releases	L-H2-E, X-H2-E, L-CI-E, X-CI-E, and L-CC-L
IV	High noble gas, medium volatile, and high non-volatile	H-H2-E and H-CI-E
V	High noble gas, high volatile, nd low non-volatile releases	SGTR and L-SR-E
VI	High noble gas, volatile, and non-volatile releases	ISLOCA

4.4 Containment Failure Characterization

Plant-specific phenomenological evaluations have been performed in support of the Prairie Island IPE to determine the likelihood of all postulated containment failure modes and mechanisms identified in NUREG-1335. These detailed evaluations were performed to address the controlling physical processes or events specific to the Prairie Island containment configuration. Modeling and bounding calculations, based upon extensive experimental data, phenomenological uncertainties, and complemented with MAAP calculations in some cases, comprise the general approach taken in these evaluations. A majority of these postulated containment failure mechanisms were shown to be of limited potential for the Prairie Island containment. These potential failure mechanisms are considered to be very unlikely to challenge the Prairie Island containment integrity since the predicted pressures resulting from a realistic assessment of these failure mechanisms are far less than the containment ultimate strength.

The failure mechanisms considered unlikely to cause early containment failure are (1) failure to isolate containment, (2) hydrogen combustion, (3) direct containment heating (DCH), (4) steam explosions, and (5) vessel thrust forces. Long term challenge to containment by (6) thermal attack of containment penetrations is also considered of low potential. More likely to occur but still rare are (1) containment overpressurization from steam generation or failure to cool debris, and (2) containment bypass. Table 4.4-1 summarizes the results of the containment failure mode evaluations.

Note: Documents referenced in this section are listed under section 4.4.4. The reference numbers appear in the text inside square brackets [].

4.4.1 Containment Ultimate Strength

Four factors are important in determining the potential for radionuclide release and establishing the effects of containment failure on accident sequence progression: (1) the capability of the containment to withstand these challenges, (2) the timing of containment failure, (3) the location of the failure, and (4) the potential break size. An examination of the Prairie Island containment to determine the possibility of failure under various accident conditions was performed as part of the IPE.

A simplified plant-specific structural analysis of the Prairie Island containment was conducted to determine the ultimate internal pressure capacity and the most likely failure locations associated with this pressure. The containment design calculations were used with actual material failure stresses substituted for the code allowable stresses. The results of the ultimate pressure analysis are presented in Figure 4.4-1 as a containment fragility curve. This curve shows the total failure probability for individual locations as a function of containment pressure. From the total failure probability curve, it can be determined that the total mean (50%) failure pressure is 165 psia while the 5% lower bound and the 95% upper bound are 136 psia and 191 psia, respectively.

Based on a review of the Prairie Island original design calculations, the most likely containment failure locations, along with their associated mean failure pressures, are listed below:

Cylindrical Shell Wall	181 psia
Ellipsoidal Lower Head	181 psia
Emergency Personnel Airlock	209 psia
Main Personnel Airlock	216 psia

Uncertainty in the estimated failure pressures listed above is expressed as a coefficient of variation. The coefficient of variation is simply the standard deviation divided by the mean. The coefficients of variation for the lower head and the two personnel airlocks were assumed to be 15%. The coefficient of variation for the cylindrical shell wall was assumed to be 11%. The total containment failure probability is simply the sum of the individual failure probabilities. As shown in Figure 4.4-1, the median failure pressure for the Prairie Island containment, where the total probability of failure is 50%, is 165 psia.

Source term analysis assumes that containment failure occurs at 165 psia due to membrane stresses in the cylindrical section of the shell wall exceeding the ultimate stress of the steel material. Figure 4.4-1 shows that the ellipsoidal lower head is the more probable failure location, although this failure location is dominant solely due to a larger uncertainty. This, coupled with the fact that a radionuclide release from the lower head would benefit from the scrubbing characteristics of the soil, means that the best estimate and more conservative failure location is in the mid-height region of the cylindrical steel shell.

The containment fragility curve is used in two ways. The first is to determine the timing of long term containment over pressure failures. Long term pressurization of containment from steam or noncondensible gas generation is discussed in the next section. The second method for applying the fragility curve is to determine the potential for containment failure given a temporary but limited pressure challenge. Such challenges may occur from phenomena associated with hydrogen burning or direct containment heating (DCH) and is discussed in section 4.4.3.

4.4.2 Dominant Containment Failure Modes

Containment Overpressurization

Containment overpressurization, defined as a failure mode caused by steaming and/or non-condensible gas generation, is a potential containment failure mode at Prairie Island. Depending on the specific accident sequence characteristics, overpressurization failures may be observed across a wide range of event times. The potential for containment overpressurization failure is dominated by failure of containment heat removal systems. Overpressurization challenges can be both long term or short term challenges, although the short term challenges are highly unlikely. Potential short term challenges include:

- Reactor vessel blowdown,
- Ex-vessel steam explosions, and
- Hydrogen combustion in concert with a DCH event.

Long term challenges include:

- Steam generation due to decay heat, and
- Non-condensible gas generation from molten core-concrete interactions (MCCI).

The potential peak pressure as a result of the short term challenges was derived for these events, and the probability of containment failure at these pressures was obtained from the containment fragility curve. None of the short term challenges produced any significant challenge to the containment. Discussion of the challenge to containment from these events is provided in Section 4.4.3.

Overpressurization failure is expected to be a slow mechanism, such that the containment failure pressure is approached gradually, as would be the case for the long term challenges listed above. The resulting stresses on the containment steel shell wall will likely result in a large catastrophic failure of the steel shell. This conclusion is supported by the experimental evidence (i.e., Sandia 1/8 steel shell experiment) for free standing steel shell containment structures [7]. As mentioned earlier, the most likely failure location will be the cylindrical portion of the steel shell.

The timing of long term overpressurization failure depends on the means by which pressurization is occurring. Analyses of the two modes of gradual pressurization noted above, steam from decay heat and noncondensible gas from core concrete interaction, were performed for the Prairie Island containment and are summarized in Section 7. Steam pressurization to 165 psia assumes the operation of no decay heat removal systems after the injection of the RWST (see Section 7.2.6 - Large

LOCA with RWST). This scenario would be expected to lead to the containment ultimate pressure on the order of two to three days. Pressurization from noncondensible gas requires all debris cooling to be lost and would be expected to take much longer than steam generation (see Section 7.2.5 - Large LOCA with one FCU but no RWST). Without debris cooling, basemat penetration would be expected before overpressure failure, more than four days into an accident. Even if decay eat removal in the form of Fan Coolers were not available, between three and four days would be required before pressurization of the containment to 165 psia (see Section 7.2.4 - Large LOCA with no safeguards).

Regardless of the status of engineered safeguards, the size of containment results in a very long time for pressurization of containment to its capacity if either debris cooling or decay heat removal is assumed to be unavailable. During this period, accident management strategies not credited in the PRA may be successful in terminating the event and preserving the integrity of containment.

Direct Containment Bypass

Direct containment bypass is another possible containment failure mode at Prairie Island. Containment bypass refers to failure of the pressure boundary between the high pressure reactor coolant system and a lower pressure line penetrating containment. This results in a direct pathway from the RCS to the auxiliary building or the environment, bypassing the containment. Containment bypass into the auxiliary building is considered an accident initiator that can lead to core damage because it prohibits the use of emergency core cooling system (ECCS) recirculation as a means of long term core cooling.

Three mechanisms for this failure mode were identified as being important for Prairie Island: (1) steam generator tube rupture sequences where the faulted steam generator cannot be isolated (discussed in Sections 3.4.2.5 and 3.4.2.9), (2) interfacing systems LOCA (ISLOCA), which has a relatively low frequency but is potentially significant in terms of source term magnitude, and (3) induced creep rupture of the steam generator tubes following RCP restart with an overheated core and dry steam generators.

Systems most likely to contribute to ISLOCA include RHR injection to cold leg, RHR injection to vessel and RHR suction from the RCS hot legs. The potential for this failure mode is small, however, and is discussed in Section 3.4.2.11.

4.4.3 Unlikely Containment Failure Modes

Containment Isolation

Isolation valves are provided on lines penetrating the containment shell to assure integrity of the containment under accident conditions. Those isolation valves which must be closed to assure containment integrity immediately after a major accident are automatically controlled by the containment isolation system.

Many types of penetrations were considered during the containment isolation evaluation. The following piping and hatch penetrations were examined:

- Feedwater, Auxiliary Feedwater, and main steam lines
- Instrument and sample lines
- Purge and vent lines
- Instrument Air lines
- RHR lines
- Charging and letdown lines
- RCP seal cooling lines
- Steam generator blowdown lines
- Fuel transfer tube
- Containment sump discharge and suction lines
- Safety Injection lines
- Fire Protection lines
- Containment Spray lines
- Component Cooling lines
- Containment vacuum breaker lines
- Equipment hatch, and personnel and maintenance airlocks

The following criteria helped focus the analysis on those penetrations that contribute most significantly to a release:

- Penetrations of open containment or reactor systems: If the system is not connected to the containment atmosphere or the reactor the probability of simultaneous failure of the isolation valve(s) in the system and a pipe break is negligibly small.

- Pipes with diameters greater than 2 inches: These pipes are considered to contribute most significantly to the magnitude of release following containment isolation failure. Furthermore, aerosol plugging is likely to reduce the amount of leakage that could occur from smaller penetrations.

- Hatches and airlocks: These items are closed during operations as part of technical specification requirements.

- Normally closed lines: Lines containing normally locked closed valves, or lines containing closed valves that would not be expected to open during the course of an accident do not contribute significantly to containment isolation failure.

Table 4.4-2 shows the containment penetrations that remain for further consideration using the criteria given above. The table shows the configuration of the containment isolation valves, their normal positions, the signals required to close the valves, and the dependencies of the valves on support systems for motive and control power.

Table 4.4-3 gives the resulting containment isolation failure probabilities, shown by availability of support systems.

Direct Containment Heating

Direct Containment Heating (DCH) is a postulated event of rapid heat transfer between finely fragmented core debris and the containment atmosphere assuming: 1) the occurrence of post core melt reactor pressure vessel failure at a high pressure, and 2) the high pressure melt ejection (HPME) causes extensive debris dispersal. DCH has been hypothesized as a means of early containment failure because the stored energy in the debris, including potential energy releasable through oxidation and hydrogen combustion, is enough to cause high containment pressures if a large quantity of the core inventory participates. The extent of containment pressurization depends upon:

- the amount of debris which could be discharged from the RPV at vessel failure,

- the fraction of the debris which could be finely fragmented and dispersed into the containment atmosphere, and

- the containment geometry, which can enhance or impede debris dispersal beyond the reactor cavity.

The use of mechanistic models for debris dispersal, which take into account entrainment from within the cavity and de-entrainment by structures and equipment at the instrument tunnel exit, to evaluate the containment response to a postulated high pressure melt ejection show the resulting pressurization to be much less than containment failure pressure. The model predictions are in good agreement with available experiments, including the Zion 5% linear scale experiment. The potential for hydrogen combustion ignited by the high temperature debris during a high pressure melt ejection is highly unlikely due to steam inertion. Bounding calculations show that even if a burn is assumed to occur in a steam inerted containment, the pressure increase would be much less than that required to challenge containment integrity at Prairie Island.

The overall pressure rise due to DCH at Prairie Island was calculated to be approximately 39 psi. If it was assumed that all the hydrogen generated before and after the HPME was burned, the resulting pressure rise would be approximately 83 psi. These conservative estimates of the containment response to a DCH event demonstrate that the containment integrity will not be challenged by DCH.

The potential for containment failure due to direct containment heating was derived by adding the overall pressure rise calculated above to the containment pressure at the time of vessel penetration. A typical transient initiated event without secondary cooling or bleed and feed operation was considered to be representative of transient and small LOCA events. Such an event was evaluated using MAAP and is summarized in Section 7.2.1 (HPME with injection after vessel failure). The containment pressure at the time of vessel failure in this analysis was o the order of 10 psig. The total differential pressure across the containment shell for the DCH loading by itself would then be near 50 psig from the above evaluation, and with coincident hydrogen burning, 93 psig. These pressures are at the tail of the containment fragility curve in Figure 4.4-1 at less than 1E-3 and 5E-3 respectively. A value of 1E-3 was used as an estimate of the potential for containment failure due to DCH in the CET quantification for sequences in which the core is assumed to exit the lower head of the vessel at high pressure. The effects of hydrogen are also treated but are discussed later in this section.

Liner Melt-Through

The potential failure of the steel shell due to direct contact with molten corium was analyzed to address the potential of early containment failure. It is postulated that during a high pressure vessel blowdown, debris becomes entrained in the gas stream and exits the cavity at the seal table structure. Since the seal table at Prairie Island is situated outside the secondary shield wall, a high pressure vessel blowdown could result in corium in a location where it could potentially come into contact with the containment steel shell.

The liner melt-through analysis concluded that, due to the large amount of equipment and structural barriers located in and around the seal table structure, the majority of the debris that would be ejected during a high pressure melt ejection will become de-entrained and flow back into the instrument tunnel or settle out and form a crust on the floor surrounding the seal table. The core debris that manages to escape the seal table area is expected to be very small airborne particles rather than a large, monolithic debris bed capable of substantial internal heat generation. The small particles will rapidly give up their energy to the containment atmosphere. Therefore, by the time these particles reach the containment walls, they will be unable to generate the amount of energy necessary to ablate through the containment steel shell.

Vessel Thrust Forces

The issue for this phenomenon is whether the thrust force generated following core damage and reactor vessel lower head breach are sufficient to cause the reactor to shift its position and tear containment penetrations. The approach taken was to (1) estimate the thrust force generated during corium ejection, (2) compare this estimate to the weight of the reactor vessel and the capability of the primary shield wall acting as a restraint, and 3) determine if this phenomenon could significantly challenge containment integrity at Prairie Island.

If the best estimate breach radius of 0.67 ft is used, the calculated thrust force is approximately 994,000 lb_f. Using the upper bound failure radius of 3.7 ft, the upper bound thrust force is calculated to be approximately 30.3×10^6 lb_f.

This upward thrust force will tend to place the hot and cold leg piping in shear because the piping is constrained by the primary shield wall. Using first principles and available plant data, the thrust force necessary to shear the hot and cold leg piping is approximately 48.8×10^6 lb_f. To achieve a force of this magnitude a failure radius of 4.7 ft is required. This is approximately 85% of the inner radius of the cylindrical portion of the RPV. The failure radius is likely to be much less than the vessel radius, therefore the hot and cold legs will remain intact.

The shield wall is essentially a rigid structure that will not deform under the loads presented here. This would only occur if the imposed stress due to the vessel blowdown thrust force is greater than the allowable compressive stress of the shield wall concrete. The vessel thrust forces induce a stress of approximately 100.5 psi, which is far below the allowable compressive stress of 4000 psi. Therefore, the integrity of the primary shield wall will not be threatened by thrust forces under the postulated conditions.

The bounding analysis for the magnitude of the thrust forces when molten corium is ejected from the failed vessel at high pressure indicates that this force can just barely lift the dead weight of the vessel itself, given a credible break size in the RPV and a complete melt of the fuel and the lower core support materials. Taking credit for the series of restraints that are designed to prevent any vertical or horizontal movement of the reactor vessel, shows that the hot and cold legs will not be sheared off and the concrete in the shield wall will not fail under compression. Even if the vessel could shift, the Prairie Island containment is configured so that the reaction forces cannot be transmitted the containment wall. Therefore, this postulated containment failure mode is not capable of threatening containment integrity.

Thermal Attack of Containment Penetrations

Containment penetration thermal attack is a postulated condition where non-metallic seal materials in containment penetrations could be exposed to elevated containment temperatures for prolonged periods of time during a severe accident. Following vessel failure, containment gas temperatures may reach sufficient levels to cause seal performance to decline significantly, therefore inducing excessive leakage around the seals. The concern is that the excessive leakage could occur before other more likely containment failure mechanisms (e.g. overpressurization). Another concern about thermal attack of containment penetrations, is the potential for debris dispersal and direct contact of the molten debris and containment penetrations. The impact of penetration thermal attack on containment failure timing depends on gas temperature, the characteristics of the materials involved and the exposure time at elevated temperatures.

The issues important to thermal attack are the severe accident thermal loadings for non-metallic penetration seal materials and the potential for accelerated adverse thermal effects on material properties that influence sealing performance.

The first step in the penetration analysis was to identify all non-metallic pressure retaining components at the containment boundary. This investigation identified the following penetrations and materials:

Penetration	Material
Equipment Hatch	Silicone Rubber
Personnel Airlock	Silicone Rubber
Emergency Airlock	Silicone Rubber
Conax Electrical Penetrations (EPAs)	Polysulfone Kapton Viton
D. G. O'Brien EPAs	Polysulfone Silicone Rubber (Parker S604-70) Dow Corning Sylgard DC-170 RT-876/WCSF

Representative severe accident temperature profiles from MAAP analyses were also reviewed as part of the investigation. Three accident sequence types (large LOCA, small LOCA, and station blackout) were considered to determine the thermal conditions which might be experienced by the penetrations. A station blackout sequence was selected to envelope the most conservative severe accident temperature profile. The temperature profile used in the thermal analysis of the Prairie Island containment penetration is shown in Figure 4.4-2.

An aging calculation was then performed for each of the non-metallic materials in the limiting penetrations mentioned above. In addition, a failure modes and effects analysis of the penetrations was performed to establish the possible impact of its failure on the magnitude of fission product release from containment. The findings of the penetration analysis are summarized below:

- Thermal attack of containment penetrations is not a significant failure mode in accident sequences where debris cooling or containment heat removal is successful in preventing a significant rise in containment temperature.

- Based on research performed in support of thermal attack analysis, the large penetrations (i.e., personnel airlocks and equipment hatch) are not expected to deteriorate and leak. Full-scale experiments have demonstrated that the non-metallic penetration and sealant materials will function up to and beyond temperatures of 486°F (steam). As shown in Figure 4.4-2, the maximum sustained gas temperature that is anticipated for postulated severe accident sequences in the Prairie Island containment is less then 450°F.

- Using the Arrenhius equation, the time that the D. G. O'Brien penetrations will survive under the conditions shown in Figure 4.4-2 can be determined. From the material testing data provided by PI Environmental Qualification files, the activation energy and testing conditions are used to calculate the operational limits of the non-metallic materials. Using the same equation and the test data, the extent of thermal degradation due to a 40 year service life at 120°F is then determined. The extent of thermal degradation due to the severe accident is determined using the test data and the severe accident temperature profile illustrated in Figure 4.4-2 is also determined. If the thermal degradation due to a 40 year service life and the severe accident is less then the operational limits of the non-metallic material, the integrity of the seals is not threatened. The results of this analysis showed that the non-metallic seals in the D. G. O'Brien EPAs will not degrade to failure at the containment boundary.

- The electrical penetration assemblies manufactured by Conax also utilize non-metallic materials as part of their leak-tight pressure retaining barriers. For this analysis, the percent volatilization of the Polysulfone and Kapton materials was used as the failure criterion. Data available on the percentage of volatilization of Polysulfone and Kapton as a function of time and temperature show that these materials experience little or no volatilization at temperatures below 300°C (570°F). Since Figure 4.4-2 shows that the containment temperature does not approach 570°F within the first 48 hours, the non-metallic materials in Conax electrical penetrations will not experience thermal attack sufficient to fail the Prairie Island containment prior to other failure modes such as overpressurization or basemat penetration.

- The evaluation of debris dispersal reveals that it is very unlikely that any penetration will come in direct contact with molten core debris dispersed during a high pressure melt ejection.

- The penetration analysis used the containment gas temperature to represent the actual seal material temperature. In fact, the temperature of the seal material will "lag" behind the actual gas temperature in the containment, as discussed in assumption 14 in section 4.2.2. This assumption adds to the conservatism of the thermal attack analysis.

Therefore, for the reasons stated above, the potential of containment failure due to excessive leakage from thermally degraded seals is not expected during the conditions expected at Prairie Island during a severe accident.

Steam Explosions

Both in-vessel and ex-vessel steam explosions were evaluated as potential mechanisms for containment failure under severe accident conditions.

In-Vessel

The issue for in-vessel steam explosions is whether an explosion of sufficient magnitude to fail the reactor vessel, with consequential failure of the containment, could occur. This was addressed by evaluating the fundamental physical processes required to create an explosion of such magnitude. The analysis closely follows the IDCOR assessment of this phenomenon [1] and indicates that explosions of this magnitude are not likely to occur within the Prairie Island reactor vessel. This is in agreement with the findings of the NRC sponsored Steam Explosion Review Group (SERG) [2] which concluded that the likelihood of an in-vessel steam explosion leading to an alpha-mode containment failure was very unlikely.

Experimental evidence [3] [4] [5] has demonstrated that a relatively high reactor coolant system pressure prevents steam explosions altogether. For conditions in which the primary system pressure exceeds 150 psia, steam explosions are not considered possible. For accident scenarios where the primary system pressure is likely to be low, a number of conditions must be met in order for an energetic fuel-coolant interaction to occur and potentially jeopardize the integrity of the reactor vessel:

- Large amount of core debris entering the lower plenum at once.
- Fragmentation of the hot material within the water in the lower plenum.
- A trigger to initiate the explosion.
- Efficient energy transfer from the debris to the coolant.
- An overlying slug of water to transmit energy in a coherent fashion.
- The ability of the slug to be transmitted through the upper structures within the reactor pressure vessel.

All of these conditions are required for an explosion of sufficient magnitude to rupture the reactor pressure vessel.

Molten core debris is expected to flow into the lower plenum in a stream as opposed to dropping as a large mass. This limits the rate of energy transfer to the coolant. Furthermore, there is no physical means of finely dispersing large amounts of debris within the coolant, particularly given the limited free space in the lower reactor vessel head. Also, the inherent capability of the vessel to withstand internal forces makes it unlikely that the limited fuel-coolant interactions that may occur will cause vessel failure.

There is some concern that an in-vessel steam explosion could jeopardize other parts of the primary system than the reactor vessel itself. Of primary concern is the tubes in the steam generators failing due to a steam explosion because such a failure would lead to a containment bypass. This failure mode is very unlikely because:

- An in-vessel steam explosion is very unlikely, as discussed above.

- A steam explosion cannot occur if the primary system pressure is above 150 psia. At these low pressures, hot leg natural circulation will not be significant and the steam generator tubes will be relatively cool.

- There will not necessarily be a large pressure differential across the tubes. If the steam generator is completely depressurized, the maximum differential pressure across the tubes prior to any steam explosion is about 135 psid.

- Creep rupture of the tubes would require several minutes or hours, depending on the temperature. Steam explosions produce only a transitory pressure spike, which would not threaten the tubes in a creep rupture mode.

- The pressure at the interaction zone of a steam explosion is theoretically limited to 1450 psia. The pressure from the shock wave produced would dissipate from this upper bound before it reaches the steam generator tubes. There is a long distance from the vessel lower head where such an interaction may take place to the steam generator tubes. Also, there will probably be a primary system LOCA or an open PORV (primary must be < 150 psia for explosion to occur) to vent some of the pressure produced by the shock wave.

In summary, for an in-vessel steam explosion in a low pressure accident sequence, (1) the steam generator tubes will not be hot enough to threaten their integrity by creep rupture, (2) there will not be a large pressure differential across the tubes, and (3) the pressure differential will be sustained for only a second or so. Therefore, this mode of steam generator tube rupture at Prairie Island is not considered further.

Consistent with the Steam Explosion Review Group conclusions, a relatively low potential for containment failure due to in vessel steam explosions is assigned to the CET, on the order of 1E-4. A similar value is assigned for accident sequences occurring at both high and low pressure. Although it is recognized that the potential for steam explosion at low pressure is greater than for a transient or small LOCA at high pressure, the conditions required to impart a significant amount of energy to the upper vessel head noted above, as well as the inherent vessel capability are assumed to limit the potential for missile generation that would cause containment failure.

Ex-Vessel

Ex-vessel steam explosions also may occur when molten debris is discharged from the reactor vessel into a pool of water. A steam explosion within the containment could exert pressure forces on submerged surfaces or pressurized compartments. A significant pressure differential could generate missiles or impair load-carrying capabilities of walls, either of which could result in containment failure.

The two aspects of ex-vessel steam explosions addressed in the Prairie Island IPE are:

1. Containment Failure Due to Rapid Steam Generation - The calculated containment pressure increase due to the rapid generation of steam is only approximately 1 psi. This value is negligible compared to the predicted containment failure pressure. This pressure rise was calculated based on the following assumptions:

   - The cavity floor was partially flooded at the time of vessel failure. A steam explosion is deemed unlikely in any sequence when the cavity is completely flooded because the water contacting the reactor vessel is expected to prevent vessel failure. In fact, for any sequence where the RWST was injected, the Prairie cavity will be flooded or partially flooded at the time of vessel failure.

   - The debris dispersed in the water on the cavity floor in such a way to ensure a large heat transfer rate (30 Mw/m^2) to the water.

   - The explosive interaction time (Δt) was assumed to be approximately a second.

2. Shock Waves - The maximum impact pressure pulse at the containment boundary due to shock waves was calculated to be about 2 psi. Again, this value is not sufficient to induce failure of the containment. The impact pressure at the containment boundary due to shock waves was estimated based on the following assumptions:

   - The maximum attainable pressure in the interaction zone is 10 MPa (1450 psi). This corresponds to a condition of critical size bubble growth. For pressures greater than this value, the vapor cannot be produced at a pressure higher than the local pressure.

   - A steam explosion can only occur in the event that the vessel fails while the cavity is only partially full of water. The shock wave would expand until it contacted the cavity walls. The pressure at the cavity walls would be 130 psia. This load would have very little effect upon the cavity walls since the walls are approximately 8 ft. thick with a compressive strength of 4000 psi.

   - The shock wave will propagate through the cavity keyway and instrument tunnel. No credit is taken for dissipation of the shock wave in the keyway and instrument tunnel because free expansion is not possible until the shock wave exits. The effects of heat transfer and friction on the shock wave are also conservatively ignored.

   - Once the shock wave exits the instrument tunnel, it expands freely until it contacts the containment wall. Assuming the seal table exit is located 10 m (about 30 ft) from the containment wall, the impact pressure on the containment wall would be approximately 2 psi.

Therefore, it has been concluded that the slumping of molten debris into the RPV does not result in sufficient energy release to threaten the vessel integrity, and hence, does not directly lead to containment failure. Likewise, evaluation of both the steam generation rate and shock waves induced by ex-vessel explosive interactions show that these mechanisms are not sufficient to threaten containment integrity. Shock waves generated in the cavity by ex-vessel explosive interactions decay substantially prior to reaching the containment boundary.

A simplifying assumption is made in the quantification of the CET that there is a high potential for water in the reactor cavity at the time of vessel penetration. This assumption is made regardless of the status of injection systems or the location of water from the RWST. With his assumption, the potential for a steam explosion in the reactor cavity is assumed to be higher than in the reactor vessel simply because the containment is at relatively low pressure. For this reason ex-vessel steam explosion are assigned a higher value in the CET quantification at 1E-3.

Hydrogen Combustion

Potential detonability and flammability of the Prairie Island containment atmosphere was analyzed as part of the Prairie Island IPE. Detonation is evaluated based on geometric configuration and detonation cell width scaling. Hydrogen deflagrations are evaluated assuming an adiabatic isochoric complete combustion (AICC) of the maximum amount of hydrogen available in the containment.

The initiation of a hydrogen detonation by direct deposition of energy requires a large energy source to initiate the detonation. The most energetic ignition sources available in containment are at least several orders of magnitude too small to trigger a hydrogen detonation. A hydrogen detonation could also occur by a transition from a deflagration due to acceleration of the flame front.

The potential of a deflagration to detonation transition (DDT) is addressed as a function of two variables [6]; reactivity of the mixture and geometric configuration. From the hydrogen detonation analysis, it is concluded that containment failure due to hydrogen deflagration to detonation transitions are very unlikely to occur in the Prairie Island containment. This analysis was performed based on the assumption of a completely dry containment (i.e., no steam inerting credited) and 100% oxidation all zirconium and the lower core plate.

A detailed Prairie Island specific assessment of potential hydrogen deflagration was performed for a station blackout, since a station blackout will result in the highest zirconium clad oxidation fractions. For transient-induced core damage sequences, where there is no leak in the primary system, hydrogen produced from the zircalloy-water reaction within the vessel will be directed through the pressurizer PORVs or safety valves, into the pressurizer relief tank (PRT) and then into the containment. For LOCA events, hydrogen will be released directly to the containment through the break in the primary system.

If an ignition source is present, the hydrogen may be burned as it is generated. Energized equipment within containment, such as valve motors, could act as a hydrogen ignition source unless there is no electric power available (i.e., station blackout). For station blackout cases, where no ignition source is present, hydrogen will accumulate in containment until an ignition source is available. Upon recovery of power, systems within containment will be actuated and a combustion event may occur. The maximum resulting pressure rise from this combustion event can be calculated by performing an adiabatic isochoric complete combustion (AICC) analysis.

MAAP calculations show that the containment should be steam inerted for all core damage sequences where no active containment heat removal systems are available. Consequently, assuming 100% zirconium oxidation and pre-burn conditions of a station blackout prior to vessel failure, where the containment may not be completely steam inerted, results in a post-burn containment pressure of 95 psia. This pressure does not approach the ultimate containment pressure capacity of Prairie Island's containments. Therefore hydrogen combustion can be concluded as being of low potential for early containment failure at Prairie Island.

The pressure rise above conservatively assumes no steam inerting. Under these conditions, the pressure rise due to a hydrogen burn is greatest. Under other assumptions that initial containment pressure is higher than atmospheric, the increase in pressure due to hydrogen burning becomes less due to the steam that has entered containment from the pipe break or through the pressurizer. Because the 95 psig pressure rise is associated with oxidation of an equivalent of 100% of the active fuel cladding and because the containment is assumed not to be steam inerted, this pressure rise is considered to be a maximum expected challenge from hydrogen burning. This pressure is still in the tail of the containment fragility curve in Figure 4.4-1, and a value of 5E-3 is conservatively assigned to all accident sequences recognizing that less hydrogen may be generated and many will be inerted to some degree.

Molten Core Concrete Interactions

Molten core debris ejected from a failed reactor vessel would come into contact with the cavity floor and could interact with the concrete if the debris is not cooled in some manner. If allowed to continue, core debris attack of the concrete structures could result in extensive erosion of the concrete, leading to one of the following late containment failure mechanisms: (1) penetration of the containment basemat, or (2) sufficient deterioration of the load carrying capability of the primary shield wall causing the reactor to shift significantly, thereby inducing a gross failure of the mechanical penetrations connected to the reactor vessel.

In a PWR, the concrete surface that could experience the most severe thermal attack is the cavity floor. The heat transfer between the core debris and the floor drives the thermal decomposition and erosion of the concrete. The thermal attack on the concrete can be broken down into three separate phases:

- short term, localized attack as the debris exits the reactor pressure vessel,

- an aggressive attack by high temperature debris immediately after the core material leaves the reactor, and

- a long term attack where the debris temperature would remain essentially constant and the rate of attack is determined by the internal heat generation.

Localized Attack

Immediately after vessel failure, debris is discharged from the vessel into the cavity region. This material, which may be molten, induces an aggressive localized jet attack upon the concrete surface. This attack is confined to the area where the jet impinges. Estimates of this attack, based on experimental analyses, show the eroded depth to be approximately 4 to 8 inches, depending on the primary system conditions at the time of vessel failure.

Attack by High Temperature Debris

After the localized jet attack, the reactor cavity floor will be covered by high temperature debris which aggressively attacks the concrete substrate. Free water, bound water, and other gases generated by concrete decomposition are then released. The gases agitate the molten material and promote convective heat transfer between the material and the gases. The combination of (1) the sensible heat added to the concrete, (2) the endothermic chemical reactions involved with releasing water vapor and decomposing the concrete, and (3) the latent heat of fusion for melting the substrate extracts a considerable amount of energy from the molten corium pool. In fact, the aggressive attack generally absorbs more energy than what is generated by decay heat. Additional internal heat generation in the melt can result from the oxidation of metallic constituents by the gases released from the concrete substrate. Typically, the high temperature, aggressive attack is driven by the internal heat generation from metal oxidation and to a lesser extent by the initial stored energy of the debris.

Long Term Attack

During the long term attack, the debris remains at an essentially constant temperature, and the rate of attack is determined by the difference between the internal heat generation and the heat losses to the containment environment. These heat losses are primarily due to radiation and convection. Due to these heat losses, the resulting concrete attack rate is much slower than the high temperature attack phase. The non-condensible gases generated during this period will contribute to the long term pressurization of the containment.

The major physical phenomena that control the extent of concrete erosion by core debris are:

- the depth of the debris bed,
- the configuration of the debris mass on the cavity floor,
- the rate and amount of core debris expelled from the reactor vessel, and
- the quenching effect of water.

Debris cooling on the cavity floor was modeled using DECOMP, a subroutine of the MAAP code. DECOMP considers the debris to be a solid cylinder or molten pool surrounded by a crust, depending on the debris bed energy. Crust growth / shrinkage based on the energy balance describes the solidification process occurring within the molten debris. Temperatures are determined from phase diagrams based on the composition of the debris. Transient conduction problems are carried out in the concrete floor, the sidewall in contact with the debris, and the upper surface. Concrete ablation is allowed to occur in all directions. The heat transfer coefficient at the molten pool / crust interface and to an overlying pool of water, if present, are user-defined constants in the MAAP parameter file. Level 2 sensitivity analyses (described in section 4.8.2.4) were performed by varying the ability to transfer heat from the debris to an overlying pool of water, establishing a range of potential effects on noncondensible gas generation and containment pressurization. Using realistic assumptions for the ability of the coolant to penetrate into the debris, debris cooling and termination of noncondensible gas generation is expected for cases where the core debris remains in the cavity submerged in a pool of water.

The potential depth of the debris in the reactor cavity is relatively low because of the size of the reactor cavity in the Prairie Island containment. Even if 100% of the fuel, cladding, lower core plate and 10% of the RPV lower vessel head are melted and deposited in the cavity, the result is a debris bed thickness near 25 cm (9.8 in). While there are uncertainties, and while some core-concrete interaction may occur early, it is believed that the debris would become coolable well before containment failure. For sequences in which RWST water is supplied to the containment, CET quantification assumes this relatively low debris depth is coolable. This assumption is consistent with recommendations associated with debris coolability made in Generic Letter 88-20. However, for the purpose of the Prairie Island IPE, mechanisms which might prevent cooling the debris were postulated in order to perform relevant sensitivity studies described in section 4.8.2.4:

- Impermeable crust formation - Formation of a structurally stable impermeable crust across the span of the cavity floor area (27 sq. meters) is difficult to conceive. Especially since water flowing over the crust would cause shrinkage and cracking, and water should be able to penetrate into the debris below the crust. In addition, sparging of the debris by the gas generated from core-concrete interactions would be expected to break up any crust that forms.

- Inability of the water to penetrate the debris bed - An upward flow of steam and gases from the core-concrete interactions may prevent water from deeply penetrating into the debris bed. In this instance, the ability to cool the debris can be determined simply by performing a heat balance comparing the heat losses to the overlying pool of water and assuming that the residual energy is deposited into the concrete.

Best estimate MAAP analyses predict that the worst case core concrete attack scenario (i.e. low pressure vessel failure with no RWST injection or debris dispersal) will result in cavity basemat failure 105 hours after accident sequence initiation if no form of debris cooling is established.

4.4.4. References

[1] IDCOR, 1983, "Key Phenomenological Models for Assessing Explosive Steam Generation Rates," Technical Report 14-1A.

[2] USNRC, 1985, "A Review of the Current Understanding of the Potential for Containment Failure from In-Vessel Steam Explosions," NUREG-1116.

[3] Henry, R.E., and Fauske, H. K., 1979, "Nucleation Processes in Large Scale Vapor Explosions, "Transactions Of ASME Journal of Heat Transfer, Vol 101, pp 280-287.

[4] Hohman, H., Henry, R. E., and Kottowski, H. M., 1979, "The Effect of Pressure on NaCI-H_2O Explosions," 4th CSNI Specialist Meeting on Fuel-Coolant Interaction in Nuclear Reactor Safety, Bournemouth, U.K., CSNI Report No. 37, pp. 308-323.

[5] Hohman, H., Kottowski, H. M., Schins, H., and Henry, R. E., 1982, "Experimental Investigations of Spontaneous and Triggered Steam Explosions in the Molten Salt / Water System," International Meeting on Thermal Reactor Safety, Chicago, IL.

[6] Sherman, M. P., and Borman, M., 1987, "The Possibility of Local Detonation During Degraded Core Accidents in the Bellefonte Nuclear Plant," NUREG/CR-4803, SAND86-1180, Sandia National Laboratories.

[7] Koenig, L. N., 1986, "Experimental Results for a 1:8 Scale Steel Model Nuclear Power Plant Containment Pressurized to Failure," NUREG/CR-4246, SAND85-0790, Sandia National Laboratories.

Table 4.4-1

Phenomenological Evaluation Summaries of Postulated Containment Failure Modes

Failure Mode	Phenomena	Issue/Failure Mechanism	Major Uncertainty	Impact
1. Hydrogen Combustion	In-vessel H_2 generation Ex-vessel H_2 generation Steam inerting Auto ignition	Breach containment by overpressurization due to H_2 burn or detonation	Amounts of H_2 and CO Flammability of containment atmosphere	Low potential for early containment failure Long term containment failure possible if inappropriate recovery actions taken
2. Direct Containment Heating (DCH)	RPV failure Debris dispersion Influence of containment structures Hydrogen combustion/steam inerting Thermal exchange with entire air space	Early breach of containment by rapid over-pressurization	Degree of dispersal in containment Hydrogen combustion	Containment pressures for DCH less than ultimate structure capability
3. Steam Explosions	Missile generation Rapid steam generation Shock waves	Missile impact Early containment overpressurization and breach	Occurrence of multiple conditions required to produce large scale steam explosion	Limited threat to RPV or containment Promotes debris dispersal and cooling

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Table 4.4-1 (Continued)

Phenomenological Evaluation Summaries
on Postulated Containment Failure Modes

Failure Mode	Phenomena	Issue/Failure Mechanism	Major Uncertainty	Impact
4. Molten Core-Concrete Interactions (MCCI)	Concrete ablation and decomposition Gas evolution (H_2, CO, CO_2) Debris spreading H_2 recombination	Basemat penetration after several days of attack	Presence of water to quench debris Debris coolability	Overpressurization not likely to occur before basemat penetration Basemat penetration yields a "scrubbed" fission product release path
5. Vessel Blowdown	RPV rupture RPV thrust forces RPV restraints	Failure of containment penetration lines connected to RPV	RPV failure and failure size	No or limited RPV displacement Challenge bounded by design basis
6. Thermal loading on penetrations	Degradation of non-metallic components	Containment breach; leakage path	Magnitude and duration of elevated containment gas temperature Gas temperatures versus actual material temperatures Behavior of non-metallic materials at high temperature	No loss of containment integrity expected Potential for long term loss of electrical functionality

(continued -- next page)

Table 4.4-1 (Continued)

Phenomenological Evaluation Summaries
on Postulated Containment Failure Modes

Failure Mode	Phenomena	Issue/Failure Mechanism	Major Uncertainty	Impact
7. Over-pressurization	Noncondensible gas generation Steam generation H_2 burning	Containment breach	Timing, size, and location of containment breach	FP release to environment or other buildings
8. Containment isolation failure	Containment piping Operator response Signal dependency	FP release path through unisolated piping	FP plateout/ plugging	Low probability of direct FP path to environment or auxiliary building
9. Containment By-pass	Interfacing Systems LOCA SGTR SG tube creep rupture	FP release path that does not pass through containment air space	FP deposition in building outside containment Size location of break outside containment Water scrubbing at break location FP deposition outside containment	Low probability of direct FP path to environment or auxiliary building

Table 4.4-2

Contributors to Containment Isolation Failure

Description	Number	Size	Configuration	Position	Signals	Power/Air
Letdown line	11	2"	1 NC MOV in parallel with 4 AOVs; 1 NO in series with 3 in parallel (1 NO and 2 NC)	NO	Safety injection	AOVs fail closed on loss of air or DC
Charging line	12	2"	2 CV, 1 AOV	NO	None	AOV fails closed on loss of air or DC
RCP seal water supply	13A	2"	2 CV in series	NO	None	None
RCP seal water supply	13B	2"	2 CV in series	NO	None	None
Instrument Air	20	2"	2 AOVs in series	NO	Loop A MSL isolation, hi-hi containment pressure	AOVs fail closed on loss of air or DC
Containment sump A discharge	26	3"	2 AOVs in series	NO	Safety injection	AOVs fail closed on loss of air or DC
Containment vacuum breaker	41A	18"	1 AOV and 1 air-assist CV in series	NO	Safety injection	AOVs fail open on loss of air or DC
Containment vacuum breaker	41B	18"	1 AOV and 1 air-assist CV in series	NO	Safety injection	AOVs fail open on loss of air or DC
Post-LOCA H2 control air	42A	2"	1 MOV and 1 CV in series	NC	None	MOV fails as-is on loss of AC
Air vent	42A	2"	1 AOVs and 1 MOV in series	NC	None	AOVs fail closed on loss of air; MOV fails as-is on loss of AC
Reactor makeup to PRT	45	2"	1 AOV and 1 CV in series	NC	Safety injection	AOV fails closed on loss of air or DC
Post-LOCA H2 control air	50	2"	1 MOV and 1 CV in series	NC	None	MOV fails as-is on loss of AC
Air Vent	50	2"	1 AOVs and 1 MOV in series	NC	None	AOVs fail closed on loss of air; MOV fails as-is on loss of AC

Table 4.4-3

Prairie Island Containment Isolation Failure Probability

	Unavailable Support Systems			
	Transients, LOCAs	Loss of Train DC	Loss of IA	SBO DC
CVCS Charging/ Letdown (2)	1.8E-4	1.8E-4	1.8E-4	1.8E-4
RCP Seal Cooling (2)	8.4E-5	8.4E-5	8.4E-5	8.4E-5
Instrument Air	1.2E-6	1.2E-6	1.2E-6	1.2E-6
Containment Sump Discharge	1.8E-4	1.8E-4	1.8E-4	1.8E-4
Containment Vacuum Breakers (2)	1.4E-7	4.2E-5	8.4E-5	8.4E-5
H2 Control Air (2)	4.8E-5	4.8E-5	4.8E-5	4.8E-5
Makeup to PRT	4.1E-8	4.1E-8	4.1E-8	
Air Vents (2)	ϵ	ϵ	ϵ	ϵ
Total	4.9E-4	5.3E-4	5.8E-4	5.8E-4

These calculations use the configurations described in Table 4.4-2 and the following failure rates:

1.71E-3/d	AOV fail to close
5.00E-7/h	AOV fail to remain closed
1.55E-3/d	MOV fail to close
2.00E-7/h	MOV fail to remain closed
1.80E-5/d	CV fail to close
1.00E-6/h	CV fail to remain closed
0.1	Common Cause Beta Factor

Abbreviations:

AOV	air-operated valve	IA	Instrument air
CV	check valve	MOV	motor-operated
CVCS	Chemical and Volume Control System	MSL	main steam line
d	demand	MV	manual valve
DC-A	DC power train A	NC	normally closed
DC-B	DC power train B	NO	Normally open
h	hour	PRT	Pressurizer Relief Tank

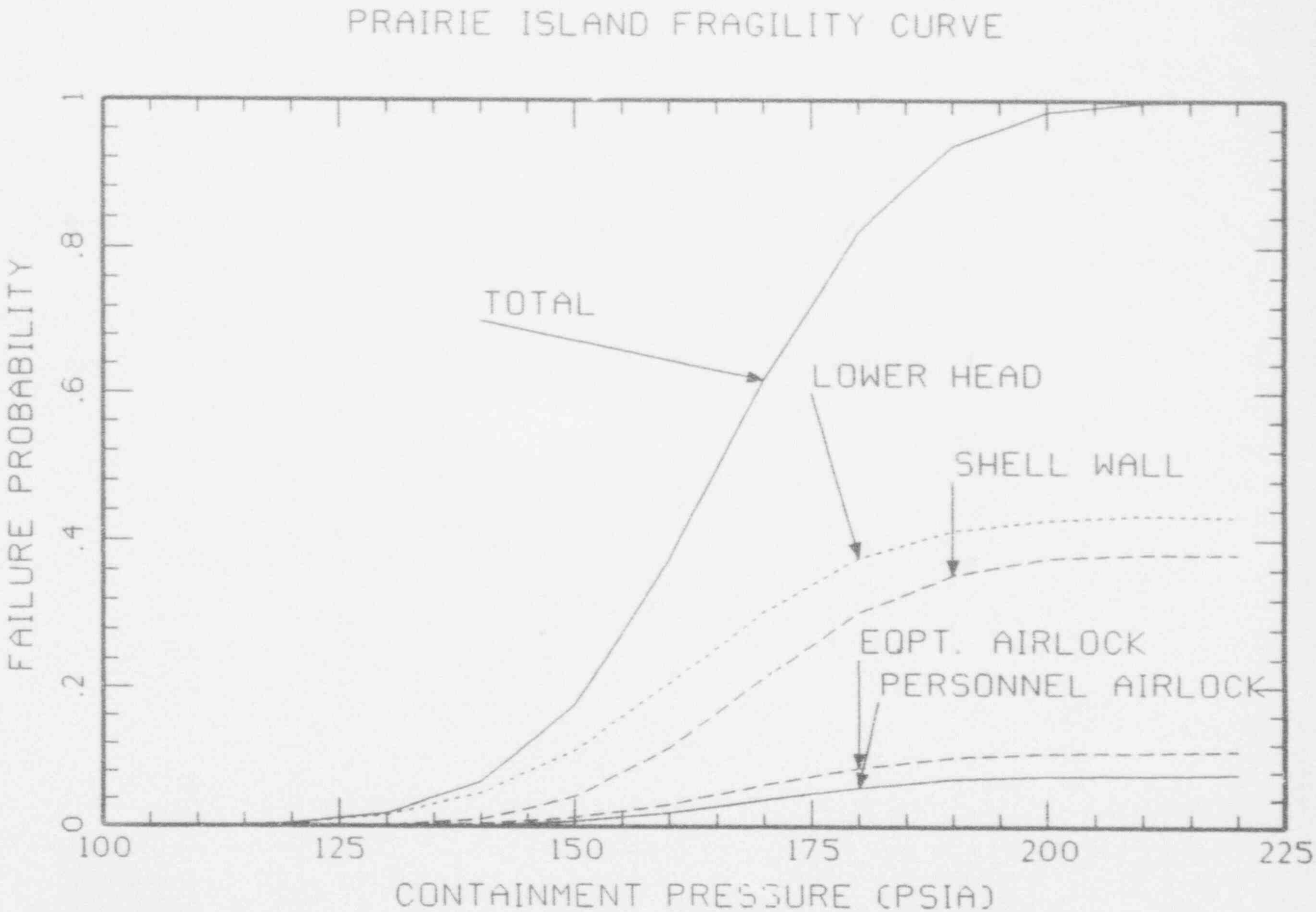


Figure 4.4-1 Prairie Island containment fragility curve

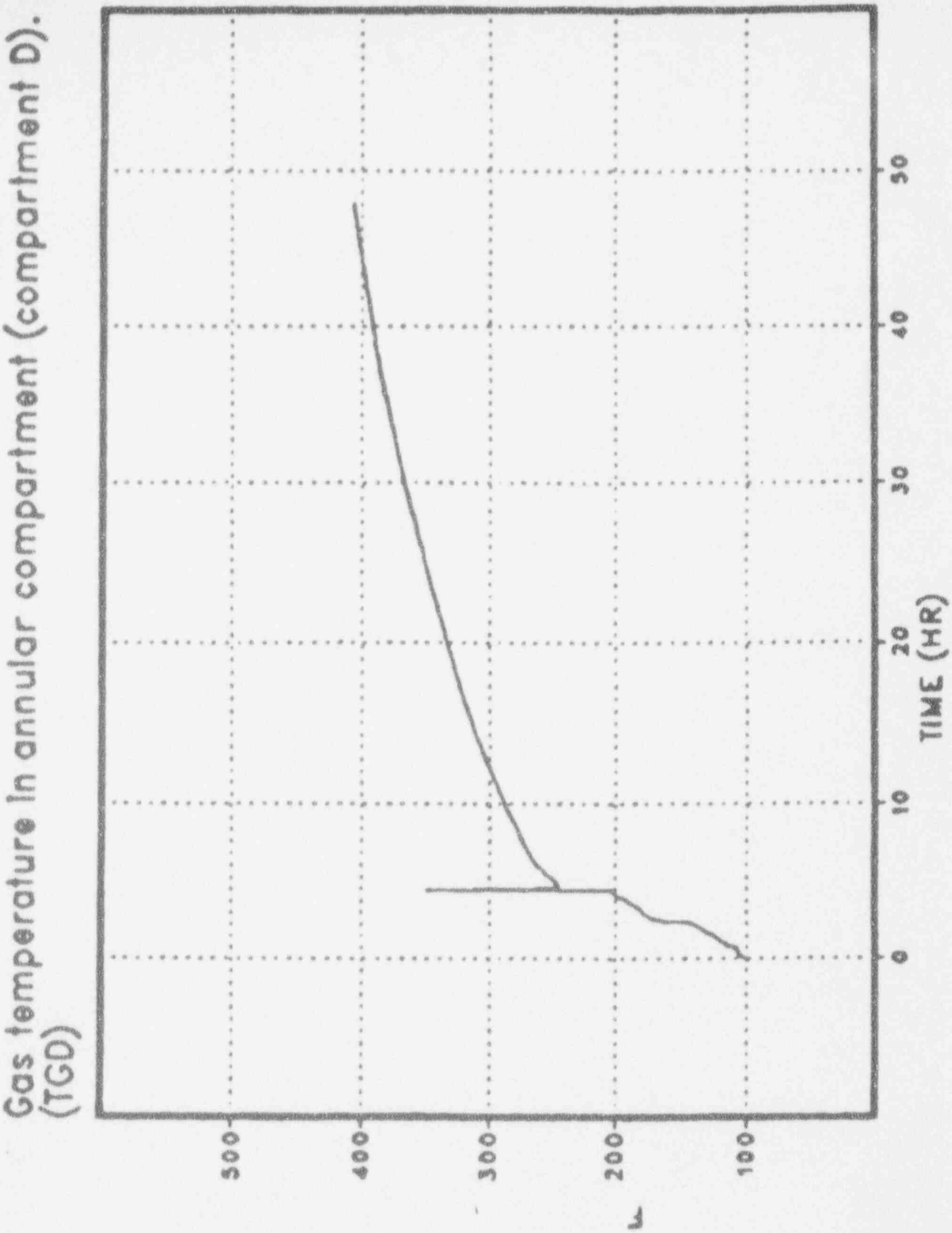


Figure 4.4-2 Prairie Island containment gas temperature
during a station blackout

4.5 CONTAINMENT EVENT TREES

This section discusses the containment event trees used for the Prairie Island Level 2 analysis.

4.5.1 Accident Classes

Containment event trees (CETs) were developed to determine the containment response and ultimately the type of release mode given that a core damage accident has occurred. Different event trees have been prepared to address the various Level 1 accident classes. CETs were prepared for the following accident classes:

- TEH - Transient initiated core damage event occurring early (bleed & feed unsuccessful) with the reactor at high pressure
- TLH - Transient initiated core damage event occurring late (recirculation failure) with the reactor at high pressure
- BEH - Station Blackout in which core damage occurs early (bleed & feed unsuccessful due to battery depletion or injection failure) with the reactor at high pressure
- BLH - TLH sequences in which SBO initially occurred (power is restored before core damage occurs) but recirculation fails with reactor at high pressure
- SEH - Small LOCA in which core damage occurs early (injection failure) and the reactor is at high pressure
- SLH - Small LOCA in which core damage occurs late (recirculation failure) with the reactor at high pressure
- SEL - Medium/Large LOCA in which core damage occurs early (injection unsuccessful) with the reactor at low pressure
- SLL - Medium/Large LOCA in which core damage occurs late (recirculation failure) with the reactor at low pressure

Containment event tree structures for accident classes are provided in the following figures:

TEH, SEH & FEH	Figure 4.5-1
BEH	Figure 4.5-2
TLH, BLH & SLH	Figure 4.5-3
SEL	Figure 4.5-4
SLL	Figure 4.5-5

Since BLH sequences are really TLH sequences (power was restored following SBO before core damage occurs) they are included as part of TLH accident class discussions below. Level 2 sequence quantification for Main Steam and Feed Line breaks use the TEH or TLH event trees depending on whether core damage is assumed to occur as a result of SI or recirculation failure. ATWS accident sequences use the TEH or TLH event trees based on whether core damage is postulated to occur due to reactor overpressure or long term reactivity insertion failure. Internal flooding sequences may use the TEH/SEH or TLH/SLH containment event tree structures depending on the impact of the flood with respect to the ability to provide reactor coolant pump seal cooling, successful bleed & feed or recirculation. ISLOCA and SGTR sequences do not require a containment event tree as the containment is assumed to be bypassed as a part of the Level 1 accident sequences.

4.5.2 CET Safety Functions

Like the Level 1 core damage event trees, the containment event trees are structured around key safety functions. This section discusses the various safety function headings used in the CETs and identifies the systems credited in fulfilling these functions. The safety functions and success criteria are summarized in Table 4.5-1.

The functions included in Prairie Island CETs also reflect to the extent practical, the guidance provided in the Functional Recovery Guidelines in the Emergency Operating Procedures.

FUNCTION	CET HEADING	COMMENT
Subcriticality	N/A	Reactor assumed to be subcritical once core damage occurs
Core Cooling	IV - In-vessel recovery DEP - Reactor depressurization INJ - Ex-vessel injection	
Heat Sink	IV - In-vessel recovery INJ - Ex-vessel injection	Credit for recovery of secondary cooling is taken in Level 1 PRA, with only limited credit given in Level 2 for the purpose of terminating the event in-vessel.
Primary Integrity	N/A	The CET focus is on restoration of adequate core cooling and assuring containment integrity as opposed to limiting rapid primary cooldown.
Containment	CPC - Containment pressure control CSS - Containment spray	

4.5.3 CET Headings

The first five headings in the CETs consider system operation and phenomena which may be important during early stages of a severe accident (on the order of the first few hours following the onset of core damage). These "early" CET headings include:

- Bypass due to Steam Generator Tube creep rupture (SR)
- Steam Generator Tube Creep Rupture (SR)
- Containment Isolation (CIS)
- In-vessel recovery (IV)
- Reactor depressurization (DEP)
- Early containment challenges (ECT).

The remaining headings of the CETs establish the effects of long term operation of plant systems and the potential for challenges to the containment that may occur on the order of many hours to days following core damage. These "late" CET headings include:

- Ex-vessel injection (INJ)
- Containment pressure control (CPC)
- Fission product scrubbing - Cont Spray (CSS).

The following sections discuss the systems and phenomena which influence the outcome of the containment event tree headings.

4.5.3.1 Early CET Headings

a. SG Tube Creep Rupture (SR)

Heading SR is associated with core damage events in which creep rupture of the steam generator tubes occurs. To result in this containment failure mode, several conditions must exist; the reactor must be at high pressure, a steam generator must be dry, and core damage must have occurred.

For creep rupture of the tubes to occur, the hot gas in the vessel must make its way to the steam generators. As the steam generators are dry, there is only limited natural circulation in the RCS. Heating of the RCS is more likely to cause failure of other parts of the RCS, such as the hot leg or the vessel wall just above the core debris once it relocates to the lower vessel. As the potential for creep rupture of the tubes from natural circulation is low, the most significant contribution to this failure mode is considered to be due to restart of the reactor coolant pumps. For accident scenarios in which lower head penetration is precluded by ex-vessel cooling, it is assumed that reactor coolant pump restart must occur prior to depressurization from failure of another part of the reactor coolant system such as the hot leg. Either lower head penetration by debris or hot leg creep rupture are expected on the order of 1/2 to an hour subsequent to the onset of core damage.

While it is understood that an induced rupture of the steam generator tubes can occur due to natural convection, this has not played a significant role in other IPEs and was neglected. The assumption that a pump start will always result in the tube creep rupture is viewed as conservative.

Current functional recovery procedures instruct the restart of reactor coolant pumps on core exit thermocouple readings exceeding 1200°F. The purpose of this guidance is to prolong core cooling by forced circulation as long as possible to delay core damage. For many of the dominant core damage sequences, reactor coolant pump restart cannot be accomplished by the operator. These sequences include loss of offsite power events and loss of train A of DC power, which does not permit closure of the reactor coolant pump breakers.

However, even if reactor coolant pump operation be successful, blowdown of a steam generator is also assumed for this accident class. This requires depressurization through a steam generator PORV or failed open safety relief valve. Emergency procedures instruct steam generator depressurization. Again, however, the events which lead to core damage often preclude operation of a steam generator PORV.

b. Containment Isolation (CIS)

Failure of this event indicates a failure of the containment to isolate resulting in a release of fission products early in the accident. The probability of failure to isolate containment was calculated based on valve failure rates used in the IPE and examination of Prairie Island plant design features associated with the following:

- penetrations connected to the containment atmosphere or primary coolant system,
- sequence dependencies dictating the availability of an isolation signal, power supply, pneumatic source, etc., and
- determination as to whether the system could be credited as a closed system inside or outside containment.

c. In-vessel recovery (IV)

It is assumed that there are two means to terminate the core damage event retaining the debris within the vessel; restoration of injection to the vessel and submerging the reactor vessel lower head. The following discusses assumptions regarding system operation and phenomena important to determining the potential for in-vessel recovery.

Systems

Restoration of injection to the vessel prior to core slumping to the lower head is the first means considered in terminating a core damage event within the reactor vessel. For transient initiators and small LOCAs this could be accomplished by restoring high head SI. For medium and large LOCA, establishing RHR would be adequate. However, for the following reasons only limited credit for restoring injection to the vessel is given in the PI Level 2 PRA:

- Transients and small LOCA.
  Approximately 2 hrs is required before the onset of core damage following loss of secondary cooling and/or vessel injection. Once core damage occurs, slumping to the bottom of the vessel is assumed on the order of 1/2 hour. The conditional probability of being able to recover SI in this 1/2 hour window given failure to recover injection to prevent core damage over the course of several hours is considered to be small.

- Medium LOCA.
  Both SI and RHR are credited in the Level 1 and must fail in order for core damage to result. Repair of failed equipment in one of these systems is required to retain the core debris in the vessel for this initiator. Given the relative short time frame for repair activities (<1/2hr), no credit for this method of recovery is given in the Level 2.

- Large LOCA.
  Only RHR is credited in the Level 1 PRA. Operation of a train of SI is not sufficient to prevent core damage but could prevent core slump to the lower head once the blowdown is complete. However, recirculation with SI requires operation of the RHR pumps as SI is piggybacked on RHR for this mode of operation.

The other method considered in preventing core debris from exiting the vessel, is to flood the containment to a level at which the lower head of the reactor vessel is submerged. Heat from the debris can be transferred to the water in the reactor cavity through the vessel wall preventing vessel penetration. The RWST contains sufficient water to submerge the lower head once injected to the vessel or the containment.

- Early core damage.
  Accident classes TEH, SFH, BEH and SEL all lead to core damage resulting from inability to inject water to the reactor early in the event. Core damage is assumed to occur for these sequences without RWST water in the containment. Containment spray is an alternate means of injection of water into containment independent of the reactor. However, for transients in which reactor inventory is lost through the pressurizer PORVs, and small LOCAs, FCUs remove sufficient heat to keep containment pressure below the actuation setpoint for containment spray (23 psig). Only during medium or large LOCA with early injection failure would containment sprays be available for submerging the lower head to prevent vessel penetration. However, this was not credited (no credit for in-vessel recovery for early core damage sequences).

- Late core damage.
  The means by which core damage occurs for accident classes TLH, SLH, and SLL is a result of failure to establish recirculation to the vessel. As the RWST is injected for these sequences, the lower head is submerged at the time core damage occurs. All that is necessary to retain the core in the vessel is to reestablish recirculation to the vessel, recirculate water through RHR to the containment sprays or condense steam and remove heat from containment with FCUs.

Phenomena (Ex-vessel cooling)

Phenomena important to the success of the IV containment event tree heading are associated with retaining the core in-vessel by submerging the lower vessel head. This includes the ability to provide coolant to the reactor cavity, transfer heat through the vessel wall to coolant on the outside of the vessel and remove it by generating steam.

An evaluation of the volume of water necessary to submerge the vessel was performed to confirm sequence success criteria in which in-vessel recovery could be credited. The lower compartment and reactor cavity volume is just under 10,000 ft^3. While the RCS and accumulators provide over 6,000

ft^3 of inventory, the RWST contains more than 27,000 ft^3. It is assumed that RWST injection is required before in-vessel recovery can be considered, as a result. On successful injection of the RWST, the containment water level will be more than 7 feet above the bottom of the vessel. This is several feet higher than the depth of the debris inside the vessel if all of the core material were to slump to the bottom of the vessel, assuring that any portion of the vessel wall in contact with the debris can transfer heat directly to coolant in which the vessel is submerged.

Heat flux through the vessel wall was evaluated assuming all of the debris was relocated to the lower vessel. A steady state heat transfer rate through the vessel wall was shown equal to more than one quarter of the decay heat at two hours. This amount of energy is easily removed from the vessel wall through nucleate boiling. The remaining decay heat is removed through radiative heat transfer from the debris in the vessel to RCS components.

Consideration for the success of recovery in-vessel must be given to the presence of insulation on the outside of the vessel as well as the existence of in-core instrument penetrations in the lower head. Joints in the insulation are expected to allow steam generated through boiling to leave the vessel wall and reactor cavity as well as permit the flow of water remaining in the cavity to the vessel wall. In-core instrument tubes may permit the flow of debris outside the vessel, but the debris is expected to solidify within the tubes given that they are submerged.

Because of uncertainties associated with retention of the debris in the vessel, a relatively large potential for debris exiting the lower head of the vessel is assumed in the quantification of the CET. For sequences in which the vessel is not submerged, lower head penetration is assumed to occur for all accidents. If the RWST has been injected to the containment, the potential for lower head penetration is estimated at 0.1. Sensitivity studies on these assumptions are performed after quantification of the CET to determine their impact on the potential for challenge to the containment.

d. Reactor Depressurization (DEP)

A CET heading for depressurization of the reactor is provided to establish the potential for effects associated with blowdown from high pressure should the debris penetrate the lower vessel head. Again, success of this heading requires consideration of the operation of certain plant systems as well as phenomena associated with severe accident sequence progression.

Systems

Two means of reactor depressurization with plant systems are considered; pressurizer PORV operation and secondary depressurization with steam generator PORVs.

- Pressurizer PORVs

Opening the pressurizer PORVs to lower reactor pressure is required in the Functional Recovery procedures if core exit thermocouples exceed 1200°F and the reactor coolant pumps can be started, or if RCS hot leg temperatures exceed 400°F after steam generator depressurization. The purpose of this action is to prolong core cooling as long as possible with reactor coolant pump flow while attempting to recover flow from SI or RHR. These actions are credited for preventing high pressure melt ejection provided the debris is retained in the vessel for a sufficient period to allow depressurization prior to lower head penetration. For scenarios in which cooling of the vessel by water surrounding the lower head occurs, delay of vessel failure by core debris is expected, perhaps preventing vessel failure altogether. Reactor depressurization with pressurizer PORVs is credited for these late evolving accident classes (TLH & SLH). For scenarios which evolve more rapidly, the time between high thermocouple temperatures, relocation of the core to the lower plenum and vessel penetration is assumed not to be sufficient to affect reactor depressurization (accident classes TEH, SEH and BEH).

- Steam Generator PORVs

Functional Recovery procedures also require the operator to lower reactor pressure with the steam generator PORVs in the event that core exit thermocouples exceed 700°F. This action can be effective only if auxiliary feedwater or feedwater flow is available to the steam generators. As transient initiators lead to core damage only if secondary cooling is lost, this means of reactor depressurization is applicable only during small LOCA in which SI failure occurred. Again, sufficient time to effect depressurization is required before lower head penetration is assumed to occur. Similar to the discussion above on pressurizer PORVs, reactor depressurization with steam generator PORVs is credited when lower head penetration is delayed by ex-vessel cooling. During Small LOCA sequences in which the RWST has been injected successfully, credit is given to this method preventing high pressure melt ejection in the PI CETs. For sequences in which the steam generators have gone dry or early injection failure has occurred, this means of reactor depressurization is not credited.

- LOCA Initiators

Medium and large LOCA initiators also determine the ability to depressurize the reactor. While not systems, in and of themselves these LOCA events are effective in causing depressurization of the reactor to low pressure and are credited in precluding high pressure melt conditions should core damage occur.

Phenomena (RCS creep rupture)

Consideration is given in the CETs to other means of reactor depressurization due to high temperatures associated with severe accident conditions. Several locations within the RCS are potential candidates for pressure boundary failure; the hot legs or pressurizer surge line, the steam generator tubes and the vessel wall just above the core debris located in the lower plenum. Of these locations, the hot legs or pressurizer surge line are considered the most likely location for RCS failure due to creep rupture.

For the purpose of the quantification of the CET, these means of reactor depressurization are considered only if the core can be retained in the vessel for a sufficient period of time to cause heating of the RCS pressure boundary to temperatures which would cause creep rupture. In the initial quantification of the CET sequences, it has been assumed that this requires the core debris to be retained in the vessel by means of submerging the lower vessel head. In accident sequences in which the RWST has been successfully injected before core damage, it is likely that lower head penetration will be delayed if not prevented altogether. A relatively low probability of not depressurizing the reactor by creep rupture is assumed for these sequences, on the order of 0.01, if the operator is not successful in initiating depressurization by other means. For high pressure sequences in which the lower head is not submerged, it is assumed debris penetration of the lower head occurs prior to depressurization of other RCS components due to creep rupture.

The timing of RCS failure due to creep rupture vs lower head penetration by core debris is subject to some uncertainty, and the assumptions above may be conservative in this regard. A series of sensitivity studies using MAAP suggests that many scenarios require an hour or more for core slumping and lower head penetration to occur, which may be sufficient for heatup of a hot leg and creep rupture to depressurize the reactor and prevent high pressure melt ejection (see Section 7.1 - station blackout and 7.2.2 - transient with failure of high head recirculation).

To account for these uncertainties, sensitivity studies were performed to determine the effect of RCS depressurization on the potential for various containment challenges following a severe accident. These sensitivities range from assuming that depressurization by RCS creep rupture is highly likely for all high pressure sequences to assuming that it does not occur at all.

e. Early Containment Challenges (ECT)

This CET heading is principally driven by phenomena associated with core melt progression within the vessel as well as that postulated to occur at the time or shortly after vessel penetration. No systems are considered in quantification of this CET heading. Rather, the success or failure of systems considered in the Level 1 accident classes and the preceding CET headings are used to determine the potential for and magnitude of early challenges to the containment.

Phenomena (Steam explosions, H_2 combustion, DCH, etc.)

The potential for five phenomenological challenges to the containment are considered as a part of this CET heading:

Sequence conditions	Phenomena
In-vessel recovery	In-vessel steam explosion H_2 combustion
Debris penetration of lower head at low reactor pressure	In-vessel steam explosion Ex-vessel steam explosion H_2 combustion
Debris penetration of lower head at high reactor pressure	In-vessel steam explosion Ex-vessel steam explosion H_2 combustion Direct containment heating Vessel blowdown forces

In evaluation of these phenomena, both the potential for the challenges as well as the magnitude is considered to determine impact on the integrity of the containment. Success of the branches of the event tree for this heading implies that the potential for the phenomena was low or the challenge to the containment boundary was not sufficient to cause failure even if the phenomena occurred.

The probability for each of these phenomena suggested for CET quantification are discussed in Section 4.4. For those events causing short term pressure challenges, deterministic evaluation of the expected peak pressure was performed and the potential for failure of the containment determined from the containment fragility curve provided in

Figure 4.4-1. For those events which result in other containment challenges such as steam explosions, a combination of deterministic analysis and expert opinion found in the open literature is applied. Because the potential for many of these events to fail containment is low, many are expected to be truncated from the final results. To assure sufficient information is retained in the final sequence cutsets, a surrogate basic event was created representing the combined potential for all of these failure modes. This event was assigned a value of 0.01, which exceeds the sum of all of the phenomena under the early challenge CET heading.

4.5.3.2 Late CET Headings

a. Ex-vessel Injection (INJ)

This heading considers the ability of plant systems to provide water to the containment onto the core debris setting up the potential for long term debris cooling. Phenomena and containment challenges associated with the inability to cool the debris is considered in subsequent headings.

Systems

This heading is considered during severe accident sequences in which the core debris is assumed to penetrate the lower vessel head and enter the reactor cavity. To accomplish quenching of the debris, operation of a single train of any of three systems is required; high head Safety Injection, low head Safety Injection or Containment Spray. Success of this heading implies injection of the contents of the RWST into the containment. This sets up the potential for debris cooling, long term decay heat removal and scrubbing of any releases from the fuel through an overlying pool of water. Recirculation for these purposes is not considered here but is left to subsequent headings in the CET.

While initial injection to the containment will be automatic for all three of these systems and can happen shortly after vessel penetration, this heading is considered to be successful even if it is not accomplished for several days into the accident. This time frame is selected based on how long it would take to overpressurize the containment with noncondensibles or penetrate the basemat if no debris cooling were available. The potential for repair of SI, RHR or Containment Spray can be considered in the success of this heading provided the components requiring maintenance are accessible.

b. Containment Pressure Control (CPC)

Two means of long term pressurization of containment are considered as a part of this heading; steam generation from decay heat and noncondensible gas generation. Again, a combination of systems and phenomenological considerations are important to determining the success of this function.

Systems

On successful termination of the accident within the vessel or supplying ample water to the debris in the reactor cavity, decay heat removal from the containment is necessary to prevent long term overpressurization. Either of two systems is sufficient to provide containment pressure control by decay heat removal from debris located in the reactor cavity; a Fan Cooler Unit or a train of RHR in recirculation. Heat removal with Fan Coolers requires operation of the Cooling Water System. Successful heat removal to Component Cooling and Cooling Water must occur if RHR is in service. RHR may be used by itself to recirculate sump water to the vessel. It can also feed the suction of SI if high head recirc is required or the suction of Containment Spray if recirculation back to the containment sump is the only means available to remove heat.

If core debris exited the lower head of the vessel with the reactor at high pressure, some of the debris will have relocated to the upper compartment during vessel blowdown. While the pressure and temperature rise from this debris is much more gradual than from steam generation due to decay heat, it is assumed that cooling of this debris with containment spray is necessary to prevent long term failure of the containment.

For accident sequences in which debris cooling was not provided by supplying the RWST to containment (INJ heading failure), long term failure of the containment by noncondensible gas generation or basemat penetration is assumed. In this type of sequence, the operation of a Fan Cooler Unit is considered for the purpose of condensation of steam and aerosol removal prior to containment failure. Use of the FCUs for this purpose is more of a fission product release control function than containment pressure control.

Repair of failed equipment in systems required for long term heat removal can be considered given that overpressure of containment due to decay heat takes on the order of days.

Phenomena (Debris Cooling)

For accident sequences in which the debris penetrates the lower head and enters the reactor cavity, water should be supplied to the debris from SI, RHR or Containment Spray as noted above. Phenomena important to preventing long term containment failure under these conditions are associated with the ability to cool the debris on the cavity floor. GL 88-20 suggests that if the debris depth is less than 25 cm, then the debris can be considered to be coolable. Above 25 cm, both a coolable and non-coolable outcome should be considered. Determination of the amount of debris which is expected to exit the vessel on lower head penetration shows that it is less than 25 cm in depth. Even if 100% of the debris were to be available for relocation to the reactor cavity floor, the maximum depth would only be on the order of 25 cm. For this reason, the quantification of the PI CET sequences assumes that the debris is quenched with little or no core concrete interaction occurring once water is provided to the debris.

For accident sequences in which water is not provided to the debris, core concrete interaction is assumed to occur. During accident sequences in which most of the debris is in the reactor cavity (debris penetration occurs at low reactor pressure), either overpressure of the containment from noncondensible gas generation or basemat penetration is considered. Preliminary examination of these failure modes suggests that the basemat will be penetrated prior to pressurization of the relatively large containment volume to the ultimate capacity of the containment shell. Basemat penetration is therefore considered to be the predominant containment failure mode for events in which debris cooling in the reactor cavity is not successful. This mode of containment challenge can be mitigated by successful recovery of an injection system or containment spray within the first several days of the accident.

Other accident sequences in which debris cooling may not be successful include those in which vessel penetration occurs at high pressure. Because a large portion of the debris is expected to leave the reactor cavity during high pressure blowdown, basemat penetration is no longer expected to be the predominant failure mode if debris cooling is not provided. Rather, long term very gradual heatup of the containment would be more likely with containment failure occurring many days into the accident as a result of high temperature and pressure. As noted above, cooling of debris in the upper compartments of containment is assumed to require successful operation of containment spray.

c. Fission Product Scrubbing with Containment Spray (CSS)

This final CET heading occurs for sequences in which either early or late challenges to the containment are assumed to result in its failure. Operation of containment spray scrubs the containment atmosphere of aerosols and limits the pressure at which releases occur.

Table 4.5-1

CET Success Criteria

	FUNCTION	DESCRIPTION	SUCCESS CRITERIA
SR	SG Tube Creep Rupture	· LOCA or transient where conditions do not allow restart of RCP on core cooling functional challenge.	RCP restart conditions not required or (SG PORV failure and SG safety fails to close)
CIS	Containment Isolation	· All penetrations connected to reactor or containment atmosphere, or closed loop outside containment.	At least one closed valve for non-closed loops
IV	In-vessel Recovery	· Recovery of an SI (high pressure) or RHR Pump (low pressure) or · Vessel submergence from injecting RWST to containment with SI, RHR or containment spray	1 Pump 1 Pump
DEP	Reactor Depressurization	· Hot leg creep rupture (high pressure) or · Medium or Large LOCA	--
ECT	No Early Containment Failure	· Containment function successful following: - In-vessel Steam Explosion - Ex-vessel Steam Explosion - H_2 Combustion - Vessel Blowdown Forces - Direct Containment Heating	--
INJ	Ex-vessel Debris Cooling	· SI Injection, or · RHR Injection, or · CS Injection	1 Pump
CPC	Containment Pressure Control	· Recirculation to vessel or · Cont. Spray recirculation or · Fan Coil Unit · HPME sequences require containment spray by itself to cool debris in upper compartment	1 Pump w/RHR
CSS	Fission Product Scrubbing	· Containment Spray recirculation . Fan Coil Unit (limited credit, INJ failure only)	1 Pump

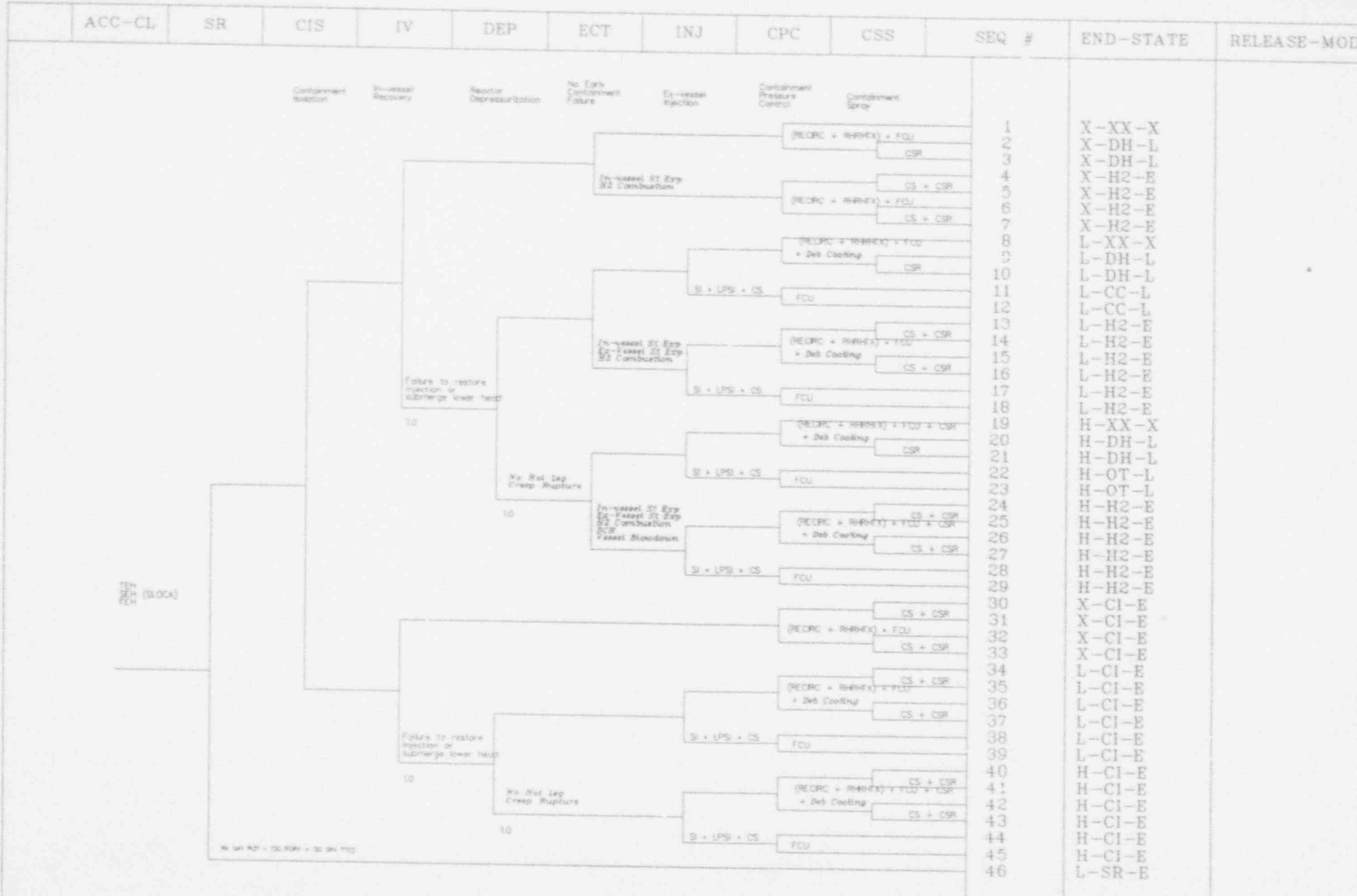

ACC-CL
SR
CIS
IV
DEP
ECT
INJ
CPC
CSS
SEQ #
END-STATE
RELEASE-MODE
Containment Isolation
In-vessel Recovery
Reactor Depressurization
No Early Containment Failure
Ex-vessel Injection
Containment Pressure Control
Containment Spray
1 X-XX-X
2 X-DH-L
3 X-DH-L
4 X-H2-E
5 X-H2-E
6 X-H2-E
7 X-H2-E
8 L-XX-X
9 L-DH-L
10 L-DH-L
11 L-CC-L
12 L-CC-L
13 L-H2-E
14 L-H2-E
15 L-H2-E
16 L-H2-E
17 L-H2-E
18 L-H2-E
19 H-XX-X
20 H-DH-L
21 H-DH-L
22 H-OT-L
23 H-OT-L
24 H-H2-E
25 H-H2-E
26 H-H2-E
27 H-H2-E
28 H-H2-E
29 H-H2-E
30 X-CI-E
31 X-CI-E
32 X-CI-E
33 X-CI-E
34 L-CI-E
35 L-CI-E
36 L-CI-E
37 L-CI-E
38 L-CI-E
39 L-CI-E
40 H-CI-E
41 H-CI-E
42 H-CI-E
43 H-CI-E
44 H-CI-E
45 H-CI-E
46 L-SR-E

Figure 4.5-1

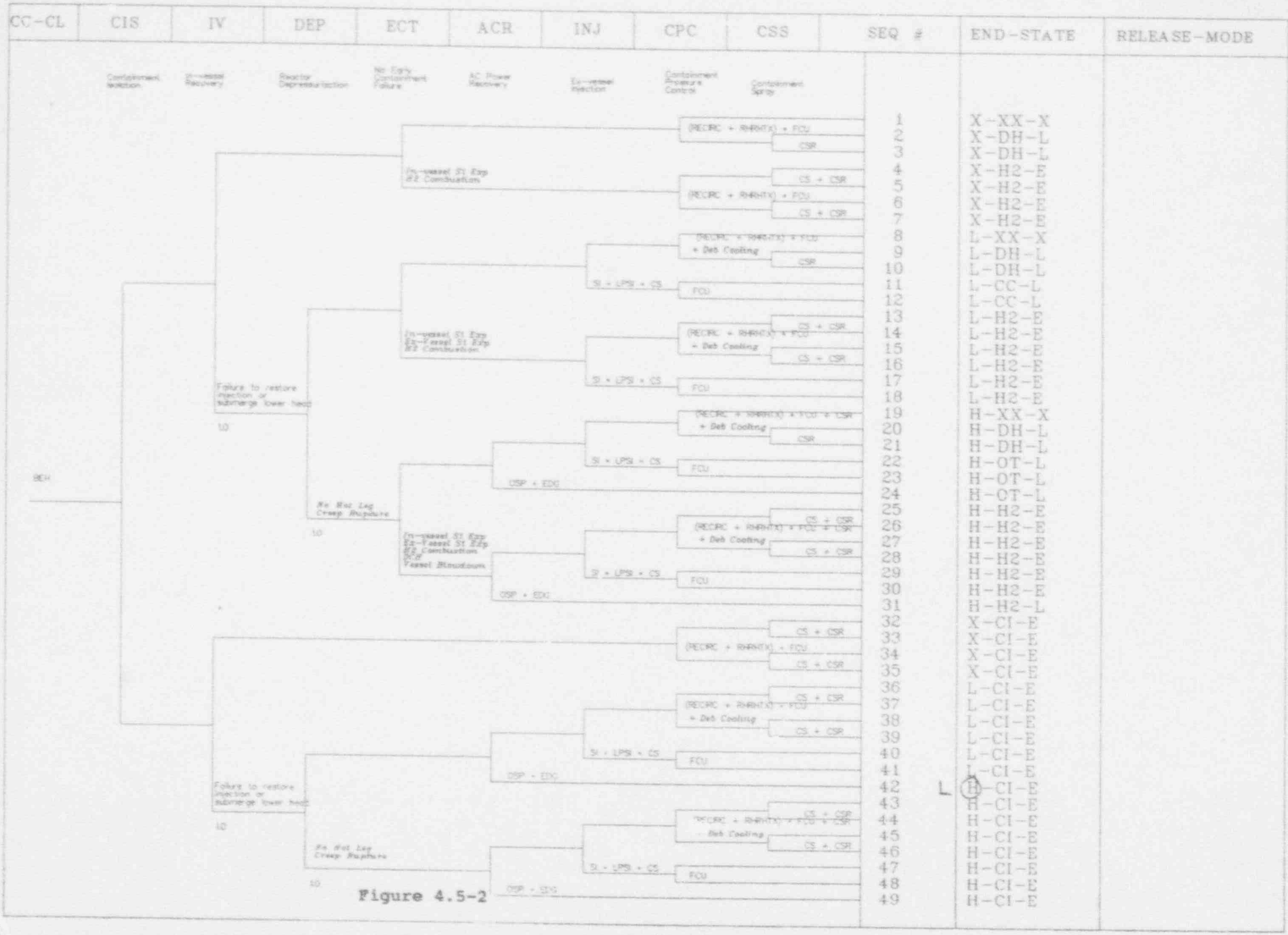

CC-CL
CIS
IV
DEP
ECT
ACR
INJ
CPC
CSS
SEQ #
END-STATE
RELEASE-MODE
Containment Isolation
In-vessel Recovery
Reactor Depressurization
No Early Containment Failure
AC Power Recovery
Ex-vessel Injection
Containment Pressure Control
Containment Spray
BEH
(RECIRC + RHRHTX) + FCU
CSR
In-vessel St Exp
H2 Combustion
CS + CSR
+ Deb Cooling
SI + LPSI + CS
FCU
In-vessel St Exp
Ex-Vessel St Exp
H2 Combustion
Failure to restore injection or submerge lower head
1.0
OSP + EDG
No Hot Leg Creep Rupture
Vessel Blowdown
1 X-XX-X
2 X-DH-L
3 X-DH-L
4 X-H2-E
5 X-H2-E
6 X-H2-E
7 X-H2-E
8 L-XX-X
9 L-DH-L
10 L-DH-L
11 L-CC-L
12 L-CC-L
13 L-H2-E
14 L-H2-E
15 L-H2-E
16 L-H2-E
17 L-H2-E
18 L-H2-E
19 H-XX-X
20 H-DH-L
21 H-DH-L
22 H-OT-L
23 H-OT-L
24 H-OT-L
25 H-H2-E
26 H-H2-E
27 H-H2-E
28 H-H2-E
29 H-H2-E
30 H-H2-E
31 H-H2-L
32 X-CI-E
33 X-CI-E
34 X-CI-E
35 X-CI-E
36 L-CI-E
37 L-CI-E
38 L-CI-E
39 L-CI-E
40 L-CI-E
41 L-CI-E
42 L H-CI-E
43 H-CI-E
44 H-CI-E
45 H-CI-E
46 H-CI-E
47 H-CI-E
48 H-CI-E
49 H-CI-E

Figure 4.5-2

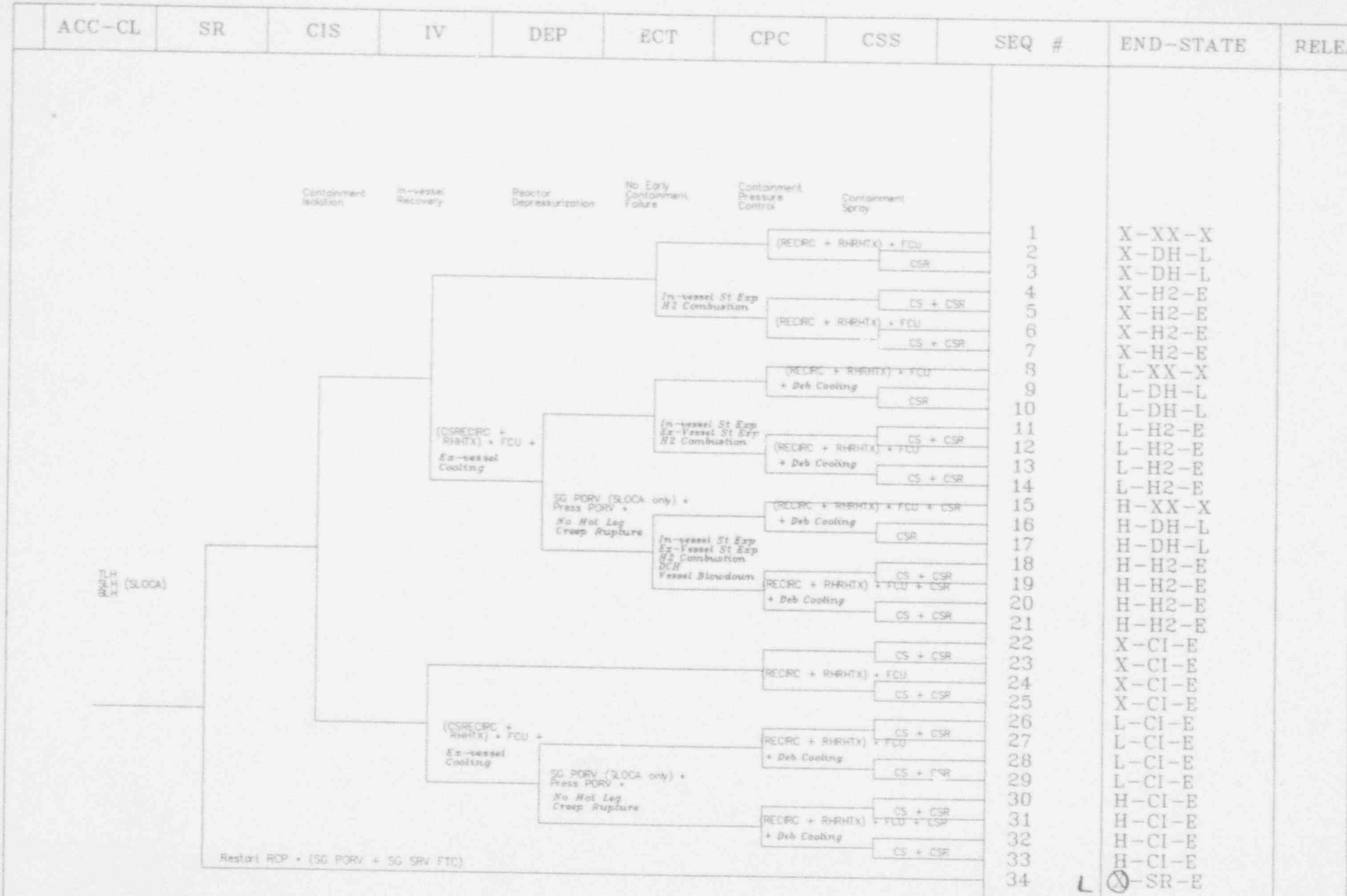

ACC-CL
SR
CIS
IV
DEP
ECT
CPC
CSS
SEQ #
END-STATE
RELEA
Containment Isolation
In-vessel Recovery
Reactor Depressurization
No Early Containment Failure
Containment Pressure Control
Containment Spray
TLH
SLH (SLOCA)
BLH
(RECIRC + RHRHTX) + FCU
CSR
In-vessel St Exp
H2 Combustion
CS + CSR
(RECIRC + RHRHTX) + FCU
CS + CSR
(CSRECIRC + RHHTX) + FCU +
Ex-vessel Cooling
(RECIRC + RHRHTX) + FCU
+ Deb Cooling
CSR
In-vessel St Exp
Ex-Vessel St Exp
H2 Combustion
CS + CSR
(RECIRC + RHRHTX) + FCU
+ Deb Cooling
CS + CSR
SG PORV (SLOCA only) +
Press PORV +
No Hot Leg Creep Rupture
(RECIRC + RHRHTX) + FCU + CSR
+ Deb Cooling
CSR
In-vessel St Exp
Ex-Vessel St Exp
H2 Combustion
DCH
Vessel Blowdown
CS + CSR
(RECIRC + RHRHTX) + FCU + CSR
+ Deb Cooling
CS + CSR
CS + CSR
(RECIRC + RHRHTX) + FCU
CS + CSR
(CSRECIRC + RHHTX) + FCU +
Ex-vessel Cooling
CS + CSR
(RECIRC + RHRHTX) + FCU
+ Deb Cooling
CS + CSR
SG PORV (SLOCA only) +
Press PORV +
No Hot Leg Creep Rupture
CS + CSR
(RECIRC + RHRHTX) + FCU + CSR
+ Deb Cooling
CS + CSR
Restart RCP + (SG PORV + SG SRV FTC)
1 X-XX-X
2 X-DH-L
3 X-DH-L
4 X-H2-E
5 X-H2-E
6 X-H2-E
7 X-H2-E
8 L-XX-X
9 L-DH-L
10 L-DH-L
11 L-H2-E
12 L-H2-E
13 L-H2-E
14 L-H2-E
15 H-XX-X
16 H-DH-L
17 H-DH-L
18 H-H2-E
19 H-H2-E
20 H-H2-E
21 H-H2-E
22 X-CI-E
23 X-CI-E
24 X-CI-E
25 X-CI-E
26 L-CI-E
27 L-CI-E
28 L-CI-E
29 L-CI-E
30 H-CI-E
31 H-CI-E
32 H-CI-E
33 H-CI-E
34 L X-SR-E

Figure 4.5-3


ACC-CL
CIS
IV
ECT
INJ
CPC
CSS
SEQ #
END-STATE
RELEASE-MODE
Containment Isolation
In-vessel Recovery
No Early Containment Failure
Ex-vessel Injection
Containment Pressure Control
Containment Spray
SEL (LLOCA & MLOCA)
(LLOCA only) SI + CS + (RECIRC + RHRHTX) + FCU + Ex-vessel Cooling
1.0 (MLOCA)
In-vessel St Exp H2 Combustion
In-vessel St Exp Ex-Vessel St Exp H2 Combustion
(RECIRC + RHRHTX) + FCU
(RECIRC + RHRHTX) + FCU + Deb Cooling
SI + LPSI + CS
FCU
CSR
CS + CSR
1 X-XX-X
2 X-DH-L
3 X-DH-L
4 X-H2-E
5 X-H2-E
6 X-H2-E
7 X-H2-E
8 L-XX-X
9 L-DH-L
10 L-DH-L
11 L-CC-L
12 L-CC-L
13 L-H2-E
14 L-H2-E
15 L-H2-E
16 L-H2-E
17 L-H2-E
18 L-H2-E
19 X-CI-E
20 X-CI-E
21 X-CI-E
22 X-CI-E
23 L-CI-E
24 L-CI-E
25 L-CI-E
26 L-CI-E
27 L-CI-E
28 L-CI-E

Figure 4.5-4

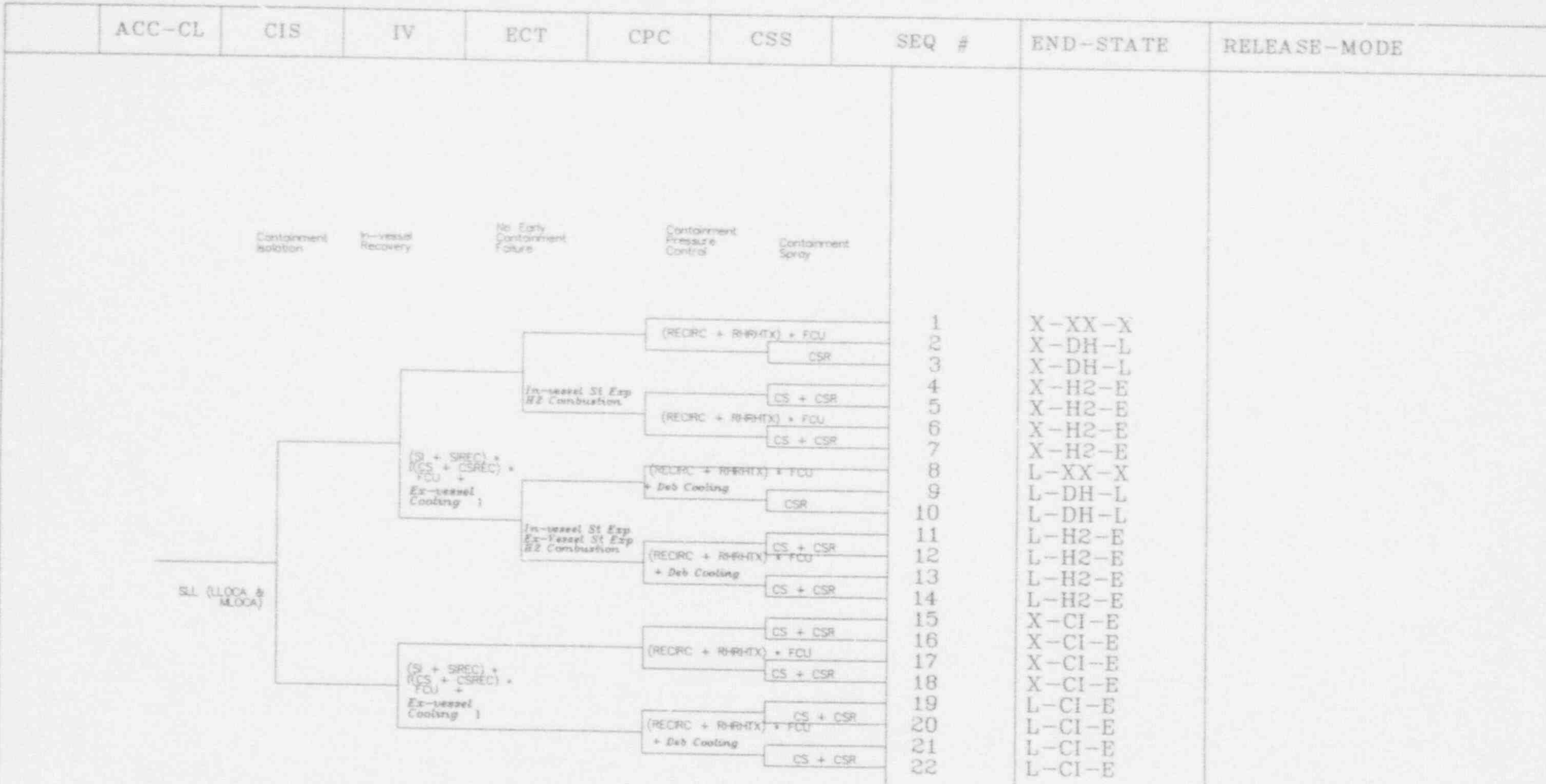

ACC-CL
CIS
IV
ECT
CPC
CSS
SEQ #
END-STATE
RELEASE-MODE
Containment Isolation
In-vessel Recovery
No Early Containment Failure
Containment Pressure Control
Containment Spray
SLL (LLOCA & MLOCA)
(SI + SIREC) + ((CS + CSREC) + FCU + Ex-vessel Cooling)
In-vessel St Exp H2 Combustion
In-vessel St Exp Ex-Vessel St Exp H2 Combustion
(RECIRC + RHRHTX) + FCU
(RECIRC + RHRHTX) + FCU + Deb Cooling
CSR
CS + CSR
1 X-XX-X
2 X-DH-L
3 X-DH-L
4 X-H2-E
5 X-H2-E
6 X-H2-E
7 X-H2-E
8 L-XX-X
9 L-DH-L
10 L-DH-L
11 L-H2-E
12 L-H2-E
13 L-H2-E
14 L-H2-E
15 X-CI-E
16 X-CI-E
17 X-CI-E
18 X-CI-E
19 L-CI-E
20 L-CI-E
21 L-CI-E
22 L-CI-E

Figure 4.5-5

4.6 Results of Level 2 Sequence Quantification

This section provides a discussion of the Prairie Island Level 2 containment event tree sequence quantification. Since Steam Generator Tube Rupture (accident class GEH and GLH) and Intersystem LOCA (Event V) events were not analyzed using the containment event tree, results for these events are reported but not discussed in detail below. For a discussion of the results of these accident classes, see Section 3.4.

Although the events are described in this section, SG Tube Creep Rupture event frequencies are not subtracted from the frequencies presented for the other end states shown in this section (including the tables and figures) because their high end state probability (including the "puff" release) would mask important CET results from the other end states. Performing a recommended procedure change (see Section 1.4.6) would greatly reduce the potential for SG Tube Creep Rupture. Source term results are presented in Section 4.7 which do include SG Tube Creep Rupture events.

The conditional probability of containment bypass or failure following core damage is 40% (total release frequency of 2E-5 per reactor-year). This means that the containment remains intact with a probability of 60% following core damage (containment intact frequency of 3E-5 per reactor-year). If SG Tube Creep Rupture events are included, conditional probability of containment bypass or failure following core damage is 69% (total release frequency of 3.4E-5 per reactor-year). The magnitude of the release source terms are described in Section 4.7. The most probable causes of releases at Prairie Island are Steam Generator Tube Rupture events. About half of all containment failure events are due to sequences which do not involve containment bypass (1E-5).

4.6.1 Level 2 CET Quantification Results By Plant End State

This section gives a description of each plant end state, in order by frequency, with examples of the dominant sequences within each end state. Table 4.6-1 gives this information in tabular form. Figures 4.6-1 through 4.6-4 show the results of the quantification in pie chart form.

End State H-XX-X

End state H-XX-X includes Level 1 core damage sequences for which containment isolation was successful, the core is not arrested in vessel (core goes ex-vessel at high pressure) and *Hot Leg Creep Rupture* does not result in vessel depressurization. The containment remains intact (no containment failure). This end state occurs with a probability of 40.0% following core damage (2E-5).

This is the most probable end state, and it is dominated by early (high pressure) core damage event sequences with short term injection failure. On vessel depressurization, containment spray and low pressure injection automatically provide means to quench the debris. Long term debris cooling and containment pressure control are provided by containment spray (in recirculation) and the FCUs. These systems do not play a part in failure of short term inventory control which led to early core damage.

The dominant sequence for this end state is FEHCET-SEQ19. This sequence is made up of a single initiator, a flood in the auxiliary feedwater pump/instrument air compressor room due to a rupture in one of the two cooling water headers that passes through the room in the overhead. The containment remains intact because containment isolation was successful and no early containment phenomena occur for this sequence and long term heat removal can be supported with the unaffected cooling water header.

End State X-XX-X

End state X-XX-X includes Level 1 core damage sequences for which containment isolation was successful, the core is arrested in vessel and that do not cause containment failure. This end state occurs with a probability of 20.0% following core damage (1E-5).

This end state contains only late core damage event sequences in which the RWST has been injected successfully and the vessel is submerged. In-vessel recovery is not credited for early core melt sequences since they involve failure of systems required for providing water to the vessel or containment (safety injection or depressurization and low pressure injection) and the small amount of time available to restore failed injection systems before the core goes ex-vessel.

SLLCET-SEQ1 and SLHCET-SEQ1 are the dominant CET sequences in this category. SLLCET-SEQ1 involves medium and large LOCAs with successful short term inventory function (low pressure injection). SLHCET-SEQ1 involves small LOCAs with successful short term inventory function (high pressure injection). The majority of these sequences are a result of failure to initiate recirculation given the relatively short time frame in which to perform this action.

X-XX-X is the second most probable end state, since the containment isolation function is highly reliable. Also, the in-vessel injection and containment pressure control systems are reliable in late core damage sequences since the injection systems, also used for containment pressure control, have already been successful. A much longer time frame for establishing recirculation for containment pressure control purposes is available (on the order of days) even though the function was unsuccessful in the prevention of core damage.

End State H-OT-L

This end state includes core damage sequences for which the reactor vessel fails at high pressure and the containment fails late on high temperature and pressure. Containment heatup is assumed to be a result of failure to cool debris which may have relocated to the upper compartments of containment following blowdown from high pressure. This plant damage state is assumed to occur with a probability of 16.0% following core damage (8E-06).

The dominant sequences for this end state are SEHCET-SEQ23 and TEHCET-SEQ23. A discussion of these sequences is given in Section 4.6.2 below. It should be noted that while long term containment failure is assumed for this sequence, the timing of this failure is many days following core damage due to the large volume of containment and the relatively high ultimate capacity (150 psig).

Accident Class GLH

This accident class involves late core damage at high pressure with containment bypass due to a Steam Generator Tube Rupture initiator. This accident class is assumed to occur with a frequency of 6E-06 per reactor year.

This accident class is described in Section 3.4. Core damage for this accident class results from depletion of the RWST prior to depressurization of the RCS to terminate primary to secondary leakage. Because of the size of the RWST, core damage would not be expected for approximately 24 hours for this accident class.

End State H-DH-L

This end state includes core damage sequences for which the reactor vessel fails at high pressure and the containment fails late due to failure to remove decay heat from the containment. This is assumed to occur with a probability of 6.0% following core damage (3E-06).

This plant damage state differs from the preceding one in that containment pressurization results from steam generation due to decay heat as opposed to debris cooling failure in the upper parts of containment. Pressurization from steam can reach the ultimate strength of containment earlier than for overpressure/temperature challenges, but still requires days to occur due to the size and strength of containment.

The dominant sequences for this end state are SEHCET-SEQ21 and TEHCET-SEQ21. A discussion of these sequences is given in Section 4.6.2 below.

Accident Class GEH

This accident class involves early core damage at high pressure with containment bypass due to Steam Generator Tube Rupture. This accident class occurs with a frequency of 6E-07 per reactor year.

This accident class is described in Section 4.6.2 below. It differs from the earlier GLH accident class in that injection from the RWST is not available, either due to SI failure or auxiliary feedwater/main feedwater failure coincident with the tube rupture.

End State H-H2-E

This end state includes core damage sequences for which the reactor vessel fails at high pressure and the containment fails early due to challenges such as *Hydrogen Combustion*. This is assumed to occur with a probability of 0.6% following core damage (3E-07).

The dominant sequence for this end state is FEHCET-SEQ24. A discussion of this sequence is given in Section 4.6.2 below. *Hydrogen Combustion* is one of a number of early challenges considered in the evaluation of containment response to severe accidents. Others include *Direct Containment Heating*, *Steam Explosions* and *Vessel Blowdown* forces. None provide a significant potential to fail containment because of its size and strength.

End State X-H2-E

This end state is similar to the previous one except the core is successfully retained in the reactor vessel. This end state is estimated to occur with a probability of 0.2% following core damage (9E-08).

The dominant sequence for this end state is SLLCET-SEQ4. A discussion of this sequence is given in section 4.6.2 below.

End State L-XX-X

End state L-XX-X includes Level 1 core damage sequences for which containment isolation was successful but the core is not arrested in-vessel (the core goes ex-vessel at low pressure). No containment failure occurs due to successful ex-vessel debris cooling and containment pressure control functions. This end state is estimated to occur with a probability of 0.2% following core damage (8E-8).

The dominant sequence for this end state is SELCET-SEQ8. This sequence is dominated by a Large LOCA with common cause failures of the RHR pumps to start or run.

Intersystem LOCA (ISLOCA)

This event involves early core damage at either high or low pressure due to an intersystem LOCA event. This event is estimated to occur with a frequency of 2.3E-07 per reactor year.

This event is described in Section 4.6.2 below. Systems considered in evaluation of the potential for intersystem LOCA include low head injection to the hot leg, low head injection to the vessel and RHR shutdown cooling suction.

End State L-CC-L

End state L-CC-L includes Level 1 core damage sequences for which containment isolation was successful but are not arrested in-vessel (the core goes ex-vessel at low pressure) and ex-vessel injection by containment spray fails. This end state is estimated with a probability of 0.1% following core damage (4E-8).

The dominant sequences for this end state are SELCET-SEQ12 and SELCET-SEQ11. These sequences involve medium or large LOCAs with failure of all safeguards 480 V buses or RWST rupture. Safety injection and containment spray injection failure (due to 480V-powered MOVs which must open or RWST failure) and RHR injection failure (due to failure of RHR pit cooling or RWST failure) fail the in-vessel injection and ex-vessel injection functions for these sequences.

End State L-DH-L

End state L-DH-L includes Level 1 core damage sequences for which containment isolation was successful but are not arrested in-vessel (the core goes ex-vessel at low pressure) and containment pressure control fails. This end state is estimated to occur with a probability of less than 0.1% following core damage (8E-9).

The dominant sequence for this end state is TLHCET-SEQ10. This sequence involves late core damage at high pressure following a loss of offsite power with failure of D1 and D5 (Unit 1 and Unit 2 Train A) emergency diesel generators to run, followed by failure of 11 and 12 auxiliary feedwater pumps to run and failure of a Train B motor-operated valve to open (12 RHR heat exchanger CC inlet valve, RHR to SI suction valve, or either Train B RHR suction valve from sump B).

End States X-CI-E, H-CI-E, and L-CI-E

End state X-CI-E includes Level 1 core damage sequences for which containment isolation has failed, causing early containment failure with the core arrested in vessel. End state H-CI-E includes Level 1 core damage sequences for which containment isolation has failed, causing early containment failure with vessel failure occurring at high pressure. End state L-CI-E includes Level 1 core damage sequences for which containment isolation failed, causing early containment failure and vessel failure occurs at low pressure. All of these ends states are collectively estimated to occur with a probability < 0.1% following core damage.

These end states have very low frequencies due to the high reliability of the containment isolation function. The dominant sequence for the X-CI-E end state is SLLCET-SEQ15, which involves medium LOCA with failure of high head recirculation followed by containment isolation failure. The dominant sequence for the H-CI-E end state is FEHCET-SEQ40, which involves flooding in the auxiliary feedwater pump/instrument air compressor room (due to rupture of one of the two cooling water headers that pass through the room in the overhead) followed by containment isolation failure. In-vessel recovery is not credited for early core damage sequences. End state L-CI-E is estimated to have a negligible probability of occurrence following core damage (0) because vessel depressurization via the *Hot Leg Creep Rupture* phenomenon is not credited with failure of in-vessel recovery for early core damage sequences.

End State L-H2-E

This end state includes core damage sequences for which the reactor vessel fails at low pressure and the containment fails early due to *Hydrogen Combustion*. This is estimated to occur with a probability of < 0.1% following core damage.

The dominant sequence for this end state is SELCET-SEQ13 and SELCET-SEQ18. These sequences involves large LOCA with common cause failure of the RHR pumps to start or run, with containment failure due to *Hydrogen Combustion*. Also dominating these sequences is medium LOCA followed by common cause failure of the safeguards 480 V bus room unit coolers, with containment failure due to *Hydrogen Combustion*. This end state has a very low probability due to the relatively unlikely occurrence of this containment phenomena.

End State X-DH-L

End state X-DH-L includes Level 1 core damage sequences that are arrested in vessel and that involve failure to remove decay heat from the containment. This occurs with a negligible probability following core damage (0). This is due to the same reasons described above that make end state X-XX-X the second highest probability of occurrence following core damage.

End States Involving SG Tube Creep Rupture

SG Tube Creep Rupture events are not subtracted from the other end states shown in Table 4.6-1 because their high end state probability (including the "puff" release) would mask other important CET results from other end states. Performing a recommended procedure change (see Section 1.4.6) would greatly reduce the potential for SG Tube Creep Rupture.

End State L-SR-E: End State L-SR-E is associated with core damage events in which creep rupture of the steam generator tubes occurs. To result in this cor nment failure mode, several conditions must exist; the reactor must be at high pressure, a steam generator must be dry, core damage must have occurred and the reactor coolant pumps must be restarted during the short interval between the initiation of core slumping and lower vessel head penetration. For accident scenarios in which lower head penetration is precluded by ex-vessel cooling, it is assumed that reactor coolant pump restart must occur prior to depressurization from failure of another part of the reactor coolant system such as the hot leg. Either lower head penetration by debris or hot leg creep rupture are expected on the order of 1/2 to an hour subsequent to the onset of core damage.

Functional recovery procedures instruct the restart of reactor coolant pumps on core exit thermocouple readings exceeding 1200°F. The purpose of this guidance is to prolong core cooling by forced circulation as long as possible to delay core damage. For many of the dominant core damage sequences, reactor coolant pump restart cannot be accomplished by the operator. These sequences include loss of offsite power events and loss of train A of DC power, which does not permit closure of the reactor coolant pump breakers. Of all core damage events, on the order of 20% lead to conditions required for steam generator tube creep rupture (2E-5/yr).

However, even if reactor coolant pump operation is successful, blowdown of a steam generator is also assumed for this accident class. This requires depressurization through a steam generator PORV or failed open safety relief valve. Emergency procedures instruct steam generator depressurization. Again, however, the events which lead to core damage often preclude operation of a steam generator PORV. Loss of instrument air and turbine building flood initiators make up the bulk of this plant damage state, limiting the potential for continuous releases from this failure mode.

End state L-SR-E constitutes 1.4% of the total core damage frequency from internal events initiators (7E-07). Inclusion of this event into the CET quantification results would reduce the X-XX-X end state by approximately this amount.

"Puff" Release End State: This event is the same as L-SR-E discussed in above, but in this case, the valve which opened to relieve the steam generators successfully reclcses. This limits the release to a relatively short duration puff followed by a series of shorter puffs as the pressure in the steam generator with the failed tube oscillates about the relief valve setpoint. All releases are terminated upon vessel failure, when the primary (and therefore the steam generator with the ruptured tube) system depressurizes to containment pressure.

This end state constitutes 30.0% of the total core damage frequency from internal events initiators (1.5E-05). Inclusion of this event into the CET quantification results would reduce the X-XX-X end state by approximately 3.5E-06 and would reduce the H-XX-X end state by approximately 1.1E-05.

4.6.2 Dominant Containment Event Tree Sequences

This section describes the dominant containment event tree sequences in order by frequency. Table 4.6-2 gives this information in tabular form.

1. SGTR-SEQ5 6E-6

   This sequence is a core damage sequence which leads to containment bypass. It is responsible for 12% of the core damage frequency and 30% of the total release frequency. It involves late core damage at high pressure and release following a Steam Generator Tube Rupture event. A description of this event can be found in Section 3.4.

2. SEHCET-SEQ23 5E-6

   This sequence is assumed to occur with a conditional probability of 10% following core damage and accounts for 25% of the total release frequency. It involves early core damage at high pressure from a small LOCA initiating event or a transient which leads to a consequential small LOCA, together with failure of ex-vessel injection and containment pressure control. This leads to containment failure on overpressure.

   Dominant failure mechanisms for this sequence involve combinations of initiating events and component failures which lead to an early loss of all cooling water. Attempts to recover cooling water fail. Loss of cooling water causes the loss of component cooling water to the reactor coolant pump thermal barrier heat exchanger. It also causes loss of the safeguards chillers, which is assumed to result in failure of the 480 V safeguards buses for Unit 1. Loss of 480 V power results in failure of charging to the RCP seals. This causes an RCP seal leak (consequential small LOCA). Without cooling water, all systems for providing decay and containment heat removal are lost.

3. <u>TEHCET-SEQ23</u> 4E-6

This sequence is assumed to occur with a conditional probability of 8.0% following core damage and is responsible for 20% of the total release frequency. It involves early core damage at high pressure from a transient initiating event with failure of ex-vessel injection and containment pressure control. This leads to containment failure on overpressure.

Dominant failure mechanisms for this sequence involve loss of instrument air (and failure of instrument air system recovery) with random failures in the auxiliary feedwater system. Loss of instrument air causes reactor trip and failure of feedwater (feedwater regulating valve and bypass valve closure). This together with failure of auxiliary feedwater causes loss of secondary heat removal. The loss of instrument air also causes failure of bleed and feed due to loss of the pressurizer PORVs. It also causes the safeguards chiller cooling water outlet valves to fail closed, tripping the chillers. This results in failure of room cooling to the safeguards 480 V buses for Unit 1, and subsequent failure (closed) of the safety injection suction MOVs, the containment spray discharge MOVs and the FCUs (time for 480 V room heatup not credited). Loss of bleed and feed, depressurization capability and containment spray injection causes failure of the ex-vessel injection function. Loss of the FCUs causes failure of the containment spray function.

4. <u>SEHCET-SEQ21</u> 2E-6

This sequence is assumed to occur with a conditional probability of 4.0% following core damage and accounts for 10% of the total release frequency. It involves early core damage at high pressure from a small LOCA initiating event or a transient which leads to a consequential small LOCA, together with failure of containment pressure control and containment spray recirculation. This leads to containment failure due to failure to remove decay heat from the containment.

Dominant failure mechanisms for this sequence involve a small LOCA with failure of safety injection due to common cause failure of both of the cooling water inlet valves to the component cooling heat exchangers. Without component cooling water, containment spray recirculation fails which causes failure of both the containment pressure control and the containment spray functions.

5. <u>SGTR-SEQ9</u> 6E-7

This sequence is a core damage sequence which leads to containment bypass. It is responsible for 1.2% of the core damage frequency and 2% of the total release frequency. It involves early core damage at high pressure and release following a Steam Generator Tube Rupture event. A description of this event can be found in Section 3.4.

6. <u>TEHCET-SEQ21</u> 5E-7

This sequence is assumed to occur with a conditional probability of 1.0% following core damage and accounts for 2.5% of the total release frequency. It involves early core damage at high pressure from a transient event where containment pressure control and containment spray recirculation functions have both failed. This sequence leads to containment failure due to failure to remove decay heat from the containment.

The dominant failure mechanism for this sequence involves SBO (due to diesel cooling water pump failure and Unit 2 diesel generator failures following a LOOP). AC power is recovered within 5 hours following the SBO, but the operator fails to align Bus 27 to restore power to the 121 CL pump (Unit 1 4160 V Bus 15 is the power supply assumed restored on the recovery of AC power).

7. <u>TEHCET-SEQ46</u> 5E-7

This sequence is a core damage sequence which leads to containment bypass. It accounts for the potential for creep rupture of the steam generator tubes and release of fission product from the reactor to the atmosphere outside containment through the steam generators. This sequence is accounts for approximately 1.0% of the core damage frequency and 2.5% of the total release frequency.

For this containment failure mode to occur, at least one steam generator must be dry, the reactor coolant system must be at high pressure and the operator must start a reactor coolant pump in the time period between the onset of core damage and reactor depressurization resulting from either lower head penetration or creep rupture of another location in the primary system, such as the hot leg. For a continuous release to occur, the steam generators must also be vented to the atmosphere through an open steam generator PORV or stuck open safety relief valve.

For the TEH accident class, both steam generators are assumed to be dry with the reactor at high pressure. Functional recovery procedures currently instruct the restart of a reactor coolant pump and the depressurization of the steam generators on exceeding core exit thermocouple temperature of 1200°F. However, for the majority of sequences in this accident class, the operator will not be able to accomplish both of these actions. For example, the reactor coolant pumps cannot be operated following loss of offsite power events. Loss of train A DC power will also not provide permissive for closure of any of the reactor coolant pump breakers. Loss of instrument air results in the inability to open the steam generator PORVs for sequences in which it was responsible for loss of the pressurizer PORVs for bleed and feed operation.

For the majority of this accident class, the events which lead to core damage also limit the potential for continuous releases from the steam generator tubes as a result of creep rupture.

f. <u>BEHCET-SEQ24</u> 2E-7

This sequence is assumed to occur with a conditional probability of 0.4% following core damage, and accounts for 1% of the total release frequency. It involves early core damage at high pressure from a Station Blackout (SBO) in which power was not restored during the event. There is no power for operation of ex-vessel injection systems and containment pressure control systems. This leads to containment failure due to failure to cool debris in the containment.

Dominant failure mechanisms for this sequence involve an extended SBO (due to LOOP with common cause failures of all diesels, or diesel cooling water pump failure and Unit 2 diesel generator failures). Attempts to restore power before systems to prevent containment failure become ineffective are not successful. It should be noted that while AC power recovery is assumed to be unsuccessful, many days are available to provide a means of debris cooling before containment failure would be expected.

9. FEHCET-SEQ24 1E-7

This sequence is assumed to occur with a conditional probability of 0.2% following core damage and accounts for 0.5% of the total release frequency. It involves early core damage at high pressure from an internal flooding transient initiator with early containment failure.

Dominant failure mechanisms for this sequence involve a rupture in one of the two cooling water headers in the auxiliary feedwater pump/instrument air compressor room (T1FLD). The auxiliary feedwater pumps and the instrument air compressors are submerged and are assumed to be lost before the operators can respond to isolate the flood. On the loss of instrument air, main feedwater regulating and bypass valves fail closed, as do the instrument air to containment isolation valves. These events cause the loss of secondary cooling (auxiliary feedwater and main feedwater), and bleed and feed capability. Later in the event, credit is given for the possible successful isolation of the flood per plant procedures so that one train of cooling water remains intact for ex-vessel injection systems and containment pressure control systems. However, early containment failure is assumed to occur (dominant failure mode is *Hydrogen Combustion*).

10. FEHCET-SEQ46 1E-7

This sequence is a core damage sequence which leads to containment bypass. It accounts for the potential for creep rupture of the steam generator tubes and release of fission products from the reactor to the atmosphere outside containment through the steam generators. This sequence accounts for approximately 0.2% of the core damage frequency and 0.5% of the total release frequency.

For this containment failure mode to occur, at least one steam generator must be dry, the reactor coolant system must be at high pressure and the operator must start a reactor coolant pump in the time period between the onset of core damage and reactor depressurization resulting from either lower head penetration or creep rupture of another location in the primary system, such as the hot leg. In addition, for a continuous release to occur, the steam generators must also be vented to the atmosphere through an open steam generator PORV or stuck open safety relief valve.

The majority of the FEH accident class is dominated by a cooling water pipe break in the turbine building auxiliary feedwater pump/instrument air compressor room. For this flood, AFW, MFW as well as air compressors are assumed to be lost. The ability to start the reactor coolant pumps is unaffected as the RCP 4160V AC bus is located outside the area affected by the flooding. However, the loss of the air compressors does not allow for depressurization of the steam generators as they depend on instrument air. Releases are limited to those that occur during the initial blowdown of the reactor to the steam generators. Continuous release occurs only if steam generator safety relief valves fail to close after the blowdown.

Table 4.6-1

Level 2 Containment Event Tree Results by Plant End State

End State	Probability	Cond. Prob. Following Core Damage (%)	End State Description	Dominant CET Sequences	Probability
X-XX-X	1E-05	20.0	No Vessel Failure No Containment Failure	SLLCET-01 SLHCET-01	8E-06 3E-06
X-DH-L	0.0	0.0	No Vessel Failure Containment DHR Failure Late Containment Failure	N/A	N/A
X-H2-E	9E-08	0.2	No Vessel Failure Hydrogen Combustion Early Containment Failure	SLLCET-04	5E-08
L-XX-X	8E-08	0.2	Low Pressure Vessel Failure No Containment Failure	SELCET-08	4E-08
L-DH-L	8E-09	<<0.1	Low Pressure Vessel Failure Containment DHR Failure Late Containment Failure	TLHCET-10	7E-09
L-CC-L	4E-08	0.1	Low Pressure Vessel Failure Core-Concrete Interaction Late Containment Failure	SELCET-12 SELCET-11	3E-08 8E-09
L-H2-E	8E-10	<<0.1	Low Pressure Vessel Failure Hydrogen Combustion Early Containment Failure	SELCET-13 SELCET-18	3E-10 3E-10
H-XX-X	2E-05	40.0	High Pressure Vessel Failure No Containment Failure	FEHCET-19	1E-05
H-DH-L	3E-06	6.0	High Pressure Vessel Failure Containment DHR Failure Late Containment Failure	SEHCET-21 TEHCET-21	2E-06 5E-07
H-OT-L	8E-06	16.0	High Pressure Vessel Failure Containment Overpressure Late Containment Failure	SEHCET-23 TEHCET-23	5E-06 4E-06
H-H2-E	3E-07	0.6	High Pressure Vessel Failure Hydrogen Combustion Early Containment Failure	FEHCET-24	1E-07
X-CI-E	4E-09	<<0.1	No Vessel Failure Containment Isolation Failure Early Containment Failure	SLLCET-15	3E-09
L-CI-E	0.0	0.0	Low Pressure Vessel Failure Containment Isolation Failure Early Containment Failure	N/A	N/A
H-CI-E	8E-09	<<0.1	High Pressure Vessel Failure Containment Isolation Failure Early Containment Failure	FEHCET-40	6E-09

(continued on next page)

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

Table 4.6-1, cont.

Level 2 Containment Event Tree Results by Plant End State

End State	Probability	Cond. Prob. Following Core Damage (%)	End State Description	Dominant CET Sequences	Probability
GLH[2]	6E-06	12.0	Steam Generator Tube Rupture Late Core Damage at High Pressure	SGTR-SEQ5[1]	6E-06
GEH[2]	6E-07	1.2	Steam Generator Tube Rupture Early Core Damage at High Pressure	SGTR-SEQ9[1]	6E-07
ISLOCA[2]	2E-07	0.5	Intersystem LOCA	ISLOCA-[illegible][1]	2E-07
"Puff"[3] Release	1.5E-5	30.0	Steam Generator Tube Creep Rupture Early Core Damage at High Pressure (SG Relief Valves Cycle)	N/A	1.5E-05
L-SR-E[3]	7E-07	1.4	Steam Generator Tube Creep Rupture Early Core Damage at High Pressure (SG Relief Valve Fail Open)	TEHCET-SEQ46 FEHCET-SEQ46	5E-07 1E-07

NOTE 1: These are Level 1 core damage sequences rather than CET sequences. They are listed here because they involve containment failure. See Section 3.4 for descriptions of these sequences.

NOTE 2: These are Level 1 accident classes rather than CET end states. They are listed here because they involve containment failure. See Section 4.3 for descriptions of these accident classes.

NOTE 3: The frequencies for the SG Tube Creep Rupture end states were not subtracted from the other end states results for this table, but were in the source term results table (see discussion Section 4.6.1 and Table 4.7-4).

Table 4.6-2

Dominate Level 2 Containment Event Tree Sequences

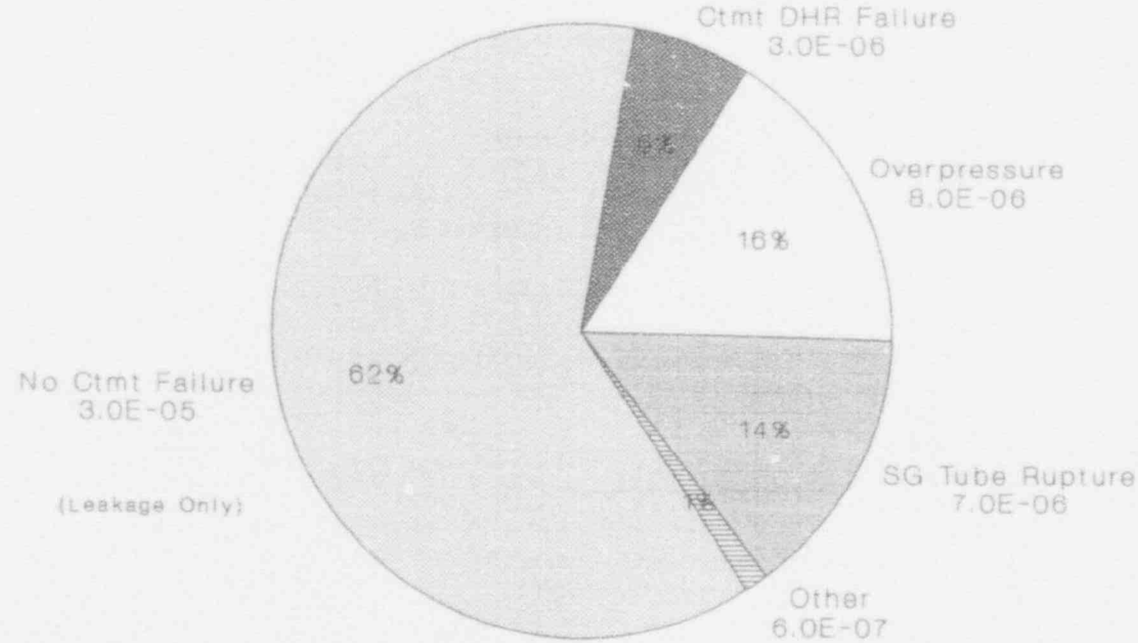
No.	Probability	Cond. Prob. Following Core Damage (%)	Sequence	End State
1	1.5E-05	30.0[3]	N/A[3]	"Puff" Release[3]
2	6E-06	12.0	SGTR-SEQ5[1]	GLH[2]
3	5E-06	10.0	SEHCET-23	H-OT-L
4	4E-06	8.0	TEHCET-23	H-OT-L
5	2E-06	4.0	SEHCET-21	H-DH-L
6	6E-07	1.2	SGTR-SEQ9[1]	GEH[2]
7	5E-07	1.0	TEHCET-21	H-DH-L
8	5E-07	1.0[3]	TEHCET-46[3]	L-SR-E[3]
9	2E-07	0.4	BEHCET-24	H-OT-L
10	1E-07	0.2	FEHCET-24	H-H2-E
11	1E-07	0.2[3]	FEHCET-46[3]	L-SR-E[3]

NOTE 1: These are Level 1 core damage sequences rather than CET sequences. They are listed here because they involve containment failure. See Section 3.4 for descriptions of these sequences.

NOTE 2: These are Level 1 accident classes rather than CET end states. They are listed here because they involve containment failure. See Section 4.3 for descriptions of these accident classes.

NOTE 3: The frequencies for the SG Tube Creep Rupture sequences were not subtracted from the other sequence results for this table, but were in the source term results table (see discussion Section 4.6.1 and Table 4.7-4).

Prairie Island Level II PRA
Int. Events by Ctmt. Failure Mode

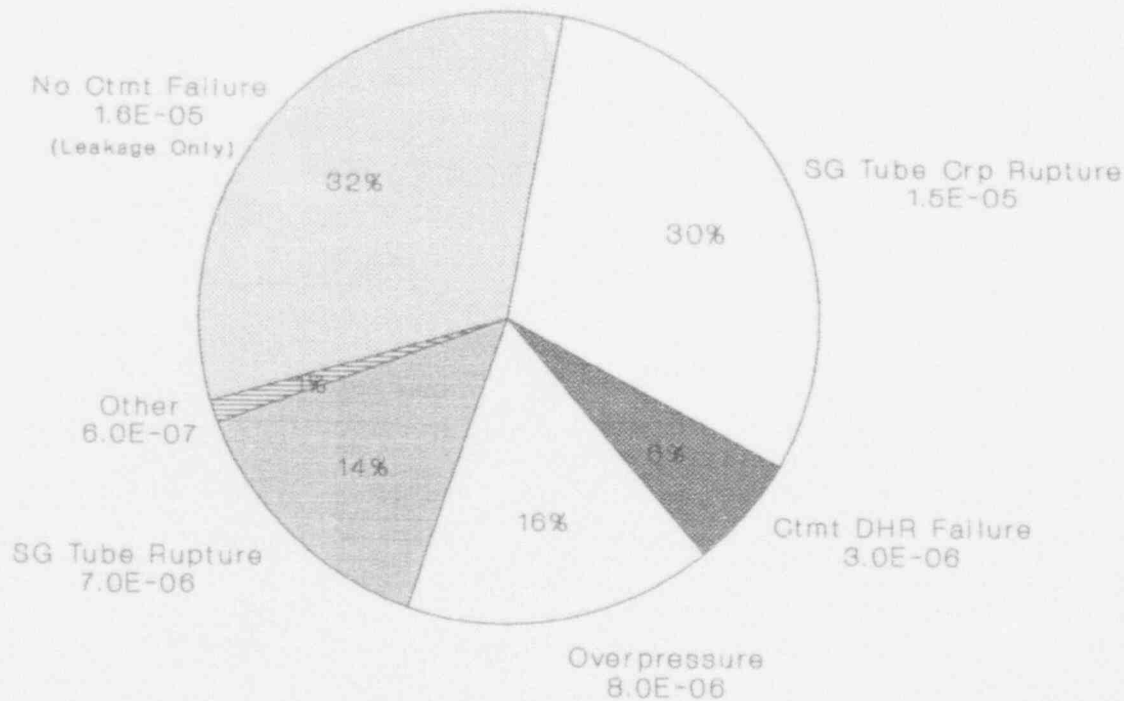


Note: Excludes SG Tube Creep Rupture

(Other: H2 Combustion, 0.7%; ISLOCA, 0.5; Core Concrete Interaction, Ctmt. Isolation Failure <0.1%)

Figure 4.6-1

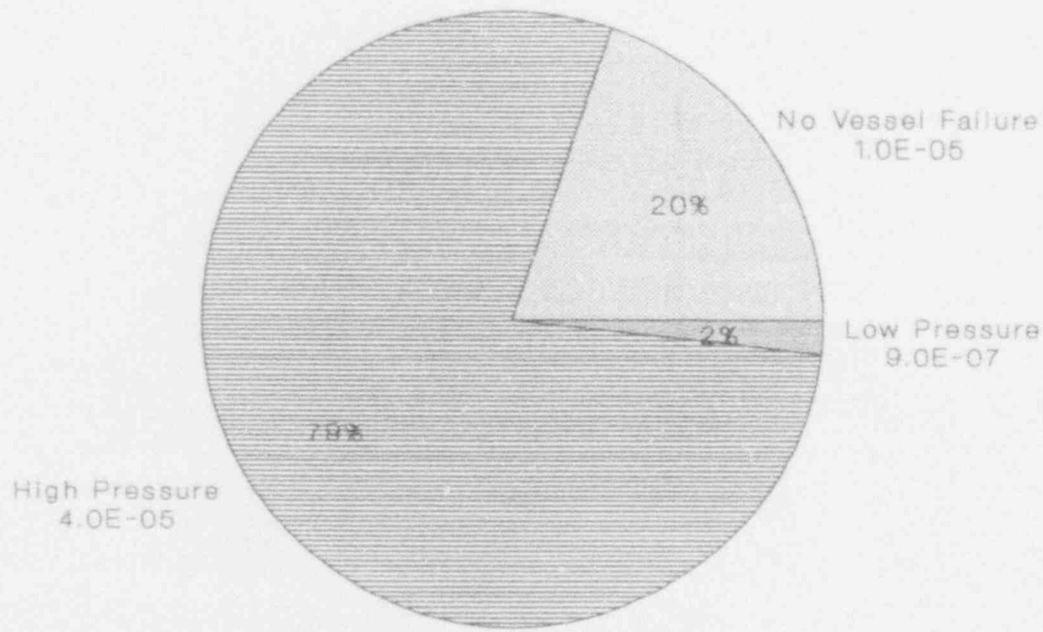
Prairie Island Level II PRA
Int. Events by Ctmt. Failure Mode



(Other: H2 Combustion, 0.7%; ISLOCA, 0.5; Core Concrete Interaction, Ctmt. Isolation Failure <0.1%)

Figure 4.6-2

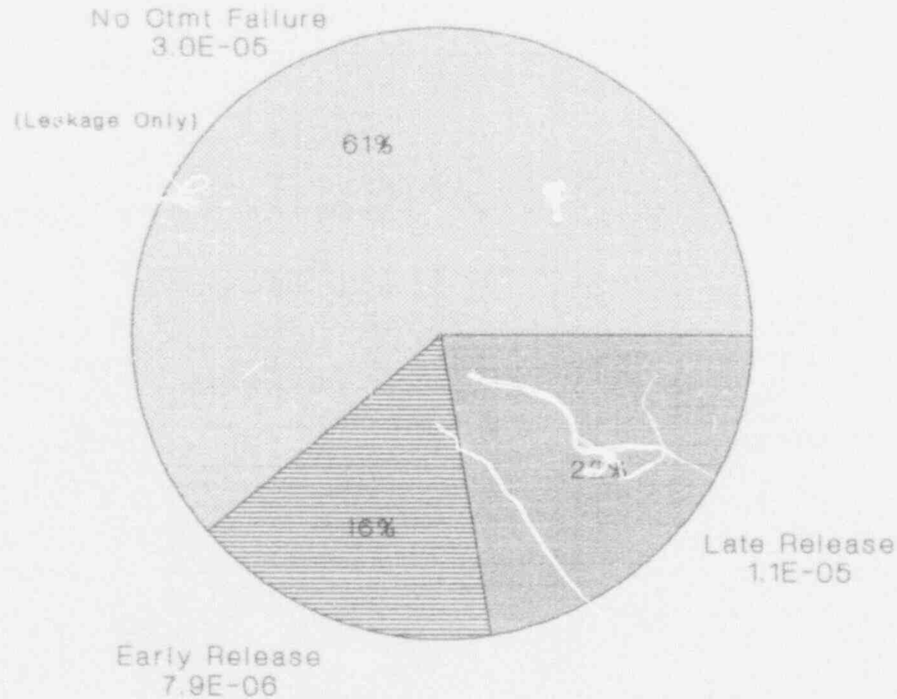
Prairie Island Level II PRA
Int. Events by Vessel Failure Pressure



Note: Excludes Containment Bypass Events

Figure 4.6-3

Prairie Island Level II PRA
Internal Events by Release Timing



(Early Release includes Ctmt Bypass except for SG Tube Creep Rupture)

Figure 4.6-4

4.7 Fission Product Release Characterization

In this section, fission product releases that may occur due to potential accident progressions at Prairie Island will be developed. In this analysis, the fission product release characterization (source terms) is defined as a release of radionuclides from the containment of a specific magnitude and distribution. MAAP3.0B-PWR, Revision 19.0 was used to develop the source terms for the representative accident progressions described below.

4.7.1 Discussion

As described in Sections 4.5 and 4.6, the Containment Event Trees (CETs) were developed in such a way that each end state, in principle, defines a unique fission product release category. The CET end states define the reactor status, the containment status, and the timing of fission product releases. In practice, the simplifying assumptions used to make the CET quantification tractable occasionally lead to the grouping of sequences which do not behave in an entirely similar way. The purpose of this analysis is to choose specific accident progression sequences that will best approximate the representative source term results for each relevant CET 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 are taken directly from the MAAP calculations. Typically, the MAAP calculations were continued for 48 hours from sequence initiation or for 24 hours following containment failure, whichever was longer. 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 representative 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 in the Summary section. The sections which follow will elaborate on the selection of the representative sequences, provide discussion of 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).

4.7.2 Representative Sequence Selection

As described above, the initial effort in performing the source term analysis is to choose representative sequences for each of the relevant CET end states. Table 4.7-1 summarizes the representative sequences, and a brief discussion for each of the CET end states follows.

4.7.2.1 H-XX-X End State Discussion

This CET end state describes a high pressure vessel failure scenario with no containment failure and releases limited to leakage. The dominant sequences in this end state are SEHCET-19 and FEHCET-19, with contributions from TEHCET-19 and BEHCET-19, and with much smaller contributions from various other scenarios. Given the nature of this end state (i.e. - limited fission product releases), the choice of SEHCET-19 as the only representative sequence was deemed adequate to provide representative source term results.

Thus, a small break LOCA (1" diameter cold leg LOCA assumed) with no high pressure injection available was chosen as the initiator. Significant initial vessel depressurization does not occur, so the RHR injection is only available following vessel failure which is calculated to occur at 4.0 hours. AFW, the accumulators, containment fan coolers, and RHR in recirculation mode are all assumed to operate successfully. The use of containment sprays (although available) is not necessary in this sequence. The limited releases begin following core degradation at about 3 hours from sequence initiation, and continue at a decreasing rate with the exception of the noble gases until the end of the sequence at 48 hours. Since the noble gases do not settle out, their release rate continues without significant decay. The radionuclide release fraction results are presented for this and other representative sequences in Section 4.7-3 (Table 4.7-2).

4.7.2.2 L-XX-X End State Discussion

This CET end state describes a low pressure vessel failure with no containment failure and releases limited to leakage. The dominant contributor is SLLCET-08. Since containment heat removal is available and the releases are also limited to leakage in this case, representative source term results are taken to be similar to the results for the H-XX-X end state.

4.7.2.3 X-XX-X End State Discussion

This CET end state describes a sequence with recovery in vessel with no containment failure and releases limited to leakage. The dominant contributors are from sequences SLLCET-01 and SLHCET-01 with smaller contributions from other sequences. For this case, since the releases are also limited to leakage and since the core debris is recovered in the vessel, the representative source term results are judged to be similar to the results for the H-XX-X end state. Small variations in the quantities of volatile and non-volatile releases may occur, but not enough to alter the categorization of the release described later in this section.

4.7.2.4 H-H2-E End State Discussion

This CET end state describes a high pressure vessel failure scenario with early containment failure assumed to occur due to a failure mode such as hydrogen combustion or Direct Containment Heating (DCH). Numerous scenarios comprise this end state, but all at relatively low frequencies. The dominant contributors are FEHCET-24, SEHCET-24, SEHCET-25, and SEHCET-29. Of those cases, only SEHCET-29 does not continue with containment pressure control. This case and sequences SEHCET-27 & 29 may lead to slightly different source term results compared to sequences SEHCET-24, 25, 26 and 28. However, the small contribution of these sequences to the total H-H2-E end state results and the low contribution of the H-H2-E end state to the overall results makes separate analysis unwarranted. Therefore, SEHCET-25 was chosen as the representative sequence with RHR injection in recirculation as the only containment heat removal system available.

Similar to the H-XX-X end state sequence, a 1" diameter cold leg LOCA was chosen as the initiator. Again RHR does not inject until after the vessel depressurizes following vessel failure. AFW, the accumulators and RHR in recirculation mode are all assumed to operate successfully. The containment failure is assumed to occur two seconds after vessel failure in this case, upon which the majority of the noble gas and volatile fission product releases occur. Core-concrete attack is assumed to occur in the upper compartment due to debris dispersal into the upper compartment upon vessel failure. Prolonged releases of non-volatile fission products occurs as a result of this interaction. The calculated radionuclide release fractions at 48 hours for this case are presented in Table 4.7-2.

4.7.2.5 L-H2-E End State Discussion

This CET end state describes a low pressure vessel failure scenario with early containment failure assumed to occur due to a failure mode such as hydrogen combustion or DCH. The dominant sequence for this end state is SLLCET-13 with small contributions from SLLCET-14 and other scenarios. Thus, SLLCET-13 was chosen as the representative sequence.

A medium LOCA (6" diameter cold leg LOCA assumed) was chosen as the initiator with both low and high pressure injection initially available but unavailable in recirculation mode. AFW, the accumulators, and containment fan coolers are assumed to be available. Core uncovery is calculated to occur by 7 hours, after the accumulators and RWST have depleted. Vessel failure is calculated to occur at about 9 hours, and containment failure is assumed to occur two seconds after that. This case also differs from the H-H2-E sequence in that all of the core debris that leaves the vessel at failure stays in the cavity versus entraining to the upper compartment. In any event, the majority of the fission product releases occur immediately after the assumed containment failure. The calculated radionuclide release fractions at 48 hours for this case are presented in Table 4.7-2.

4.7.2.6 X-H2-E End State Discussion

This CET end state describes a sequence with recovery in vessel, but with early containment failure presumably by an in-vessel steam explosion or by hydrogen combustion. The dominant sequences for this end state are SLLCET-04 and SLLCET-05. For this end state, the core debris is assumed to be recovered in vessel, so the representative source term results are taken to be bounded by the results for the L-H2-E end state.

4.7.2.7 H-CI-E End State Discussion

This CET end state describes a high pressure vessel failure scenario with containment isolation failure assumed at sequence initiation. The dominant sequence is FEHCET-40 (2.0E-9/yr) with contributions from SEHCET-40, SEHCET-41, SEHCET-45, and a few other sequences. The total contribution of core damage frequency for these sequences is small (<< 1%). Thus, a unique MAAP calculation was not performed for this end state, and the representative results were taken to be similar to the H-H2-E early containment failure results.

4.7.2.8 L-CI-E End State Discussion

This CET end state describes a low pressure vessel failure scenario with containment isolation failure assumed at sequence initiation. No sequences remained following truncation leading to this end state. However, a representative sequence was initially run for this end state and it was used to provide representative source term results for the X-CI-E end state as well, so it is described below.

The sequence definition is similar to the L-H2-E case with the exception of the assumed containment failure time. A medium LOCA (6" diameter cold leg LOCA assumed) was chosen as the initiator with both low and high pressure injection initially available but unavailable in recirculation mode. AFW, the accumulators, and containment fan coolers are assumed to be available. Core uncovery is calculated to occur by 7.5 hours, after the accumulators and RWST have depleted. Vessel failure is calculated to occur at about 9.5 hours. The fission product releases from containment initiate shortly after 8 hours with the majority of the release complete by 10 hours. The calculated release fractions at 48 hours for this case are presented in Table 4.7-2.

4.7.2.9 X-CI-E End State Discussion

This CET end state describes a sequence with recovery in vessel, but with containment isolation failure assumed at sequence initiation. The dominant sequence is SLLCET-15. For this end state, since the core debris is assumed to be recovered in vessel, the representative source term results are taken to be bounded by the results for the L-CI-E end state.

4.7.2.10 H-OT-L End State Discussion

This CET end state describes a high pressure vessel failure scenario with late containment failure assumed due to combined overtemperature/overpressure conditions. The dominant sequence is SEHCET-23 (4.2E-6/yr) with smaller contributions from other sequences. Thus, SEHCET-23 was chosen as the representative sequence.

Similar to the other SEH scenarios, a small break LOCA (1" diameter cold leg LOCA) was assumed as the initiator with no high pressure injection available. In this case, RHR and all containment heat removal are also unavailable. After vessel failure at 4.0 hours, all molten core debris is entrained to the upper compartment. The core debris that melts thereafter stays in the cavity. With no containment heat removal available and with no water addition to the debris in the upper compartment, the containment gradually pressurizes and heats up. Even though the actual failure may not occur until much later, containment failure was induced in MAAP at 40 hours to provide representative source term results. The calculated releases at 64 hours for this case (24 hours after containment failure) are presented in Table 4.7-2.

4.7.2.11 L-CC-L End State Discussion

This CET end state describes a low pressure vessel failure scenario with late containment failure principally due to basemat penetration from core concrete interaction. The only contributors to this end state are SELCET-11 and SELCET-12. SELCET-12 was chosen as the representative sequence since it does not have fan coolers available, and this would provide for the most limiting condition for source term results.

Thus, a large break LOCA (18" diameter) in the cold leg with no injection or containment heat removal was analyzed to provide representative source term results. In this large LOCA scenario, core damage and vessel failure are calculated to occur within one hour. Since the vessel fails at low pressure, all of the core debris remains in the cavity. Core-concrete attack initiates shortly thereafter, and even though the actual failure may not occur until later, containment failure was induced in MAAP at 40 hours to provide representative source term results. The calculated releases at 64 hours for this case (24 hours after containment failure) are presented in Table 4.7-2.

4.7.2.12 H-DH-L End State Discussion

This CET end state describes a high pressure vessel failure scenario with late containment failure assumed due to decay heat loading. The dominant sequence is SEHCET-21 (2.7E-6/yr), with contributions from BEHCET-21, and other sequences. SEHCET-21 was chosen as the representative sequence for analyzing source term results.

Again, a small break LOCA (1" diameter in the cold leg) was assumed as the initiator with no high pressure injection available. For this end state, two scenarios were analyzed to provide source term results. The first case assumed RHR injection initiated following vessel failure and continued in recirculation mode, but without a functional heat exchanger. The second case assumed RHR in recirculation mode was totally unavailable. The latter case proved to be most limiting since the pressurization of containment was greater in that case. Therefore, it was chosen to provide the representative source term results. Again, even though the actual failure may not occur until much later, containment failure was assumed to occur at 40 hours. The calculated releases at 64 hours are presented in Table 4.7-2.

4.7.2.13 L-DH-L End State Discussion

This CET end state describes a low pressure vessel failure scenario with late containment failure assumed due to decay heat loading. One of the dominant sequences is BLHCET-10, and it was chosen as the representative sequence.

A late SBO (i.e. TDAFW available for 2 hours) with an induced hot leg rupture during core degradation characterizes the representative sequence. RHR injection is assumed to be recovered at vessel failure, but no recirculation or containment heat removal is available. In this case, the steam generators are calculated to be dry shortly after 5 hours, and core uncovery occurs after 6 hours. Prior to 8 hours, core damage is calculated and an induced hot leg rupture is assumed to occur, depressurizing the vessel. Low pressure vessel failure is calculated at about 10 hours upon which RHR injection is assumed to recover. Recirculation is assumed to be unavailable after RWST depletion near 11 hours. Again, even though the actual failure may not occur until later, containment failure is assumed to occur at 40 hours to provide representative source term results. The calculated releases at 64 hours (24 hours after containment failure) are reported in Table 4.7-2.

4.7.2.14 SGTR End State Discussion

This end state represents a containment bypass scenario via a steam generator tube rupture (SGTR). The representative SGTR was chosen as a single tube rupture transient with a steam generator relief valve sticking open when water flows through the valve. AFW is terminated to the broken steam generator at 25 minutes. The relief valve is assumed to stick open when water is first calculated to flow through the valve at about 40 minutes. After RWST depletion (~6.5 hours), and with no AFW to the broken loop, the primary and broken loop secondary inventory eventually boils away. The broken loop steam generator is calculated to be dry at about 22 hours, and core uncovery occurs at about 23 hours. The majority of the fission product releases occur through the tube rupture and through the stuck steam generator relief valve during core degradation prior to vessel failure at about 26 hours. The calculated releases at 48 hours for this case are reported in Table 4.7-2.

4.7.2.15 L-SR-E End State Discussion

In cases where the reactor coolant pumps would be restarted by the operators with hot gases initially circulating through the tubes of dry steam generators, several steam generator tubes could fail due to creep rupture. This would result in a short-duration release because the steam generators wou'd be exposed to reactor pressure, causing relief valves to open. When the relief valves reseat, the release would be terminated. In some cases the relief valve(s) may not reseat, resulting in a continuing release.

Assuming that the relief valves do not reseat, this end state is very similar to the SGTR end state described above. Therefore, the SGTR end state is used to represent L-SR-E.

Note that the L-SR-E end state may be accompanied by another release at a later time if the vessel fails and radionuclides are released through some other containment failure mechanism. This possibility is ignored here, because the severity of the L-SR-E release would dominate any subsequent release.

4.7.2.16 BYPASS-ISLOCA End State Discussion

This end state represents a containment bypass scenario via an interfacing system LOCA (ISLOCA) outside of containment. The representative ISLOCA was chosen as a 10" RHR line break with no injection or containment heat removal available. AFW and accumulators are assumed to be available. In this case, core damage and vessel failure are predicted to occur within one hour. 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.

4.7.2.17. "Puff" Release End State Discussion

This event is the same as L-SR-E discussed in section 4.7.2.15, but in this case, the valve which opened to relieve the steam generators successfully recloses. This limits the release to a relatively short duration puff followed by a series of shorter puffs as the pressure in the steam generator with the failed tube oscillates about the relief valve setpoint. All releases are terminated upon vessel failure, when the primary (and therefore the steam generator with the ruptured tube) depressurizes to containment pressure. The calculated releases at 48 hours are presented in Table 4.7-2.

4.7.3 Representative Source Term Results

The results from the MAAP analysis for each of the relevant CET end states are shown in Table 4.7-2. The table shows the radionuclide release fraction for each of the twelve MAAP fission product groups and the sequence time at which the results are presented.

4.7.4 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%

For this report, NSP adopts this scheme and applies this categorization 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 CET end state are given in Table 4.7-3.

Examining the results in Table 4.7-3, the source term results 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 release magnitudes. These categories have been developed specifically in the Prairie Island analysis 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, and high non-volatile releases. Type V releases characterize the sequences with high noble and volatile releases, but with low 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 in the high, medium, and low or low-low release categorization were not prevalent for Prairie Island. 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 31.2% of all core damage sequences. Type II releases with high noble gas releases, but with low or low-low volatile and non-volatile releases are comprised of late containment failure sequences due to overpressure or decay heat loading or the SG Tube Creep Rupture "puff" release. These types of sequences represent 52.0% of all core damage sequences. High noble gas releases with medium volatile releases, but with low or low-low non-volatile releases (Type III) make up only 0.3% of the CDF. Six of the seven end-states in this category are early containment failures or containment isolation failures. The only late containment failure end state in this category is the L-CC-L end state which, with no injection available, fails containment due to core-concrete interactions in the cavity. A type IV release occurs for high pressure vessel failure scenarios with early containment failure and core-concrete interactions in the upper compartment. These releases make up 0.6% of the total CDF. A type V release is indicative of a SGTR scenario with bypass of containment through the tube rupture and through the secondary relief valve. High noble gas and volatile releases, but with low non-volatile releases characterize this category which represents 13.4% of the CDF. The last category (Type VI) represents a high release from containment of noble gases, volatile, and non-volatile fission products. This type of release is only representative of ISLOCA scenarios at Prairie Island which makes up only 0.5% of the overall core damage frequency.

Table 4.7-1
Summary of Fission Product Release
Characterization Representative Sequence Selection

CET End State[1]	% CDF[2]	Representative Sequence	Description
H-XX-X	18.0%	SEHCET-19	SBLOCA; no high pressure injection; AFW, ACCUM, containment spray, FCU, and RHR in recirc available. No containment failure.
L-XX-X	0.2%	-	Source term characterized by H-XX-X results
X-XX-X	13.0%	-	Source term characterized by H-XX-X results
H-H2-E	0.6%	SEHCET-25	SBLOCA; no high pressure injection; AFW, ACCUM, RHR, and RHR in recirc available; FCUs and CS unavailable. Containment failure assumed two seconds after vessel failure.
L-H2-E	<<0.1%	SLLCET-13	Medium LOCA; high and low pressure injection initially available, but not in recirc; AFW, ACCUM, and FCUs available. Containment failure assumed two seconds after vessel failure.
X-H2-E	0.2%	-	Source term characterized by L-H2-E results
H-CI-E	<<0.1%	-	Source term characterized by H-H2-E results
L-CI-E	<<0.1%	SLLCET-15	Medium LOCA; high and low pressure injection initially available, but not in recirc; AFW, ACCUM, and FCUs available. Containment isolation failure assumed at sequence initiation.
X-CI-E	<<0.1%	-	Source term characterized by L-CI-F results
H-OT-L	16.0%	SEHCET-23	SBLOCA; no injection or containment heat removal available; AFW and accumulators are assumed to be available. Containment failure assumed at 40 hours[3] on overpressure.

(Continued on next page)

[1] The CET end states are defined in section 4.6.1.

[2] Includes SG Tube Creep Rupture frequencies.

[3] Containment failure was assumed to occur at 40 hours in all source term cases where it did not fail earlier. This was done to save CPU time. Actual failure may be several days later. This issue was explored by sensitivity studies in section 4.8.2.6, which concluded that the source terms given by the 40 hour failure cases are good representations of what the actual source term would be later.

Table 4.7-1
Summary of Fission Product Release
Characterization Representative Sequence Selection
(Continued)

CET End State	% CDF[4]	Representative Sequence	Description
L-CC-L	0.1%	SELCET-12	Large LOCA; no injection or containment heat removal available; AFW and accumulators are assumed to be available. Containment failure assumed at 40 hours[5] due to core concrete interactions in cavity.
H-DH-L	6.0%	SEHCET-21	SBLOCA; no containment heat removal available; RHR injection following vessel depressurization, but fails in recirc; AFW and accumulators are assumed to be available. Containment failure assumed at 40 hours[3].
L-DH-L	<<0.1%	BLHCET-10	SBO; TDAFW for two hours; induced rupture of hot leg during core degradation; RHR injection available following vessel failure, but no recirc or containment heat removal available; accumulators are assumed to be available. Containment failure assumed at 40 hours[3].
SGTR	12.0%	GLH	SGTR; SG Relief Valve sticks open; AFW terminated to broken SG at 25 minutes; no injection after RWST depletion; accumulators and FCUs assumed to be available.
L-SR-E	1.6%	-	Source term characterized by SGTR results
ISLOCA	0.1%	ISLOCA	ISLOCA; no injection or containment heat removal available; AFW and accumulators are assumed to be available. Fission product releases bypass containment through LOCA; no credit taken for retention in auxiliary building.
"Puff"	30.0	-	Loss of feedwater; no auxiliary feedwater, injection, or containment sprays; fan cooler units and accumulators function normally; induced SGTR at 1200°F core temperature; relief valves on steam generator function normally.

[4] Includes SG Tube Creep Rupture frequencies.

[5] See Footnote 3 on preceding page.

Table 4.7-2
Representative Source Term Results

Calculated Source Terms from MAAP3.0B-PWR, Rev. 19.0													
CET End State	Radionuclide Release Fractions												End Time
	Noble Gases	CsI	TeO_2	SrO	MoO_2	CsOH	BaO	Lantha-nides	CeO_2	Sb	Te_2	UO_2	(hrs)
H-XX-X	1.03E-3	3.06E-6	0.00	1.57E-8	7.94E-7	3.16E-6	1.64E-7	7.14E-7	7.14E-7	2.67E-6	0.00	0.00	48.0
L-XX-X	(Represented by H-XX-X Results)												
X-XX-X	(Represented by H-XX-X Results)												
H-H2-E	0.729	0.019	6.38E-9	2.22E-3	6.98E-3	0.019	2.43E-3	3.43E-4	1.31E-3	0.061	0.311	1.98E-6	48.0
L-H2-E	0.751	0.023	0.00	1.89E-5	2.59E-4	0.023	1.50E-4	2.89E-7	1.40E-6	2.59E-3	1.38E-4	6.02E-9	48.0
X-H2-E	(Represented by L-H2-E Results)												
H-CI-E	(Represented by H-H2-E Results)												
L-CI-E	0.690	0.033	0.00	2.48E-5	7.17E-5	0.033	2.11E-4	0.012	0.012	3.64E-3	8.17E-5	3.77E-9	48.0
X-CI-E	(Represented by L-CI-E Results)												
H-OT-L	0.914	5.97E-4	0.00	3.34E-7	1.82E-5	7.87E-4	3.42E-6	4.28E-7	4.28E-7	1.35E-3	0.00	0.00	64.0
L-CC-L	0.996	4.19E-3	1.13E-5	4.87E-6	1.68E-7	0.011	4.05E-6	3.82E-6	6.65E-6	0.021	4.34E-3	2.21E-8	64.0
H-DH-L	0.961	5.85E-5	0.00	4.67E-7	2.13E-5	3.65E-5	4.86E-6	1.17E-6	1.17E-6	4.75E-4	0.00	0.00	64.0
L-DH-L	0.999	5.51E-5	2.2E-10	1.27E-8	3.52E-8	1.54E-4	1.44E-7	1.96E-5	1.96E-5	5.62E-5	3.37E-7	9.38E-14	64.0
SGTR	0.961	0.345	0.00	3.19E-4	1.90E-4	0.334	1.91E-3	6.16E-4	6.71E-4	0.067	2.27E-3	1.08E-7	48.0
L-SR-E	(Represented by SGTR results)												
ISLOCA	1.000	0.760	4.78E-6	0.025	7.80E-4	0.760	0.014	0.107	0.120	0.338	0.361	6.85E-5	48.0
"Puff"	0.158	4.81E-3	0.0	2.37E-6	5.38E-6	4.44E-3	1.31E-5	3.61E-8	3.77E-8	5.71E-4	0.0	0.0	64.0

Table 4.7-3
Source Term Magnitude and Timing Categorization

CET End State	% CDF[6]	Timing	Nobles	Volatiles	Non-Volatiles
H-XX-X	18.0%	-	L	LL	LL
L-XX-X[1]	0.2%	-	L	LL	LL
X-XX-X[1]	13.0%	-	L	LL	LL
H-H2-E	0.6%	E	H	M	H
L-H2-E	<<0.1%	E	H	M	LL
X-H2-E[2]	0.2%	E	H	M	LL
H-CI-E[3]	<<0.1%	E	H	M	H
L-CI-E	<<0.1%	E	H	M	LL
X-CI-E[4]	<<0.1%	E	H	M	LL
H-OT-L	16.0%	L	H	LL	LL
L-CC-L	0.1%	L	H	M	L
H-DH-L	6.0%	L	H	LL	LL
L-DH-L	<<0.1%	L	H	LL	LL
SGTR	12.0%	L	H	H	L
L-SR-E[5]	1.4%	E	H	H	L
ISLOCA	0.1%	E	H	H	H
"Puff"	30.0	E	H	L	LL

[1]Inferred from H-XX-X results
[2]Inferred from L-H2-E results
[3]Inferred from H-H2-E results
[4]Inferred from L-CI-E results
[5]Inferred from SGTR results
[6]Includes SG Tube Creep Rupture frequencies

Table 4.7-4
Summary Source Term Categorization

Category	Description	Relevant CET End States	Total % CDF
I	Releases limited to leakage	H-XX-X, L-XX-X, and X-XX-X	31.2% (60.2%)[1]
II	High Noble gas, low or low-low volatile and non-volatile releases	H-OT-L, H-DH-L, and L-DH-L, and "Puff" release	52.0% (22.0%)[1]
III	High Noble Gas, medium volatile, and low or low-low non-volatile releases	L-H2-E, X-H2-E, L-CI-E, X-CI-E, and L-CC-L	0.3%
IV	High noble gas, medium volatile, and high non-volatile	H-H2-E and H-CI-E	0.6%
V	High noble gas, high volatile, and low non-volatile releases	SGTR and L-SR-E	14.6% (13.2%)[1]
VI	High noble gas, volatile, and non-volatile releases	ISLOCA	0.5%

[1]Excluding SG Tube Creep Rupture contribution

4.8 Level 2 Sensitivity Studies

A number of assumptions made in the quantification of potential containment failure modes and the source term analysis may be important to the outcome of the Level 2 analysis. Two types of sensitivity studies were performed to determine the effects of key assumptions on the final results. The first of these sensitivity studies are probabilistic in nature and address uncertainties in the quantification of the various containment failure modes modeled in the containment event trees. The probabilistic sensitivity studies are described in Section 4.8.1. Deterministic analyses were also performed to establish the sensitivity of the Level 2 analysis to uncertainties in the physical modeling of containment response and the source term. The results of the deterministic analyses are presented in Section 4.8.2.

4.8.1 Probabilistic Sensitivities

Several key assumptions were made in the quantification of the containment event trees with respect to the response of the reactor and containment to the progression of a severe accident. These assumptions were summarized in Section 4.5 under the descriptions of the CET headings. The basis for a number of these assumptions were provided in Sections 4.1 through 4.5.

The following sensitivity studies were performed probabilistically to determine the impact of these assumptions on the distribution of various containment failure modes.

- Retention of the debris in the reactor vessel by submerging the lower vessel head.

- Depressurization of the reactor by hot leg creep rupture.

- Debris coolability in the reactor cavity.

- Cooling of the debris relocated to the upper parts of containment following a high pressure melt ejection.

Figure 4.8-1 is a pie chart summarizing the results of the Level 2 analysis from a containment failure mode perspective. The distribution of the Level 2 results among each of the CET end states is reproduced for each sensitivity study for comparison with this baseline.

The percentages given for the baseline containment failure modes in Figure 4.8-1 do not exactly match those given in Figure 4.6-1. This is due to requantification of the Level 2 analysis with new events included in order to perform the sensitivity studies. The differences between the sensitivity baseline percentages and those from the original Level 2 analysis do not significantly affect any of the results or insights gained from the sensitivity studies.

In-vessel recovery (vessel submergence)

Quantification of the effects of terminating the event within the reactor vessel by submerging the lower head was performed by modifying the success criteria for the IV heading of the containment event tree. The assumption was made in the Level 2 analysis that if the RWST had been injected successfully to the reactor or though containment sprays, decay heat could be removed from the debris in the vessel by a combination of radiation and heat transfer through the vessel wall. Penetration of the lower head of the vessel was assumed not to be likely in this condition. This means of debris cooling precludes a number of sequences from becoming high pressure melt ejection events and prevents the core from entering containment avoiding debris coolability considerations in the reactor cavity and upper compartment.

In this sensitivity study, submergence of the lower head is assumed not to be effective in cooling the debris and all core melt sequences are assumed to lead to lower head penetration.

Figure 4.8-2 provides the results of this sensitivity, which varies very little from the baseline quantification.

- A very minor increase in long term overpressure failure is noted. This is due to an increase in high pressure melt sequences which relocate debris to the upper compartment. In this location, fan coolers are assumed to be ineffective in cooling the debris and prevention of overpressure requires containment spray operation. The increase in HPME sequences is small reflecting the fact that the majority of sequences which are affected by the vessel submergence assumption are large and medium LOCAs that are already at low pressure at the time of vessel penetration (accident class SLL). Accident classes TLH and SLH which can lead to HPME are not significant contributors to core damage and the potential for depressurization of the reactor prior to vessel penetration by operator action or creep rupture of the hot leg is high.

- A very minor increase in early containment failure modes is also noted (labeled "Others" on Figures 4.8-1 and 4.8-2). This increase is also a result of additional HPME sequences that may lead to short term challenges to containment such as DCH. As noted in Section

4.4, the potential for a number of these early containment failure modes is small due to the configuration of the reactor cavity and strength of the containment. Combined with the low frequency of these additional sequences (classes TLH and SLH), the increase in potential for these early failure modes due to assumptions regarding cooling the debris through the lower vessel head is also small.

Hot Leg Creep Rupture

The depressurization heading of the CET (heading DEP) depends on a number of means of lowering reactor pressure following core damage. These include operator action to open the PORVs on the pressurizer and steam generators as required in the EOPs as well as by creep rupture of primary system components such as the hot legs. The assumptions made in quantification of the CETs were that events in which the lower head is not submerged proceeded relatively rapidly to lower head penetration and depressurization was not likely in this time frame. Depressurization during sequences in which the RWST had been injected to the containment were considered to be very likely to lead to depressurization of the vessel because lower head penetration would be delayed or precluded altogether by submergence and cooling of the vessel.

A sensitivity is performed on this assumption assuming that creep rupture of the hot leg does not occur and that all sequences that begin with core melt at high pressure remain pressurized.

The results of this sensitivity is shown in Figure 4.8-3. Once again, very little change from the baseline is noted.

- o A small increase in long term overpressure failure occurs. This is due to a small addition to the number of high pressure melt ejection sequences that occur relocating debris to upper compartments of the containment where fan coil units are assumed not to be effective in providing cooling for the debris. The majority of this minor increase is from accident classes TLH and SLH. The increase is small due to the majority of these sequences being terminated in the vessel by submergence of the lower head and the ability of the operator to depressurize the reactor through the operation of pressurizer PORVs in accordance with the EOPs.

- o Little or no change is noted in the early containment challenge contribution to the pie chart. It might be expected that since all high pressure core damage events are assumed to remain at elevated pressure, that the increase in HPME sequences would be noted by a rise in the frequency of containment failure due to challenges such as DCH. Once again, however, the majority of sequences affected by depressurization due to hot leg creep rupture also can be terminated before vessel penetration or successfully depressurized by operator action.

Section 4.8.2 contains a series of sensitivity studies that examine the potential for hot leg creep rupture. The majority of accident sequences, in fact, take much longer than 1/2 hour from the onset of core damage to lower head penetration. These analyses suggest that this sensitivity study as well as the baseline Level 2 quantification for Prairie Island are conservative with respect to the ability to depressurize the reactor and avoid an HPME event.

Debris Coolability

The reactor cavity at Prairie Island is large, providing a significant area over which the debris can spread, promoting debris cooling. If all of the fuel material, cladding, lower core plate and 10% of the lower head were to relocate to the reactor cavity, the debris depth is estimated to be on the order of 25 cm. The baseline analysis assumes that this debris depth is relatively small and can be cooled provided water is supplied to the debris before basemat penetration or overpressure failure due to noncondensible gases (event tree heading CPC).

In this sensitivity study, the debris cooling assumption is changed such that long term containment failure eventually occurs even if water is supplied to the debris. While this assumption may not be realistic for the amount of debris that actually would enter or remain in the reactor cavity for any of a number of accident sequences, the analysis addresses several potential sensitivities including the effects of concrete erosion on the thickness of the debris and the effectiveness of containment heat removal systems such as RHR and fan coil units given long term operation under severe accident conditions.

The results of this sensitivity are provided in Figure 4.8-4. Not unexpected is that long term containment failure becomes a large part of the diagram.

- o While labeled as failure due to noncondensibles or steam, the majority of the increase in this CET end state may be basemat penetration.

- o The portion of the diagram associated with an intact containment is largely made up of those sequences in which the event is terminated within the vessel by submerging the lower vessel head.

- o Source term effects are limited as the time to containment failure is on the order of days, there is ample time for settling of particulates before any releases, and the additional sequences which contribute to long term failure for the most part include those in which the RWST has been added to the containment and is overlying the debris in the reactor cavity.

The majority of the effects of his sensitivity study is to move accident sequences from Release Category I (leakage of mostly nobles) to Category II (nobles, low or low-low volatile and non-volatile releases). Releases occur on the order of days into the event allowing for accident management strategies not credited in the PRA to further minimize or preclude any releases.

The results of this sensitivity study do not suggest any changes to the plant design or procedures. Insights from this sensitivity suggest that submerging the vessel to prevent vessel penetration is appropriate and the best course of action is to provide water to the debris as currently required by the EOPs.

Debris Cooling in the Upper Compartment

The containment pressure control heading (CPC) of the containment event tree also considers the potential for cooling debris in areas of containment other than the reactor cavity. Scenarios in which core penetration of the lower head occurs with the reactor at high pressure are assumed to carry a portion of the debris out of the reactor cavity, through the instrument tunnel to the upper compartment. Deentrainment of the debris occurs at the exit of the instrument tunnel. It is assumed that debris located in this area cannot be cooled by water injected to the reactor cavity through the reactor or by condensation of steam from fan coil units. The success criteria for the CPC heading of the containment event tree assumes containment spray is required to cool any debris that has been relocated out of the reactor cavity to upper areas of containment.

It is possible that barriers to debris flowing from the instrument tunnel may also shield the debris from the containment sprays. In this analysis, a sensitivity of the effectiveness of containment spray in cooling the debris in the upper compartment is performed.

The results of this sensitivity are provided in Figure 4.8-5. The results are essentially the same as the preceding sensitivity study for debris coolability. The similarity between these two evaluations reflects the fact that the majority of core damage events are assumed to occur at high pressure and therefore will result in debris relocation to the upper compartment. Also similar to the debris cooling sensitivity, the timing of any releases is very late (on the order of several days) and the source term is low.

Insights from this sensitivity are that attempting to provide water to the debris by way of containment spray is the appropriate action and is already required by the EOPs. Even if some of the debris were not to be coolable, containment spray would scrub the containment atmosphere limiting the magnitude of any releases were they to occur.

4.8.2 Phenomenological Sensitivity Studies Using MAAP 3.0B

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 Prairie Island IPE, 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 [1], (2) the augmentations to these recommendations provided in the NRC sponsored MAAP 3.0B code evaluation [2], and (3) other specific areas deemed important for Prairie Island.

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 Prairie Island MAAP parameter file are also based on the recommendations provided in the EPRI Guidance Document [1]. 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 six 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)
- Containment failure mode

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 Prairie Island IPE were performed with the "blockage" model turned off as recommended in reference [1]. 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 Prairie Island generally support this conclusion as Table 4.8-1 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), and a separate SBO case used an increased value for the eutectic latent heat of fusion (LHEU=400 KJ/Kg) The activation of the blockage model resulted in 27% clad reacted, and the increased latent heat of fusion case resulted in 56% clad reacted. These can be considered as reasonable estimates for the lower and upper bounds of in-core hydrogen production, respectively. As can be seen in Table 4.8-1, 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 [3]. 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 [4]. These analyses did not consider tube temperatures resulting from the restart of the reactor coolant pumps after core uncovery which has been evaluated as a possibility for Prairie Island. 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, surge line, and steam generator tube temperatures have been considered for the core blockage model and the increased eutectic latent of fusion cases previously described. Another aspect deemed worthy of consideration in the EPRI MAAP Guidance Document [1] for this issue is whether or not pump suction loop seals are assumed to clear. Thus, another MAAP case 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 [2] recommends that this parameter be set to one in a high pressure station blackout sequence. This was done for Prairie Island in an additional MAAP case.

Figures 4.8-6, 4.8-7, and 4.8-8 show the hot leg, surge line, and steam generator tube temperatures, respectively for each of the relevant sensitivity cases. 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, as was previously indicated, steam generator tube temperatures are much lower than either the hot leg or surge line temperatures if restart of the reactor coolant pumps is not considered. Table 4.8-2 summarizes the predicted hot leg temperatures at vessel failure for each of the cases. In all but the pump suction loop seal clearing case, 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.

Additionally, 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 heat-up of the hot legs, which should lead to even higher hot leg temperatures.

Therefore, based on these results, similar calculations performed by EG&G [4], and separate analyses performed by FAI [5], it appears that hot leg rupture can be considered likely in SBO sequences at Prairie Island. However, there are other sequences in which the primary system could be at pressures sufficient to cause high pressure melt ejection (i.e. greater than 400 psi or so) but less than that which would result in induced rupture.

To investigate the uncertainty associated with the primary system pressure at vessel failure, as recommended in the Guidance Document, one additional small LOCA case was 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 a 1" diameter cold leg LOCA without injection for Prairie Island. The resulting primary system pressure shown in Figure 4.8-9 indicates repressurization to slightly above the steam generator relief valve setpoint. This repressurization is 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 source 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. This led to some material remaining in the vessel for the duration of the analysis in most cases. 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 [1] 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 [2] extended this recommendation to consider all representative sequences which predict vessel failure prior to containment failure.

For Prairie Island, sensitivity analyses were performed for a station blackout sequence and for a small break LOCA sequence in which all of the core material was allowed to leave the vessel after vessel failure. A sensitivity analysis was not performed for a large break LOCA case since the nominal large break LOCA results already predicted all core material to leave the vessel. Key results for these sensitivity analyses are shown in Table 4.8-3. It is interesting to note that the primary system gas temperature is reduced in both of the sensitivity cases at the expense of increasing the containment pressure. This occurs because more of the core material is in the cavity instead of in the vessel which allows the decay heat to go towards boiling water instead of heating the primary system heat sink structures. Because of the relatively small portion of the core debris which can differ between remaining in the vessel versus entering the cavity in these cases, however, there is only a minor impact on the ultimate fission product releases. The SBO sensitivity exhibits a general reduction in releases, but the SLOCA sensitivity results in a slight increase in the releases at 64 hours.

A more dramatic affect of the core debris remaining in the vessel can be seen by examining the full set of SBO long term sensitivity cases discussed thus far. Figure 4.8-10 shows the CsI releases for each of these cases, and it turns out that the CsI releases are almost directly proportional to the amount of core material that remains in the vessel. Table 4.8-4 summarizes the key results from these cases. Clearly, the larger the amount of core debris which remains in the vessel, the higher the resulting primary system gas and heat sink temperatures, and the larger the potential for revaporization to occur. Thus, if core debris remains in the vessel instead of dropping to the cavity, the pressurization threat to containment is smaller (see Table 4.8.3 results), but if containment failure does occur, the consequences may be greater if material remains in the vessel (see Table 4.8-4 results). Future accident management developments will need to take these uncertainties into account.

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 [1] 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 by a factor of ten (FVPREV=0.1 instead of 1.0). This could be done to mimic the suppression of revaporization that could occur if the chemical reactions had been modeled. This was done for Prairie Island in a MAAP case, and key results from this sensitivity analyses are presented in Table 4.8-5. As can be seen, this case did not lead to significant differences in the results compared to the base case analysis.

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 Prairie Island, 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 refueling pool. For reference, if one assumes that all of the core debris is spread uniformly over the cavity floor (~27m^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 490 kw/m^2; this neglects any heat load from chemical reactions which would eventually cease. If the debris is dispersed over the refueling pool floor (~118m^2), the required heat flux is about 112 kw/m^2.

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 Prairie Island, 100% of the core material (~60,000 kg) at a theoretical density of 8,000 kg/m^3 would result in a debris bed thickness of just over 25 cm if all of the debris is in the cavity. Much smaller debris depths can then be expected for debris expelled to the refueling pool. Thus, debris coolability of debris transported to the refueling pool and thence covered by water is not of concern (which would only be the case if containment sprays were operational). 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 490 kw/m^2 required to cool debris in the cavity) such that debris coolability should also be assured in the cavity. In any event, a sensitivity case was run for a low pressure vessel failure scenario with a reduced heat flux multiplier model parameter.

In the sensitivity case, 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 [1], 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. However, with water continually in the cavity, even without containment heat removal in this case, the core-concrete interactions terminate at about 20 hours into the sequence after only about 0.7' of concrete attack occurred. Key results for this case compared to the base case are presented in Table 4.8-6. Since concrete attack eventually ceases even in the sensitivity case and containment failure is assumed to occur late in both cases, there is not a significant difference in the results other than slightly different containment pressures and the amount of concrete attack.

Separate sensitivity cases were considered for high pressure failure scenarios in which the core debris is expelled to the upper compartment and containment sprays are unavailable. The base analyses assumed that the debris was spread over the entire refueling pool area, and with the small heat flux required to cool debris in these cases, concrete attack was not predicted even without containment sprays operational. To explore the uncertainty associated with this large debris spread assumption, both an early and a late containment failure case were rerun with the refueling pool area reduced by slightly more than a factor of two to 600 ft^2 (55.7 m^2). The key results from this uncertainty analysis are shown in Table 4.8.7. The late containment failure case did result in slightly larger non-volatile releases, but not in a manner significant enough to change the source term characterization. Even with a continued source of fission products from the core-concrete interaction, the late failure time ensures ample opportunity for the majority of the fission products to settle prior to releasing from containment. However, the early containment failure case does result in substantially larger releases of non-volatiles compared to the base case. Thus, the representative source term results in Section 4.7 for high pressure vessel failure-early containment failure end states have been adjusted to take this uncertainty into account.

4.8.2.5 Energetic Events in Containment

Direct containment heating (DCH) is the first issue that falls into this category. 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 Prairie Island, one high pressure melt scenario with about 75% of the initial core material entrained to the upper compartment was rerun with an upper range value of FCMDCH=1.0 and with hydrogen burns forced to occur coincident with DCH. The sensitivity case resulted in a peak containment pressure of 125.9 psia after vessel failure. The nominal high pressure vessel failure cases with the default value of FCMDCH and without forcing burns to occur resulted in a peak containment pressures after vessel failure of less than 50 psia. Given the best estimate median containment failure pressure of 165 psia, these results are consistent with the discussion in Section 4.4.3 that concludes that containment failure by DCH for Prairie Island is unlikely.

Hydrogen burning is the other issue which falls into this category. In Section 4.4.3, it states that 100% zirconium oxidation and pre-burn conditions of a station blackout prior to vessel failure may result in a post-burn containment pressure of 95 psia. This pressure rise was calculated by performing an adiabatic isochoric complete combustion (AICC) analysis. Since the pressure is well below the ultimate containment failure pressure of 165 psia, it was concluded that hydrogen combustion has a low potential for early containment failure at Prairie Island. However, the potential for late containment failure by hydrogen combustion must also be addressed for scenarios in which additional hydrogen generation occurs due to core-concrete interactions. MAAP analysis with power recovery assumed at 24 hours were performed to investigate this phenomena.

The base case was chosen as a large break LOCA with no injection or containment heat removal available. This allowed all of the core debris to enter the cavity which maximized the potential for concrete attack and the resulting hydrogen generation. In the base case, about 267 lb of hydrogen was consumed due to jet burning by hot gases in the cavity. This tended to limit the long term buildup of hydrogen throughout containment. In the sensitivity case, jet burning was disabled, and by 24 hours, about 1300 lb of total hydrogen had been generated and distributed throughout containment. Restart cases were then set up which assumed that the containment sprays and fan coolers were recovered at 24 hours. The sprays were assumed to terminate prior to the burns occurring, and variations were made in the MAAP flame flux multiplier model parameter (FLPHI) as was recommended in the BNL/NRC report [2]. Key results from these cases are shown in Table 4.8-8. As can be seen, variations in the flame flux multiplier have little effect on the results with an almost complete hydrogen burn occurring in all three cases. Additionally, the maximum peak containment pressure of 112.1 psia is still well below the containment failure pressure of 165 psia.

4.8.2.6 Containment Failure Mode

The mode of containment failure (i.e. the location, timing, and size of failure) is one of the primary influences in analyzing severe accident progression and radionuclide releases. The structural analysis performed for the Prairie Island containment resulted in a median failure pressure of 165 psia as described in Section 4.4.1. This is conservatively assumed to occur in the mid-height region of the cylindrical steel shell such that no benefit of scrubbing is credited which may occur in other failure locations. Thus, sensitivity studies on the location of failure were not deemed necessary. However, uncertainty analyses for the timing and size of failure were performed and these are described below.

The MAAP source term runs reported in Section 4.7 assumed that a containment failure of 1.0 ft^2 occurred early (by sequence definition) or at 40 hours (for late containment failure cases) even though the calculated pressure had not yet reached 165 psia. To examine the effects of this latter assumption, two cases were rerun (one with all core material expelled from the vessel and one with material retained in-vessel) in which the containment failure was delayed until 165 psia was reached in containment. Key results from this uncertainty analysis are presented in Table 4.8-9. Since significant differences did not occur in the fission product releases for these cases (even with core material left in the vessel), it is judged that the 40 hour containment failure time assumption was conservative and adequate to provide representative source term results.

As stated previously, the representative source term analyses assumed a 1.0 ft^2 containment failure area. To investigate the uncertainty to this assumption, both an early and a late containment failure case were rerun with a leak-before-break type of failure area equal to 0.05 ft^2. The key results for this uncertainty analysis are reported in Table 4.8-10. Again, the sensitivity cases resulted in similar but generally smaller fission product releases. Thus, it is judged that the assumed size of containment failure was also adequate to provide representative source term results.

REFERENCES

[1] M.A. Kenton and J.R. Gabor, "Recommended Sensitivity Analyses for an Individual Plant Examination Using MAAP3.0B," EPRI TR-100167 to be published.

[2] J.U. Valente and J.W. Yang, "MAAP3.0B Code Evaluation Final Report," Brookhaven National Laboratory, FIN L-1499, October 1992.

[3] W.A. Stewart et. al., "Experiments in Natural Circulation Flows in Steam Generators During Severe Accidents," Proceedings: International ANS/ENS Topical Meeting on Thermal Reactor Safety, San Diego, February 2-6, 1986.

[4] P.D. Bayless, "Analyses of Natural Circulation During a Surry Station Blackout Using SCDAP/RELAP5," NUREG/CR-5214, EGG-2547, October 1988.

[5] Burelbach letter to R. Rohrer and attached FAI document December 22, 1993.

Table 4.8-1

In-Core Oxidation: Base MAAP Results for Prairie Island and Surry Results from NUREG-1150

Case Description	Percent Clad Reacted	
	P.I. (MAAP)	Surry (NUREG-1150)
Base case station blackout (SBO)	51%	44%
SBO with a large induced rupture of the hot leg	44%	50%
Small LOCA with failure of injection	45%	48%

Table 4.8-2

Summary of Predicted Hot Leg Temperatures in Station Blackout Sensitivity Cases

Case Description	Time of Vessel Failure (Hrs)	Peak Hot Leg Temperature Prior to Vessel Failure
Base case station blackout (SBO)	4.30	1713°F
SBO with core blockage model activated (FCRBLK=1)	4.46	1396°F
SBO with increased eutectic latent heat (LHEU=400kJ/kg)	4.23	1816°F
SBO with pump suction loop seals clear	5.90	993°F
SBO with through core baffle annulus circulation (FNCBP=1)	4.50	1907°F

Table 4.8-3

Key Results for Core Drop Fraction Sensitivity Cases

Case Description	Core Debris Distribution (Lb)			At 40 Hours (time of CF)		FP Releases at 64 Hours					
	In Vessel	In Cavity	In Upper Comp.	Primary System Gas Temp	Containment Pressure	Nobles	CsI	CsOH	MoO_2	Sb	Te_2
Base case station blackout (SBO-FCRDR=0.1)	2.8E4	0.4E4	11.1E4	817°F	61.1 psia	0.939	1.36E-3	1.61E-3	7.55E-7	9.27E-4	0.00
SBO-FCRDR=0.8	0.0E0	3.4E4	11.1E4	587°F	86.6 psia	0.954	2.82E-4	4.04E-4	2.22E-7	6.82E-4	0.00
SLOCA with RHR after VF, but no recirc or CHR (FCRDR=0.1)	3.3E4	1.3E4	9.6E4	626°F	72.1 psia	0.961	5.85E-5	3.65E-5	2.13E-5	4.75E-4	0.00
SLOCA with RHR after VF, but no recirc or CHR (FCRDR=0.8)	0.0E0	4.9E4	9.6E4	472°F	82.1 psia	0.992	7.20E-5	1.27E-4	2.05E-5	8.27E-4	0.00

Table 4.8-4

Key Results of SBO Sensitivity Cases

Case Description	Core Debris Left in Vessel	Primary System Gas Temp		FP Releases at 64 Hours		
		at 40 Hours	at 64 Hours	Nobles	CsI	CsOH
SBO - Seals Clear	6.0E4 lb	1273°F	1522°F	0.867	4.31E-3	5.31E-3
Base case station blackout (SBO)	2.8E4 lb	817°F	961°F	0.939	1.36E-3	1.61E-3
SBO-FCRDR = 0.8	0.0E0 lb	587°F	715°F	0.954	2.82E-4	4.04E-4
SBO-FNCBP = 1.0	0.0E0 lb	573°F	670°F	0.958	1.62E-4	1.00E-4

Table 4.8-5

Radionuclide Release Fractions for
Vapor Pressure Multiplier Sensitivity Analyses

Case Description	Radionuclide Release Fractions at 64.0 Hours						
	Nobles	CsI	MoO_2	CsOH	BaO	Sb	Te_2
Base case station blackout (SBO-FVPREV = 1.0)	0.939	1.36E-3	7.55E-7	1.61E-3	9.41E-8	9.27E-4	0.00
(SBO-FVPREV = 0.1)	0.934	1.01E-3	4.94E-7	5.12E-5	7.14E-8	8.40E-4	0.00

Table 4.8-6

Key Results for the Core Debris to Overlying
Water Pool Heat Flux Multiplier Sensitivity Analysis

Case Description	Cavity Concrete Attack Depth	At 40 Hours (Time of CF)		Fission Product at 64 Hours					
		Primary System Gas Temp	Containment Pressure	Nobles	CsI	CsOH	MoO_2	Sb	Te_2
Late SBO w/induced hot leg rupture; all core debris in cavity (FCHF=0.10)	0.03 ft	490°F	97.3 psia	0.999	5.51E-5	1.54E-4	3.52E-8	5.62E-5	3.37E-7
Late SBO w/induced hot leg rupture; all core debris in cavity (FCHF=0.02)	0.67 ft	504°F	101.8 psia	1.000	4.95E-5	1.42E-4	3.13E-8	6.20E-5	3.44E-6

Table 4.8-7

Key Results for Reduced Refueling Pool Area Sensitivity Cases

Case Description	Refueling Pool Concrete Attack Depth	Fission Product Release at End of Run				Fission Product Release Characterization*				
		Nobles	CsI	CsOH	Te_2	Timing	Nobles	Volatiles	Non-Volatiles	Category
Early high pressure vessel failure; late containment failure; ARP = 1273.4 ft^2	0.00 ft	0.934	1.09E-3	1.23E-3	0.0	L	H	< 1E-2 (L)	< 1E-3 (LL)	Type II
Same; ARP = 600 ft^2	4.33 ft	9.924	9.94E-4	1.38E-3	3.36E-3	L	H	< 1E-2 (L)	< 1E-2 (L)	Type II
Early high pressure vessel failure; early containment failure; ARP = 1273.4 ft^2	0.00 ft	0.665	0.018	0.018	0.00	E	H	< 1E-1 (M)	< 1E-2 (L)	Type III
Same; ARP = 600 ft^2	3.54 ft	0.729	0.019	0.019	0.311	E	H	< 1E-1 (M)	> 1E-1(H)	Type IV

*Based on scheme adopted by NSP for Prairie Island as described in Section 4.7

Table 4.8-8

Summary of Late Power Recovery Sensitivity Cases

Flame flux Multiplier (FLPHI)	Time Burns are initiated	Total Duration of Burns	Amount of H_2 Burned	Peak Containment Pressure/ Temperature
10.0	30.7 hrs	17.7 sec	1260 lb	112.1 psia/ 1801°F
12.0	30.7 hrs	17.8 sec	1270 lb	II2.1 psia/ 1805°F
3.0	30.7 hrs	21.6 sec	1265 lb	111.2 psia/ 1768°F

Table 4.8-9
Containment Failure Timing Uncertainty Analysis

Description	Core Material Left In-Vessel	Containment Failure			Fission Product Release Characterization*				End of Run
		Time	Pressure	Temperature	Nobles	Volatiles	Non-Volatiles	Category	
SBLOCA; No high pressure injection or containment heat removal	No	40.0 hrs	82.1 psia	495°F	0.992 (H)	<<1E-3 (LL)	<<1E-3 (LL)	Type II	64.0 hrs
Same	No	101.7 hrs	165.0 psia	439°F	0.999 (H)	<<1E-3 (LL)	<<1E-3 (LL)	Type II	125.7 hrs
SBLOCA; No high pressure injection or containment heat removal	Yes	40.0 hrs	72.6 psia	485°F	0.961 (H)	<<1E-3 (LL)	<<1E-3 (LL)	Type II	64.0 hrs
Same	Yes	150.8 hrs	165.0 psia	566°F	0.985 (H)	<<1E-3 (LL)	<<1E-3 (LL)	Type II	168.0 hrs

*As adopted by NSP for Prairie Island and described in Section 4.7

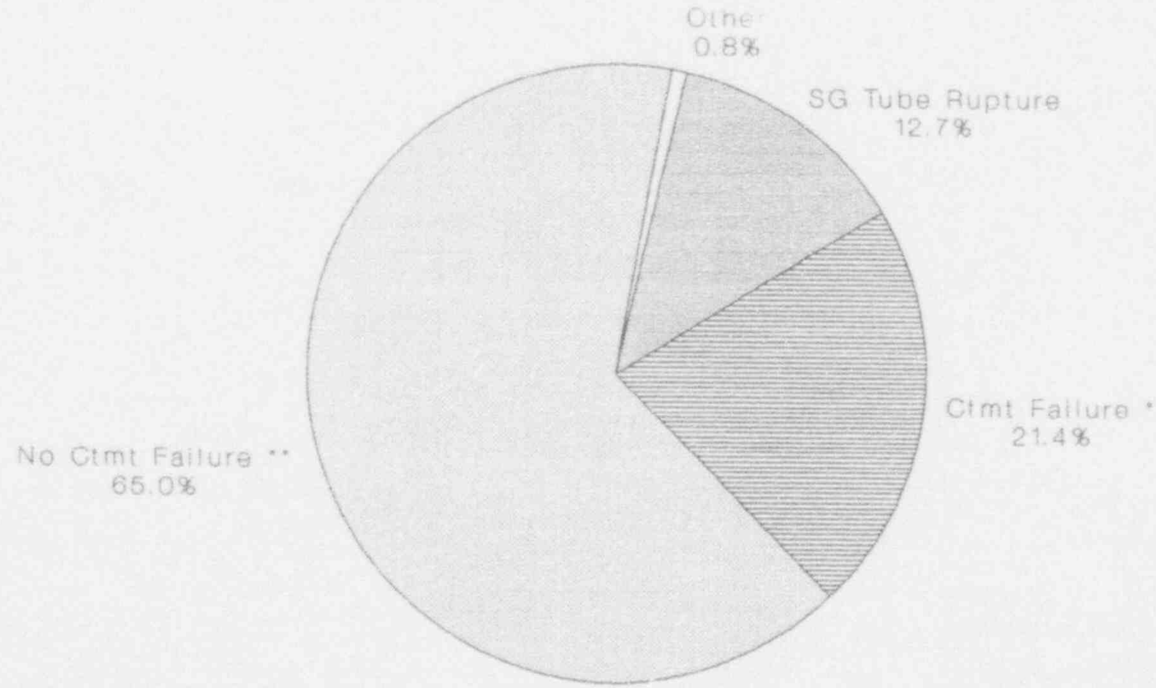
Table 4.8-10

Containment Failure Size Uncertainty Analysis

Description	Core Material Left In-Vessel	Containment Failure			Fission Product Release Characterization*				End of Run
		Time	Pressure	Size	Nobles	Volatiles	Non-Volatiles	Category	
SBLOCA; No high pressure injection; early containment failure assumed	Yes	3.99 hrs	42.2 psia	1.0 ft^2	0.665 (H)	<1E-1 (M)	<1E-2 (L)	Type III	48.0 hrs
Same	Yes	3.99 hrs	42.2 psia	0.05 ft^2	0.630 (H)	<1E-2 (L)	<1E-2 (L)	Type II	48.0 hrs
SBLOCA; No injection or contair ment heat removal; late containment failure	Yes	40.0 hrs	61.5 psia	1.0 ft^2	0.914 (H)	<1E-3 (LL)	<1E-3 (LL)	Type II	64.0 hrs
Same	Yes	40.0 hrs	61.5 psia	0.05 ft^2	0.870 (H)	<1E-3 (LL)	<1E-3 (LL)	Type II	64.0 hrs

*As adopted by NSP for Prairie Island and described in Section 4.7

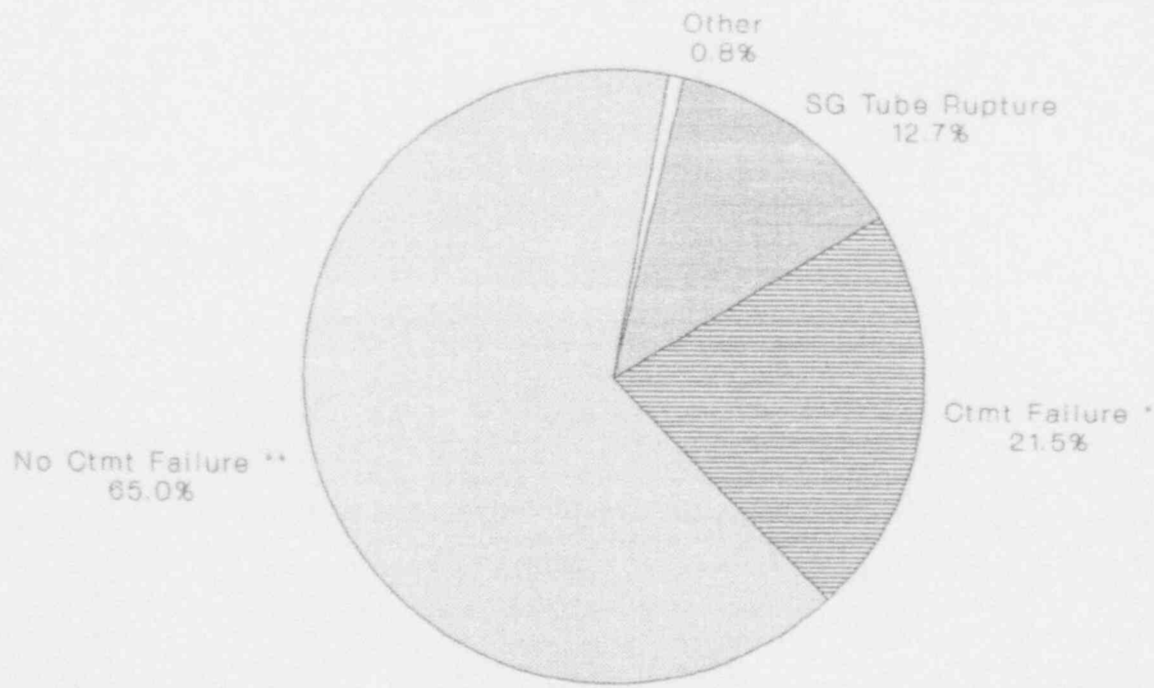
PI Level 2 PRA Sensitivity Analysis
Base Line



* (Non Condensibles and Steam)
** (Leakage Only)

Figure 4.8-1

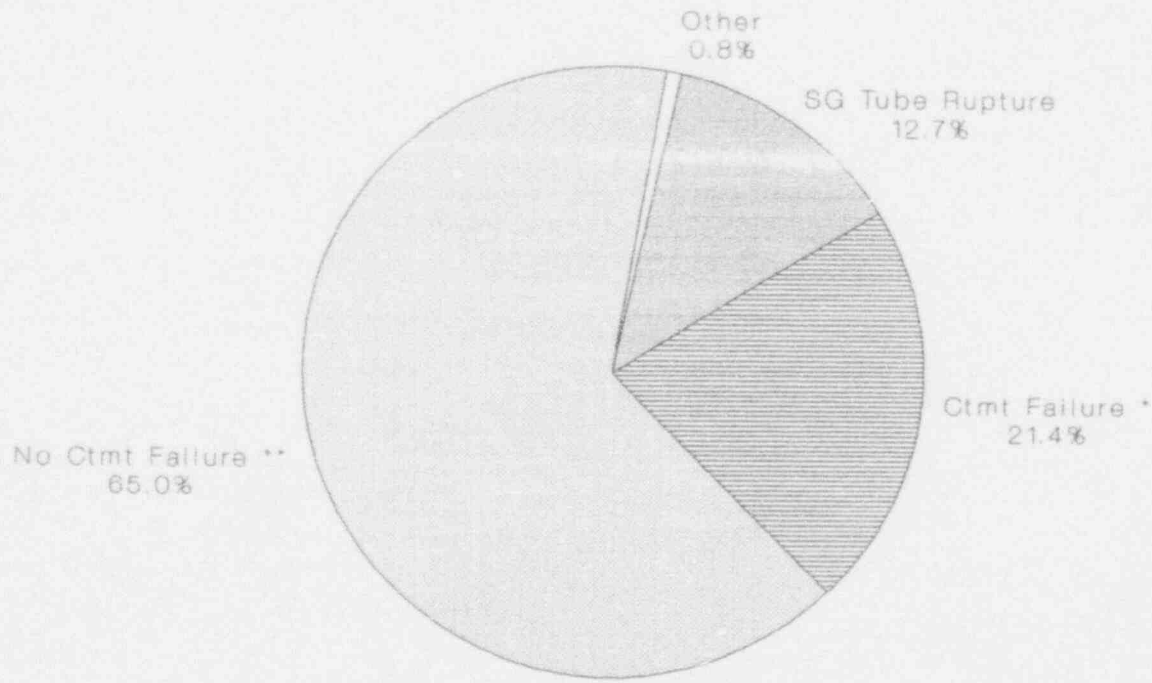
PI Level 2 PRA Sensitivity Analysis
In Vessel Recovery Failure



* (Non Condensibles and Steam)
** (Leakage Only)

Figure 4.8-2

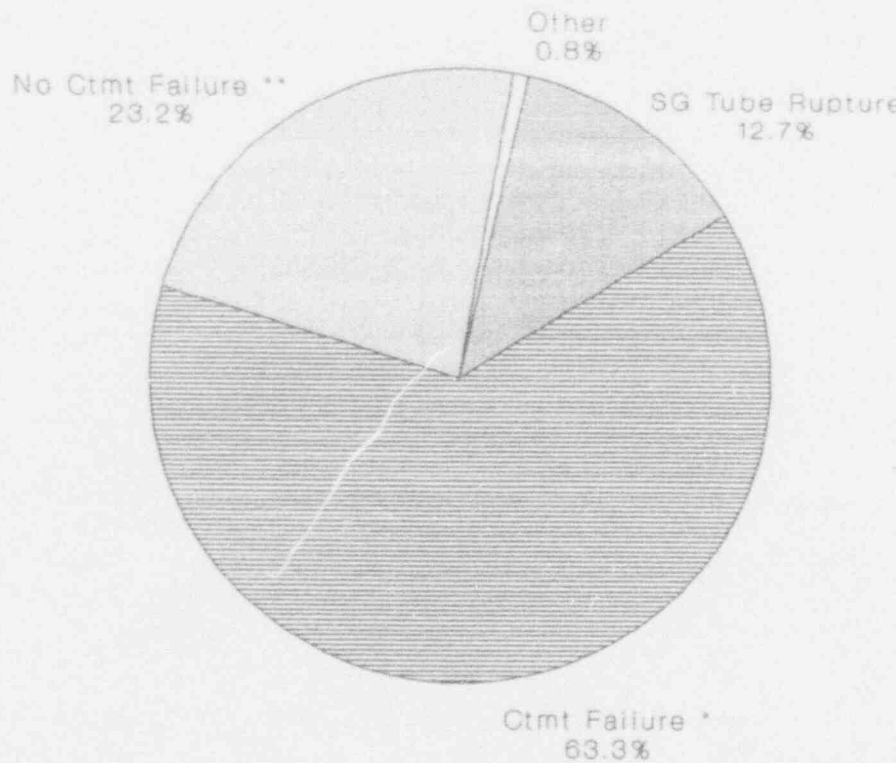
PI Level 2 PRA Sensitivity Analysis
Hot Leg Creep Rupture Failure



* (Non Condensibles and Steam)
** (Leakage Only)

Figure 4.8-3

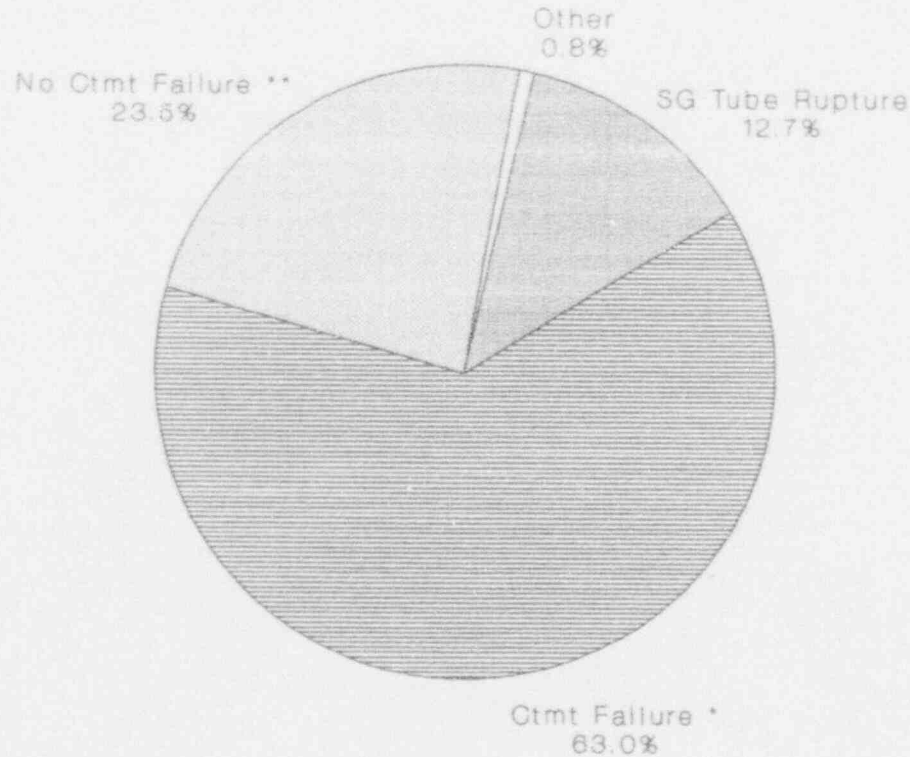
PI Level 2 PRA Sensitivity Analysis
Debris Cooling Failure



* (Non Condensibles and Steam)
** (Leakage Only)

Figure 4.8-4

PI Level 2 PRA Sensitivity Analysis
Debris Cooling in Upper Compt Failure



* (Non Condensibles and Steam)
** (Leakage Only)

Figure 4.8-5

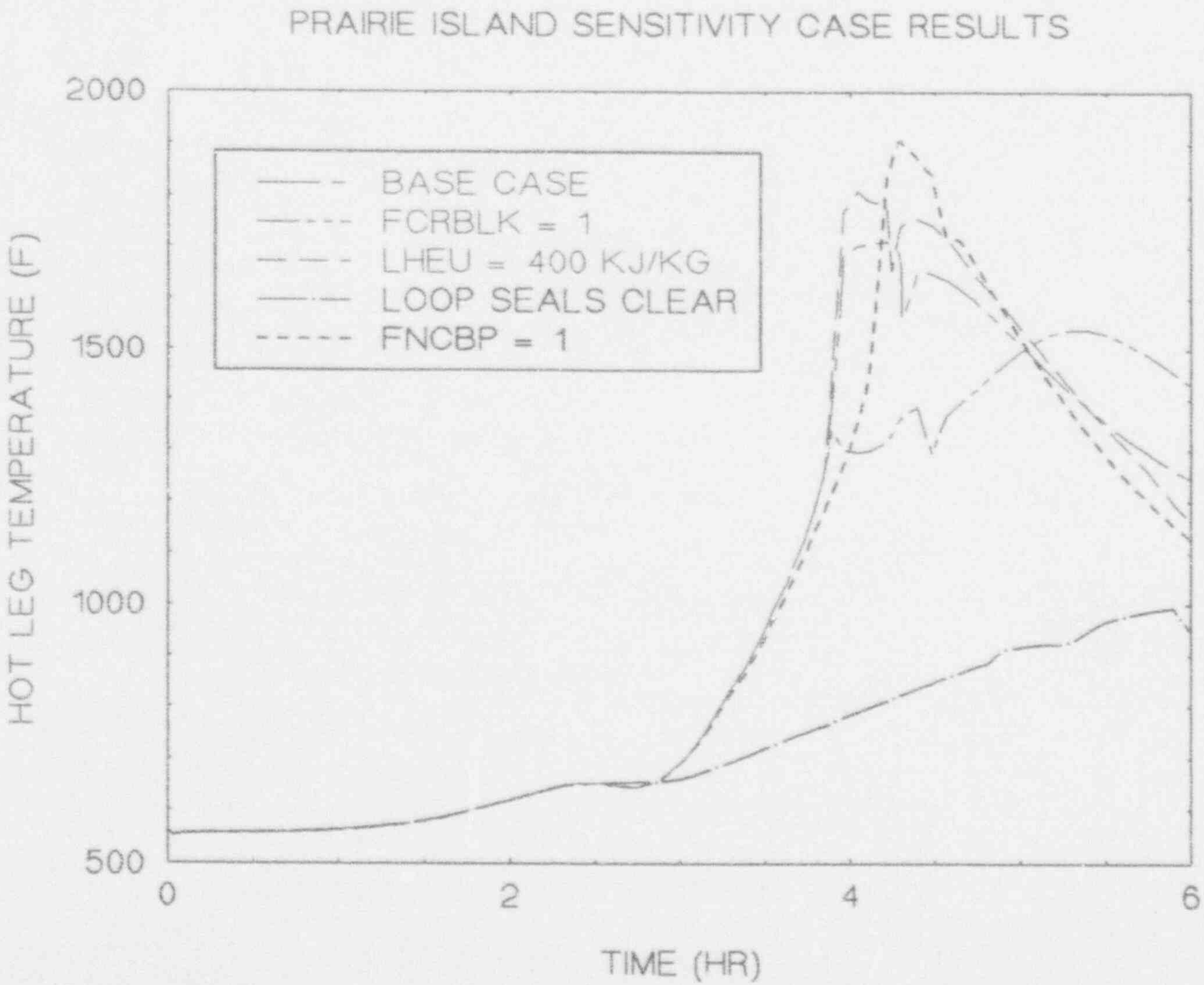


Figure 4.8-6: Predicted Hot Leg Temperatures for Various High Pressure Sensitivity Cases

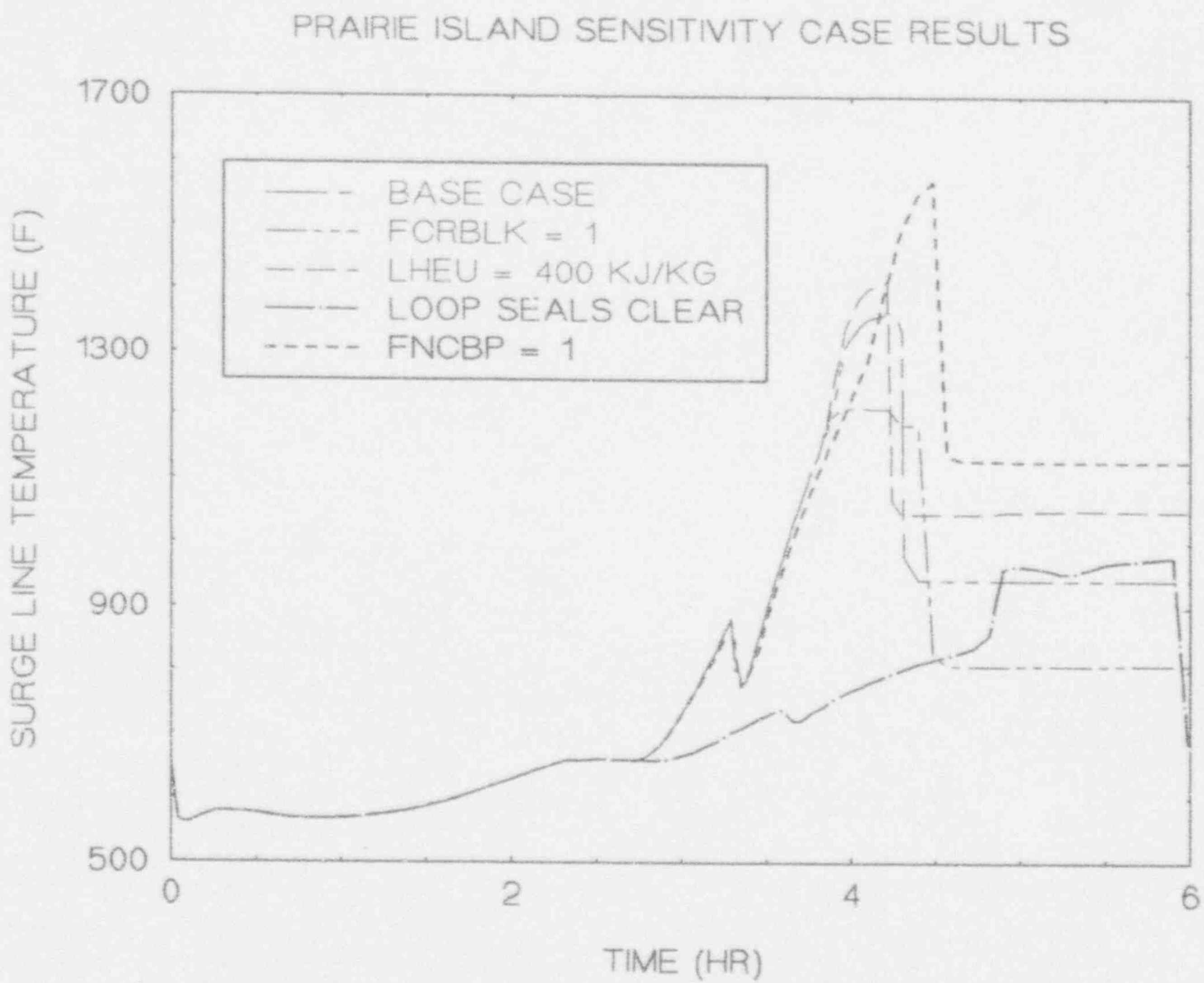


Figure 4.8-7: Predicted Surge Line Temperatures for Various High Pressure Sensitivity Cases

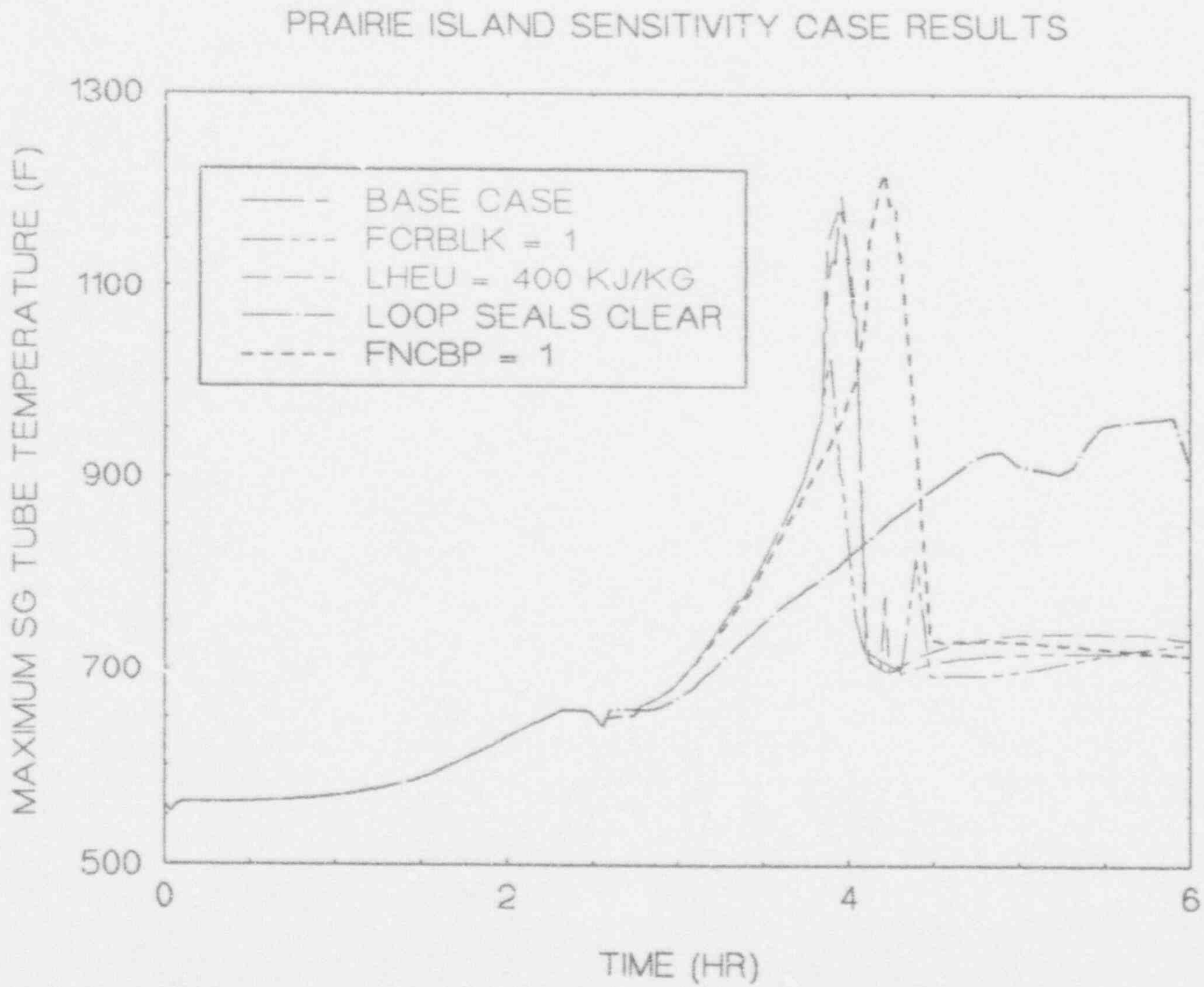


Figure 4.8-8: Predicted Maximum Steam Generator Tube Temperatures for Various High Pressure Sensitivity Cases

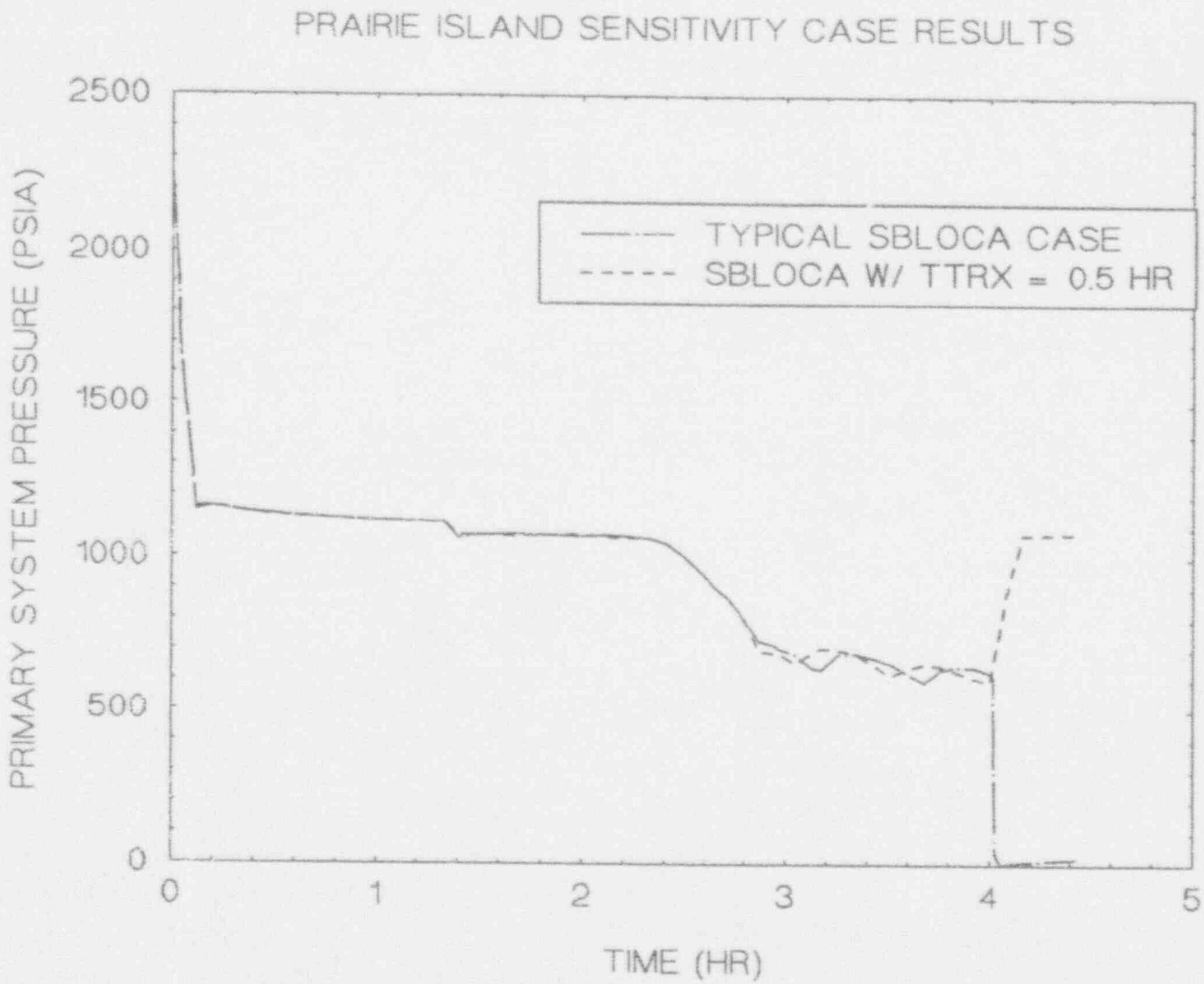


Figure 4.8-9: Predicted Primary System Pressures with One Minute and 30 Minutes to Vessel Failure after Core Plate Failure

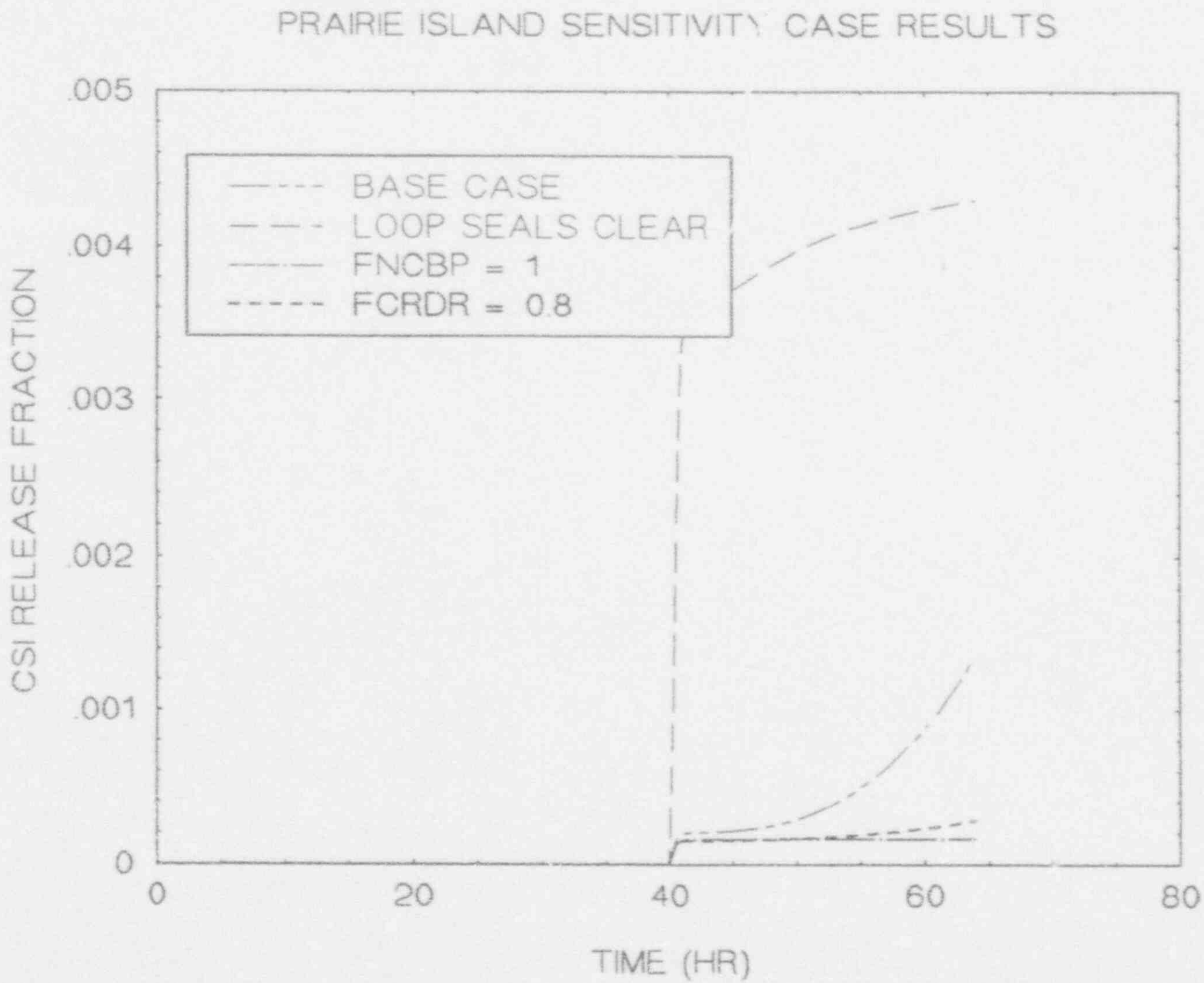


Figure 4.8-10: Predicted CsI Release Fractions for Various Station Blackout-Like, Late Containment Failure Cases

5. UTILITY PARTICIPATION AND INTERNAL REVIEW TEAM

5.1 IPE Program Organization

The NSP Director of Licensing and Management Issues has the overall review and approval responsibility. The members of the NSP PRA Self Managed Work Team (SMWT) report to the Director of Licensing and Management Issues and, as a team act as the NSP PRA/IPE program manager. The NSP PRA SMWT is responsible for the details and overall project management for all PRA and IPE analysis at NSP. The NSP PRA staff working on the Prairie Island PRA/IPE was made up of five engineers and one engineer associate. Two members of the PRA staff are located at the Prairie Island site and the rest at the General Office. Having PRA staff at the site makes it easier to interface with the plant staff and to conduct walkdowns to ensure the PRA represents the as built plant. Having PRA staff at the General Office makes it easier to interface with the other analysis groups, interface with management, and use the PRA staff for both Monticello and Prairie Island. The experience and training of the NSP PRA staff includes the following:

1. Two individuals maintain SRO certification at Prairie Island. One of the SRO certified individuals previously held an SRO license at Prairie Island.

2. An average of 12 years experience in the nuclear field, with the maximum having 14 years and the minimum having 9 years.

3. All of the NSP PRA staff engineers are degreed engineers, which includes B. S. in Nuclear Engineering, M. S. in Nuclear Engineering, and B. S. in Chemical Engineering.

4. There is also experience in the following related areas: Core transient analysis, operations, system engineering, plant technical staff, nuclear Navy and reactor physics.

5. Active involvement in industry committees and meetings; (1) On the steering committee and past chairperson of the MAAP users group; (2) On the WOG Severe Accident Working Group; (3) On the review team for the accident management Technical Bases Report.

6. Other activities include, being on the plant integrated planning committee, five ANS papers, one ASME paper, and one ENS paper.

TENERA, Westinghouse Electric Corporation and Fauske & Associates Inc., which are part of IPEP (Individual Plant Evaluation Partnership), were used to help NSP develop the PRA/IPE. Gabor, Kenton & Associates (GKA) also provided consulting services. The IPEP program manager, from TENERA, reported directly to the NSP PRA SMWT and provided NSP with a single point of contact for all IPEP activities.

The NSP PRA staff was involved with all aspects of the IPE. To ensure a complete understanding and to ensure the level 1 and 2 are properly integrated the same NSP PRA staff worked on both parts of the analysis. There was complete transfer of the technology to NSP including the use of the PRA computer codes, level 1 methodology, and level 2 methodology.

5.2 Composition of Independent Review Team

There are four levels of review being done to ensure the correctness and that the NSP personnel are cognizant of the PRA/IPE.

The first review is the verification of the calculations to ensure the traceability of the input, correctness of the calculation, assumptions used, and that the results are correct. This was an independent review done by someone other than the preparer. Most of the calculations were prepared and verified by the NSP PRA staff with only a few calculations either prepared or verified by IPEP. In no case was a calculation both prepared and verified by IPEP. This was done to ensure a complete transfer of technology to the NSP PRA staff.

The second review is the review of other analyses performed in the industry. The IPE reports submitted to the NRC for the Kewaunee and Point Beach plants were reviewed because the two plants are also two loop Westinghouse plants with large dry containments. NUREG-1150 and 4550 were also reviewed for information specifically pertaining to Surry, since this plant most closely resembles Prairie Island.

The third review is the review by the Senior Review Team (SRT). This is a team of four industry experts which reviewed the PRA/IPE to ensure correctness of the methodology and that the results are consistent with other PRA's in the industry. The team is made up of the following:

- Vice President, Nuclear Systems Group, Fauske & Associates, Inc., responsible for severe accident Level 2 analysis in support of a number of industry IPEs in response to the Generic Letter in addition to performance of severe accident research for LWR and ALWR designs.

- President, Gabor, Kenton & Associates, Inc., responsible for managing PWR IPE activities at GKA, contributor to a number of industry IPEs in response to the Generic Letter, developed severe accident models and performed analyses in support of ALWR certification process, while with FAI responsible for architecture of MAAP code and development of PWR version.

- Manager, PRA Risk and Reliability Organization, Westinghouse Electric Corporation, responsible for development and application of PRA methodologies, principal contributor to the development of a number of industry IPEs in response to the Generic Letter, contributor to the development of the PWR IPEM for IDCOR.

- Vice President, TENERA L.P., responsible for oversight and review of a number of industry PRAs in response to the Generic Letter, former utility Chief Nuclear Engineer responsible for the management of engineering organizations including those responsible for the development and application of PRA, utility representative for IDCOR.

The fourth review is the independent in-house review done by NSP personnel other than those on the NSP PRA staff. This is made up of NSP personnel not involved in the development of the PRA.

NSP plans to have a living PRA program to support the Prairie Island licensing, training, engineering and operations. The PRA assumptions and models will be updated periodically to ensure the models reflect the current plant status. The NSP PRA staff is part of the modification process to ensure changes to the plant which could affect the PRA results are reviewed, and is on the integrated planning committee to help management determine the priority of proposed modifications.

The NSP PRA staff has already been involved with a significant number of support activities. Table 5-1 list some of those activities.

TABLE 5.1-1

PRAIRIE ISLAND PRA APPLICATIONS

PI AFW Reliability Study

PI AFW system cooling water pipe plugging by clams

PI AFW strainer & flush valve analysis

Safety Injection System component importance rankings

Risk based allowable outage times for emergency diesel generators

Using risk based approach to support D5, D6 tech spec submittal

Study to support D5, D6 license submittal

Spent fuel steaming quantification

Unit 1 outage risk model quantification

Unit 2 outage risk model quantification

Dual unit shutdown risk

Unit 1 shutdown electrical model

Unit 2 shutdown model quantification with reactor head on

Diesel Comparison operating vs shutdown

Safety Evaluation for changing normal position of Low Pressure injection motor valves

Safeguards chilled water system seismic risk analysis

Fault tree analysis to assist in root cause investigation of several late 1989 reactor trips involving Rod Control System failures

6.0 PRAIRIE ISLAND IPE INSIGHTS AND RECOMMENDATIONS

6.1 Introduction

The purpose of this section is to present insights resulting from the IPE analysis. An insight is defined as a unique design feature or operator action which drives risk either positively or negatively. Changes to plant design or operating procedures which may significantly lower risk are considered insights as well.

This section defines those unique safety features at Prairie Island which are believed to impact risk from a severe accident. The following sections are broken down by damage classes, miscellaneous considerations and containment performance improvement issues. The majority of the miscellaneous considerations come from discussions in Generic Letter 88-20 Supplement 2. The discussion includes:

1. Factors positively influencing the results.

2. Factors negatively influencing the results.

3. What can be done to improve plant safety, and how much the core damage frequency can reasonably be reduced where such an analysis has been performed.

6.2 Unique Safety Features of Prairie Island

This section identifies significant and unique safety features at Prairie Island which helped to minimize the risk from severe accidents. The following features limit the potential for challenges to core cooling and containment systems and assure the capability of these systems to cope with transients or accidents in general. A list of safety features follows:

1. The offsite switchyard has a highly reliable and diverse dual ring bus arrangement, minimizing the chance for loss of offsite power. Safeguards buses are normally powered from the 1R [2R] or CT11 [CT12] transformers which are not required to transfer on loss of the main generator.

2. The relatively low contribution to risk from blackout at Prairie Island is a result of the emergency AC power configuration which includes four diesel generators of diverse design and support system requirements. In the event of an SBO condition, each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of essential loads of the blacked

out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. The crosstie of a safeguards 4160V bus from one unit to the diesel generator for the other unit can be performed from the control room.

3. Prairie Island-specific transient initiating event frequencies related to plant challenges are lower than the industry average. This results in fewer challenges to the safety systems.

4. Prairie Island has a diverse cooling water system consisting of five pumps of which two are horizontal motor driven, and three are vertical pumps with one motor driven and two diesel driven. The single vertical motor driven pump is backed by safeguards diesel generators while the two diesel driven pumps do not rely on AC power for operation. The cooling water system consists of a ring header that can be divided into two separate headers on receipt of an SI signal. Each header supplies half of both trains of safeguards equipment.

5. The RCP seal cooling is provided by two independent systems, the charging pumps and the CC system. Although the CC system requires cooling water for cooling, the charging pumps do not require CC to provide RCP seal injection. In addition, the charging pumps do not provide the dual function of SI pumps.

6. The equipment located in the Auxiliary Building does not require room cooling for extended periods of operation. Analysis has been performed which demonstrates that the CS, CC, RHR and SI pumps do not require ventilation for sustained periods of pump operation.

7. The free standing steel shell containment is extremely robust. Plant specific analysis calculates that the best estimate failure pressure is over two and one half times the design pressure of 46 psig. In addition, the cavity design provides a relatively large area to spread out the corium from the postulated melting of the reactor core through the reactor vessel lower shell.

8. The conditional probability of containment failure for core damage sequences that do not bypass containment is low. This is due in part to the fact that two completely redundant, diverse means of providing containment heat removal and pressure control exist in the form of the containment spray system and the containment fan coil units. If either of these two systems are available, and in service, the probability of containment failure is very low.

The insights that follow are arranged according to damage class with the largest contributors to CDF listed first. For a description of the Prairie Island damage classes refer to section 3.1.5.

6.3 Class FEH-TB1 - Flood with Loss of Secondary Cooling and Bleed and Feed

This class of events was the largest contributor to the overall core damage frequency due to a single flood failing all secondary cooling and instrument air which then fails causes failure of bleed and feed cooling as the pressurizer PORVs need air to operate.

Factors positively influencing this damage class were:

1. The entire cooling water header has been replaced with a new more corrosion resistant and thicker piping such that the pipe rupture frequencies calculated for the header are probably conservative.

2. As long as the operators isolate the break per procedure C35 AOP1, rev 2, "Loss of Cooling Water Header A or B", at least one train of SI and RHR is still available for RCS inventory control.

Factors which have the potential to negatively influence this damage class:

1. The auxiliary feedwater pumps for both units are all located in the same room such that a pipe rupture in the loop A or B cooling water line can result in the failure of all auxiliary feedwater for both units.

2. The instrument air compressors are also located in the same room as the auxiliary feedwater pumps such that all the compressors could fail because of the flood, causing loss of instrument air for both units. Loss of instrument air results in closure of the main feedwater regulating and bypass valves which together with auxiliary feedwater failure, results in the loss of secondary cooling. Bleed and feed then fails because the pressurizer PORVs require instrument air to operate.

3. The cross-tie line between the loop A and B cooling water headers could be used to mitigate this accident by supplying cooling water to the main feedwater pump lube oil coolers after automatic closure of the turbine building isolation valve on high flow and low pressure. However, one of the two valves that must be opened to utilize the cross-tie is air operated and fails closed on loss of air.

4. If the operator is unsuccessful in isolating the break, cooling water will be lost for both units.

5. The fire door between the two halves of the AFW pump room is left open resulting in a single pipe break flooding both sides of the room.

The following recommendations should be considered for this accident class:

1. Proceduralize the cross-tie from station air to instrument air such that C34 AOP1, Rev 0, "Loss of Instrument Air" utilizes the cross-tie. The station air compressors are cooled from loop B cooling water and would not be affected by a LOOP A CL pipe break. If the cross-tie could be accomplished within 1 hour after the flood initiator, main feedwater or bleed and feed cooling could be restored and core melt could be prevented. The instrument air operating procedure should also be more emphatic in stating that the station air cross-tie should be used whenever an instrument air compressor is out of service for maintenance. It is recognized that this recommendation will only restore instrument air if the flood occurs as a result of a Loop A CL pipe break. However, this recommendation would be effective for many other events in which instrument air was lost.

2. Revise C35 AOP1, rev 2, "Loss of Cooling Water Header A or B" such that it addresses the problem of closure of the turbine building cooling water header isolation valve and the subsequent loss of cooling water to the main feedwater lube oil coolers and condensate pump oil coolers. Analysis has shown that the main feedwater pumps can conservatively operate without cooling water for approximately 20 minutes before possible pump damage.

3. Provide a means to either allow additional water flow out of the AFW pump room (through modifications to the Unit 1 and Unit 2 side doors, for example) or segregate the room into two compartments (close the fire door between the two halves of the AFW pump room and upgrade the ability of the door to block water flow, for example).

6.4 CLASS TEH- Transient with Loss of Secondary Cooling and Bleed and Feed

This class of events was a large contributor to the overall CDF due to the dependence of bleed and feed cooling and main feedwater on instrument air and DC power.

Factors positively influencing this damage class were:

1. The secondary cooling function which consists of the main feedwater and auxiliary feedwater systems is very reliable. Main feedwater is lost on a reactor trip but is easily recoverable from the control room. Auxiliary feedwater is a very reliable system that has benefitted from a reliability study performed by NSP in 1986 that resulted in changes to the system and procedures that made the system more reliable. The two motor driven AFW pumps can be crosstied between both units and the condensate storage tanks allow for at least 24 hours of decay heat removal before makeup to the tanks is required.

2. Bleed and feed cooling is a proceduralized action that greatly reduces the contribution of class TEH to the overall CDF.

Factors which have the potential to negatively influence this damage class:

1. Both main feedwater and bleed and feed cooling are dependent on common support systems; instrument air, cooling water and DC power.

2. The instrument air supply to containment has two fail closed air operated valves that are in series on either side of the containment penetration. Failure of either valve results in loss of instrument air to containment.

3. Bleed and feed cooling is heavily dependent on operator action for success as the operator must manually start an SI pump and open a pressurizer PORV for success.

4. The instrument air system has a high failure probability as the system success criteria is such that if two out of three compressors fail, instrument air is considered failed, as a single compressor cannot maintain adequate header pressure for both units.

The following recommendations should be considered for this accident class:

1. See section 6.3 recommendation 1. By crosstying station air to instrument air, the loss of instrument air initiating event frequency can be reduced, which results in a reduction of class TEH CDF as loss of instrument air is a large contributor to class TEH CDF.

2. Emphasize in training the importance of bleed and feed and the operator actions that are necessary for success as bleed and feed is a significant contributor to class TEH and the overall CDF.

3. Emphasize in training the importance of the crosstie between the motor driven AFW pumps and the operator actions that are necessary for success as the AFW crosstie is a significant contributor to class TEH and the overall CDF.

6.5 Class SLL- Large or Medium LOCA with Failure of Recirculation

These events involve a large or medium LOCA in which initial short term RCS inventory control is successful, but long term RCS inventory control fails due to failure of recirculation. Class SLL was a large contributor to the overall core damage frequency due to the heavy dependence on operator action.

Factors positively influencing this damage class were:

1. Reliable and redundant high and low pressure injections systems exist in the form of SI and RHR.

2. RHR can provide short term RCS inventory control for a medium break LOCA such that if SI injection fails, the RCS will depressurize below the RHR pump shutoff head without any operator action required such that the RHR pumps may inject into the RCS.

Factors which have the potential to negatively influence this damage class:

1. Recirculation from the containment sump is dependent on the RHR system as the RHR system is the only system that has a containment sump suction supply.

2. Switchover to high head recirculation can not be performed from the control room as the RHR to SI crossover motor valves have their breakers locked in the open position. The switchover to high head recirculation must be accomplished within a small time window of when both SI, CS and/or the RHR pumps are injecting from the RWST. If the operator fails to stop any of the pumps before the RWST level decreases below approximately 5%, all pumps will be damaged as they do not have suction trips.

The following recommendations should be considered for this accident class:

1. Emphasize in training the importance of switchover to high and low head recirculation and the operator actions that are necessary for success as switchover to recirculation is a significant contributor to class SLL and the overall CDF.

6.6 Class SEH- Small LOCA with Failure of Short Term RCS Inventory

These events involve a small LOCA or RCP seal LOCA with successful reactor trip and secondary cooling but failure of short term RCS inventory due to SI system failure. This damage class was a large contributor to the overall CDF due to the dependence of RCP seal cooling and RCS short term inventory on cooling water.

Factors positively influencing this damage class were:

1. The RCP seal cooling is provided by two independent systems, the charging pumps and the CC system. Although the CC system requires cooling water for cooling, the charging pumps do not require CC or cooling water to provide RCP seal injection. In addition, the charging pumps do not provide the dual function of SI pumps.

2. The SI system is a very reliable system that does not require room cooling for successful system operation. The injection pressure of the SI pumps is high enough such that operator action is not required to lower the RCS pressure for SI injection following an "S" signal.

3. After the upcoming unit 1 outage, two new 480V safeguards buses will be installed in new locations such that loss of room cooling will only affect a single 480V safeguards train.

4. Procedures exist to cope with the loss of chilled water or room cooling to the unit 1 safeguards 480V bus rooms such that an operator can alleviate the problem through opening doors or providing portable fans for the rooms.

Factors which have the potential to negatively influence this damage class:

1. The safety injection pumps are the only injection source that can be used for short term RCS inventory control following a small LOCA due to the RCS pressure remaining above the shutoff head of the RHR pumps. Through plant specific analysis, it was found that depressurizing the SGs to lower RCS pressure to enable the RHR pumps to inject was not possible in time to prevent core damage.

2. Both RCP seal cooling and RCS short term inventory control are dependent on cooling water. Cooling water provides the ultimate heat sink for the component cooling water system which provides cooling to the RCP thermal barrier and to the SI pump lube oil coolers. Cooling water also supplies a heat sink for the control room chillers which provide room cooling for the unit 1 safeguards 480V bus rooms. On loss of cooling water, room

cooling is lost to the unit 1 safeguards 480V bus rooms. Without operator intervention, the rooms can heatup and fail the 4160/480V transformers resulting in a loss of all unit 1 480V safeguards equipment. This would cause loss of all charging pumps resulting in a loss of all RCP seal cooling causing an RCP seal LOCA in which the SI system would not be available to mitigate.

3. Loss of instrument air will cause the control room chiller outlet cooling water valves to close resulting in loss of chilled water and loss of room cooling to the unit 1 480V safeguards bus rooms. Without operator intervention, the result will be the same as described in 2 above.

There are no recommendations for this class.

6.7 Class GLH- SGTR With Failure to Cooldown and Depressurize RCS

This damage class can be characterized by a sequence in which the operator fails to cooldown and depressurize the RCS before ruptured SG overfill after a SGTR has occurred. Following overfill, a SG relief is assumed to stick open and the operator fails to cooldown and depressurize the RCS down to RHR shutdown cooling temperature and pressure operating limits before RWST depletion. This damage class is significant in that with the ruptured SG relief sticking open, containment is bypassed so the consequences of this damage class are more severe than core damage sequences with an intact containment.

Factors positively influencing this damage class were:

1. The secondary cooling function which consists of the main feedwater and auxiliary feedwater system is very reliable. Main feedwater is lost on an "S" signal but can be recovered from the control room. Auxiliary feedwater is a very reliable system that has benefitted from a reliability study performed by NSP in 1986 that resulted in changes to the system and procedures that made the system more reliable.

2. The SI system is a very reliable system that does not require room cooling for successful system operation. The injection pressure of the SI pumps is high enough such that operator action is not required to lower the RCS pressure for SI injection following an "S" signal.

3. The main steam system design is such that the non-return check valve together with the MSIVs of both the ruptured and intact steam generators must fail for ruptured steam generator isolation to fail which results in a low probability for isolation.

Factors which have the potential to negatively influence this damage class were:

1. The success or failure of this damage class is heavily dependent on operator action. In order for success, operator action is required to cooldown and depressurize the RCS and terminate SI before the ruptured SG integrity is challenged by overfill of the SG and possible opening of a SG PORV or safety valve.

2. RCS cooldown and depressurization is dependant on instrument air as all of the valves needed to accomplish this action are air operated and fail closed on loss of air.

3. The instrument air supply to containment has two fail closed air operated valves that are in series on either side of the containment penetration. Failure of either valve results in loss of instrument air to containment.

The following recommendation should be considered for this accident class:

1. Emphasize in training the importance of RCS cooldown and depressurization to terminate SI before ruptured SG overfill and the operator actions that are necessary for success this action is a significant contributor to class GLH and the overall CDF.

6.8 Class BEH-NOPWR - SBO with Failure to Restore AC Power

Class BEH-NOPWR can be characterized by a LOOP followed by failure of all four safeguards diesel generators with failure to restore either onsite or offsite power before core damage occurs. This damage class was not a large contributor to the overall CDF due to the existence of four diverse safeguards diesel generators.

Factors which positively influence this damage class were:

1. Prairie Island has four diverse safeguards diesel generators to supply AC power to each of the four safeguards 4160V buses in the event of a LOOP. Two of the diesel generators also have their own self contained cooling systems and were built by different manufacturers reducing common cause failure probabilities. In the event of an SBO condition, each diesel generator has the capability to supply the power requirements for the hot shutdown loads for its associated unit, as well as one train of essential loads for the blacked out unit through the use of manual bus tie breakers interconnecting the 4160V buses between units. The crosstie of a safeguards bus from one unit to the diesel generator from the other unit can be performed from the control room.

2. Prairie Island has a reliable grid system such that the LOOP frequency is slightly less than industry average.

3. Depressurizing the SGs so as to reduce RCS temperature and pressure for prolonged RCP seal life and to inject the accumulators is a proceduralized action that extends the time to core damage by over one hour.

4. Prairie Island has a turbine driven AFW pump that is independent of AC or DC power for operation. The pump also has an adequate supply of condensate such that operator action is not needed to augment the supply for at least 24 hours.

Factors which have the potential to negatively impact this damage class were:

1. Both D1 and D2 diesel generators rely on cooling water for engine cooling functions.

There are no recommendations for this accident class.

6.9 Class SLH- Small LOCA with Failure of Recirculation

This damage class contributed little to the overall CDF as failure of RCS cooldown and depressurization must be followed by failure of high head recirculation for core damage to occur, which results in low core damage frequencies. This damage class involves a small LOCA with successful short term RCS inventory but failure of the operator to cooldown and pressurize the RCS before RWST depletion forcing the operator to go on recirculation which then fails.

Factors positively influencing this damage class were:

1. RCS cooldown and depressurization is a proceduralized action which allows the unit to be brought to shutdown conditions without the need for high head recirculation.

Factors which have the potential to negatively influence this damage class:

1. Recirculation from the containment sump is dependent on the RHR system as the RHR system is the only system that has a containment sump suction supply.

2. Switchover to recirculation can not be performed from the control room as the RHR to SI crossover motor operated valves have their breakers locked in the open position.

There are no recommendations for this damage class.

6.10 Class TLH- Transient Followed by Failure of Secondary Cooling and Recirculation

Class TLH was not a large contributor to the overall CDF as secondary cooling failure is followed by bleed and feed success. High head recirculation from the containment sump is then required, but fails. Since secondary cooling can be provided by either the AFW system or the main feedwater system the failure probability for this function is low. High head recirculation must then fail which results in a low contribution to the overall CDF from this class.

Positive and negative factors are explained previously in Class TEH and are the same for this damage class. The recommendations for class TEH also apply here.

6.11 Class GEH- SGTR with Short Term Inventory Failure or Secondary Cooling Failure

Class GEH was not a large contributor to the overall CDF as RCS short term inventory failure is followed by failure of the operator to cooldown and depressurize the RCS before core damage occurs. Since the SI system is a reliable injection system and the operator has approximately two hours to perform the RCS cooldown, the contribution from this class is low and no recommendations are given.

6.12 Class BEH- SBO with Restoration of AC Power but Core Damage Due to RCP Seal LOCA

Class BEH was not a large contributor to the overall CDF as the probability of an SBO is low due to the four diverse, reliable safeguards diesel generators that are capable of being crosstied between the same trains on opposite units. Two of the diesel generators are from a different manufacturer and do not require an external cooling medium as they have their own self contained cooling systems. The RCP seal LOCA model used for SBO is a Westinghouse model that models the magnitude of the seal LOCA that the RCS can take as a function of time: e.g. the more time that passes before recovery of SI, the less the average seal LOCA flow that the RCS can tolerate. The model also distinguishes whether or not the RCS has been cooled down in accordance with the emergency procedures. With this in mind, the probability of core uncovery due to an RCP seal LOCA is approximately 1E-2 which when multiplied with the probability of an SBO results in a small contribution to overall CDF. Because of this, no recommendations are given for this damage class.

6.13 Class V, Interfacing System LOCAs

The Class V sequences were one of the smallest contributors to the overall CDF. This is primarily due to the following reasons:

1. Prairie Island does not test any of the valves in the ISLOCA pathways while the plant is above cold shutdown.

2. The motor operated valves nearest the RCS in the RHR loop return line and the RHR loop suction line have their power removed during normal operation to prevent inadvertent valve manipulation.

3. The low pressure piping in the RHR and SI systems can withstand full RCS pressure without exceeding the piping ultimate pressure stress. Conditional probability of low pressure piping failure following exposure to full RCS pressure was considered in the interfacing system LOCA analysis.

4. The operator has approximately four hours to cooldown and depressurize the RCS to reduce the flow from the RHR pump seals should they fail before the low pressure RHR piping fails giving him ample time for success.

For these reasons, there are no recommendations given for this damage class.

6.14 Classes RLO, REP- ATWS Damage Classes

The ATWS damage classes are grouped together as none of them are significant contributors to the overall core damage frequency due to the ability to ride out the event effectively by heat removal through the steam generators and because of the reliable reactor protection system. Because of this, no recommendations are given for this damage class.

6.15 Class SEL- LOCA Followed by Failure of Short Term RCS Inventory

The sequences within this damage class were not large contributors to the overall CDF as the large LOCA initiating event frequency combined with a relatively reliable RHR system results in the low contribution from this initiator. Medium LOCA events may be greater in frequency but are lower in risk because the SI system is capable of providing adequate core cooling in addition to the RHR system. Because of this, there are no recommendations given for this damage class.

6.16 Level 2 Insights and Recommendations

The plant design features and operating characteristics that have the largest positive effect on the unit 1 Level 2 results are as follows:

1. The containment is very large and strong (see discussion Section 6.2).

2. There are two separate systems for containment atmosphere cooling and pressure suppression, the Fan Coil Units and the Containment Spray System (see discussion Section 6.2).

3. The possibility of recovering from a core damage event in-vessel exists and is enhanced by the design of the reactor cavity. The cavity arrangement is such that following a LOCA, water injected into the RCS will flow out the break and enter the reactor cavity. Also, containment spray injection flow can reach the reactor cavity. Flooding of the cavity is accomplished through an access hatch which is left open during normal operation and allows water flow from the containment floor down into the cavity for vessel head cooling. By filling the reactor cavity with water and submerging the lower head, the core can be cooled by boiling the cavity water and recondensing the steam with the Fan Coil Units.

4. The open design and significant venting areas for the sub-compartments within the Prairie Island containment help ensure a well-mixed atmosphere, a feature that inhibits combustible gas pocketing. Steel grating around the periphery of the operating deck provides a good flow path between the annular and upper compartments. This grating also provides an effective fission product removal mechanism in the form of impaction. The lower and upper compartments communicate through openings around the steam generators and their corresponding vaults.

5. The containment free volume to power ratio is such that the oxidation of the cladding does not produce enough hydrogen to challenge containment.

Factors that negatively influence the Level 2 results are:

1. Emergency Procedure FR-C.1, Rev. 5, "Response to Inadequate Core Cooling" creates the possibility of inducing a steam generator tube rupture during an event in which degraded core cooling conditions already exist (see Level 2 recommendation 1. below).

2. See negative influences listed for SGTR events listed above (Section 6.7).

Since the starting point of the Level 2 analysis is the Level 1 core damage sequences, the preceding Level 1 recommendations will also have a positive effect on the Level 2 release frequency. The following recommendations are generated based on the results of the Level 2 analysis:

1. Revise FR-C.1, rev 5, "Response to Inadequate Core Cooling" step 18 such that the operator checks for adequate steam generator level before attempting to start an RCP. If the RCPs are started with a "dry" steam generator with core exit thermocouples greater than 1200°F, hot gases could be pushed up into the steam generator tubes causing creep rupture of the tubes and a possible containment bypass if one of the steam generator relief valves were to lift.

2. The in-core instrument tube hatches for both units should be secured open during normal operation. This could be accomplished by using a solid bar or other device, instead of a chain, to keep the hatch open but still prevent inadvertent entry during normal operation. Having this hatch open greatly improves the probability of recovering from a core damage event in-vessel (without vessel rupture), by allowing injection water from the RWST to flow into the reactor cavity and to provide cooling to the lower vessel head, and improves debris coolability in the reactor cavity following events in which the vessel fails at low pressure. For this recommendation, consideration is being given to credit given in the Level 2 analysis model for these hatches being open during normal operation.

6.17 Lowest Core Damage Frequency With Modifications

The total CDF after recommended changes are made was calculated by considering the Level 1 CDF of 5E-5/yr with the AFW room fire door closed and the procedural change to allow station air to be crosstied with instrument air. With these changes, the new estimated CDF value is 3.6E-5/yr.

6.18 Conclusions

The core damage frequency including internal flooding calculated by the Prairie Island IPE is 5E-5/yr. The largest contributors to CDF are a flood in the AFW pump room (21%), SGTR (13%), Medium LOCA (9%), small LOCA (8%), large LOCA (7.5%) and loss of instrument air (6%). Important human errors which contribute significantly to the overall CDF are failure to initiate bleed and feed cooling (9%), failure to cooldown and depressurize the RCS before ruptured steam generator overfill (7%), failure to initiate low head recirculation (5%), failure to initiate high head recirculation (4%) and failure to crosstie the motor driven AFW pump from the opposite unit (4%).

From the IPE results it can be seen that with the exception of the AFW pump room flood there are no initiating events which dominate risk at Prairie Island. Actions are being taken to mitigate the consequences of the AFW room flood through closing a fire door in the room and through procedural enhancements. Prairie Island is a safe plant that is well constructed and operated, with procedures that cover most eventualities modeled in the IPE. In short, the Prairie Island IPE has accomplished the purposes requested by the NRC in Generic Letter 88-20. No plant specific severe accident vulnerabilities have been identified. Several cost effective procedure revisions and modifications were identified in performing the IPE, which are planned to be implemented in the near future. These planned improvements are expected to reduce the Prairie Island CDF even further.

7.0 TRANSIENT ANALYSIS

A number of transient events and accident sequences were analyzed to establish (a) the minimum equipment required to achieve a safe, stable state within containment for each CET end state, and (b) the relative timing of key events during each accident class. These analyses were done using the Modular Accident Analysis Program (MAAP) 3.0B, PWR Revision 19.0, with best-estimate, Prairie Island specific input parameters. MAAP 3.0B was also used for the source term and sensitivity assessments as described in Sections 4.7 and 4.8, respectively.

7.1 Success Criteria

The success criteria cases give best-estimate determination for Prairie Island of the minimum equipment needed in order to achieve a safe, stable state within containment for each CET end state.

7.1.1 LOCA Success Criteria

7.1.1.1 RHR Success Criteria for a Large-break LOCA

In this case, the purpose of the MAAP analyses is to demonstrate that a single RHR pump, with no other injection source, is sufficient to prevent core damage during a large-break LOCA (i.e., break diameter in excess of 12"). The LOCA is modeled as a 4.6 sq. ft break at the reactor coolant pump inlet in the intermediate leg.

For the large-break LOCA, the water level in the reactor vessel falls below the top of active fuel approximately 11 seconds after accident sequence initiation. The RHR pump starts injecting as soon as the primary system pressure drops below the RHR shut-off head (roughly 2 minutes later). The hottest core node temperature does exceed 1200°F, but for less than 2 minutes and is cooled as soon as RHR injection begins. The RPV water level remains constant at 24 feet once RHR injection is established. RWST injection continues for approximately 45 minutes, until the RWST level drops to 28%, at which point the EOPs dictate that the RHR pump start taking suction from the lower containment sump. As long as the switch to recirculation is successful, long term core cooling can be maintained. Since the hottest core node temperature did not exceed 1200°F for a substantial period of time (> 30 minutes), no damage to the fuel or cladding occurred.

It is understood that MAAP may not accurately model all the details during the early phases of a large LOCA, but it was judged that the period of core uncovery is sufficiently small that the core would be recoverable. Figures 7.1-1 and 7.1-2 illustrate the following MAAP parameters of interest:

- RPV pressure
- RPV water level
- ESF injection flow rate
- Hottest core node temperature

7.1.1.2 RHR Success Criteria for a Medium-break LOCA

The purpose of this series of MAAP runs is to determine the smallest LOCA size for which a single RHR pump, with no other form of injection, is sufficient to prevent core damage. The most important factor here is to determine the smallest LOCA size which can depressurize the primary system below the RHR shut-off head before core damage occurs. MAAP analyses for break diameters below 5 inches show that the hottest core node temperature exceeds 2000°F, which is one of the criteria for core damage. For break diameters in excess of 5 inches, MAAP analyses show that the hottest core node temperature exceeds 1200°F, but not for a substantial period of time (i.e., > 30 min.) and does not exceed 2000°F at anytime.

For the MAAP sequence where a 5" break is modeled at the inlet of the reactor coolant pump on the intermediate leg, the core uncovers approximately 6 minutes after the break is initiated. As soon as the core uncovers, the fuel begins to heat up and exceeds 1200°F approximately 200 seconds after the core uncovers. The primary system pressure eventually drops below the RHR shut-off head and RHR injection is initiated roughly 12 minutes after accident sequence initiation. Once RHR injection is established, the reactor vessel level, which had fallen to 12 ft, slowly returns to 25 ft, where it remains for the duration of the MAAP run. As soon as RHR injection is initiated and the reactor vessel water level starts rising, the fuel temperature drops back below 1200°F. Since the fuel temperature did not exceed 2000°F and was not above 1200°F for more than 30 minutes, core damage is assumed not to occur. The RHR pump takes suction from the RWST for approximately 1.5 hrs until the ECPs direct the operators to align the RHR pump to take suction from the lower containment sump. As long as recirculation is successful, core damage will be averted for sequences with a break size greater than 5" and only one RHR pump available for injection.

Therefore, it is concluded that for break sizes in excess of 5", the primary system will depressurize rapid enough to allow the flow from a single RHR pump to prevent core damage. Figures 7.1-3 thru 7.1-5 illustrate the following MAAP parameters of interest:

- RPV pressure
- RPV water level
- Hottest core node temperature for 5" break diameter
- ESF injection flow rate

- Hottest core node temperature for 4.5" break diameter

7.1.1.3 SI Success Criteria for a Medium-break LOCA

The purpose for this series of MAAP analyses is to determine the success criteria for the high head Safety Injection (SI) pumps during a medium-break LOCA, assuming no other source of injection is available. Similar to the large-break LOCA success criteria analysis, the most important factor to determine is if one SI pump is sufficient to prevent core damage. The break sizes for a medium-break LOCA range from 5" to 12" in diameter. MAAP analyses for LOCAs in this range show that one SI pump is sufficient to prevent core damage.

For a medium-break LOCA, where MAAP models a 12" break in the hot leg, the core uncovers approximately one minute after the break is initiated. Roughly 2 minutes later, the core hottest node temperature exceeds 1200°F, but due to the ESF flow from the SI pump, the hottest core temperature drops back below 1200°F approximately 9 minutes later. Since the fuel temperature did not exceed 1200°F for more than 30 minutes or 2000°F for any period of time, core damage was averted.

Therefore, for medium-break LOCAs, it is concluded that one SI pump is sufficient to prevent core damage, even if no other form of injection is available. Figures 7.1-6 and 7.1-7 illustrate the following MAAP parameters of interest:

- RPV pressure
- RPV water level
- Hottest core node temperature
- SI injection flow rate

7.1.1.4 SI Success Criteria for a Small-break LOCA

The purpose of these MAAP analyses is to determine the smallest LOCA size for which a single SI pump, with no other injection source or feedwater to the steam generators, is sufficient to prevent core damage. The most important factor here is to determine the break area that will allow one SI pump to provide continuous core cooling and prevent core damage. The limiting factor is that if the break size is too small, the primary system pressure will not stay below the SI shut-off head due to the lack of secondary side cooling (MFW or AFW).

MAAP analyses show that the minimum break diameter for which 1 SI pump can prevent core damage without secondary side feedwater is 7/8" diameter. For sequences where the break size is smaller, the steam generators dry out which in turn cause the primary system pressure to increase because decay heat can no longer be transferred to the steam generators. This pressure rise eventually exceeds the shut-off head of the high head SI pumps and flow to the vessel is discontinued, even though sufficient water is still available for injection. A MAAP run modeling a 3/4" break with no AFW shows that the steam generators dry out approximately 2.8 hrs after the initiating event. As soon as the steam generators dry out, the primary system pressure begins to increase. Eventually, the primary system pressure begins to restrict full SI flow due to the higher pressures. Once the SI flow is decreased to a point where it can no longer remove decay heat, the core uncovers and begins to heat up. Core uncovery occurs at 4.5 hrs, with core damage occurring 40 minutes later.

For the MAAP sequence modeling a 7/8" break at the inlet to the reactor coolant pump in the intermediate leg, the steam generators do not dry out, the core does not uncover, and the flow from a single SI pump is sufficient to prevent core damage. Figures 7.1-8 thru 7.1-12 illustrate the following MAAP parameters of interest which demonstrate that one SI pump is sufficient to prevent core damage with no secondary side cooling or other injection sources available:

- RPV pressure for 7/8" break *
- RPV water level for 7/8" break
- Hottest core node temperature for 7/8" break
- SI injection flow rate for 7/8" break
- Hottest core node temperature for 3/4" break
- RPV pressure for 3/4" break
- SI injection flow rate for 3/4" break
- Steam generator water level for 3/4" break
- RPV water level for 3/4" break

* (For the 7/8" case shown the RWST is allowed to dry out after ten hours; the results after that point are used for a different analysis.)

7.1.1.5 SI Success Criteria for a Small-break LOCA with AFW

The purpose of these MAAP analyses is to determine the smallest LOCA size for which a single SI pump, with no other injection source and a single AFW pump supplying water to the steam generators, is sufficient to prevent core damage. The most important factor here is to determine the break area that will allow one SI pump to provide continuous core cooling and prevent core damage. A single charging pump provides sufficient makeup for a break of 3/8" in diameter. The range of interest for this case is therefore 3/8" or larger.

MAAP analyses show that the minimum break diameter for which 1 SI pump with 1 AFW pump can prevent core damage without secondary side feedwater is 3/8" diameter. RCS pressure drops to the "S" signal setpoint of 1815 psig at 13.1 minutes. The

SI pump and AFW pump both start and begin to restore both pressurizer pressure and level and SG pressure and level. The core is never uncovered. Core temperature drops to about 600°F and remains there.

For the MAAP sequence modeling a 3/8" break at the inlet to the reactor coolant pump in the intermediate leg, the steam generators do not dry out, the core does not uncover, and the flow from a single SI pump with a single AFW pump is sufficient to prevent core damage. Figures 7.1-13 thru 7.1-14 illustrate the following MAAP parameters of interest which demonstrate that one SI pump with one AFW pump is sufficient to prevent core damage :

- RPV pressure
- SI injection flow rate
- Hottest core node temperature
- SG water level

7.1.1.6 Timing for Operator Actions to Establish ECCS Recirculation

As part of the Level 1 work for LOCA sequences, the time available to establish ECCS recirculation is very important. This is the amount of time that an operator has, upon initiating a set of pumps, to perform any necessary operator actions to allow for successful establishment of ECCS recirculation. Listed below is a table which shows the estimated time available to perform these operator actions as a function of the number of pumps operating and various RWST water level. These times are based on pump run-out flows, so the actual times would be longer than those listed.

Operating Pumps	33% RWST	28% RWST	8% RWST
1 RHR pump	92 min.	99 min.	126 min.
2 RHR pumps	46 min.	49 min.	63 min.
1 SI pump	263 min.	283 min.	362 min.
2 SI pumps	132 min.	142 min.	181 min.
1 RHR & 1 SI pump	62 min.	70 min.	106 min.
2 RHR & 2 SI pumps	31 min.	35 min.	53 min.
1 RHR, 1 SI & 1 CS pumps	46 min.	50 min.	64 min.
2 RHR, 2 SI & 2 CS pumps	23 min.	25 min.	32 min.

<u>7.1.2 Transient Success Criteria</u>

7.1.2.1 Restore MFW/AFW in a Loss of Feedwater & Initiate Bleed & Feed

The purpose of this MAAP analysis is to determine the time available to restore either main or auxiliary feedwater, and the time at which an operator would have to initiate "bleed and feed" procedures. The analyzed sequence is a loss of feedwater transient with no feedwater or RPV injection. The Prairie Island turbine stop valves and steam dump valves were properly modeled in the analysis. The following timings were noted:

50% wide range steam generator level	13.4 sec
7% wide range steam generator level[1]	29.7 min
Steam generator dryout	43.0 min
Core damage	2.0 hrs

Core damage occurs due to the hottest core node temperature exceeding 1200°F for a period of time greater than 30 minutes. Therefore, if the operators initiate bleed and feed operations 29 minutes after accident sequence initiation, the operators will have approximately 15 minutes to initiate or restore main or auxiliary feedwater before the steam generators dry out. Figure 7.1-15 illustrates the following MAAP parameters of interest:

- Hottest core node temperature
- Steam Generator water level

A sensitivity study was performed by running this case and restoring feedwater 15 minutes after steam generator dryout. No core damage occurred for this sensitivity study.

7.1.2.2 Bleed & Feed Using only 1 PORV & 1 SI Pump

The purpose of this MAAP analysis is to determine if bleed and feed operations will be successful in preventing core damage if only 1 pressurizer PORV and 1 SI pump are available. This case is a loss of MFW transient with failure of the auxiliary feedwater system to provide makeup to the steam generators. At the 7% wide range steam generator level, the operator opens 1 pressurizer PORV and starts SI injection. The steam dump and turbine stop valves are modeled according to the Prairie Island EOPs.

In this case, the MAAP run is initiated by a loss of feedwater transient with failure of the AFW system. Approximately 29.7 minutes into the sequence, one pressurizer PORV is opened and a single SI pump is started. The primary system pressure decreases to approximately 1550 psig at 31.1 minutes and the operators trip the reactor coolant pumps (RCPs) one minute later. The pressurizer goes

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[1] The wide range instruments could indicate as high as 7% steam generator level when in fact the steam generator is dry. The EOPs direct operators to switch to bleed and feed when 7% is reached on the wide range instruments.

water solid at 40.7 minutes and oscillates accordingly throughout the duration of the run. Accumulator flow begins 1.2 hours after accident sequence initiation. The core does not uncover, and therefore, core damage does not occur since the fuel is adequately cooled.

Therefore, the results of this MAAP analysis indicate that 1 PORV and a single SI pump are sufficient to depressurize the primary system and prevent core damage from occurring. As long as some form of ECCS injection and recirculation is continued, the core will remain adequately cooled. Figures 7.1-16 and 7.1-17 illustrate the following MAAP parameters of interest:

- RPV pressure
- RPV water level
- Hottest core node temperature
- Pressurizer water level

7.1.2.3 Time to Recover AC Power For Station Blackout w/ TDAFW

The purpose of this case is to determine how long the plant has to restore AC power for a station blackout, with turbine driven auxiliary feedwater (TDAFW) available for 2 hours, in order to avert core damage. This case considers when steam generator dryout and core damage will occur for a station blackout with turbine driven AFW until the station batteries are depleted. Upon accident sequence initiation, all AC power is lost and an RCP seal LOCA is initiated due to the loss of RCP seal cooling. Turbine driven AFW and the station batteries are initially available at the start of the accident. The TDAFW pumps maintain steam generator water level at the 10-50% narrow range level. After two hours, the station batteries are depleted thereby disabling TDAFW and the pressurizer and steam generator PORVs. Note that TDAFW would still be functional, but it was assumed to fail when the SG level instrumentation is lost when the batteries fail causing the operator to overfill the SG and flood the TDAFW pump. The steam generator safety valves remain operable. This case also considers the air supply to the pressurizer PORV. Without AC power, the pressurizer PORV relies on DC power and the air supply in its accumulators. The air supply is sufficient for approximately 15 cycles, therefore only 15 cycles of the pressurizer PORV are allowed during this case.

This MAAP scenario is initiated by a station blackout with a RCP seal LOCA of approximately 21 gpm per loop. The actual flow rates used for seal LOCAs had a more detailed treatment which would allow different flowrates at different times depending on the actual conditions expected. After 25.4 minutes, there is water on the floor of containment. After 2 hours have elapsed, the station batteries are lost causing flow from the TDAFW pumps to cease. This causes the steam generators to dryout approximately 2.6 hours later. The core is uncovered 4.9

hours after accident sequence initiation with core damage occurring approximately 1 hour later. Core damage was due to the hottest core node temperature being above 1200°F for a period of time greater than 30 minutes. The pressurizer PORV never opened, so concerns about its air supply are not important in this case. A sensitivity analysis also considered the case where the pump seal LOCA was delayed by 45 minutes, but the RCP seal LOCA was increased to 63 gpm per loop. The sequence timing for this case was not changed significantly relative to the base case.

This run demonstrates that there would be approximately 5.8 hours for the operator to recover AC power and establish RPV injection to prevent core damage, assuming that TDAFW was successful for 2 hours without secondary side depressurization. This conclusion does not change significantly if the timing and magnitude of the RCP seal LOCA are varied over a reasonable range of values. The time to recover AC power may be greatly altered if TDAFW is not available (section 7.1.2.5), the battery life is increased, or if the steam generators are depressurized using the SG PORVs (section 7.1.2.4). Figure 7.1-18 illustrates the following MAAP parameters of interest.

- Hottest core node temperature
- Steam generator water level

7.1.2.4 Station Blackout w/ TDAFW and Secondary Side Depressurization

This MAAP case considers the timing of steam generator dryout and core damage for a station blackout with TDAFW available until the station batteries deplete. Secondary side depressurization using the SG PORVs after 30 minutes is successful. The analysis is initiated by a station blackout with a RCP seal LOCA occurring at the time of accident sequence initiation. With TDAFW available, the operator maintains 10-50% narrow range level in the steam generators. The operators depressurize both steam generators to 270 psig using the steam generator PORVs after 30 minutes have elapsed. After 2 hours, the station batteries deplete thereby disabling TDAFW and the steam generator and pressurizer PORVs. The steam generator safety valves remain operable.

After 25.4 minutes, there is water on the lower containment floor. After 30 minutes, the operator depressurizes both steam generators to 270 psig using the steam generator PORVs. The primary system pressure drops to approximately 600 psig for a short period of time and then drops to 500 psig 1 hour after accident sequence initiation. The primary system pressure remains at 500 psig until the TDAFW pumps are lost due to battery failure at 2 hours. With the primary system pressure right around the pressure in which the accumulators will inject, accumulator flow occurs sporadically throughout the first two hours of this sequence. Once the TDAFW pumps are lost, the primary system pressure increases continually up until the time of core uncovery (5.8 hrs). At the time of core damage (6.7 hrs), the primary system pressure is at the pressurizer safety valve setpoint of (2500 psig). Subsequently, vessel failure occurs at high pressure.

Therefore, this sequence shows that core uncovery and core damage can be delayed by approximately one hour by depressurizing the secondary side after 30 minutes. This is due in part to the introduction of accumulator water inventory at 0.6 hours after accident sequence initiation. If the operator can maintain TDAFW and secondary side depressurization for more than 2 hours, core uncovery and core damage can be delayed by several hours due to the gradual injection of the accumulator inventory. Figures 7.1-19 and 7.1-20 illustrate the following MAAP parameters of interest.

- Hottest core node temperature
- Steam generator water level
- Accumulator flow into the vessel
- RPV pressure

7.1.2.5 Station Blackout w/o Turbine Driven Auxiliary Feedwater

The purpose of this MAAP analysis is to determine and examine the accident sequence timing for a station blackout without turbine driven auxiliary feedwater. The only item of interest is the time that the plant operators have to restore core cooling and prevent core damage. Since no AC power is available, there are really no operator actions that need to be modeled.

For this sequence, an RCP seal LOCA of approximately 63 gpm per loop is initiated 45 minutes after accident sequence initiation. With no core cooling or secondary side cooling, core uncovery and core damage occur only several hours after accident sequence initiation. The following timing of key events is summarized below:

0.0 sec	SBO w/o TDAFW is initiated
2.1 hrs	Steam generators dry
2.6 hrs	Core uncovery
3.3 hrs	Core damage occurs (TCRHOT > 1200°F for 1/2 hr)
4.5 hrs	Vessel failure

7.1.3 Steam Generator Tube Rupture Success Criteria

7.1.3.1 Steam Generator Tube Rupture Timing

The purpose of this MAAP analysis is to determine the time to overfill the steam generator, and the time to depressurize the primary system given steam generator overfill, during a steam generator tube rupture scenario. The accident is initiated by a rupture of one tube on the hot side of the steam generator approximately 1 meter above the tube sheet. Initially, RPV injection and auxiliary feedwater are available and the accumulators are disabled. Approximately 25 minutes into the accident, the operator isolates the ruptured steam generator, but steam generator overfill causes a safety valve to fail to reseat, resulting in a stuck open safety valve. The operator never initiates high pressure recirculation. Fan coolers and containment sprays are available, but do not initiate since there is very little pressurization within containment during a tube rupture sequence. The timing for this sequence is as follows:

0.0 sec	Tube rupture initiated
1.4 min	Reactor trip signal
1.5 min	Safety injection (SI) pumps initiated
1.7 min	Primary System pressure < 1550 psig
2.7 min	Operator shuts off reactor coolant pumps
25.0 min	Isolate feedwater to broken steam generator
49.0 min	Ruptured SG filled with water
6.4 hr	RWST depleted

The results of this case show that for a rupture of a single steam generator tube on the hot side with 2 SI pumps running, there are approximately 49 minutes before the steam generator overfills. The results also show that the primary system pressure drops below 1550 psig approximately 101 seconds after accident sequence initiation. Figures 7.1-21 through 7.1-23 illustrate the following MAAP parameters of interest:

- RPV pressure
- Water flow through SG relief valve in broken loop
- Pressure in broken loop SG
- Downcomer level in broken loop SG
- Pressure in unbroken loop SG
- Downcomer level in unbroken loop SG

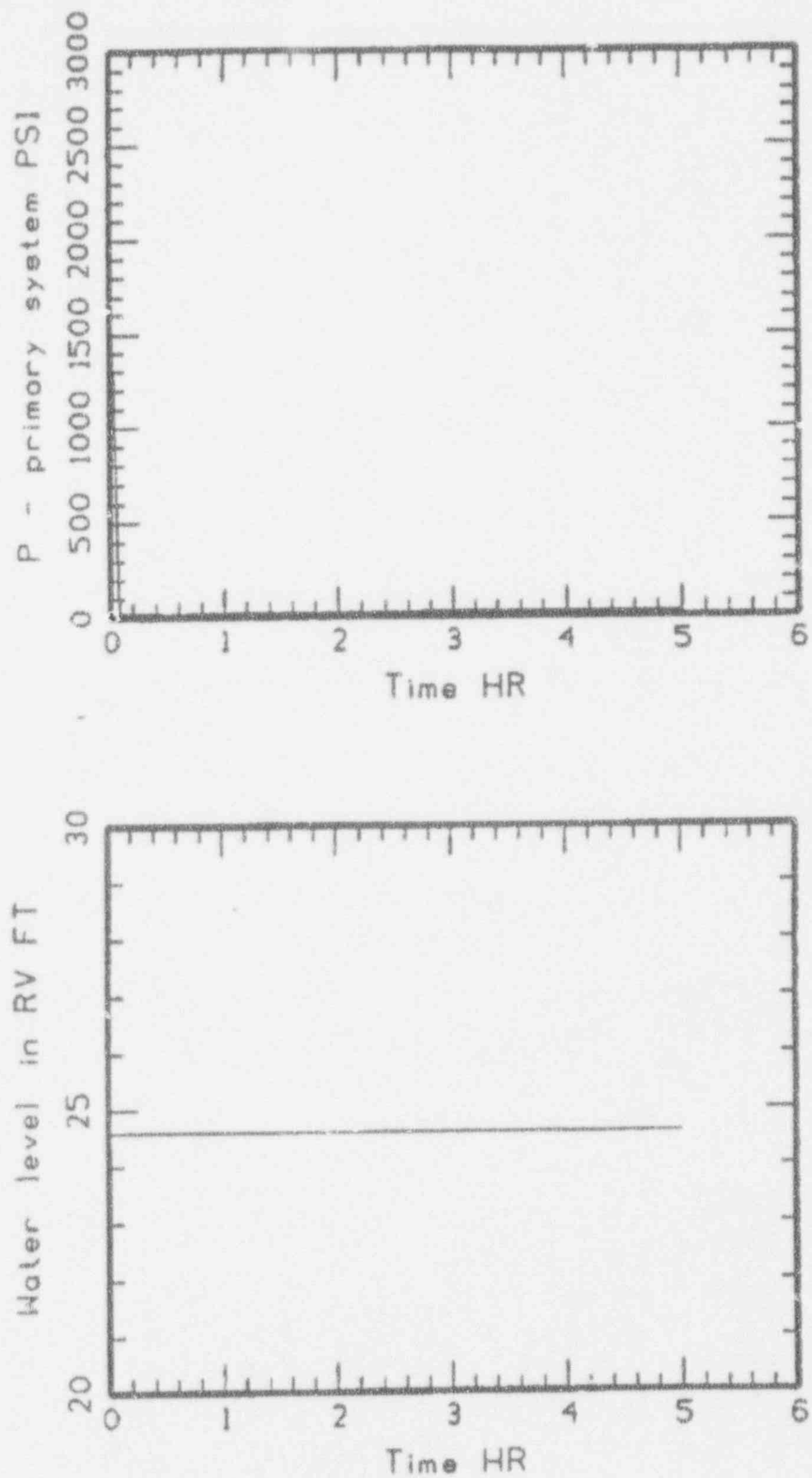


Figure 7.1-1 RPV Pressure and RPV Water Level for RHR Success Criteria During a Large-break LOCA

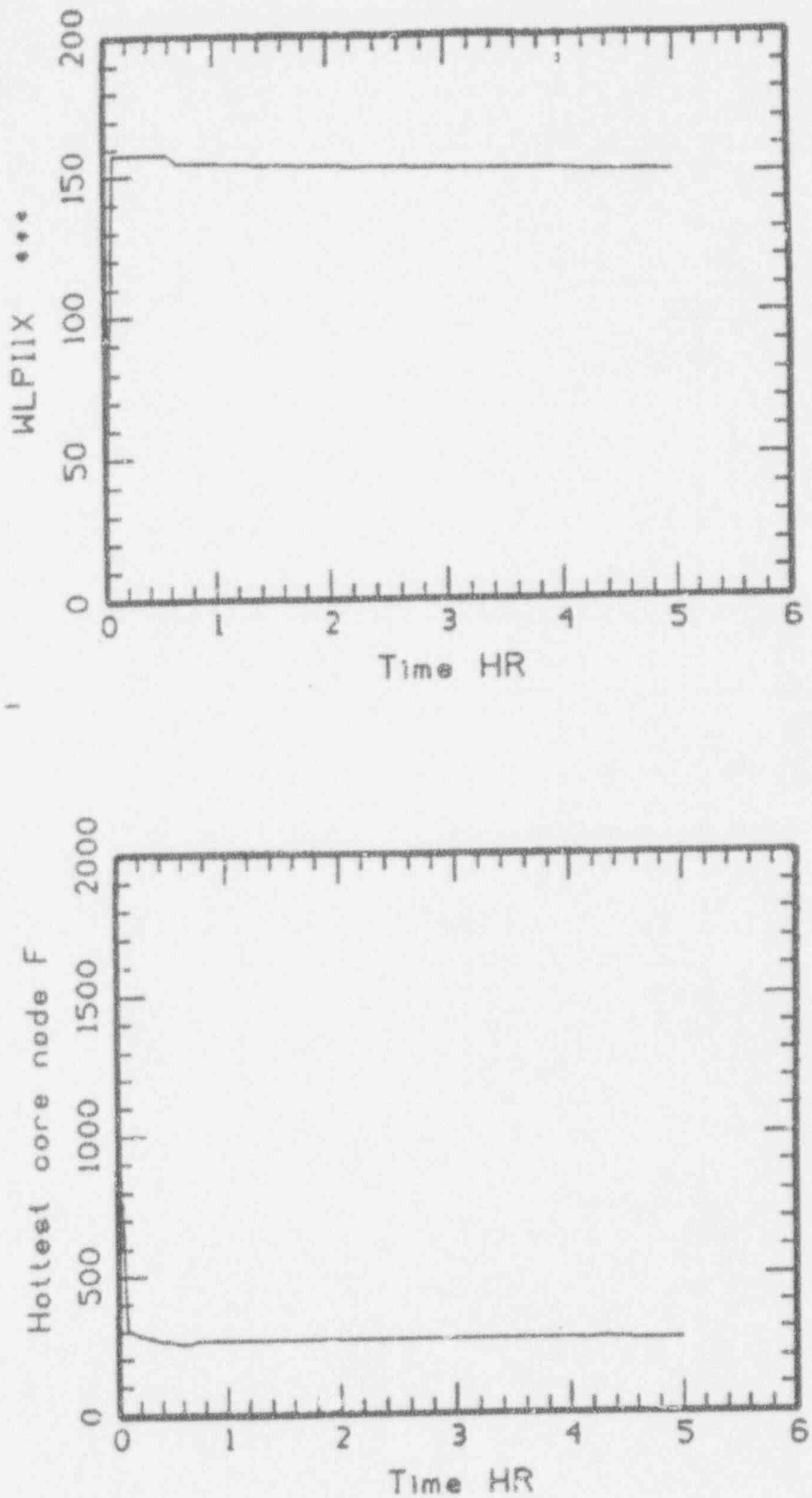


Figure 7.1-2 ESF Flow Rate and Hottest Core Node Temperature for RHR Success Criteria During a Large-break LOCA

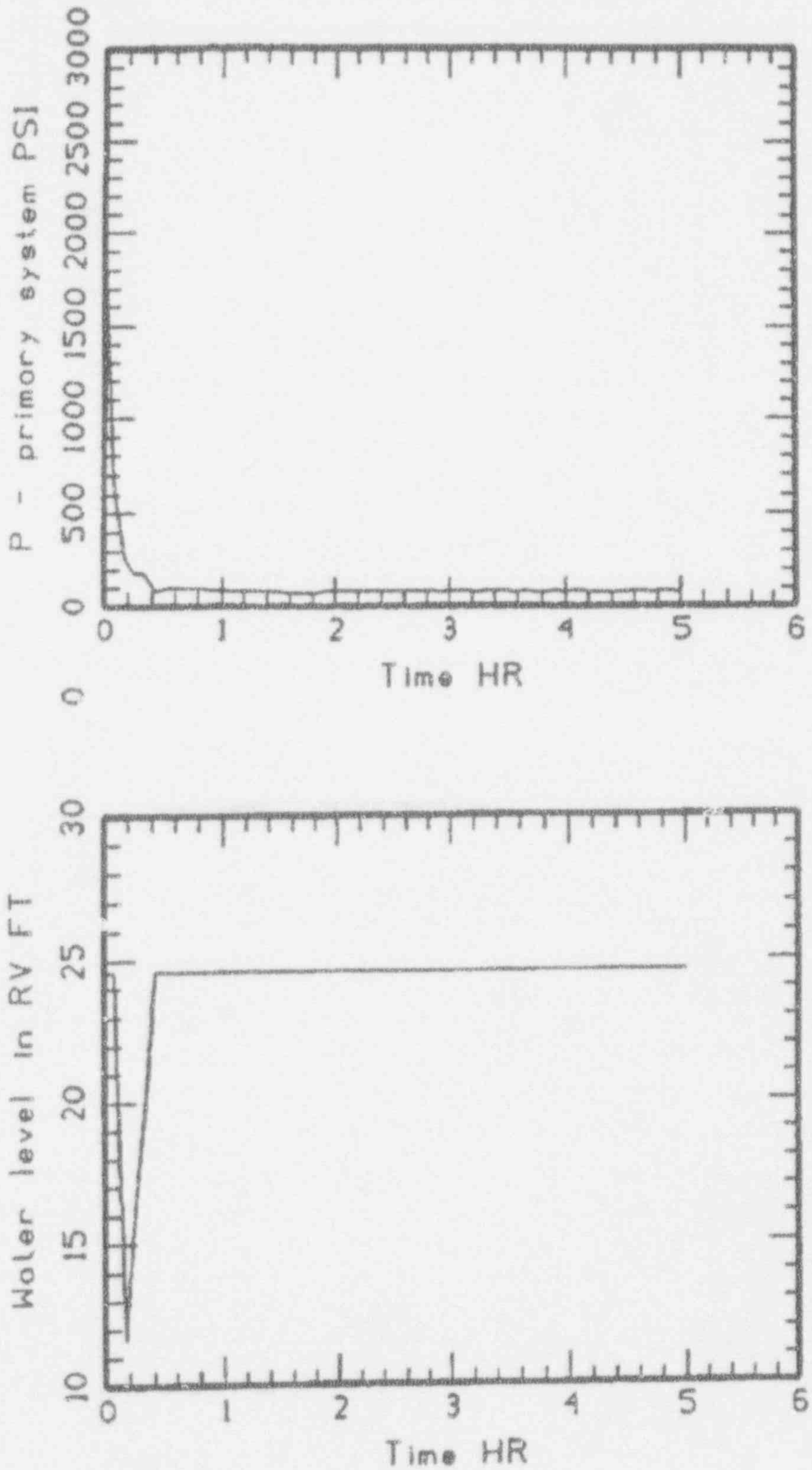
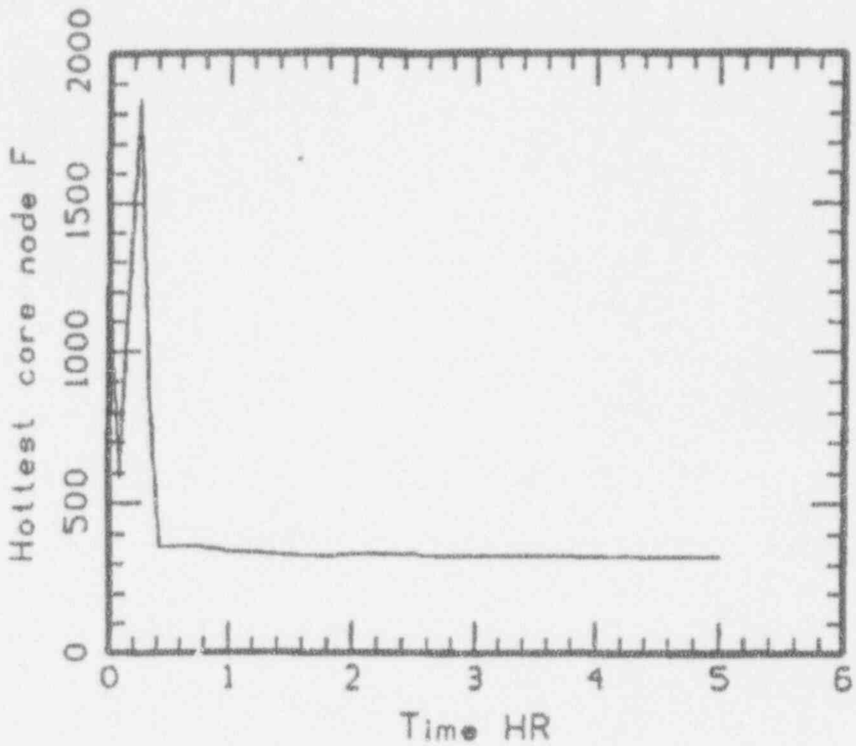


Figure 7.1-3 RPV Pressure and RPV Water Level for RHR Success Criteria During a Medium-break LOCA (5" diameter)



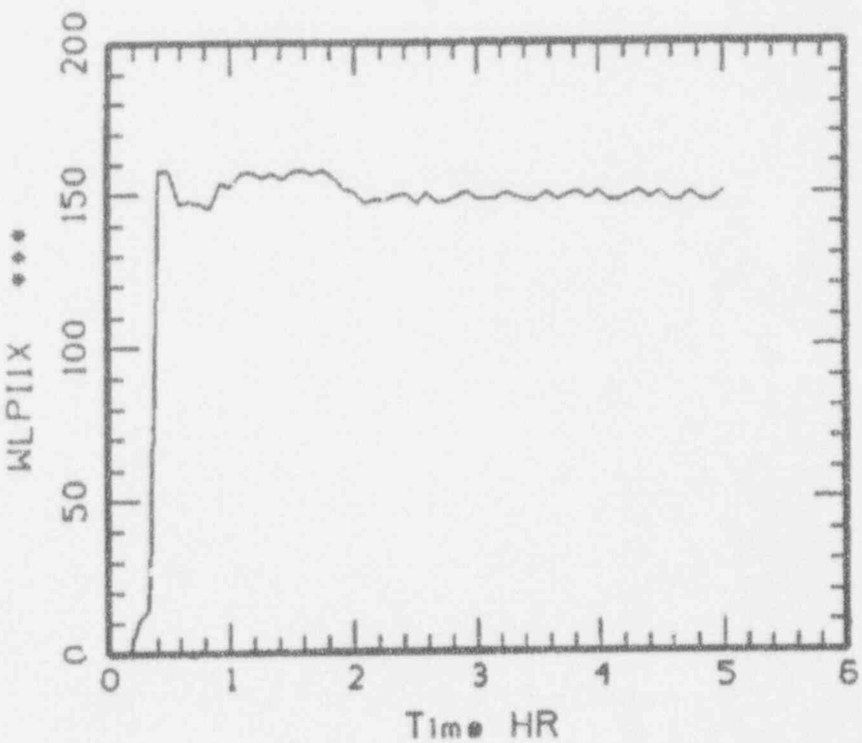


Figure 7.1-4 ESF Injection Flow Rate and Hottest Core Node Temp. for RHR Success Criteria During a Medium-break LOCA (5" diameter)

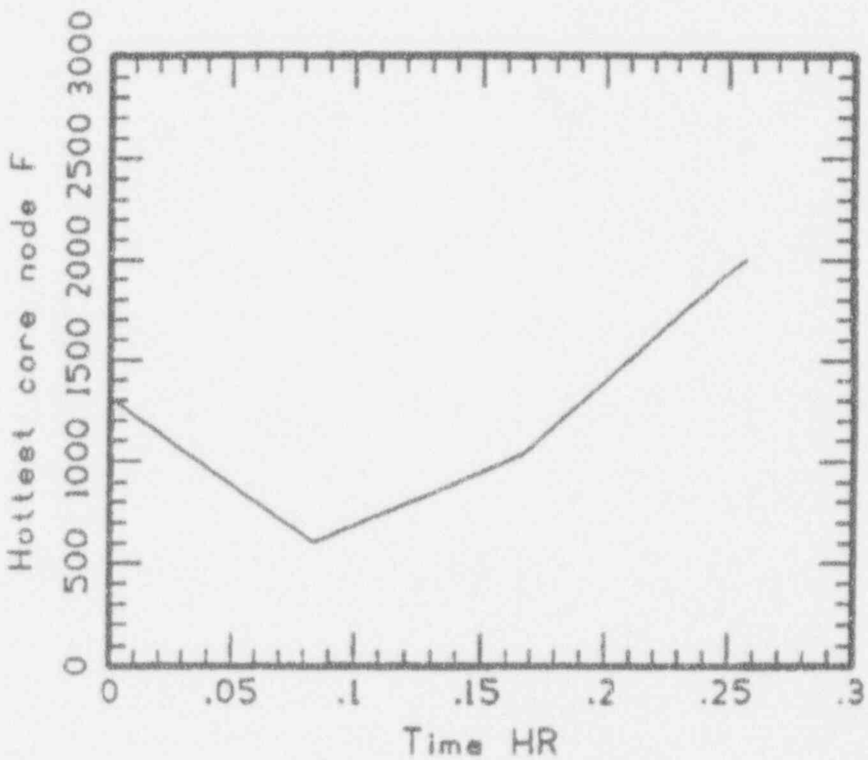
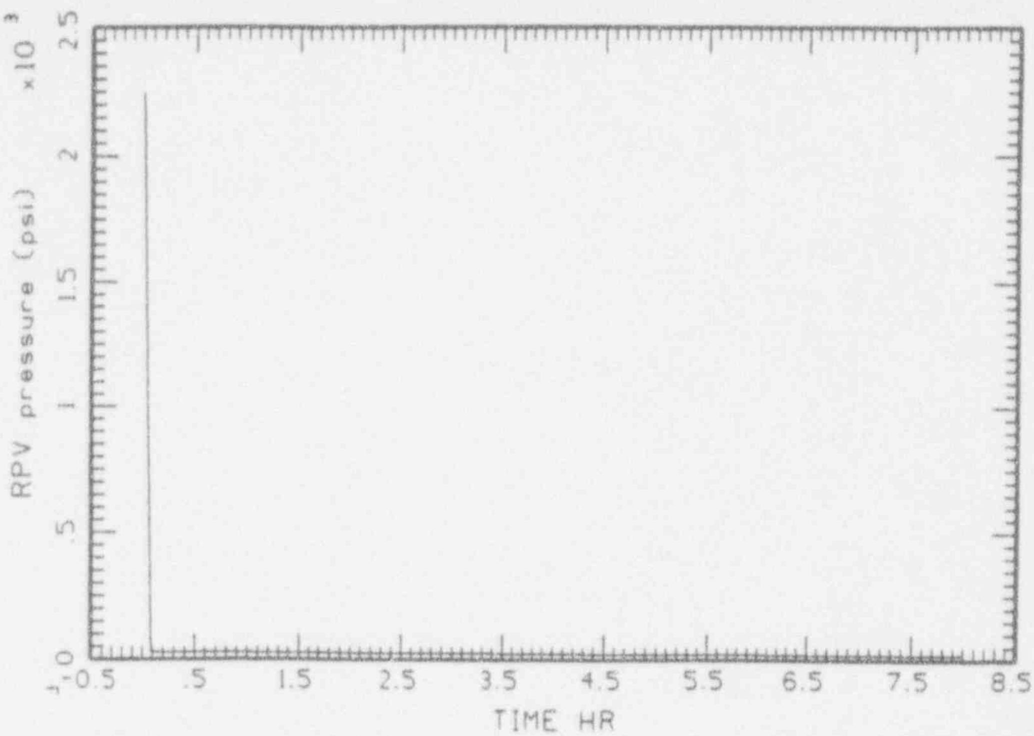


Figure 7.1-5 Hottest Core Node Temperature for a 4.5" Break Diameter for RHR Success Criteria During a Medium-break LOCA



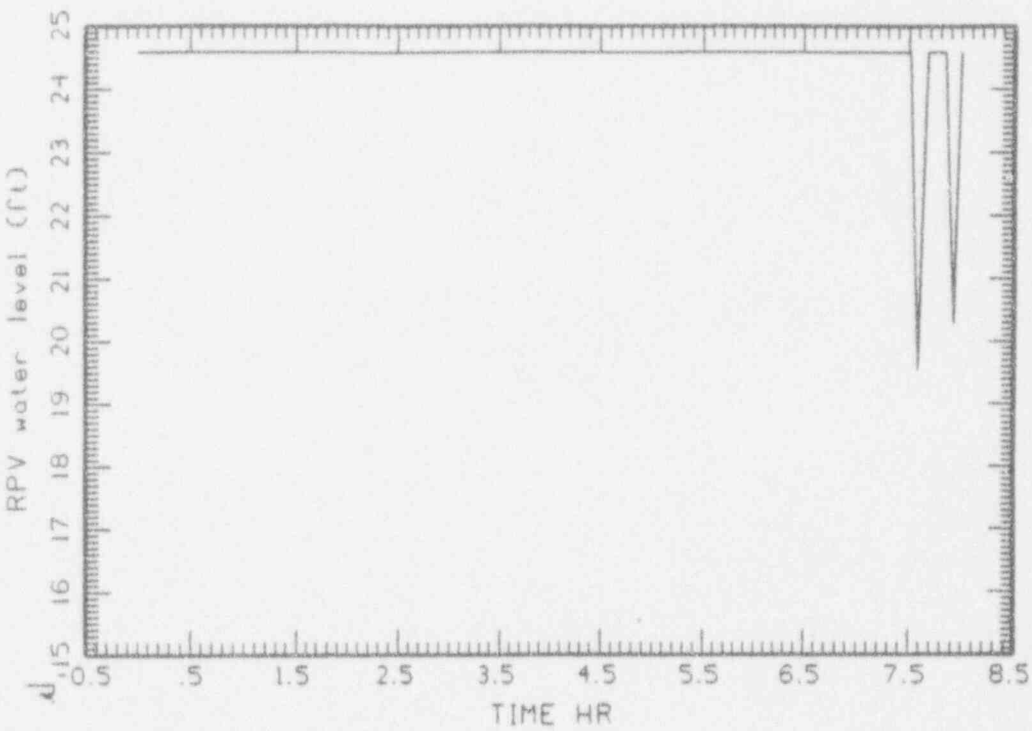


Figure 7.1-6 RPV Pressure and RPV Water Level for SI Success Criteria During a Medium-break LOCA

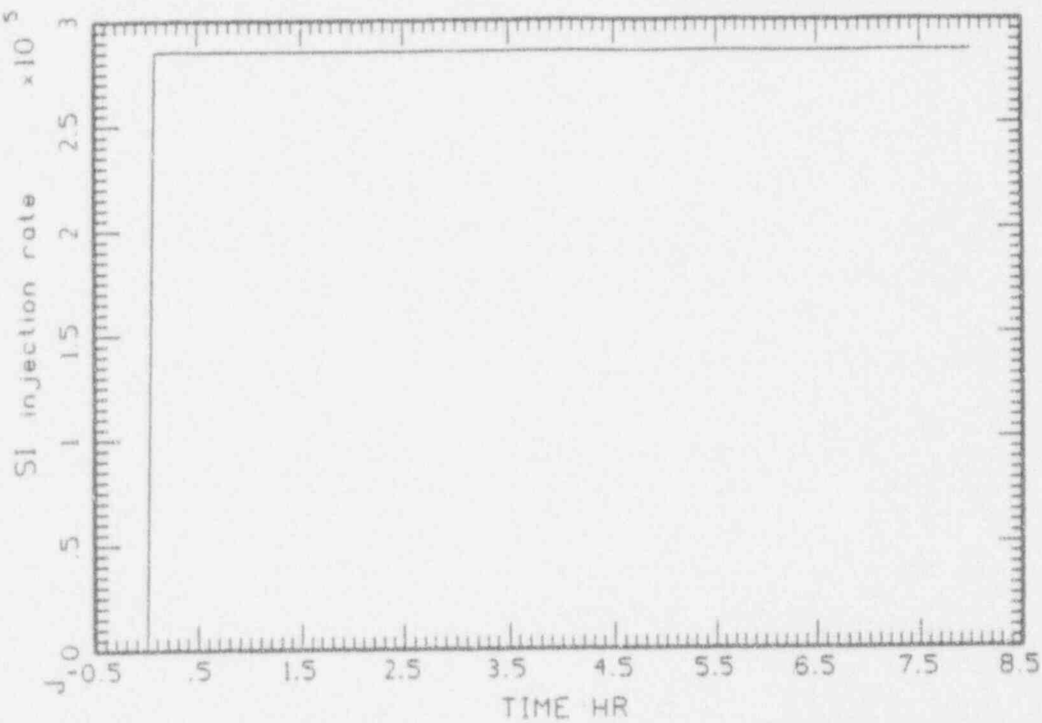
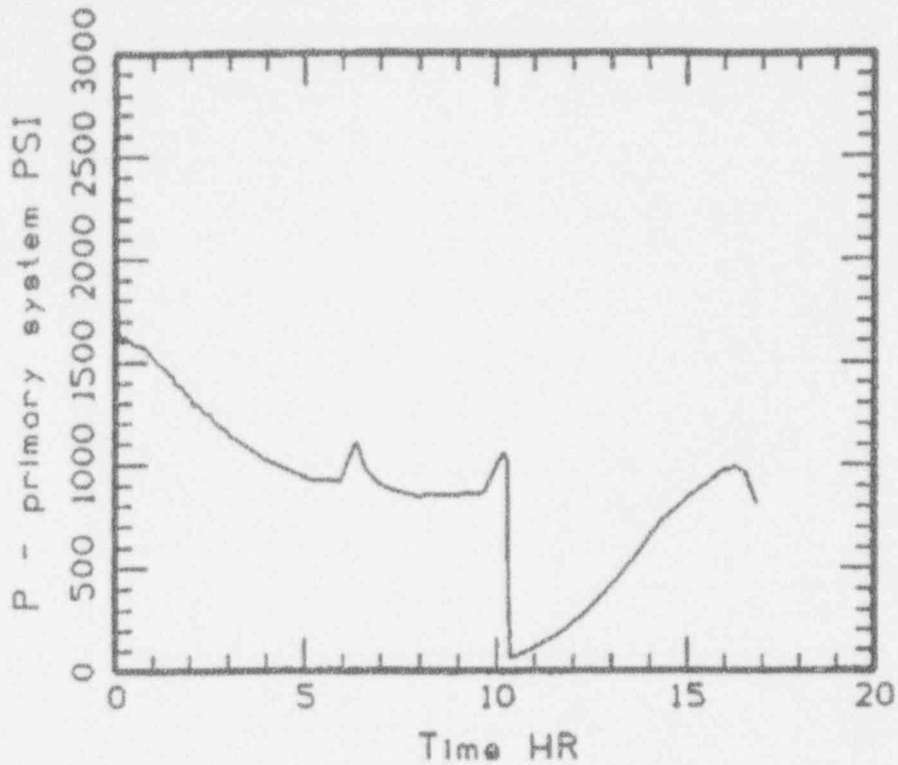


Figure 7.1-7 SI Injection Flow Rate for SI Success
Criteria During a Medium-break LOCA



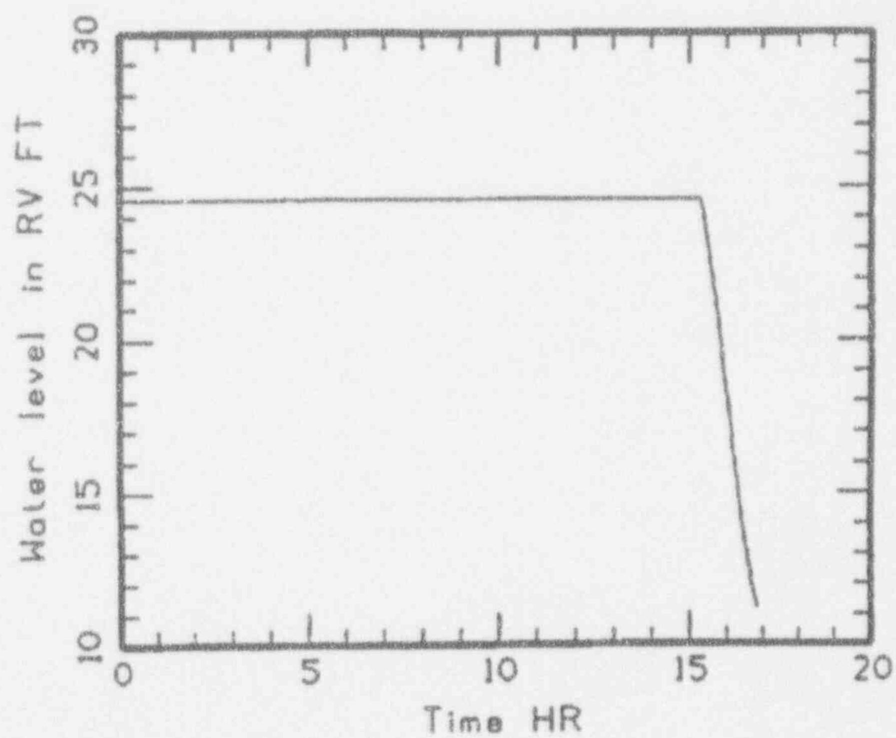
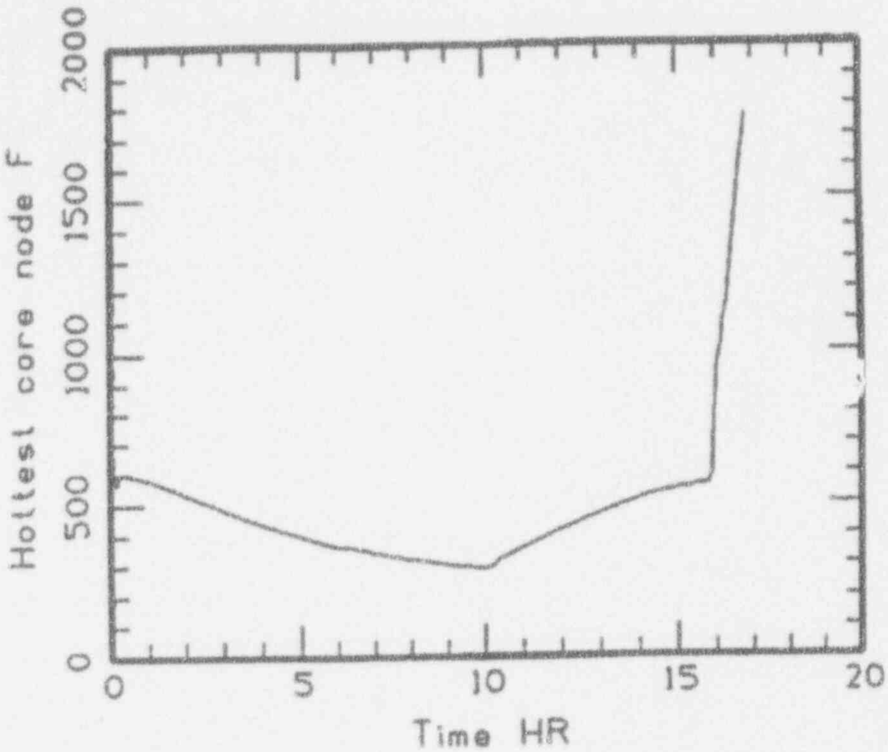


Figure 7.1-8 RPV Pressure & Water Level for 7/8" Break for SI Success Criteria During a Small-break LOCA



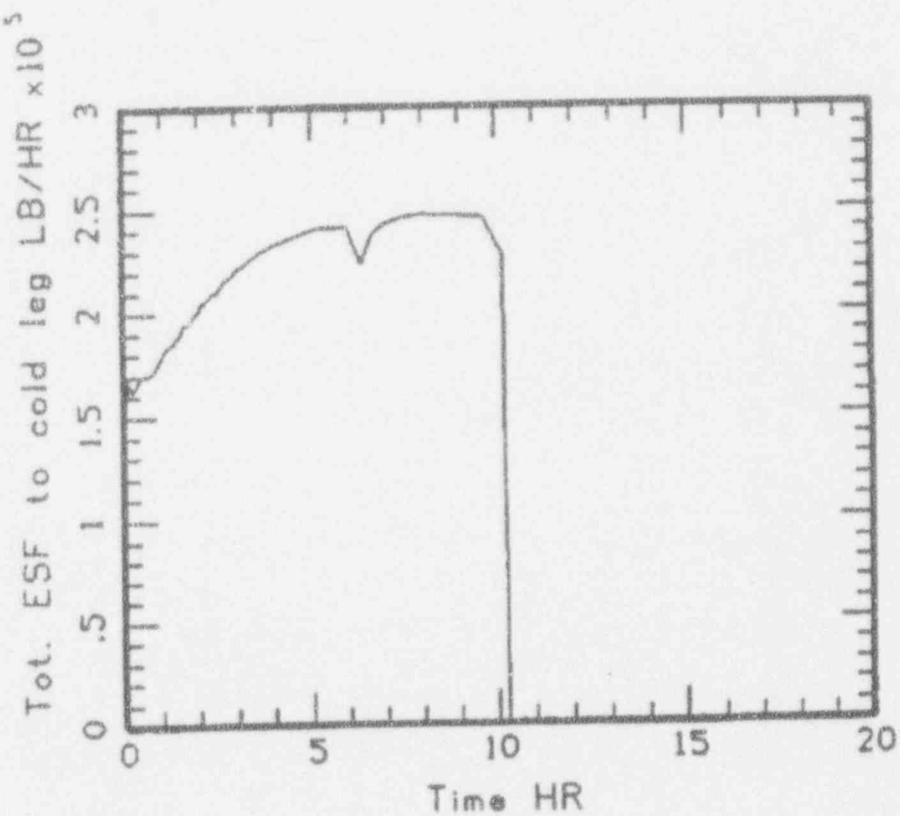
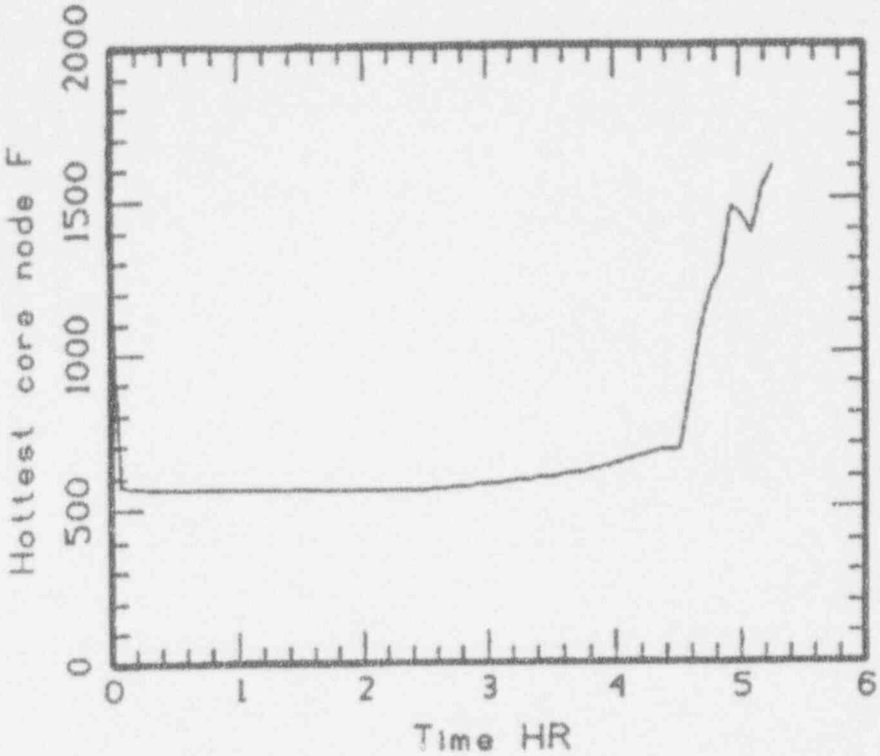


Figure 7.1-9 Hottest Core Node Temp. & SI Flow Curve for 7/8" Break for SI Success Criteria During a Small-break LOCA



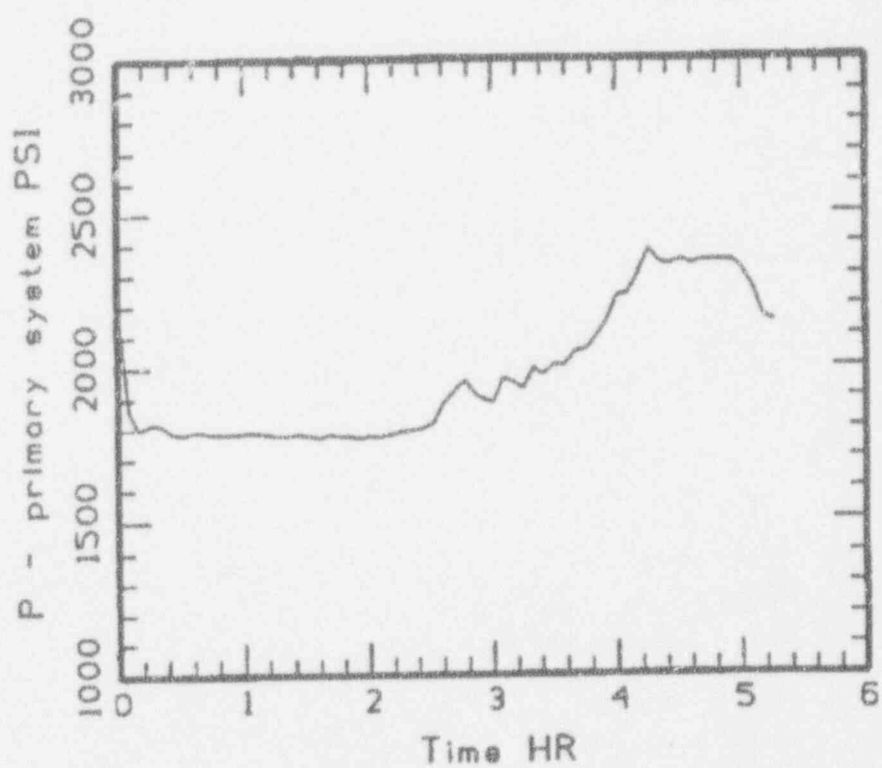


Figure 7.1-10 Hottest Core Node Temp. & RPV Pressure for 3/4" Break for SI Success Criteria During a Small-break LOCA

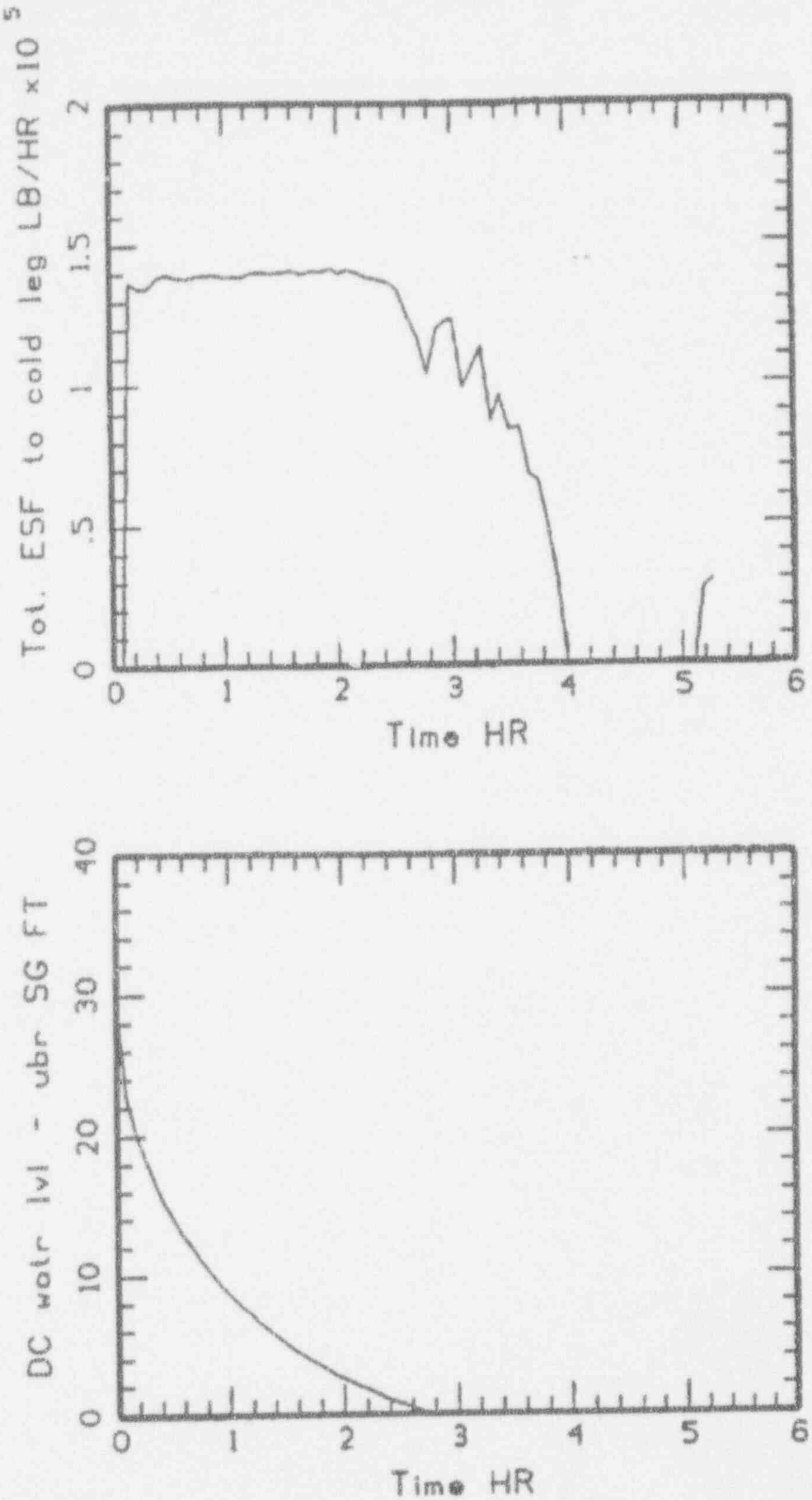


Figure 7.1-11 SI Flow Curve & SG Water Level for 3/4" Break for SI Success Criteria During a Small-break LOCA

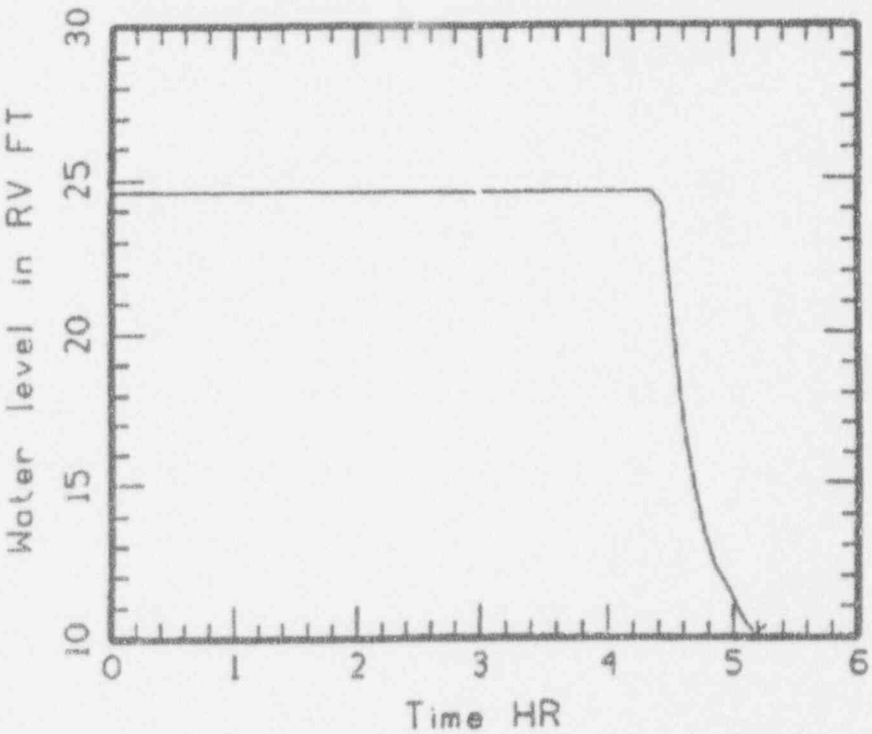
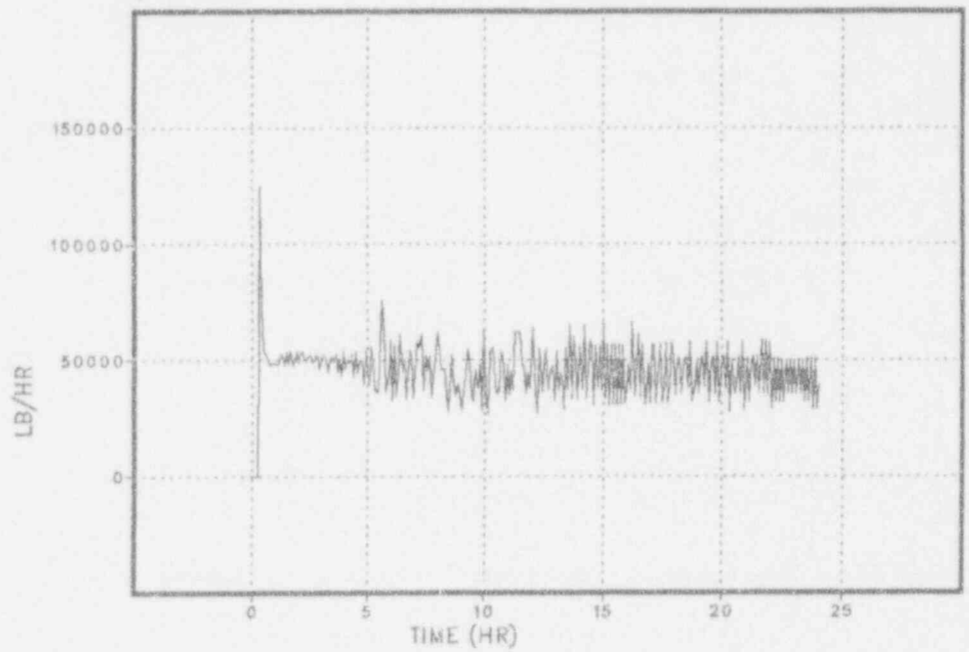


Figure 7.1-12 RPV Water Level for a 3/4" Break for SI Success Criteria During a Small-break LOCA

Total mass flow of ESF water to cold legs nodes.
(WESFCL)



Downcomer water level in unbroken steam generator(s).
(ZWUS)

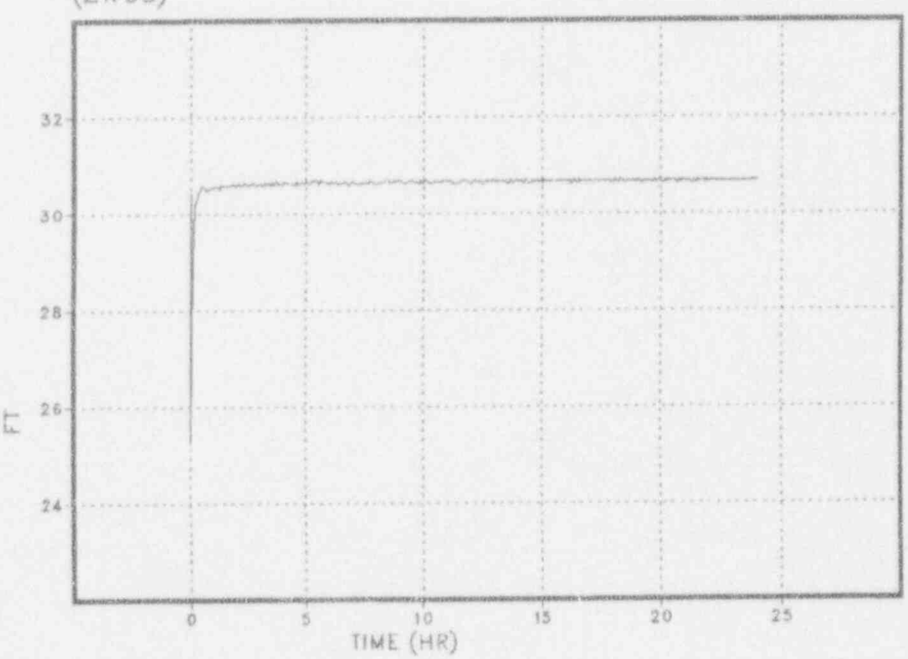
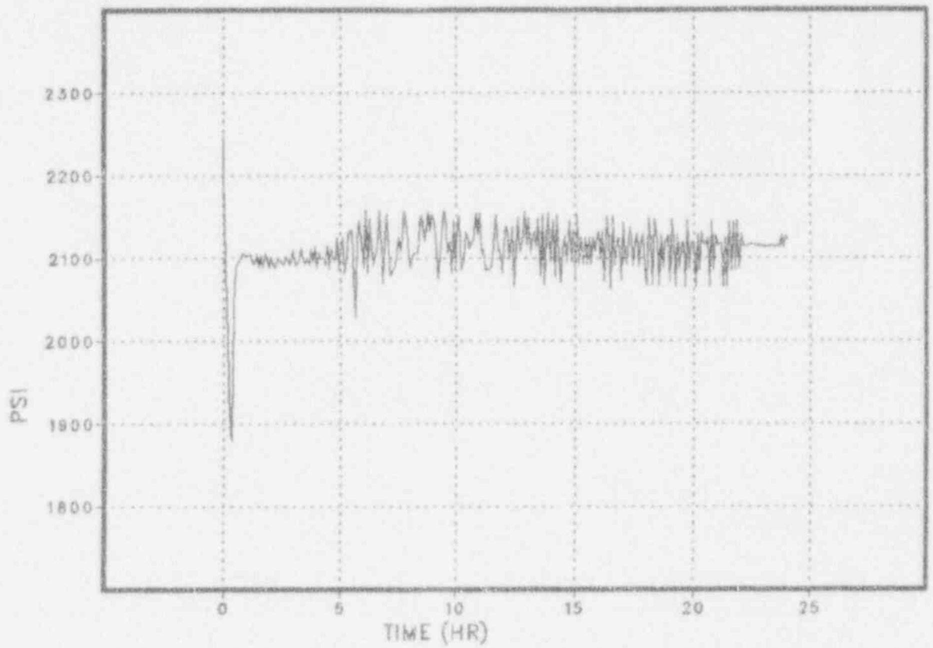


Figure 7.1-13 ESF Flow & SG Water Level for SI Success Criteria During a Small-break LOCA with AFW

Pressure in the primary system.
(PPS)



Temperature of the hottest core node.
(TCRHOT)

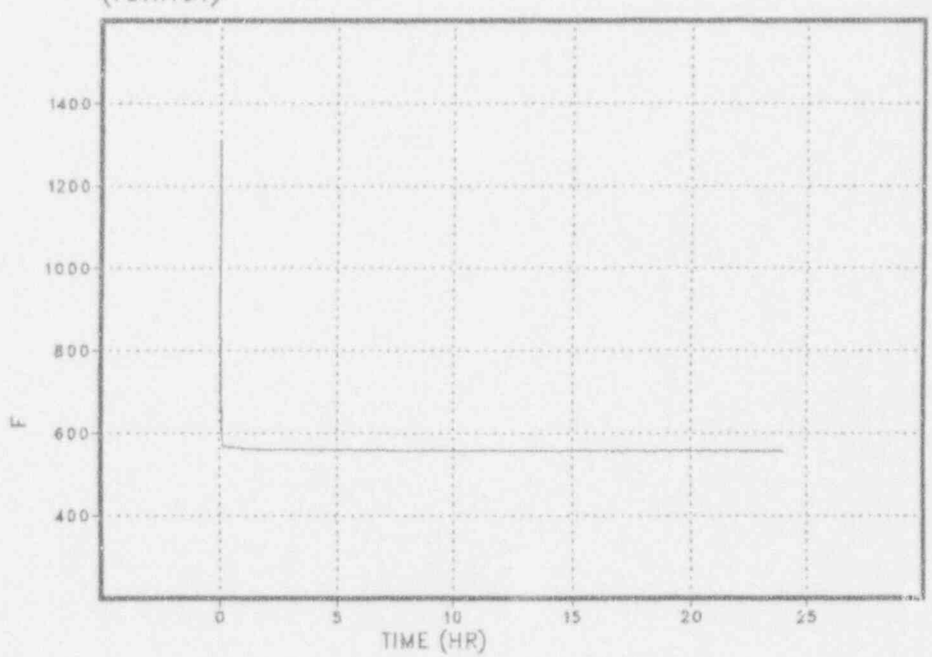
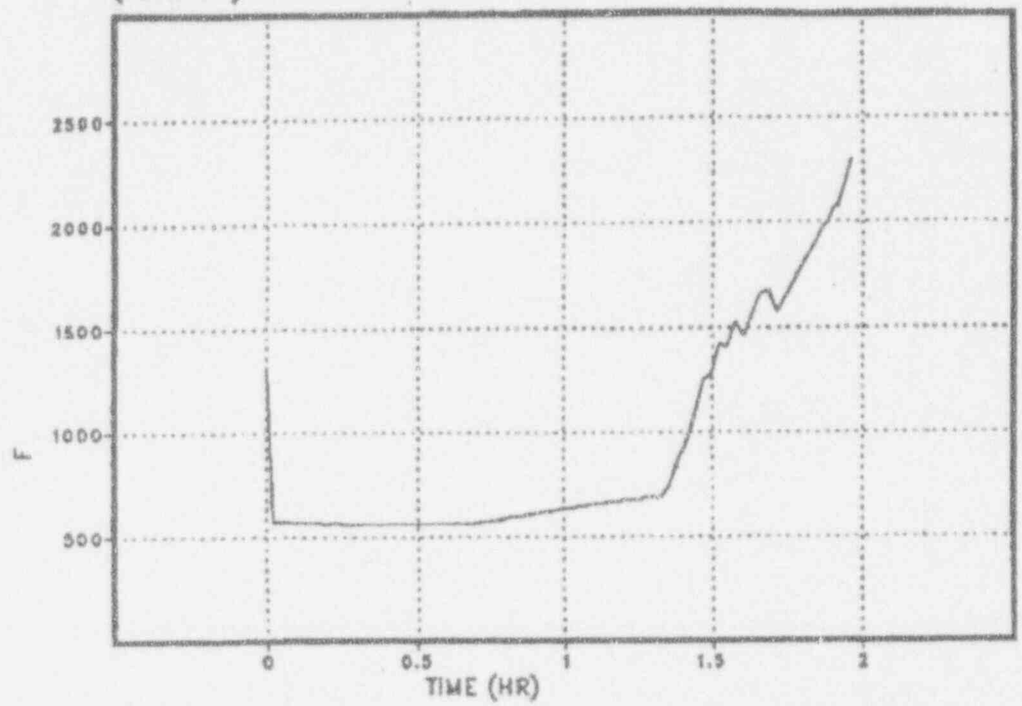


Figure 7.1-14 RPV Pressure & Hottest Core Node Temp. for SI Success Criteria During a Small-break LOCA with AFW

Temperature of the hottest core node.
(TCRHOT)



Downcomer water level in unbroken steam generator(s).
(ZWUS)

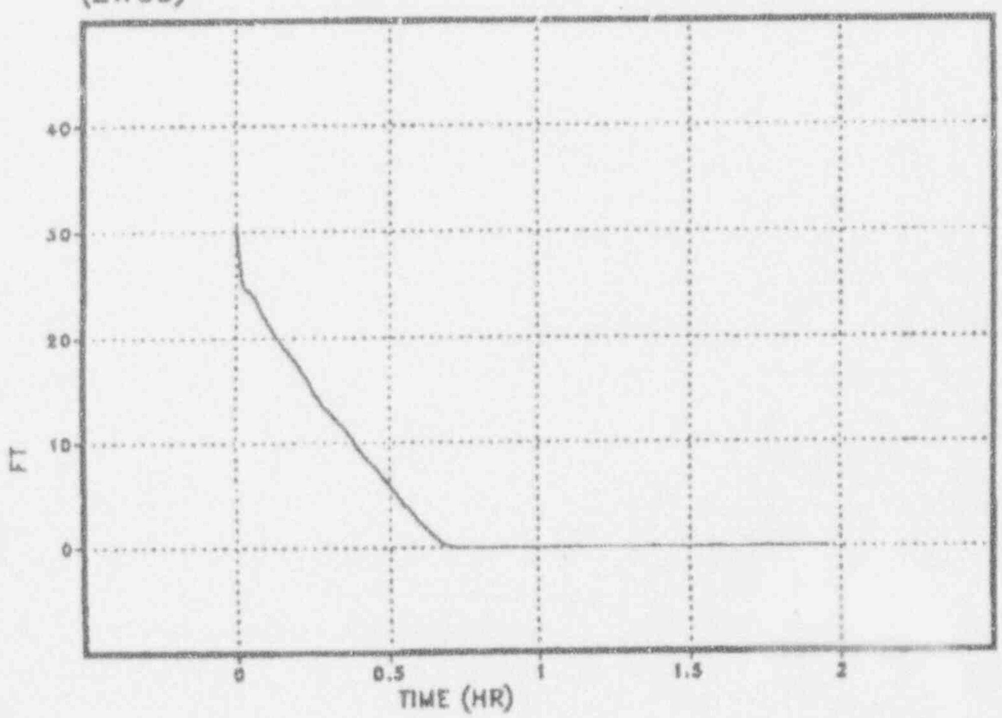
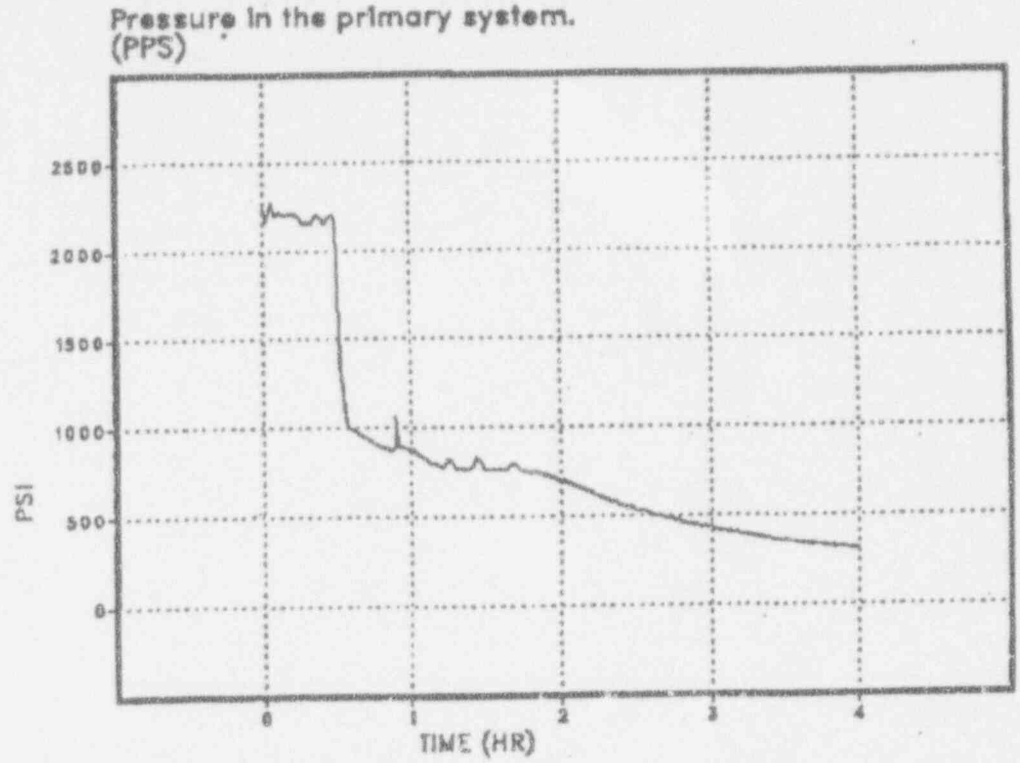


Figure 7.1-15 Hottest Core Node Temp. & SG Water Level for Transient Success Criteria to Restore Feedwater and Initiate Feed & Bleed



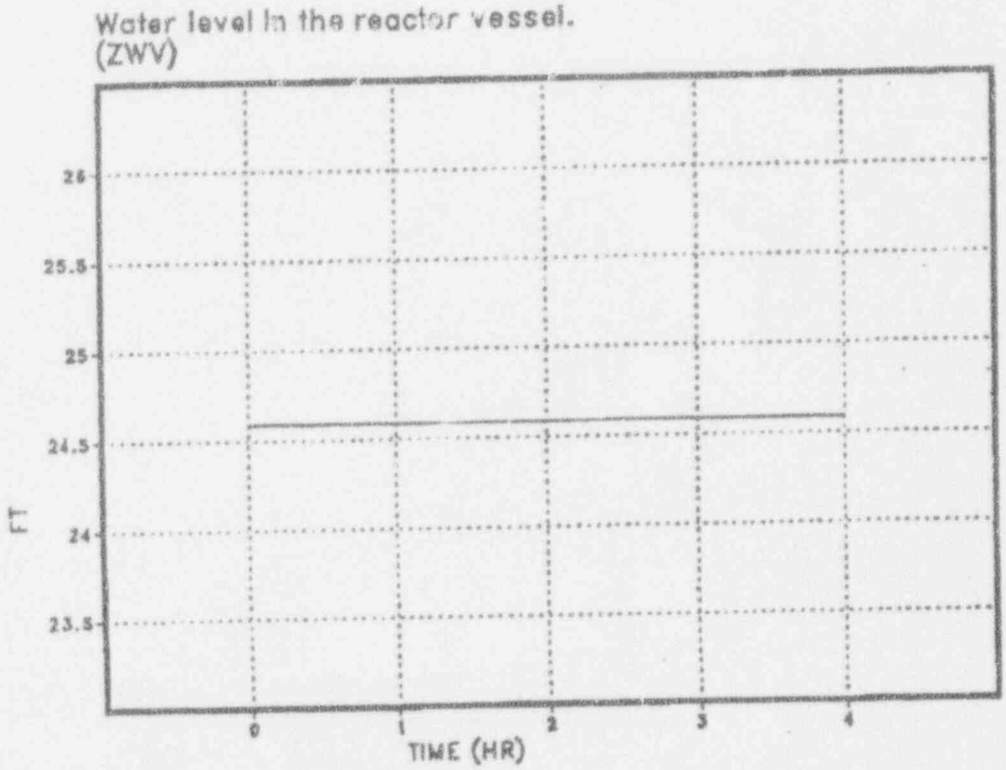
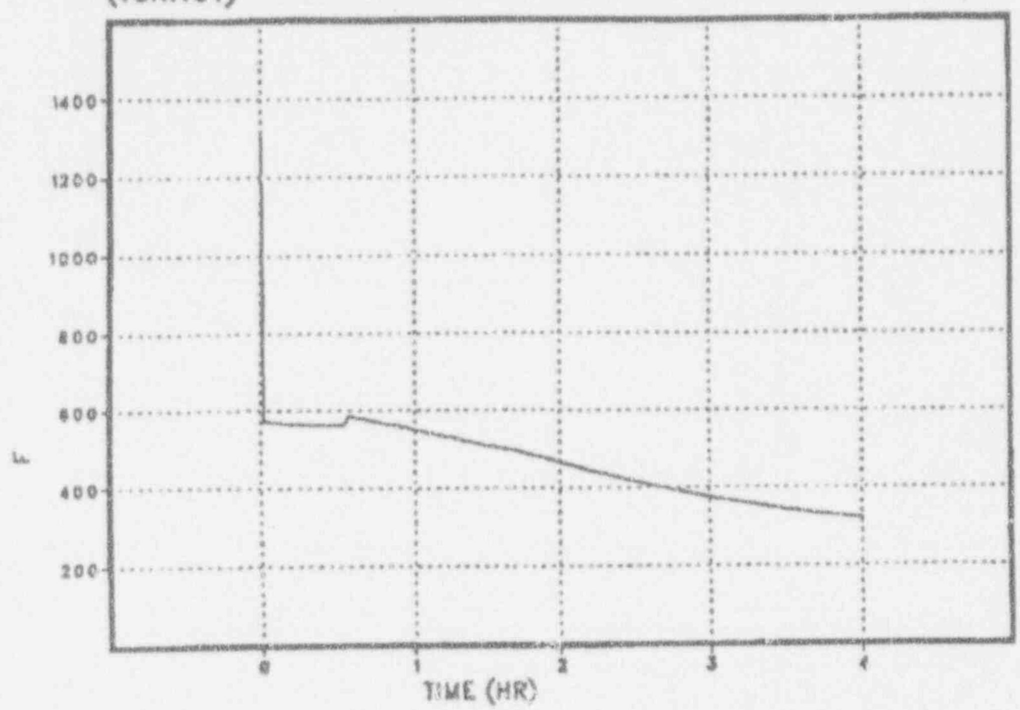


Figure 7.1-16 RPV Pressure & Water Level for Transient Success Criteria to Establish Feed & Bleed Using 1 PORV and 1 SI Pump

Temperature of the hottest core node.
(TCRHOT)



Water level in the pressurizer above the bottom of the pressurizer. (ZWPZ)

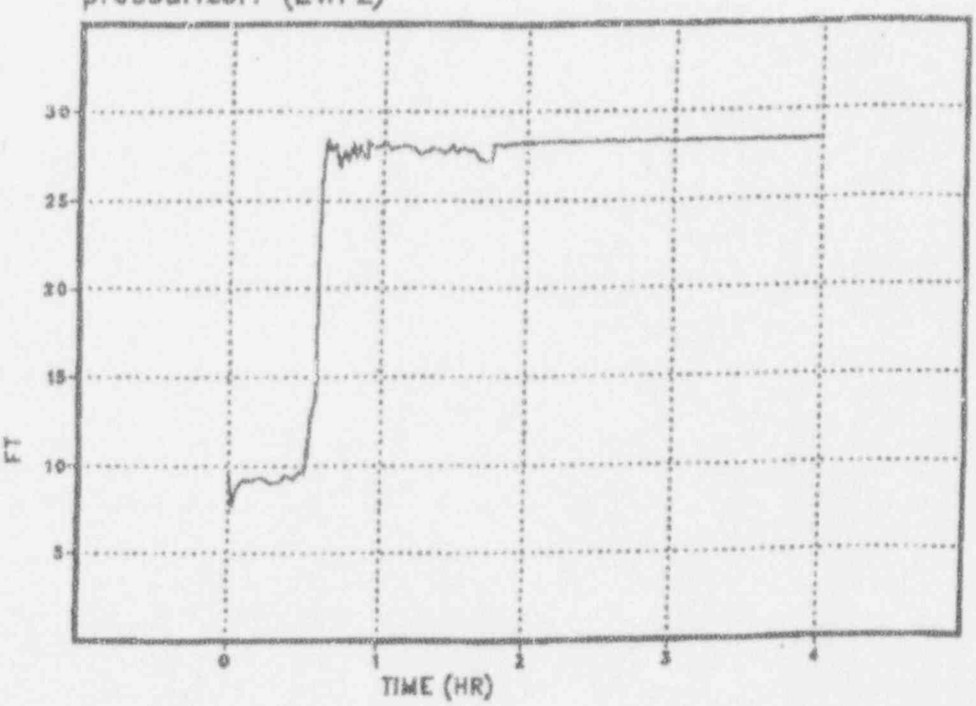
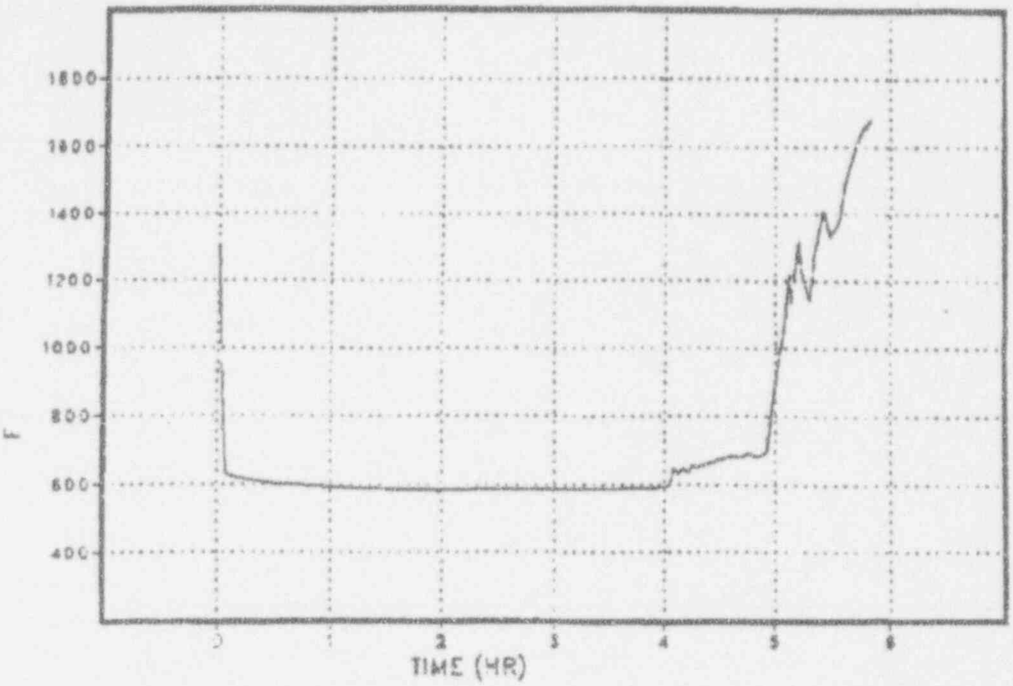


Figure 7.1-17 Hottest Core Node Temp. & Pressurizer Level for Transient Success Criteria to Establish Feed & Bleed using 1 PORV and 1 SI Pump

Temperature of the hottest core node.
(TCRHOT)



Downcomer water level in unbroken steam generator(s).
(ZWUS)

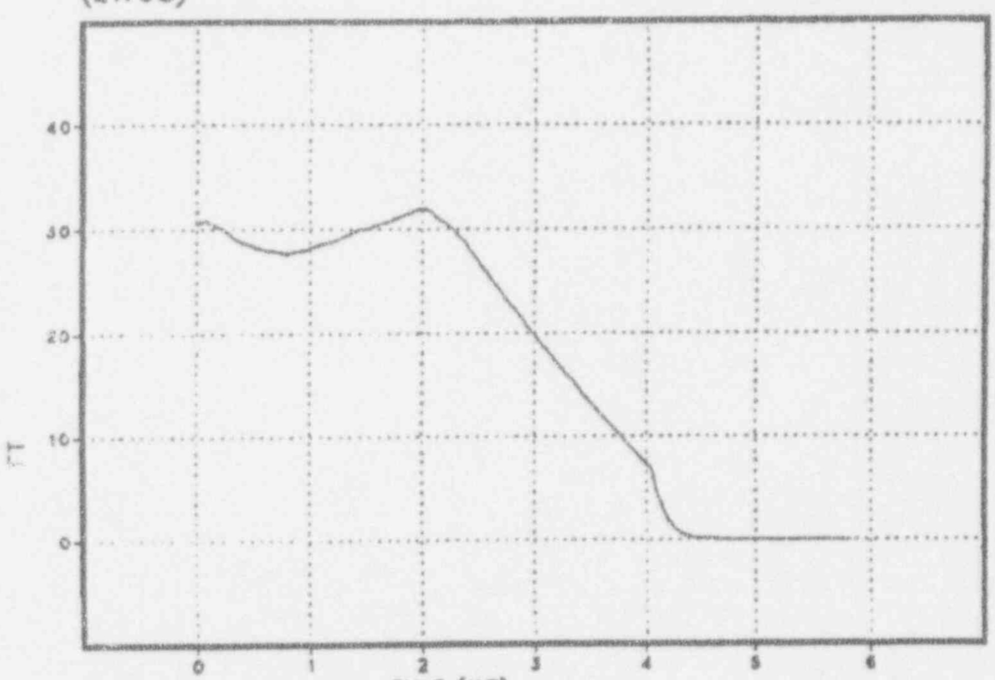
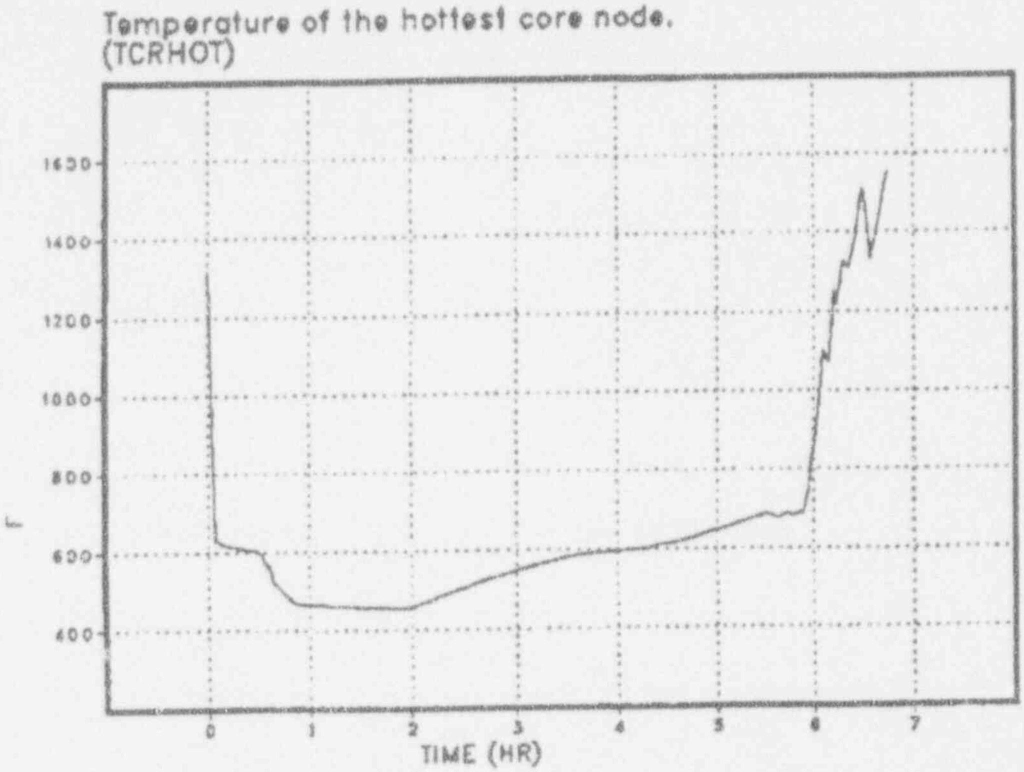


Figure 7.1-18 Hottest Core Node Temp. & SG Water Level for Transient Success Criteria During Station Blackout w/ TDAFW



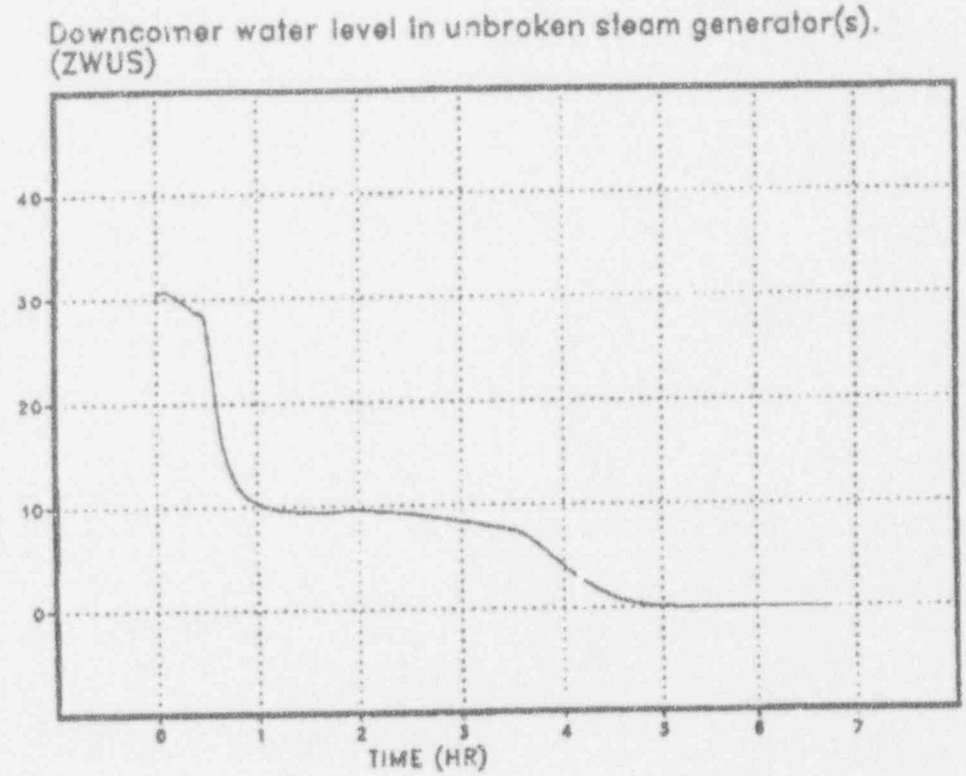
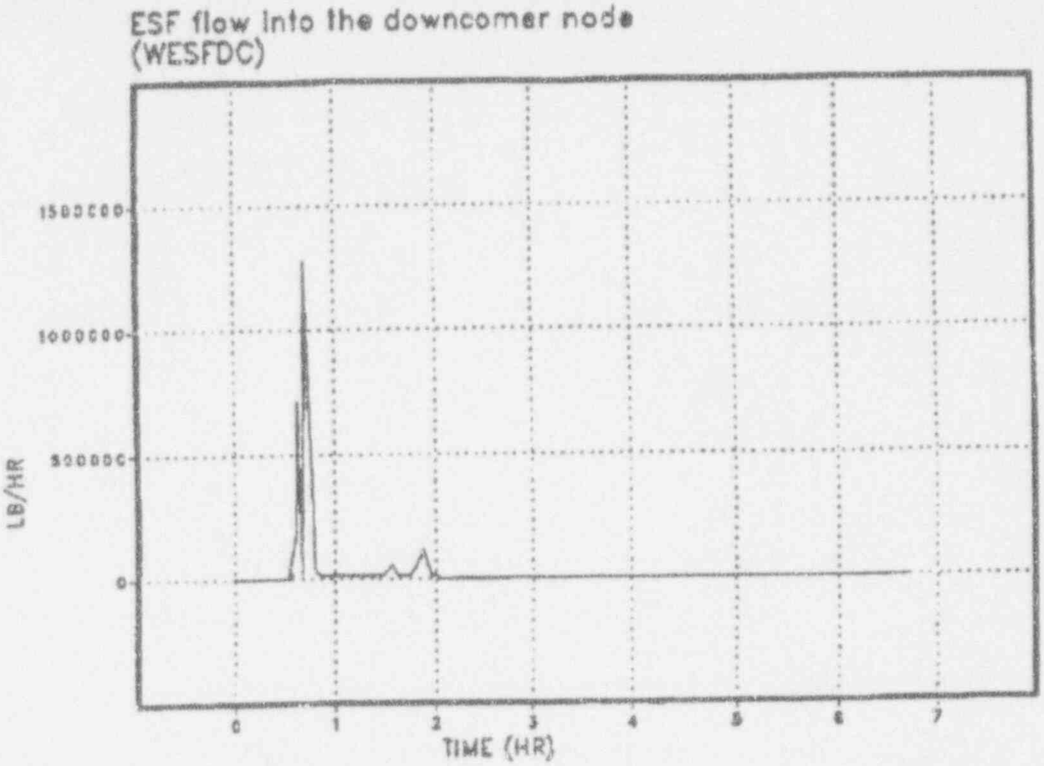


Figure 7.1-19 Hottest Core Node Temp. & SG Water Level for Transient Success Criteria During SBO with TDAFW & SG Depressurization



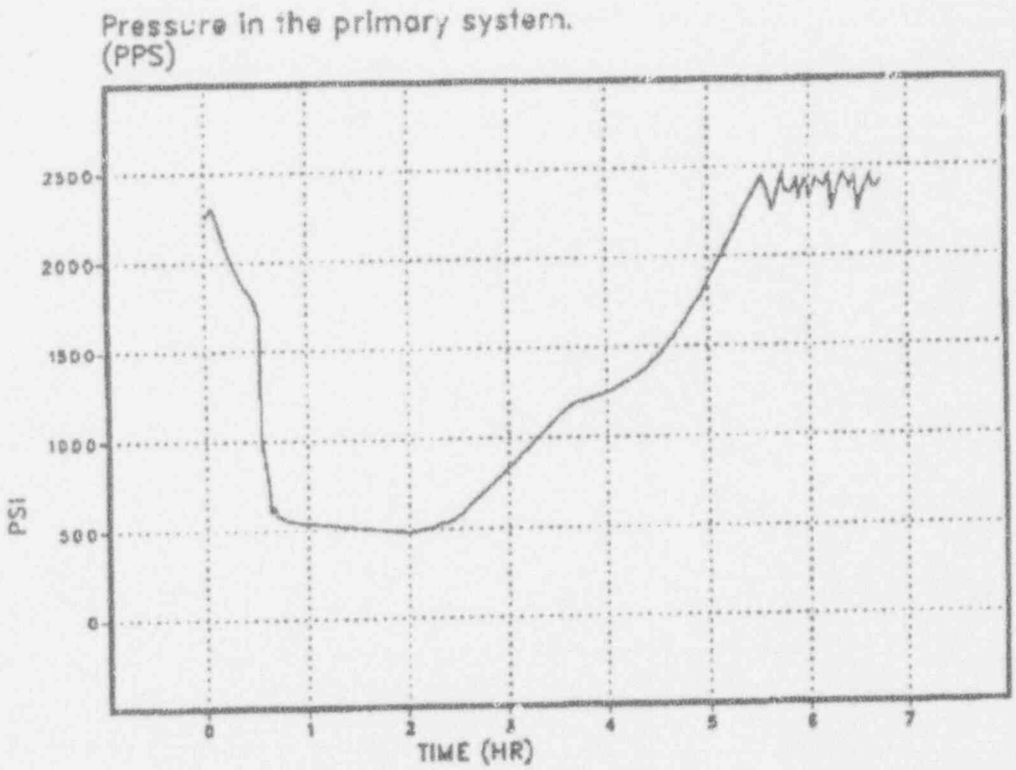
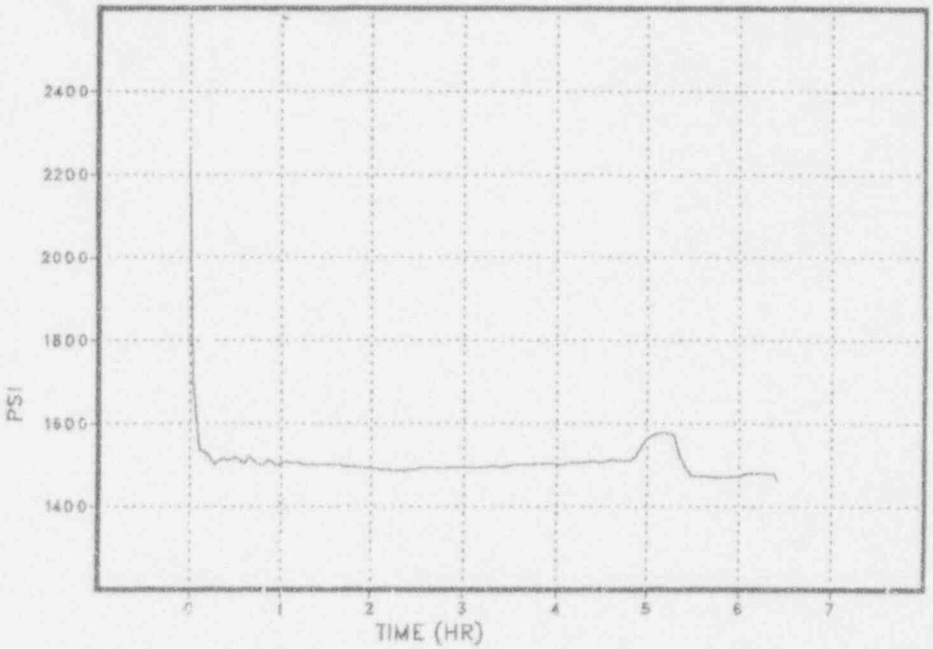


Figure 7.1-20 Accumulator Flow & RPV Pressure for Transient Success Criteria During a SBO with TDAFW & SG Depressurization

Pressure in the primary system.
(PPS)



Mass flow rate of water through the relief valve
of the broken loop steam generator (WWBST)

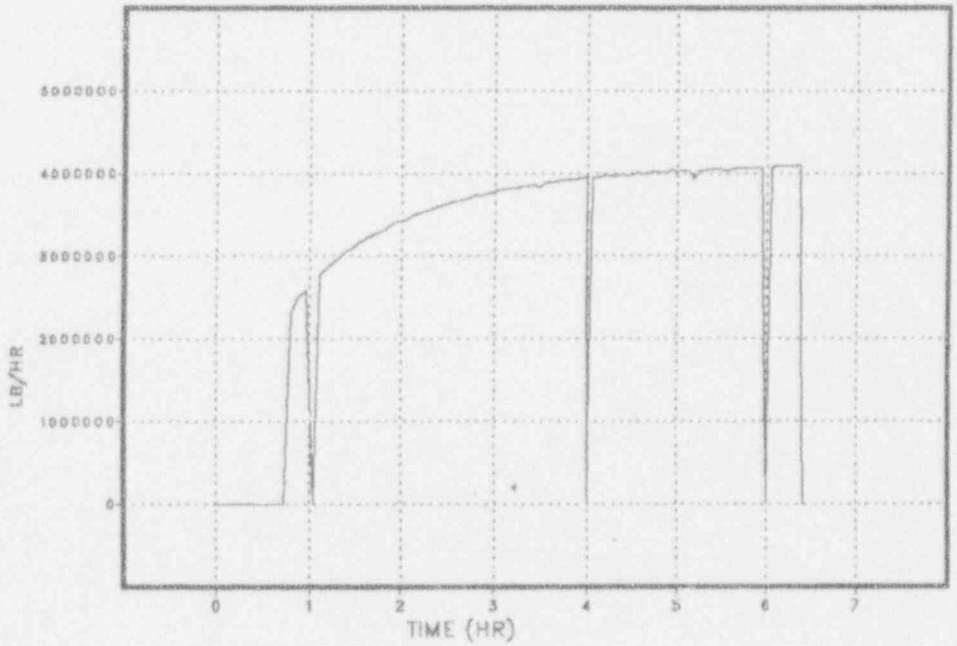
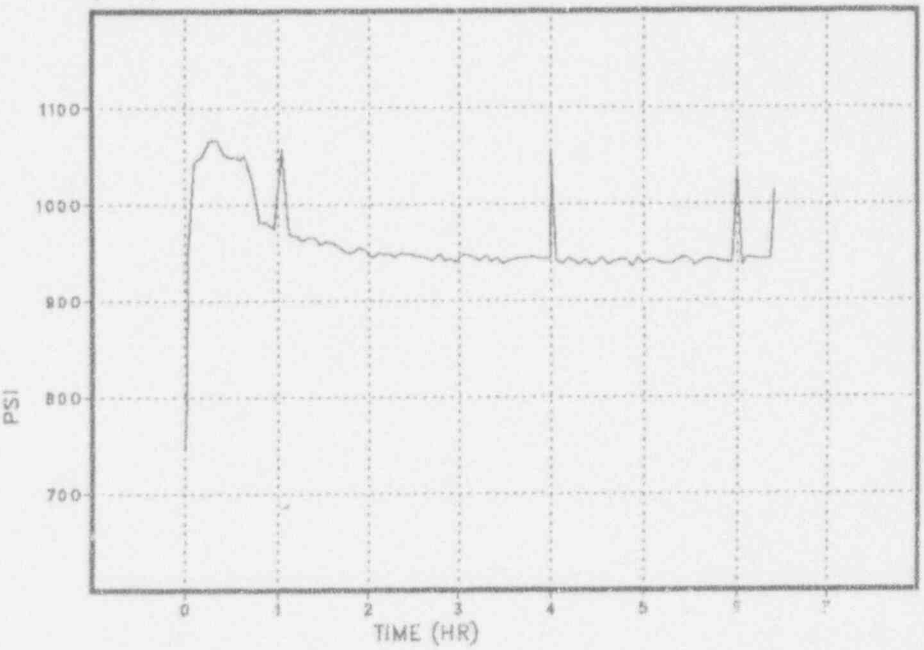


Figure 7.1-21 Steam Generator Tube Rupture Success Criteria

Pressure in broken loop steam generator.
(PBS)



Downcomer water level in the broken loop steam generator. (ZWBS)

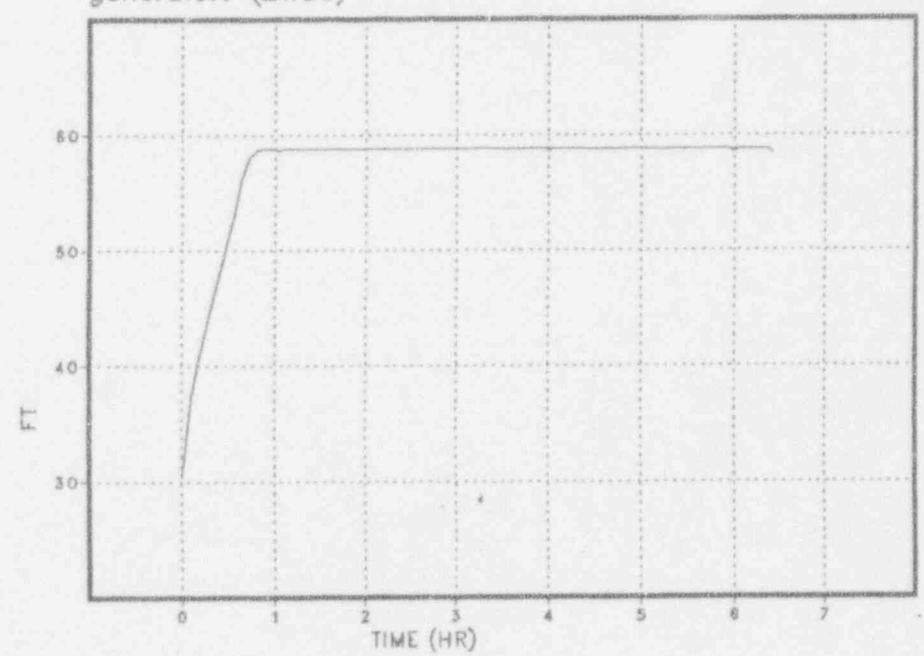
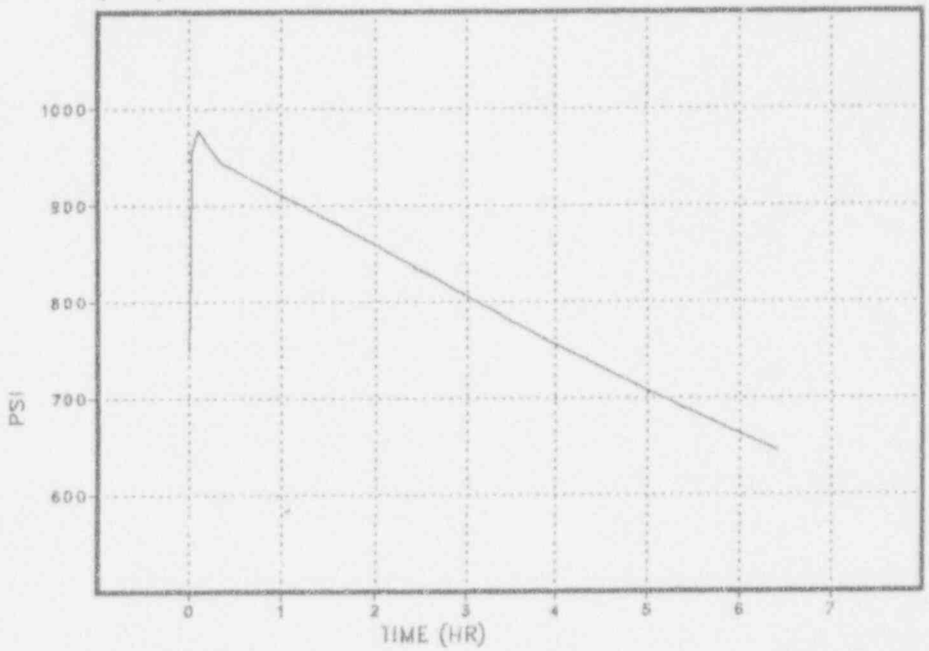


Figure 7.1-22 Steam Generator Tube Rupture Success Criteria

Pressure in unbroken steam generator(s).
(PUS)



Downcomer water level in unbroken steam generator(s).
(ZWUS)

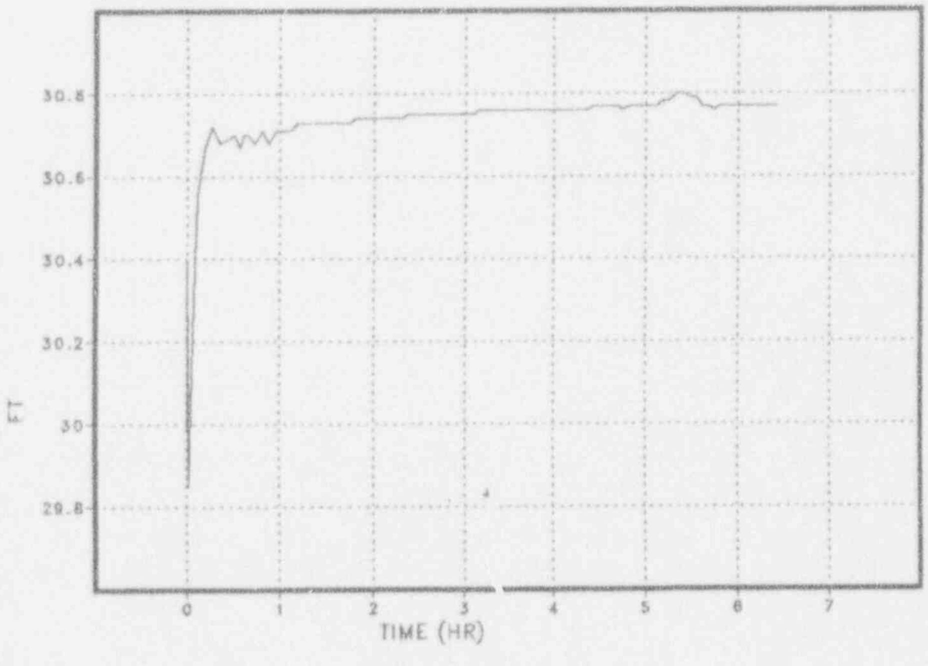


Figure 7.1-23 Steam Generator Tube Rupture Success Criteria

7.2 Containment Response and Success Criteria

Six cases are considered to establish containment response, success criteria for containment heat removal and debris coolability, and containment failure timing for both high and low pressure melt ejection sequences at Prairie Island. Sequences are considered for 48 hours to include accident progression after core damage, RPV failure, and various containment phenomena. Station blackouts, loss of feedwater transients and design basis LOCAs are considered as accident initiators.

7.2.1 High Pressure Melt Ejection with Injection after Vessel Failure

The purpose of this case is to determine how the Prairie Island containment responds to a high pressure melt ejection (HPME) with RWST injection into the containment after vessel failure, and one fan cooler available. This case is a loss of main and auxiliary feedwater transient with only one low pressure (RHR) train available for injection. All operator actions to depressurize the vessel prior to core damage were unsuccessful. Therefore, low pressure injection is unavailable until the vessel depressurizes after vessel failure. In terms of containment heat removal, one containment fan cooler and one train of containment spray injection, but not spray recirculation, are available. The operator switches to the RHR recirculation mode after the RWST level decreases to 28%, but the RHR heat exchanger is unavailable. Accumulators are also not available.

Core uncovery and core damage occur fairly rapidly in this sequence. The core uncovers in approximately 1.5 hours, and core damage occurs 2.2 hours after accident sequence initiation. The RPV fails at 2.8 hours causing the containment to pressurize beyond the setpoint for containment sprays. This causes one train of containment sprays to inject into containment. Vessel failure also depressurizes the RPV below the setpoint for low pressure injection. The one train of low pressure injection then injects to the failed vessel and the water exits the RPV through the failure at the bottom of the vessel. The containment cavity becomes water solid after 3.4 hours because of the RHR injection. With containment sprays and low pressure injection operating, the RWST is depleted to the 28% level at 3.6 hours. The operator then establishes the RHR recirculation, but containment spray recirculation is not established.

Because the melt ejection occurs at high pressure, most of the debris is not retained in the cavity, but is dispersed to higher elevations within containment. With MAAP 3.0B, this is modelled by directing the debris into the upper compartment. Immediately after vessel failure, most of the core debris in the upper compartment, with very little debris remaining in the cavity. As core material continues to melt after vessel failure, debris is introduced into the cavity. There is no significant amount of concrete ablation or hydrogen generation in the cavity. This is due to the fact that the cavity is always water solid after RWST injection is initiated.

Containment pressure and temperature increase rapidly during vessel failure, but then decrease rapidly due to the availability of the fan cooler, low pressure injection, and containment sprays. The pressure in the cavity is 79.5 psia at vessel failure; the average pressure in the rest of the containment is 48.9 psia after vessel failure then decreases rapidly. Approximately 10 hours into the sequence, the average containment pressure is roughly 25 psia throughout containment. The containment pressure remains at this level for approximately 24 hours. Fan coolers continue to condense any steam that might be generated by contact between water and the core debris. Condensed steam is refluxed back to the lower containment water pools, where it is then recirculated to the RPV via the RHR pump. Still, the gas temperature in the upper compartment stays around 400°F during this time, owing to the presence of a dry debris bed. Other compartment gas temperatures are somewhat lower, however. The temperature of the lower containment water pool increases continually after vessel failure. After roughly 35 hours, containment pressure begins to increase at a rate of about 0.2 psi/hr due to steaming from the water pools. The water pools become saturated and begin to vaporize water due to the absence of the RHR heat exchanger in recirculation.

Containment temperatures and pressures are far below those required to cause failure. However, to establish a safe, stable state within containment, containment spray recirculation is required to quench the dry debris bed and reduce containment gas temperatures. Figures 7.2-1 thru 7.2-3 illustrate several parameters of interest for this scenario.

<u>7.2.2 High Pressure Melt Ejection w/ RWST Injection Prior to Vessel Failure</u>

This MAAP analysis is a loss of main and auxiliary feedwater transient in which only one high pressure SI pump is available for injection. The accumulators are disabled, but one fan cooler is available. The operator initiates feed and bleed procedures when the steam generator water level drops to 7% wide range. (The steam generator could actually be dry when instruments indicate 7%. Therefore the EOPs direct operators to switch to feed and bleed at this point.) The operator fails to switch to the recirculation mode and the pressurizer PORV is closed when the RWST injection is stopped. Containment sprays are unavailable throughout the course of this sequence.

With the success of feed and bleed, the timing of core uncovery and core damage are very late, as shown by the following timing of key events:

0.0 sec	Loss of feedwater transient is initiated

32.1 min	.	Feed & bleed procedures initiated
1 hrs		Pressure in lower compartment > 4 psig - FCU started
5.6 hrs		Rx pressure below 200 psig
6.1 hrs		33% RWST level
6.5 hrs		28% RWST level
8.8 hrs		RWST dry - SI pumps tripped - Close pressurizer PORV
16.8 hrs		Steam generators dry
18.9 hrs		Core uncovery
20.3 hrs		Core damage
22.9 hrs		Vessel failure

Vessel failure is assumed to occur at 22.9 hours in this case, in spite of the presence of water in the cavity which can externally cool the RPV and prevent vessel failure. The potential for this mode of ex-vessel cooling is considered elsewhere in the Prairie Island IPE. As the RWST is injected, steam exits through the pressurizer PORV and is condensed by the fan coolers. The condensate joins the water pools on the containment floor, which communicate with the cavity by way of the two openings in the in-core instrument tube. As a result, the cavity is filled with water at the time of vessel failure.

Due to the failure at high pressure, about 15% of the core debris remains in the cavity after vessel failure. The cavity is always water solid after vessel failure, therefore no concrete ablation or ex-vessel hydrogen generation occurs. About 48% of the core debris is in the upper compartment, while 36% of core debris is retained in the vessel.

The peak pressure in the cavity (57.5 psia) and in the containment (50.3 psia) occurs just after vessel failure. Thereafter, containment pressures gradually decrease, due to availability of the fan coolers, until the containment pressure is approximately 35 psia at the end of the 48 hour mission time. The rate of pressure decrease is not as rapid as in the case where containment sprays are available. Gas temperatures continue to increase after vessel failure, particularly in the upper compartment, due to the presence of the dry debris layer. The rate of temperature increase is very slow (a few degrees per hour) and the final gas temperature is only 310°F.

In conclusion, containment pressures and temperatures are far too low to pose a threat during the 48 hour mission time. Still, recovery of containment sprays to quench the dry debris in the upper compartment is desirable. Figures 7.2-4 thru 7.2-6 illustrate several MAAP parameters of interest for this MAAP scenario.

7.2.3 High Pressure Melt Ejection with no RWST Injection

This case is a station blackout with no turbine driven AFW, and no accumulators. A seal LOCA of 63 gpm per pump, due to the loss of RCP seal cooling, occurs after 45 minutes. Due to the lack of AC and DC power, there are no operator actions in this case.

The timing up to core damage is discussed in Section 7.1.2.5. Vessel failure occurs at 4.5 hours. The debris is completely dispersed from the cavity to the upper compartment. There is no concrete ablation in the upper compartment, though, because the debris is dispersed into a thin, relatively cool layer that stays just below the concrete melting point. After vessel failure, the containment experiences a gradual pressure increase (0.5 psi/hr) due to the heating from the dry debris, until after approximately 24 hours, the pressurization rate increases due to steaming from the lower containment water pool. The containment pressure is 63.4 psia at 48 hours, still far less than the median containment failure pressure of 165 psia. However, the pressurization rate is still increasing at 48 hours, and containment failure is inevitable unless recovery actions are taken. The upper compartment gas temperature is 538°F, and increasing at a rate of approximately 2°F/hr. Eventually, the containment gas temperature would threaten the integrity of non-metallic seal materials in electrical penetrations. Figures 7.2-7 thru 7.2-9 illustrate several MAAP parameters of interest for this scenario.

7.2.4 Large-break LOCA with no ECCS Safeguards Available

This MAAP run illustrates the containment response at Prairie Island for a large-break LOCA with no containment safeguards available. This sequence depicts a very rapid vessel failure time at low pressure and then a fairly slow containment heatup and pressurization due to non-condensible gas generation in the cavity. This is due to extensive molten core-concrete interactions (MCCI) occurring in the cavity.

This sequence is initiated by a 4.13 sq. ft break in the cold leg at the discharge of the reactor coolant pump. Since no ECCS injection is available, the core begins to heat up, core damage occurs, the debris melts and slumps into the RPV lower plenum, and vessel failure at low pressure occurs shortly after core slump. Listed below is the timing of several key events:

0.0 sec	Large-break LOCA in cold leg initiated
12.0 sec	Core uncovers
3.5 min	Fuel damage occurs (TCRHOT > 2000°F)
8.5 min	Fuel melting (TCRHOT > 4040°F)
19.0 min	Debris in RPV lower plenum
20.0 min	Vessel Failure
31.0 min	Cavity dry

Since the vessel fails at low pressure, all the debris is retained in the cavity. There is very little water in the cavity due to the failure of the ECCS systems to inject the RWST. The water in the primary system that was discharged out of the break is not sufficient to flood up the lower compartment 18" and overflow into the cavity. Most of the primary system water flashes to steam and, without any containment heat removal, the steam is not condensed. Therefore, the debris remains at high temperatures throughout the course of the accident. Since the debris remains at high temperatures, the debris begins to attack and decompose the concrete in the cavity. This concrete decomposition is important in terms of containment response for many reasons. They are:

- As the concrete substrate is decomposed, water that is present in the concrete is liberated. This water is immediately vaporized which allows the steam to react with the unoxidized zirconium in the core debris to create hydrogen. This hydrogen is then liberated and simply accumulates within containment. Hydrogen is a concern whenever any electrical system within containment is recovered.

- Also a concern is the generation of carbon monoxide during core-concrete attack, which is volatile and will burn if ignited. This simply adds to the combustible gas mass present in containment as the accident progresses.

- Another major concern is that the debris attack, if not stopped via injection after vessel failure, could potentially ablate through the concrete basemat and fail containment.

- The last concern is the non-condensible gases generated during the core concrete attack. These non-condensible gases contribute to the containment pressurization when there is limited water available in containment. In terms of recovery, the only way to reduce the pressure due to non-condensible gases would be to vent containment, which is not desirable if the airborne fission product inventory is significant. Fortunately, Prairie Island's basemat is composed of basaltic concrete, which would not produce large quantities of non-condensible gases.

With the core debris located in the cavity and no containment safeguards available, very little is happening outside of the cavity, except for a slow heatup and pressurization within containment. At the end of the 48 hours, the containment temperature is well below temperatures presumed detrimental to the non-metallic seal material in the electrical penetrations (i.e., < 700°F) and the containment pressure is below the ultimate failure pressure of 165 psia. Listed below are the values of several key parameters of interest at the end of the

Level 2 mission time:

Containment Pressure	98.8 psia
Containment Temperature	340°F
Mass of Hydrogen in Containment	272 kg-moles
Mass of Steam in Containment	2494 kg-moles
Concrete Ablation in Cavity	6.6 ft

Containment failure beyond 48 hours, assuming no recovery actions are made, will be a race between containment overpressurization and failure of the cavity basemat due to debris attack. MAAP analyses predict that the containment will overpressurize approximately 90 hours after accident sequence initiation. MAAP predicts that cavity basemat failure will occur roughly 105 hours after accident sequence initiation. Therefore, it appears that containment failure will occur due to overpressurization before cavity basemat failure.

Figures 7.2-10 thru 7.2-15 illustrate several MAAP parameters of interest which were discussed above.

7.2.5 Large-break LOCA w/ one FCU & no RWST Injection

This MAAP run illustrates the containment response at Prairie Island during a large-break LOCA with no RWST injection, but successful operation of one containment fan coil unit (FCU). The purpose of this analysis is to determine if one containment fan coil unit is sufficient to prevent containment failure. This run is very similar to the MAAP run discussed in Section 7.2.4, except that a fan cooler is operable in this sequence.

Prior to vessel failure, the primary system behavior is identical to the run discussed in Section 7.2.4. Once the vessel fails, the containment response is slightly different. Similar to the previous sequence, all the debris remains in the cavity and significant core concrete attack is present. The core concrete concerns addressed earlier are still valid except for one; containment failure on overpressure due to non-condensible gas generation.

Since a containment fan cooler is present to condense any steam in the containment atmosphere, the containment pressure is much lower. For the case discussed in Section 7.2.4, the majority of the pressurization in containment was due to the steam inventory within containment. For these two cases, the only water inventory participating in the steaming process is the primary system inventory and the water liberated during core-concrete attack. With one fan cooler available, the steam is condensed and allowed to collect on the floor of containment. The primary system water inventory is not sufficient to flood the lower containment 18" and allow water to spill over and cool the debris in the cavity. Therefore, the extent of core-concrete attack in the cavity is practically identical to the results discussed in Section 7.2.4.

In terms of containment response, the most important issue to address for this sequence, is the fact that there is very little steam present within containment. Although the containment pressure is lower, the containment environment has lost the steam mass that acts to inert the containment and somewhat inhibit hydrogen burning. Now, with the fan cooler operating, the atmosphere is hydrogen rich with very little steam available to inert containment. In terms of recovery, even more caution should be exercised for this sequence should other electrically powered systems become available later on in the accident.

In terms of containment failure, no failure occurs within 48 hours and long term containment overpressurization is no longer a concern since the fan cooler limits the steam inventory in containment. The cavity basemat failure is still an issue for this sequence since debris coolability has not been established. Therefore, containment failure due to cavity basemat penetration would still occur after approximately 105 hours if no form of debris cooling is established. Listed below are the values of several key parameters of interest at 48 hours:

Containment Pressure	27 psia
Containment Temperature	310°F
Cavity Ablation Depth	6.6 ft
Mass of Steam in Containment	260 kg-moles
Mass of Hydrogen in Containment	132 kg-moles

Figures 7.2-16 thru 7.2-22 illustrate several MAAP parameters of interest which were discussed above.

7.2.6 Large-break LOCA w/ RWST Injection prior to Vessel Failure

This MAAP analysis illustrates the containment response at Prairie Island during a large-break LOCA with RWST injection, but failure to switch to recirculation prior to vessel failure. This sequence also has no form of containment heat removal (i.e., no FCUs). The purpose here is to determine the containment response during the progression of this accident sequence.

The sequence is initiated by a 4.13 sq. ft break in the cold leg at the discharge of the reactor coolant pump. The low pressure RHR pump starts injecting several seconds after the break is initiated. Since ECCS recirculation fails, once the pump stops injecting, the core begins to heat up, core damage occurs, the debris melts and slumps into the RPV lower plenum, and vessel failure occurs at low pressure shortly thereafter. Listed below is the timing of several key events:

0.0 sec	Large-break LOCA in cold leg initiated
40.9 min	Cavity water solid
46.9 min	33% RWST level alarm
50.4 min	28% RWST level alarm
1.1 hrs	8% RWST level alarm
2.4 hrs	Core damage occurs
3.6 hrs	Vessel failure

Since the vessel fails at low pressure, all the debris is retained in the cavity. As the debris exits the failed RPV, it is dispersed in the cavity which is full of water. This is due to the RHR injection which is sufficient enough to flood up the lower containment, well above the 18" needed to cause overflow into the cavity via the 2 instrument tunnel hatches which are left open during normal plant operations. Approximately 41 minutes after RHR injection is initiated, the cavity is water solid. Since the debris is submerged in a pool of water it was assumed that the debris is coolable and allows heat to be transferred to the water. With the debris assumed coolable, no core-concrete attack is present.

Since the debris energy is being transferred to the water, the water begins to vaporize and pressurize containment. With no containment heat removal available, there is no means to stop the pressurization. Due to extremely large steam concentration within containment, there is no concern of hydrogen burning. At the end of the 48 hours, the containment pressure is approximately 141 psia. At this pressure containment failure cannot be completely precluded. In any event, the pressure is estimated to reach the ultimate containment failure pressure of 165 psia approximately 10 hrs later.

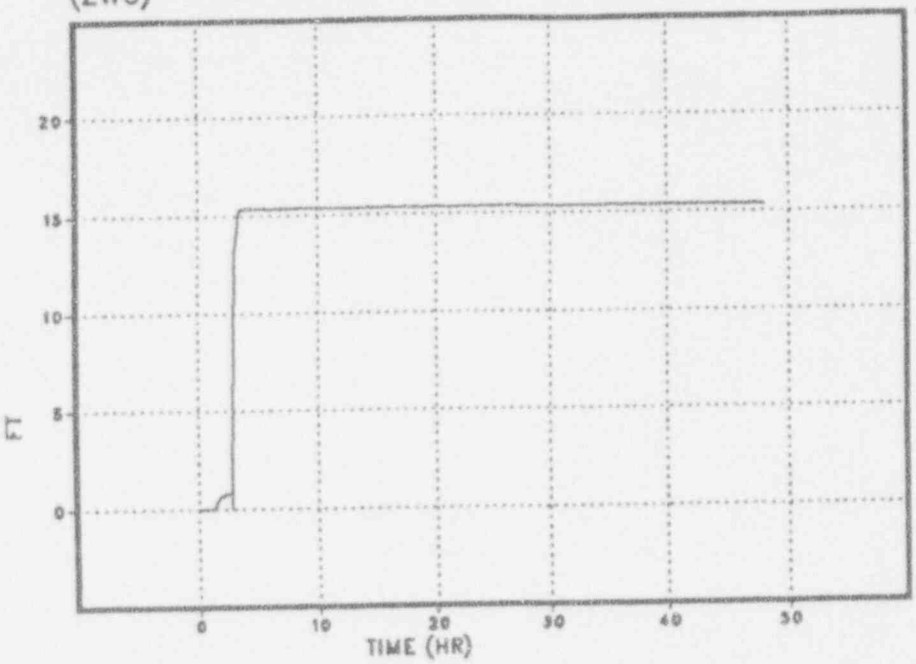
Therefore, it is concluded that 1 RHR pump injecting to the vessel is sufficient to provide debris coolability, although containment failure will occur in the long term if no form of containment heat removal is established to reduce the pressure in containment.

One important issue that was not addressed here, but is treated as a Level 2 sensitivity, is the possibility to avert vessel failure altogether by externally cooling the RPV lower head. For this sequence, RPV lower head cooling is established in the following manner: 1) RHR injection flows out the break in the primary system and onto the containment floor, 2) when the lower containment water level exceeds 18", water begins to overflow into the cavity via the two instrument tunnel hatches, and 3) as the cavity floods up, the lower head of the RPV is submerged.

Since RHR recirculation is unsuccessful, the core heats up and relocates to the RPV lower plenum which is submerged in the cavity water pool. Theoretically, heat is conducted through the RPV lower head wall and induces nucleate boiling on the outside of the RPV wall which removes the decay heat from the core debris. Small scaled experiments have shown that this form heat removal will prevent vessel failure as long as the RPV lower head is submerged. Therefore, decay heat generated from the core debris is removed via nucleate boiling in the cavity water pool.

For this sequence, since the cavity goes water solid long before core damage or vessel failure occurs, lower head cooling of the RPV could potentially prevent the RPV from failing. Any sequence where the RWST is successfully injected into the containment, via containment sprays or flow out the break in the RCS, before the molten core debris slumps into the RPV lower plenum, RPV lower head cooling can be established. One important item to note is that if there is no form of containment heat removal available to condense the steam, the containment will overpressurize and fail. Figures 7.2-23 thru 7.2-28 illustrate several MAAP parameters of interest which were discussed above.

Water level in the cavity.
(ZWC)



Mass of corium in cavity — Includes all once-molten material (UO2, Zr, ZrO2, concrete, rebar,...). (MCMTC)

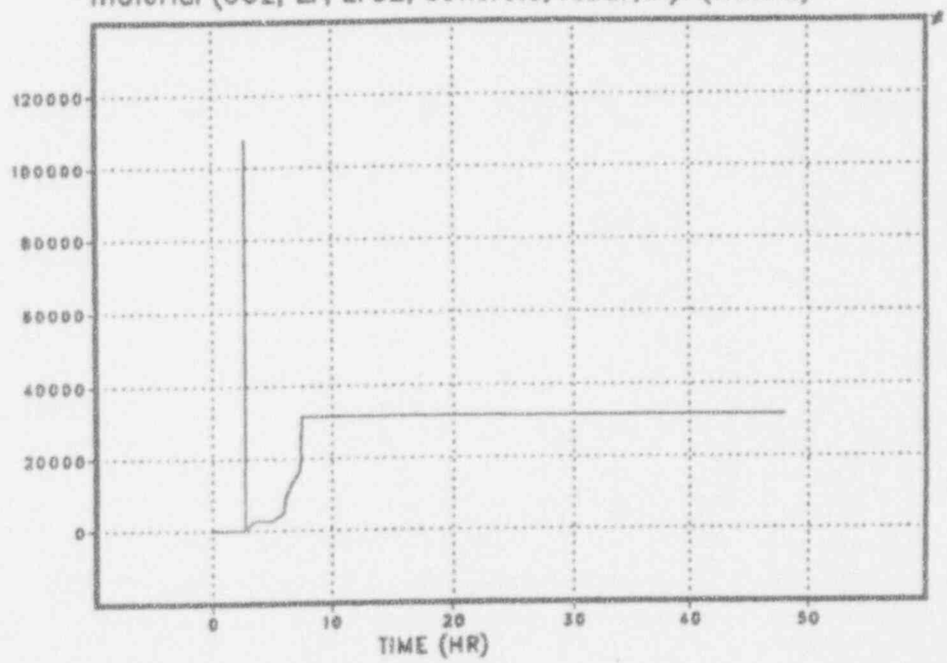
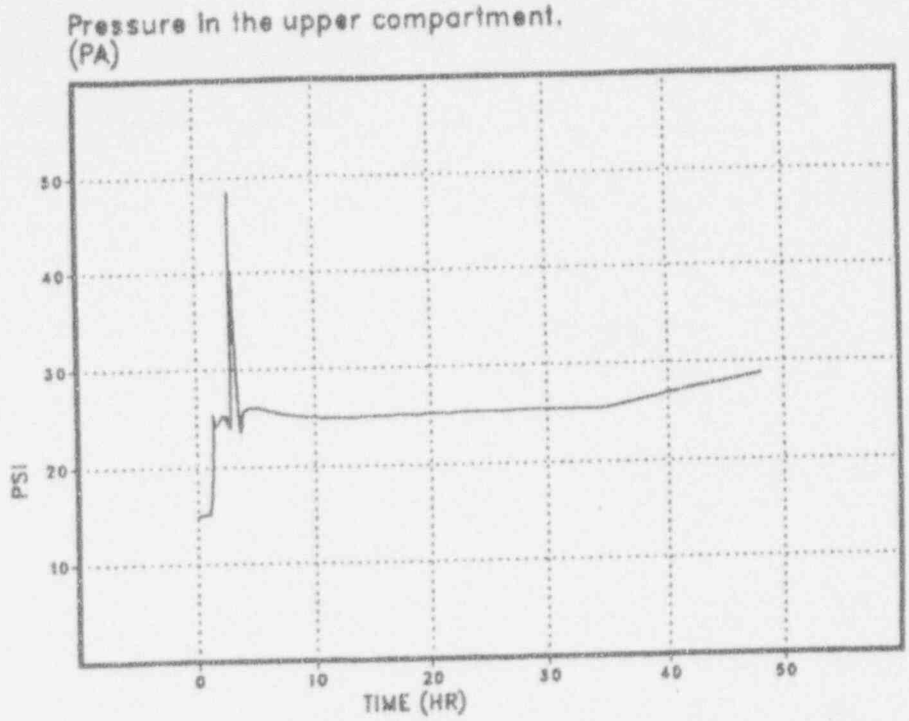


Figure 7.2-1 High pressure melt ejection with injection after vessel failure



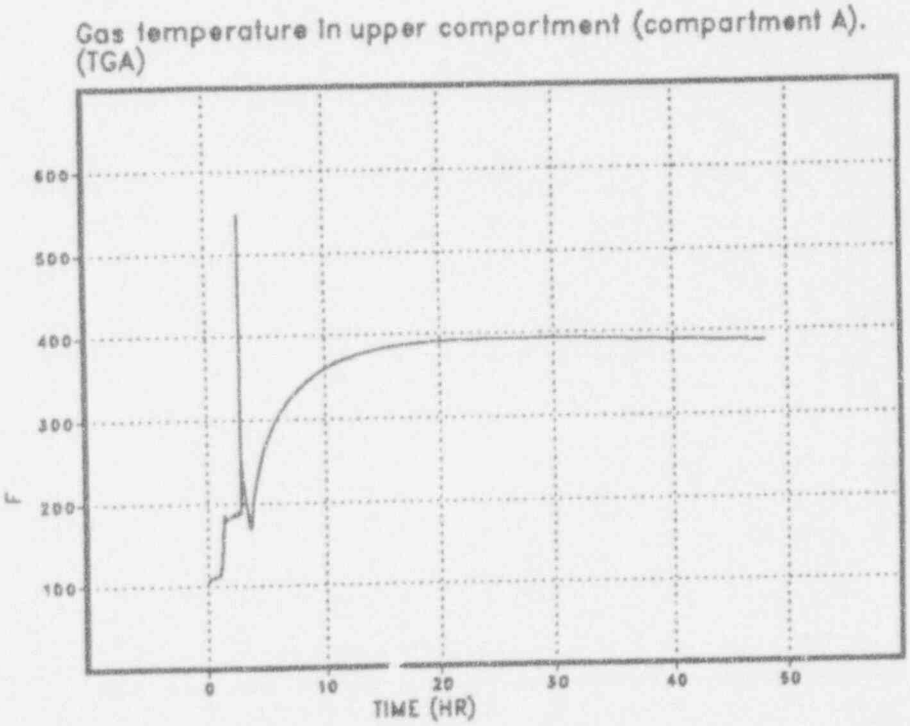
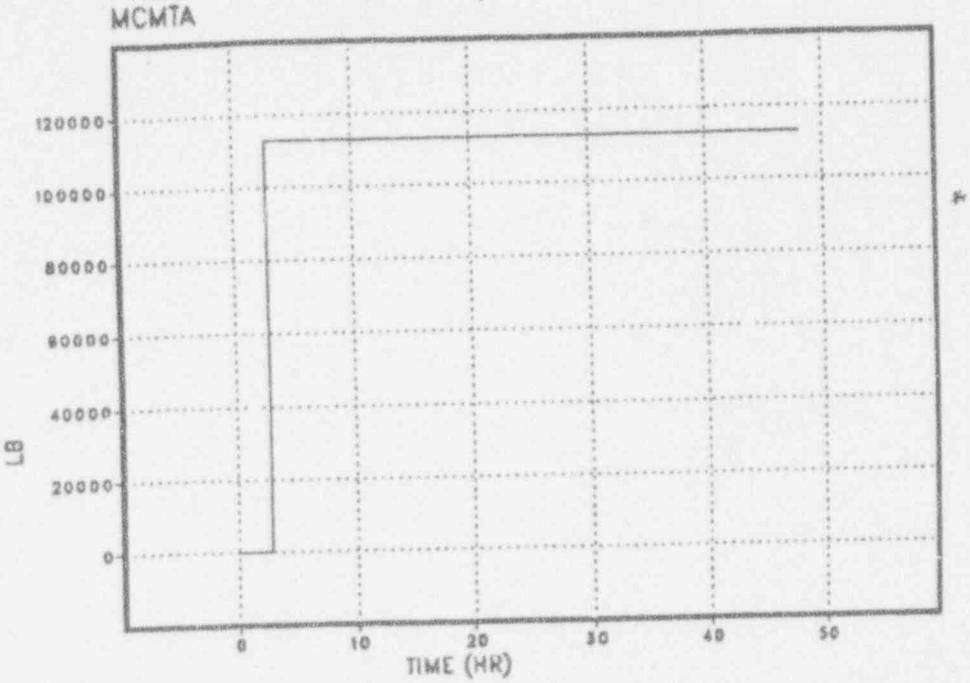


Figure 7.2-2 High pressure melt ejection with injection after vessel failure

Mass of corium in the upper compartment
MCMTA



Average temperature of corium in upper compartment.
(TCMA)

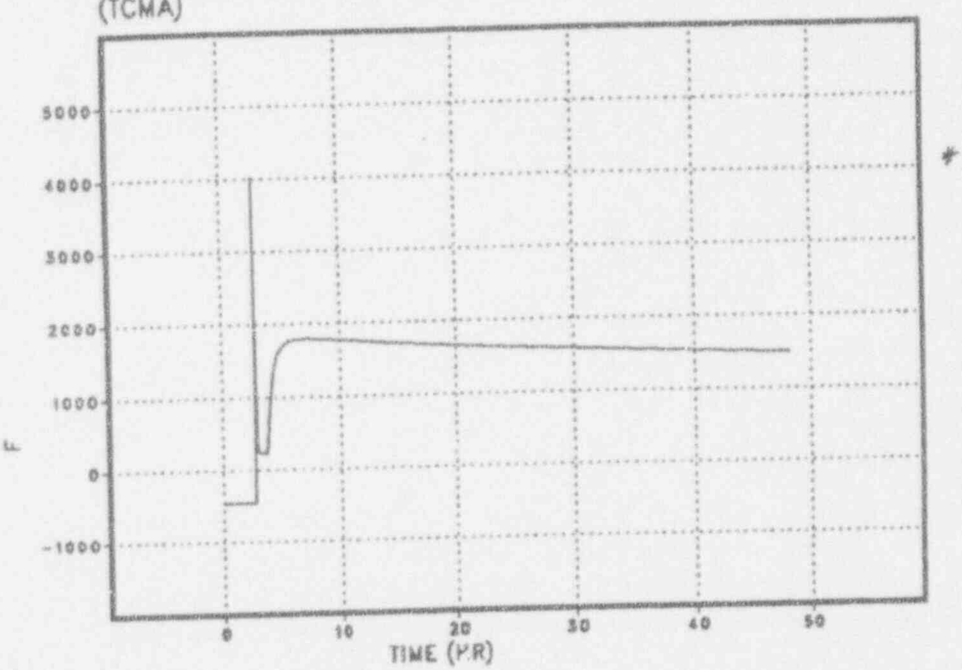
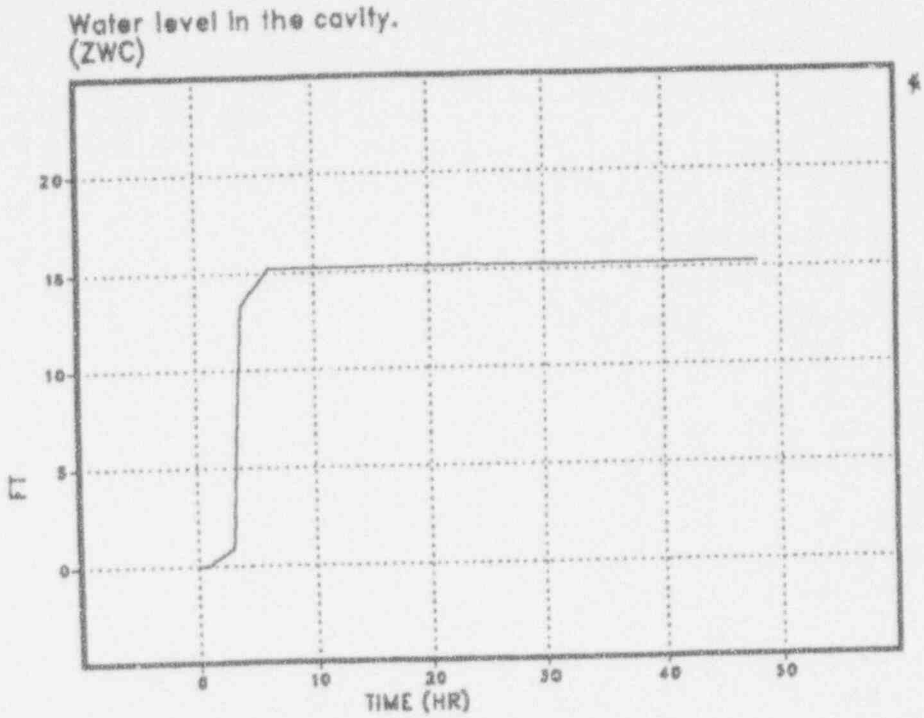


Figure 7.2-3 High pressure melt ejection with injection after vessel failure



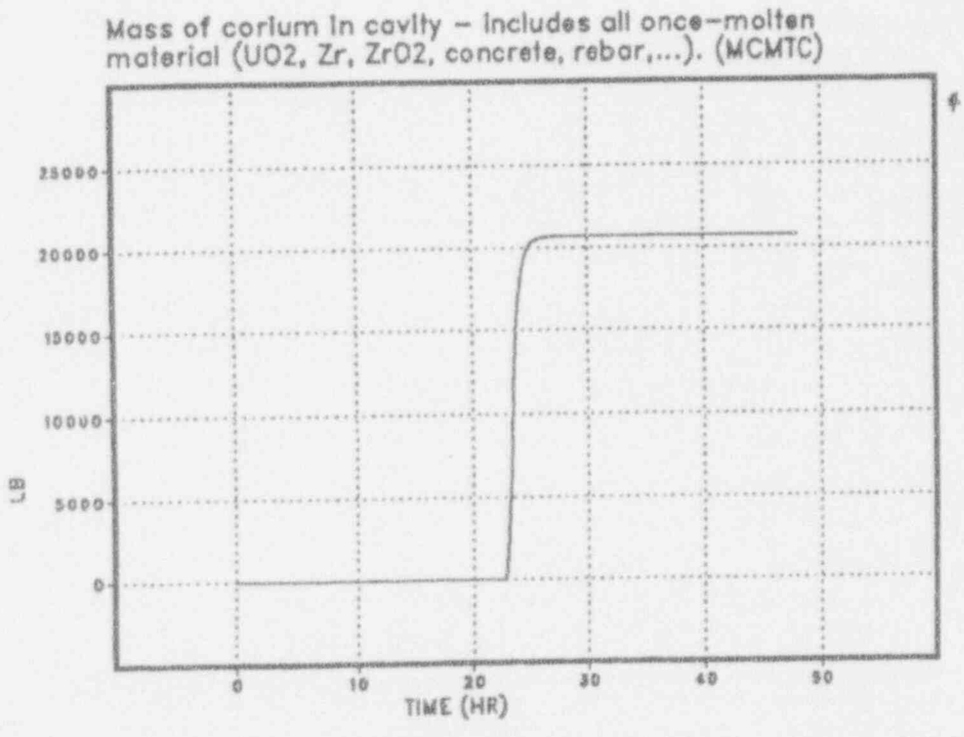
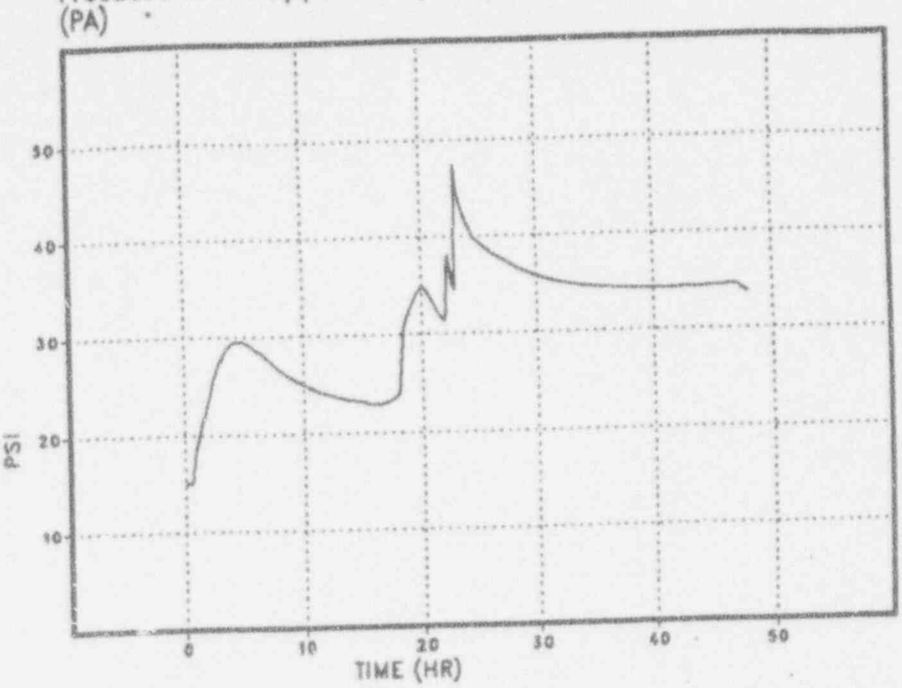


Figure 7.2-4 High pressure melt ejection with RWST injection prior to vessel failure

Pressure in the upper compartment.
(PA)



Gas temperature in upper compartment (compartment A).
(TGA)

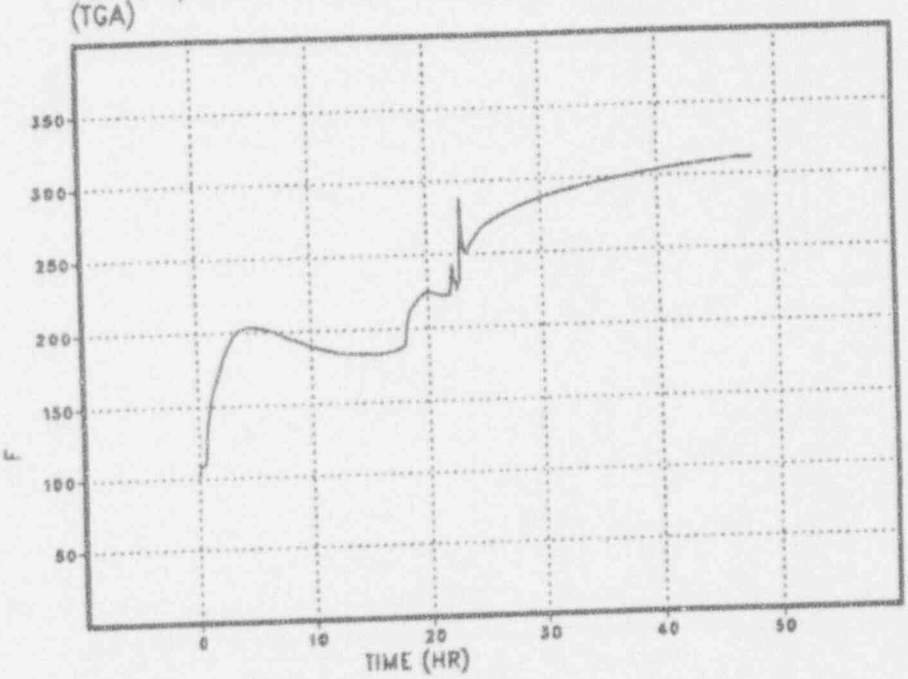
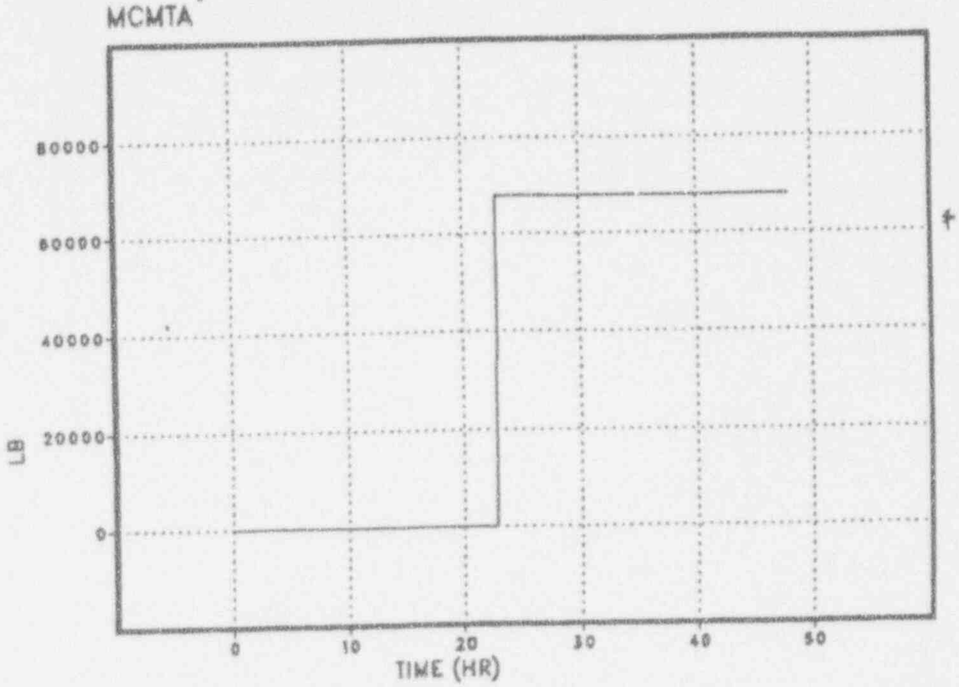


Figure 7.2-5 High pressure melt ejection with RWST injection prior to vessel failure

Mass of corium in the upper compartment
MCMTA



Average temperature of corium in upper compartment.
(TCMA)

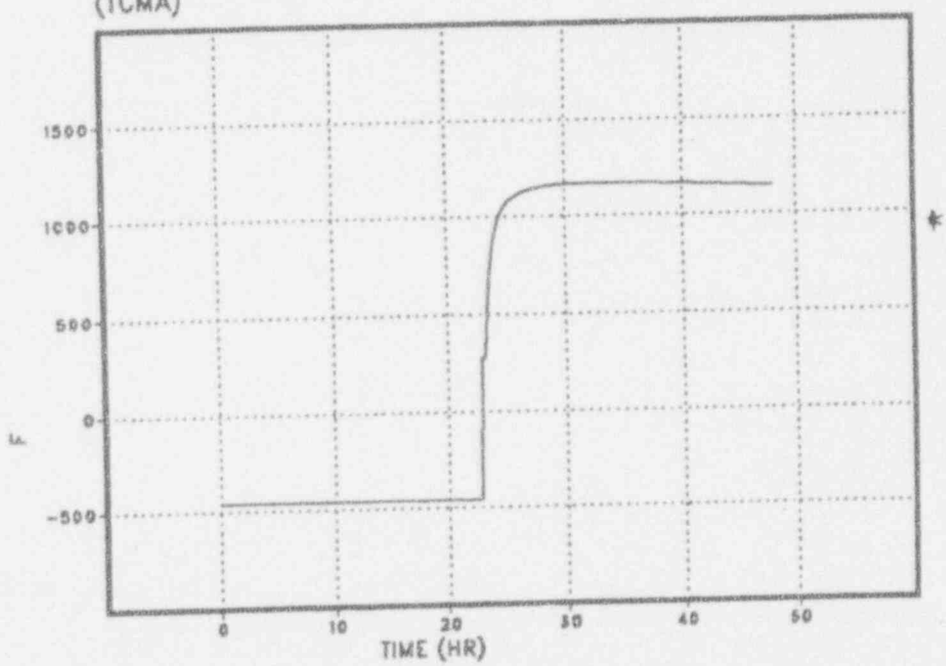
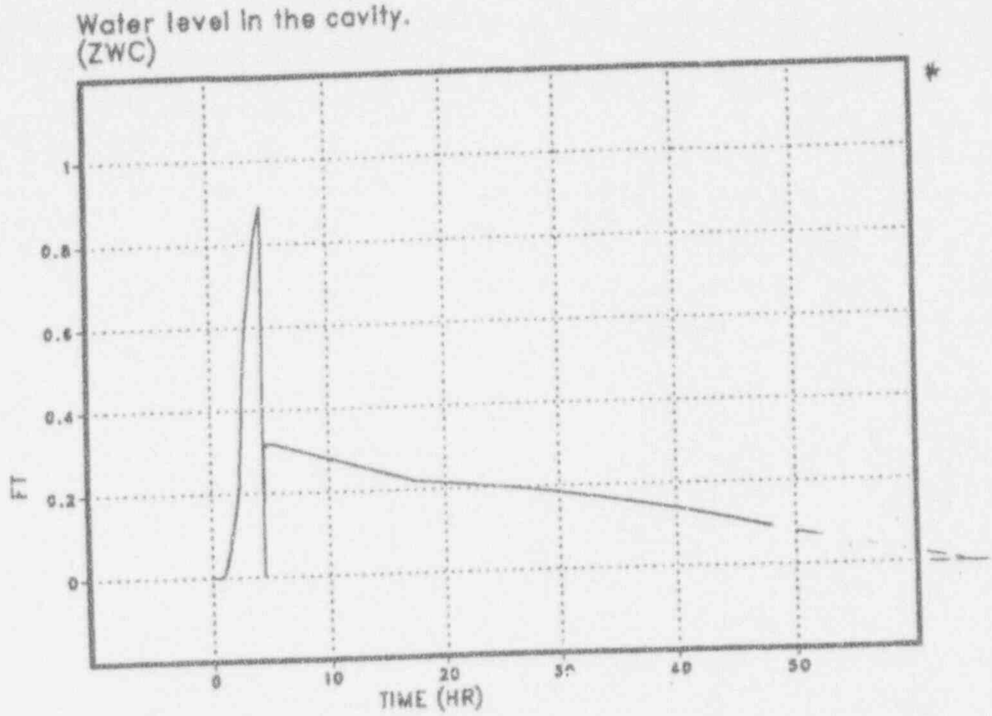


Figure 7.2-6 High pressure melt ejection with RWST injection prior to vessel failure



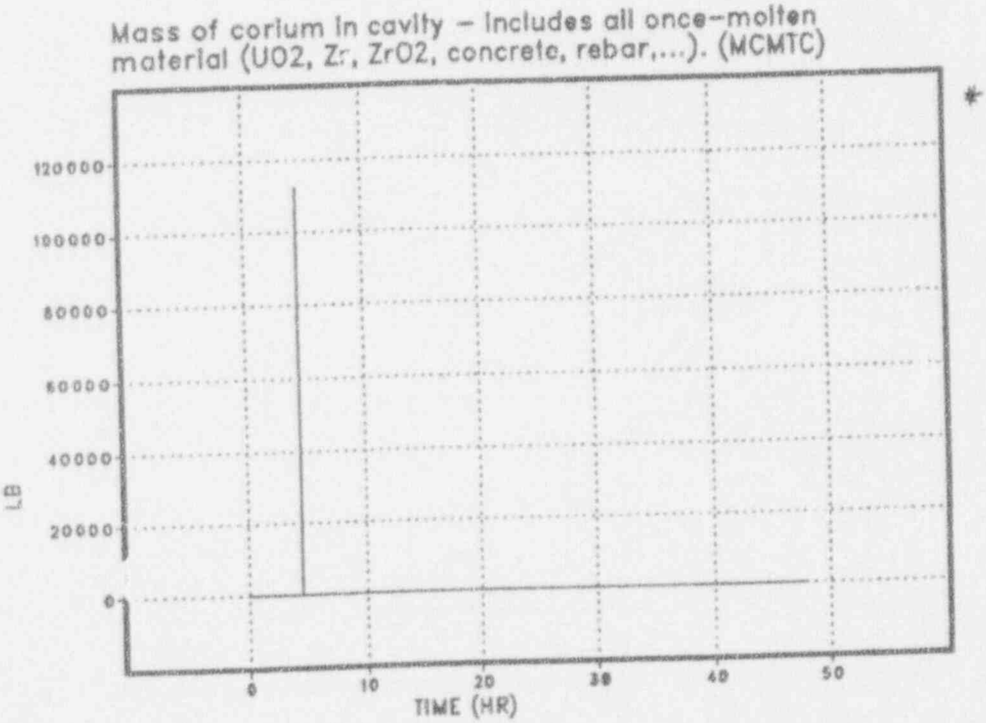
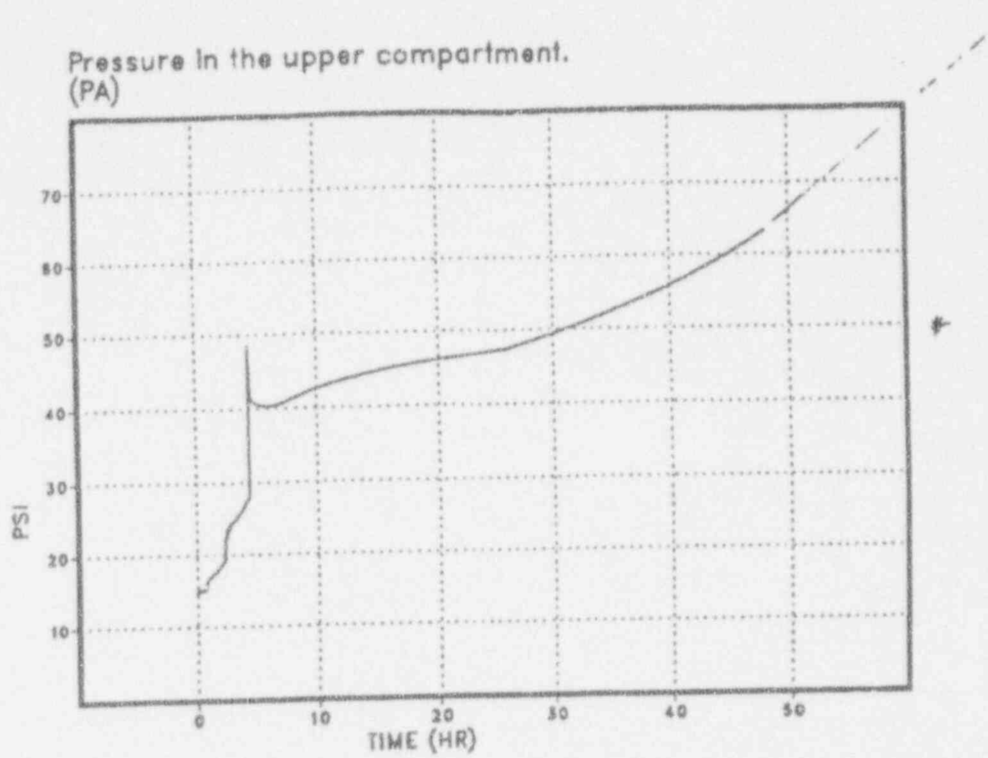


Figure 7.2-7 High pressure melt ejection with no RWST injection



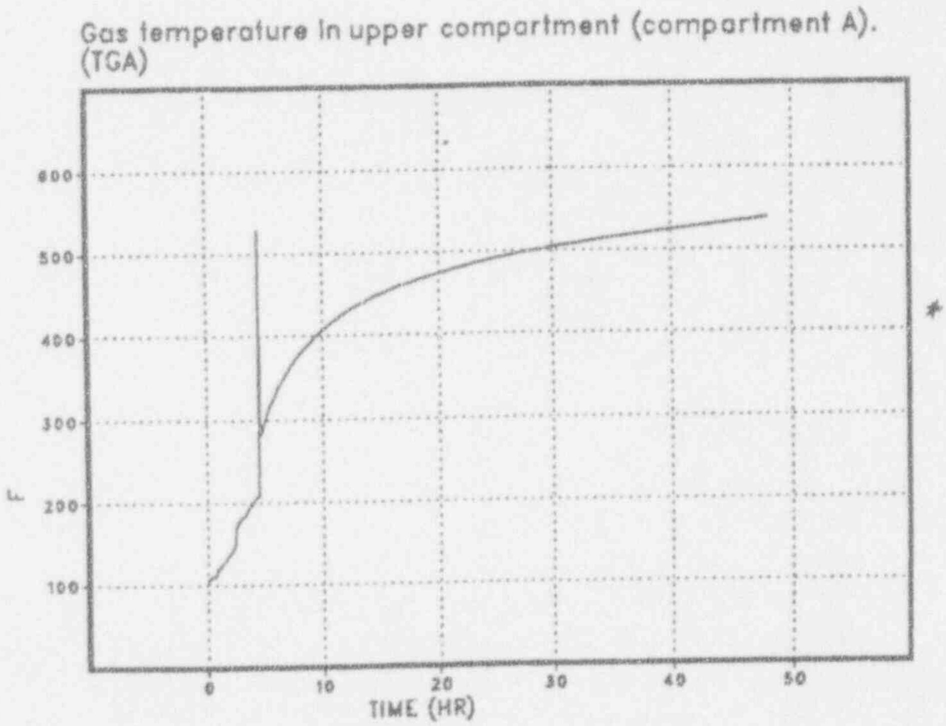
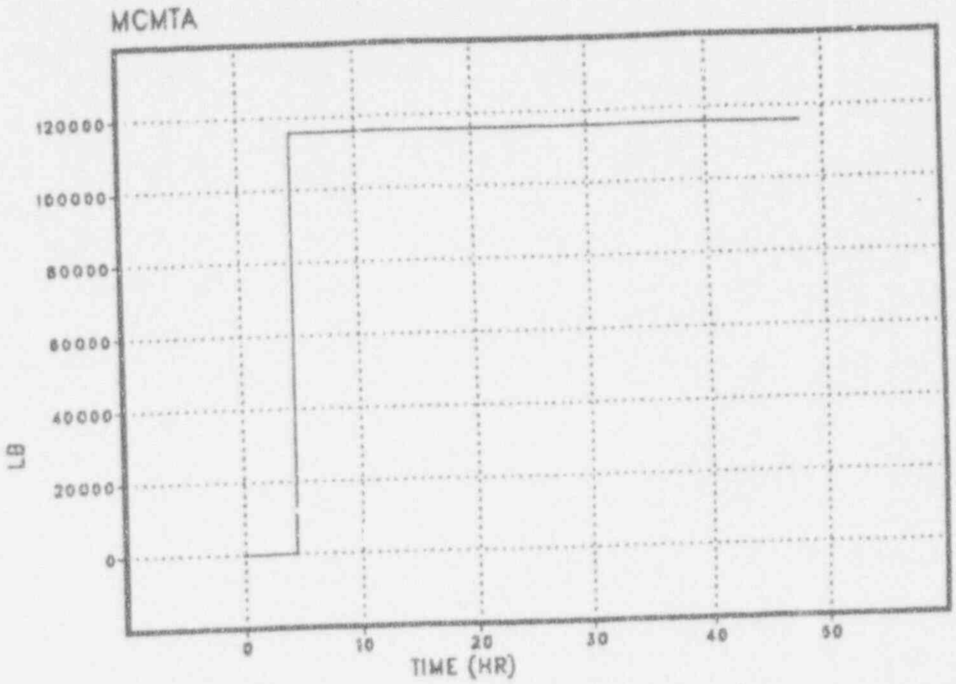


Figure 7.2-8 High pressure melt ejection with no RWST injection

Mass of corium in the upper compartment



Average temperature of corium in upper compartment.
(TCMA)

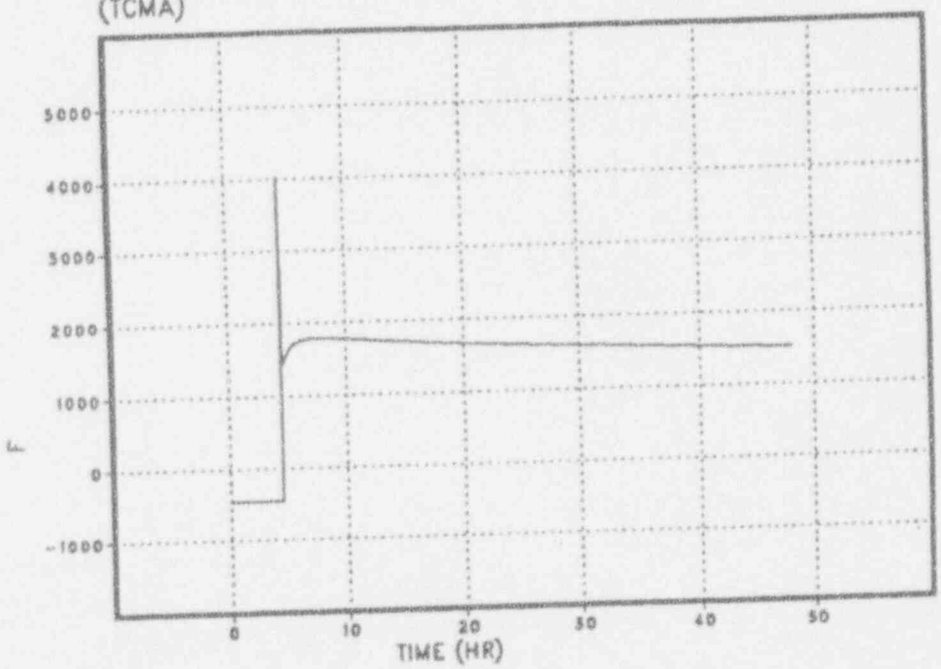
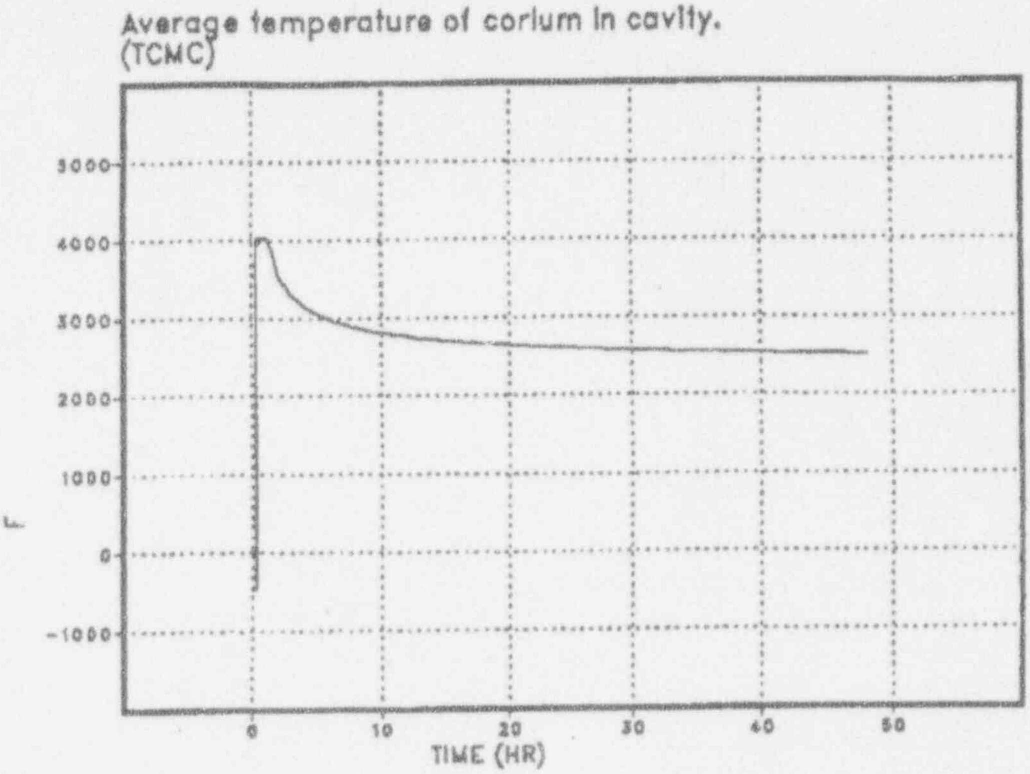


Figure 7.2-9 High pressure melt ejection with no RWST injection



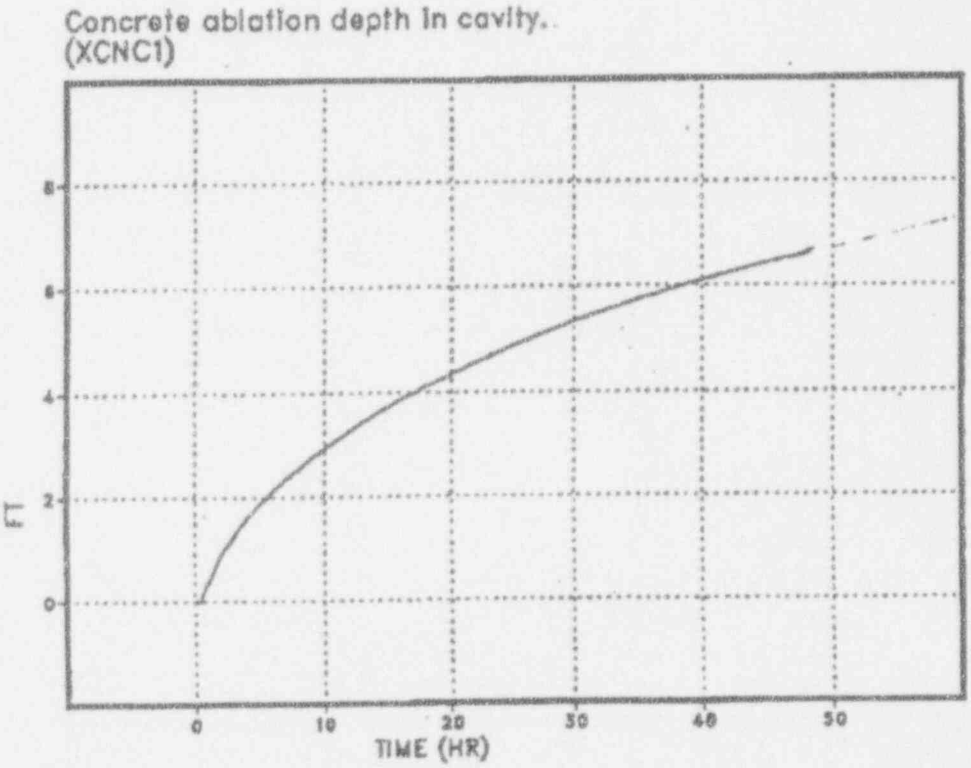
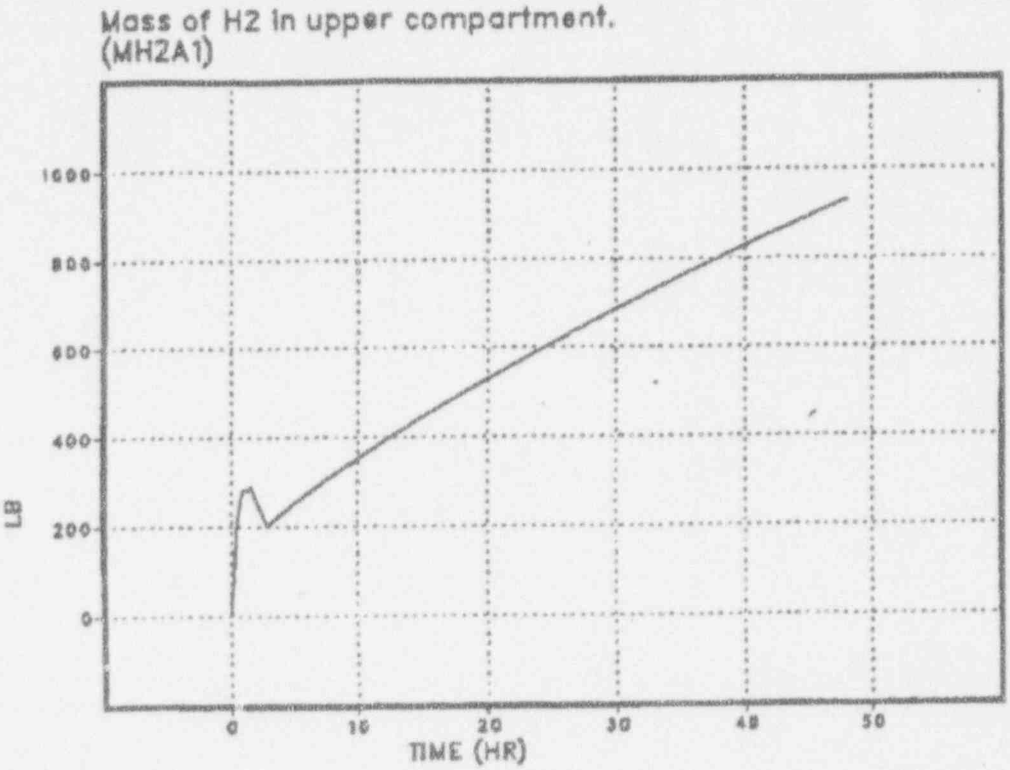


Figure 7.2-10 Large-break LOCA with no ECCS safeguards available



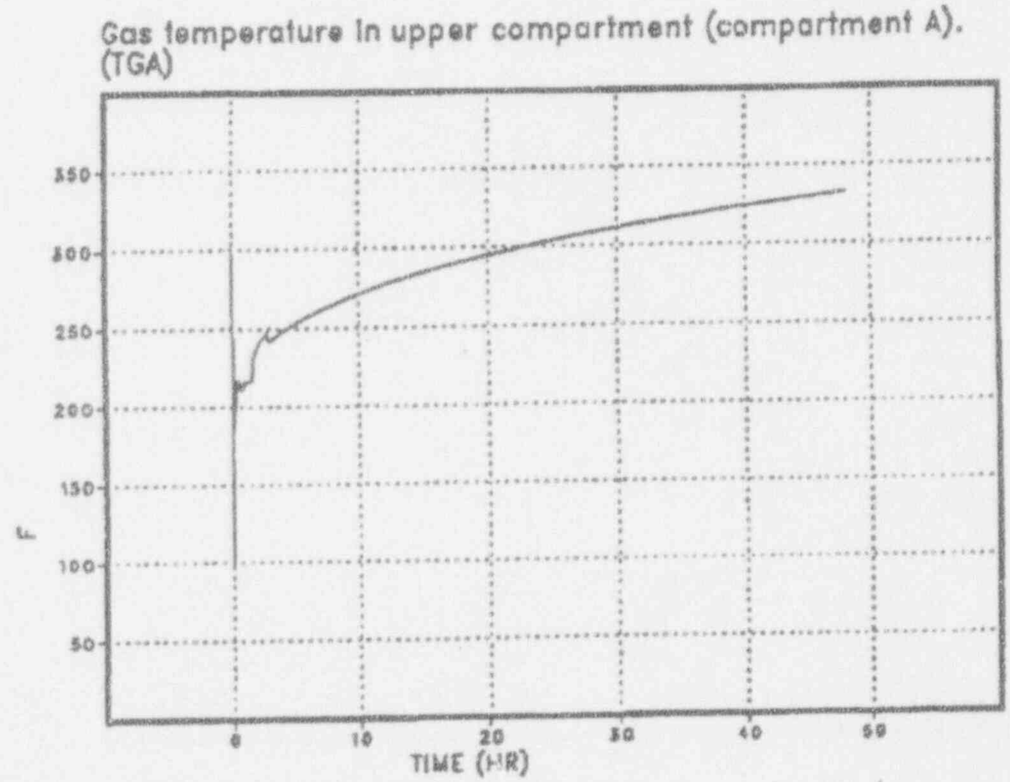


Figure 7.2-11 Large-break LOCA with no ECCS safeguards available

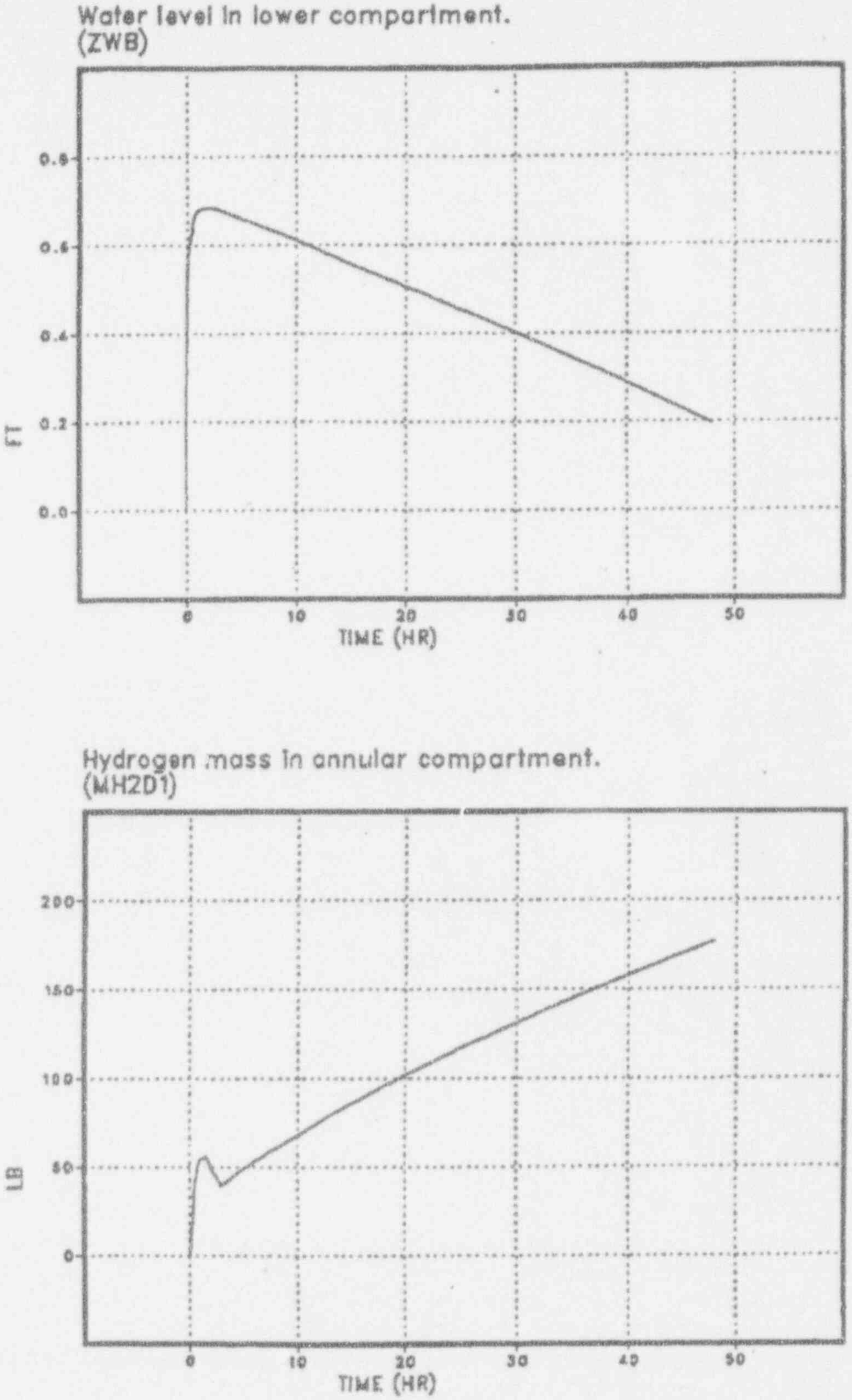
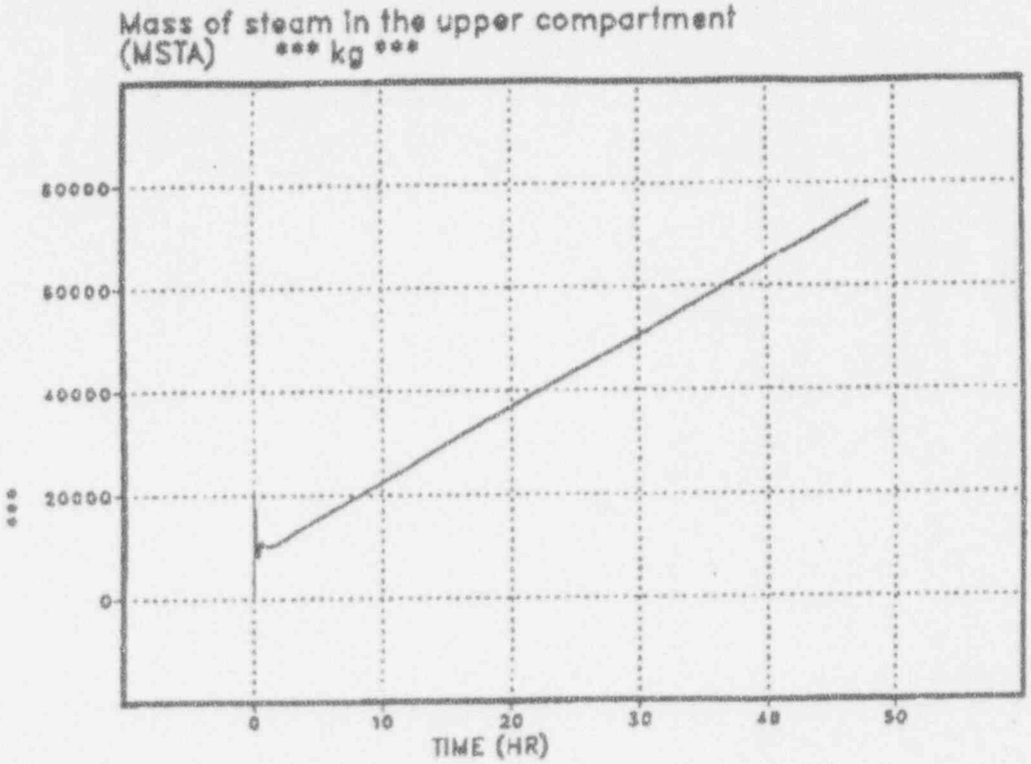


Figure 7.2-12 Large-break LOCA with no ECCS safeguards available



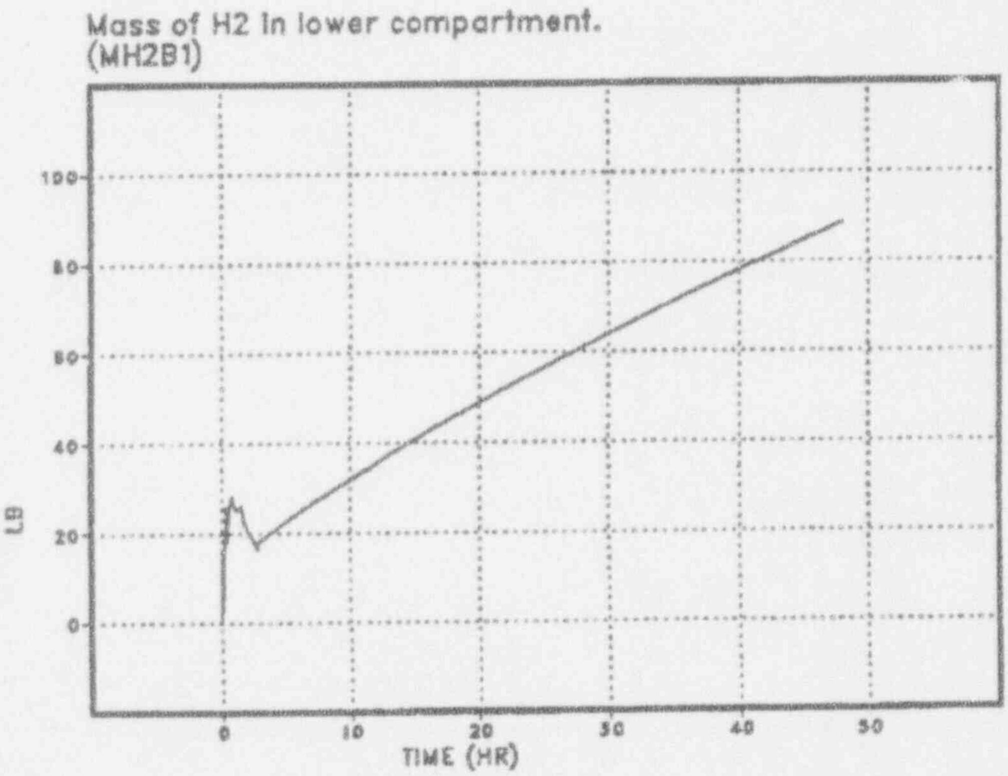
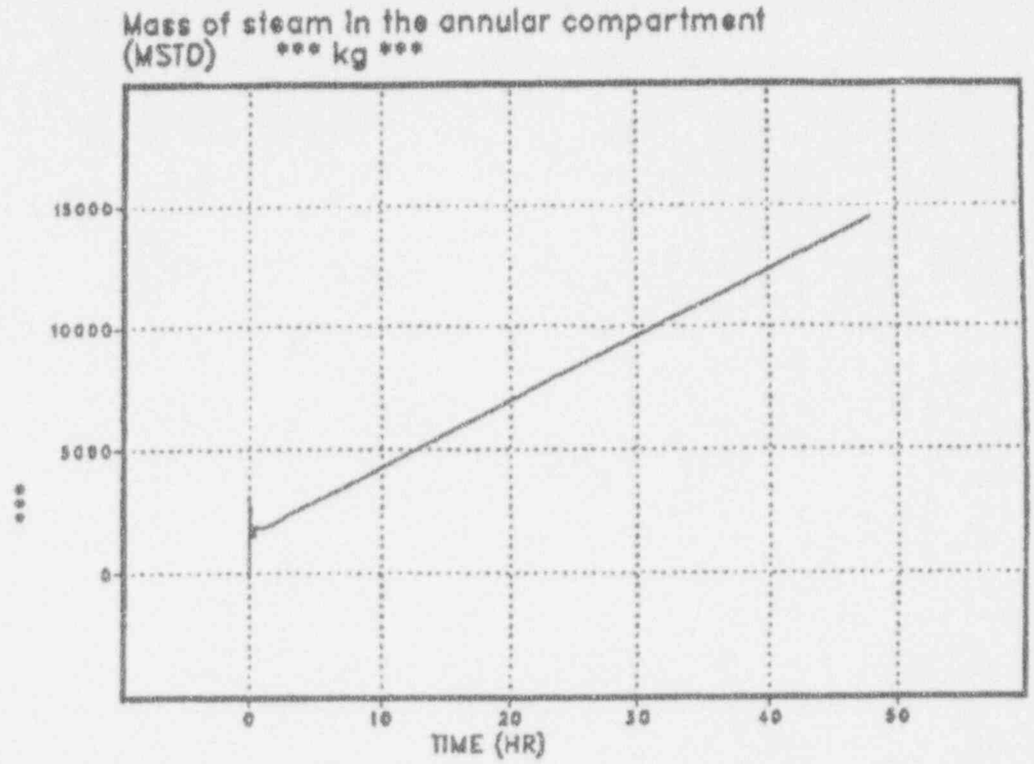


Figure 7.2-13 Large-break LOCA with no ECCS safeguards available



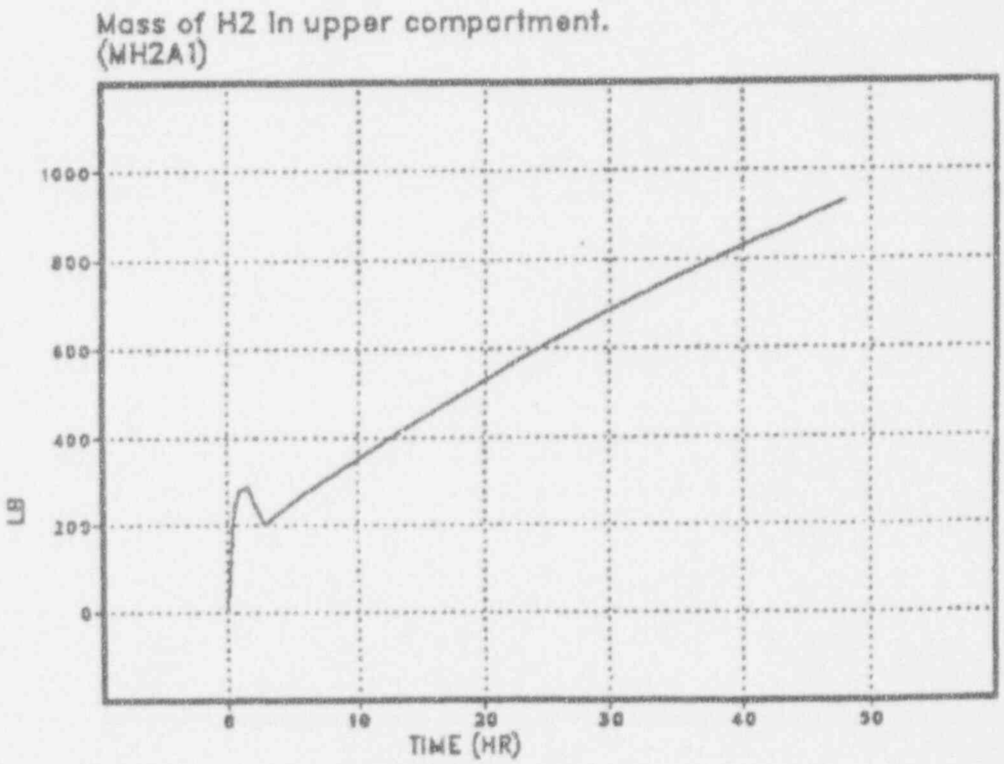
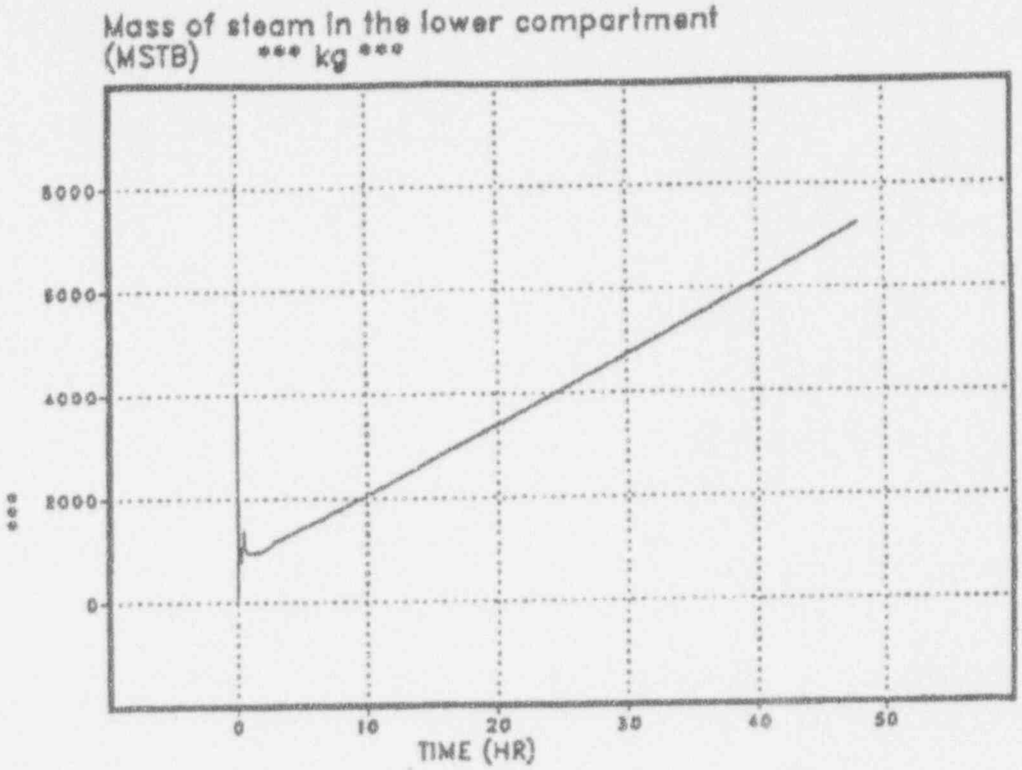


Figure 7.2-14 Large-break LOCA with no ECCS safeguards available



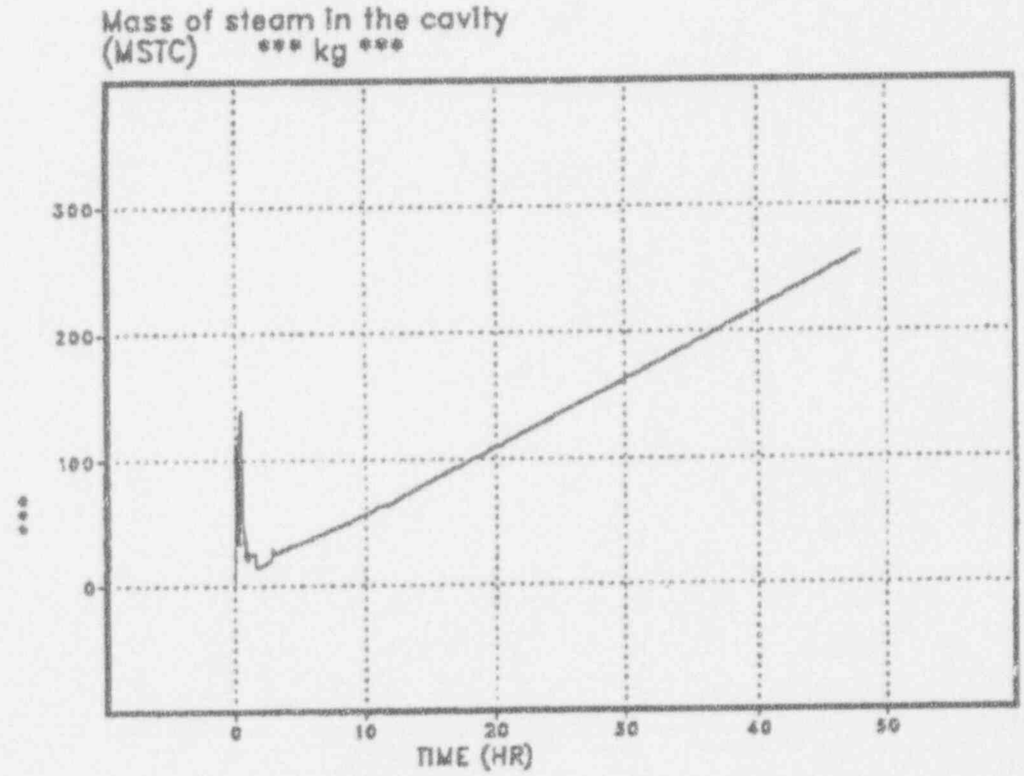
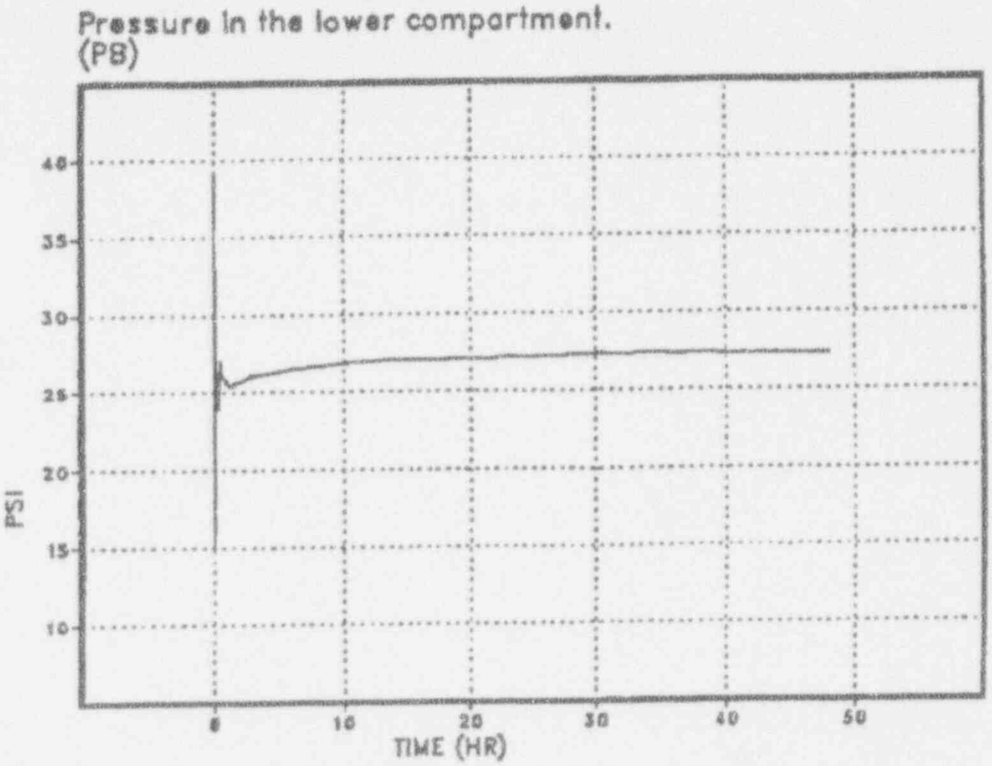


Figure 7.2-15 Large-break LOCA with no ECCS safeguards available



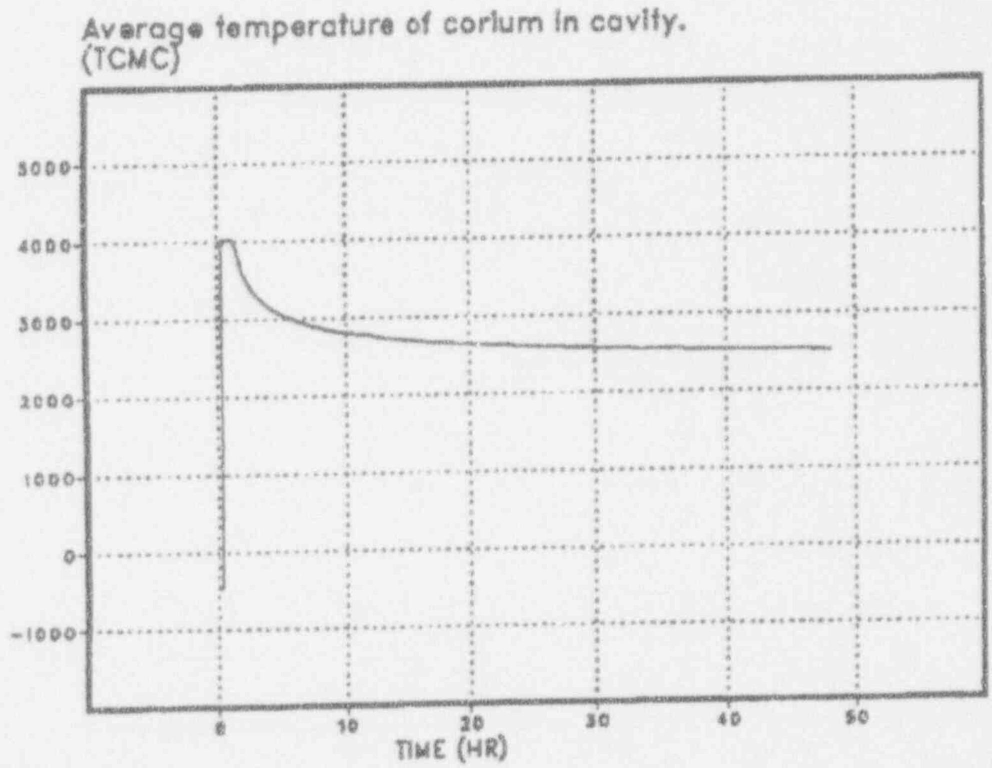
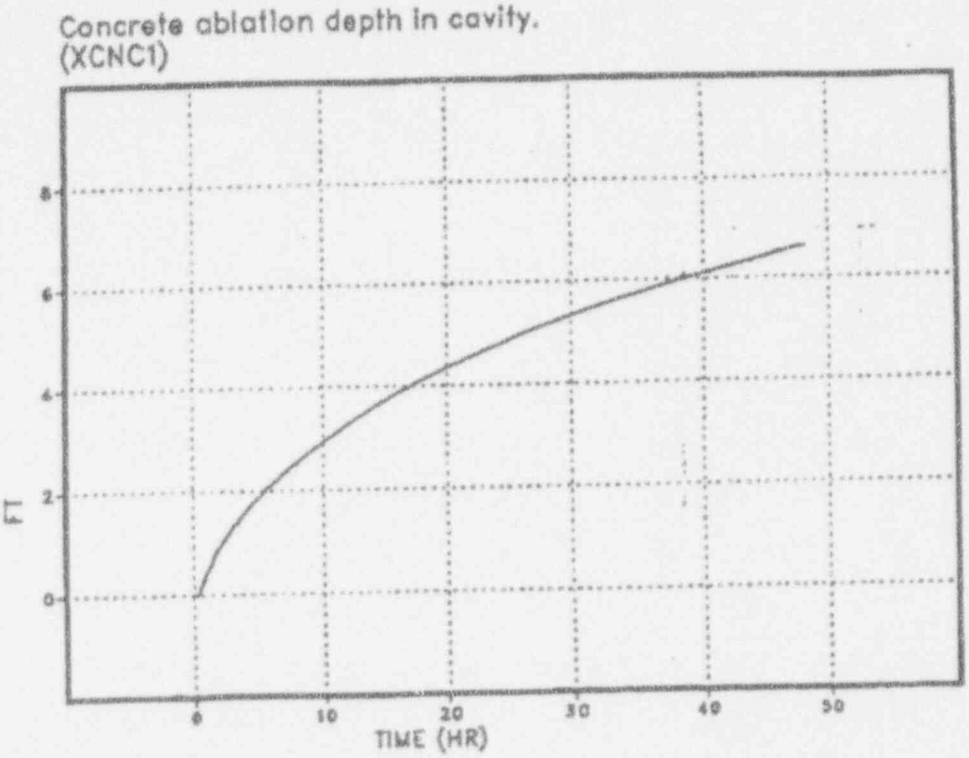


Figure 7.2-16 Large-break LOCA with one FCU & no RWST injection



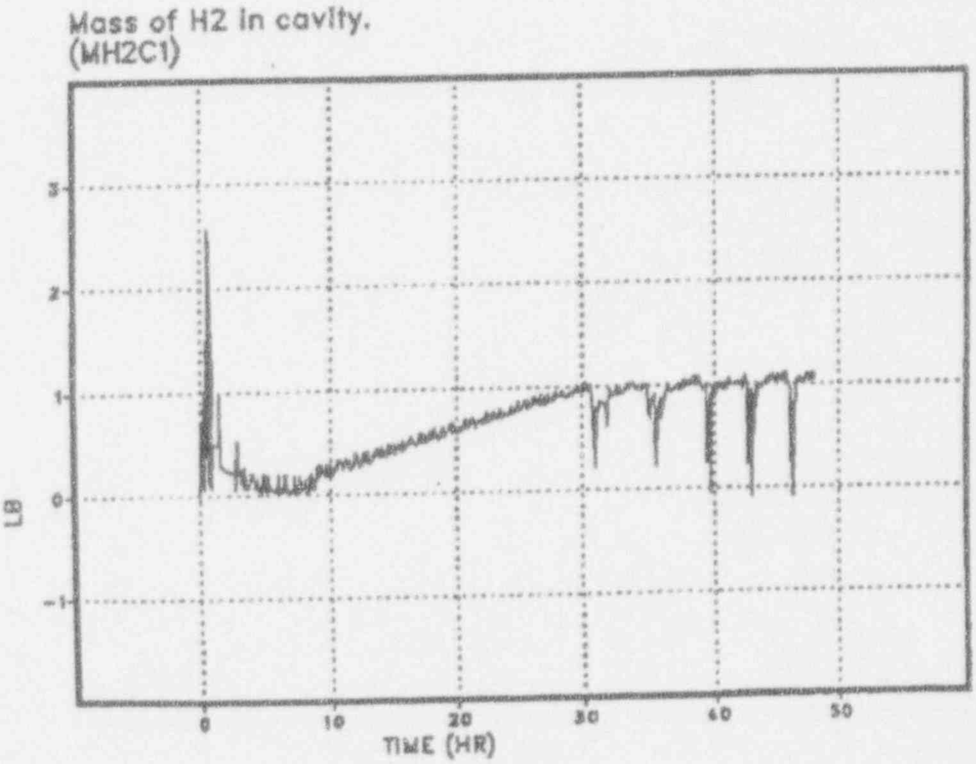
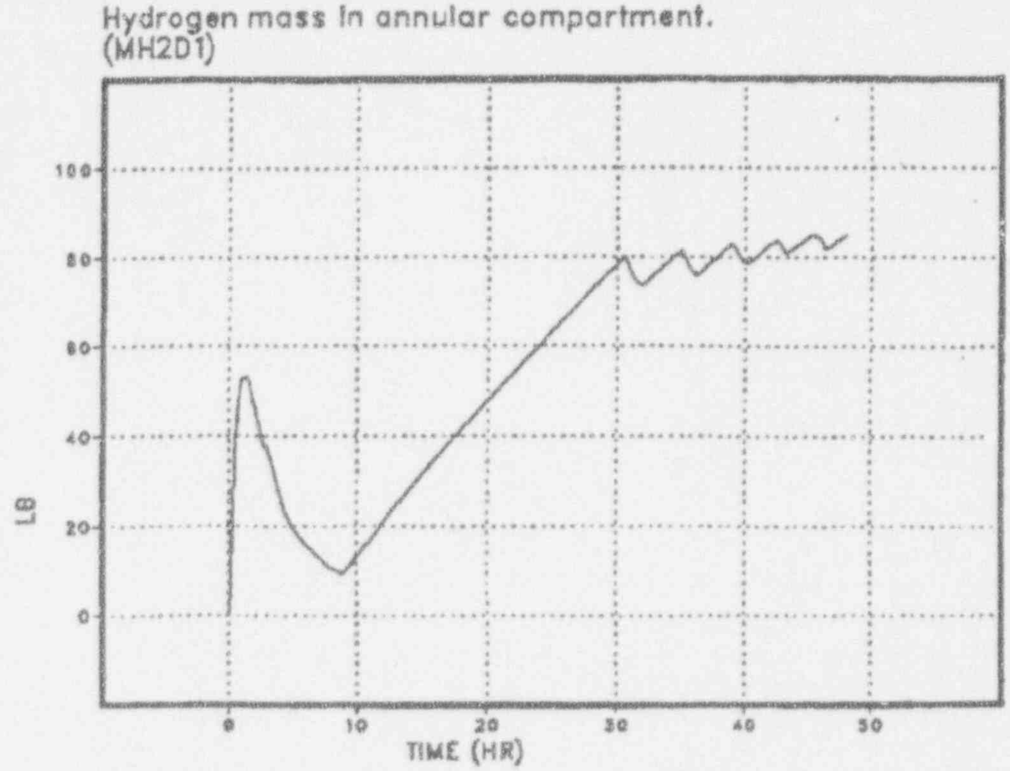


Figure 7.2-17 Large-break LOCA with one FCU & no RWST injection



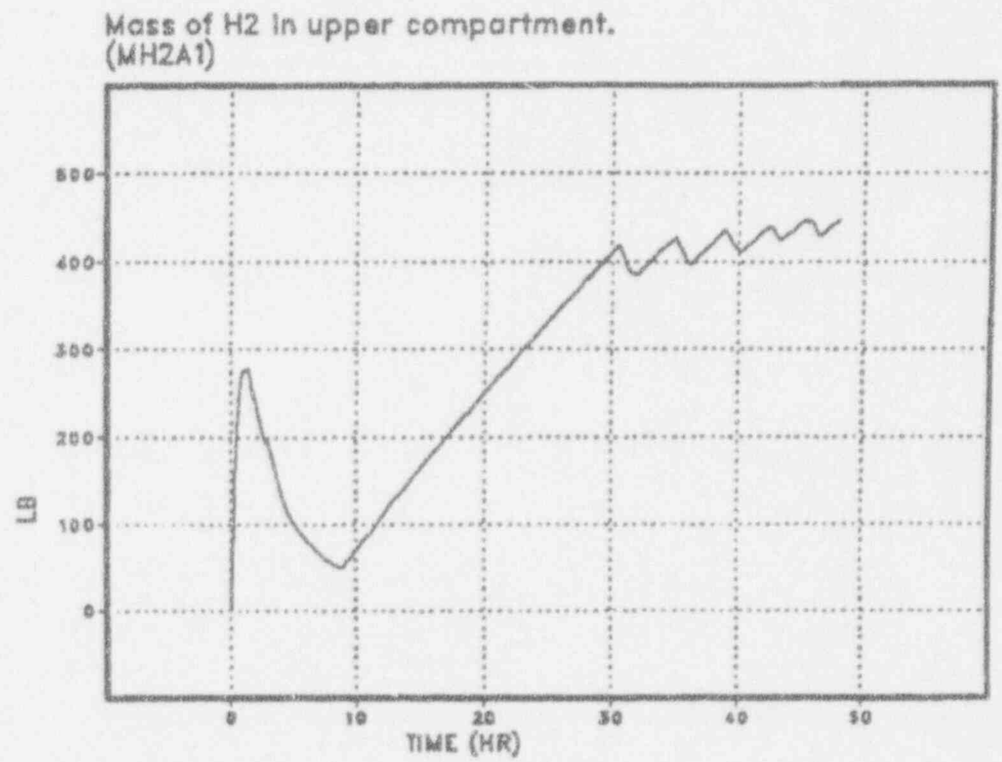


Figure 7.2-18 Large-break LOCA with one FCU & no RWST injection

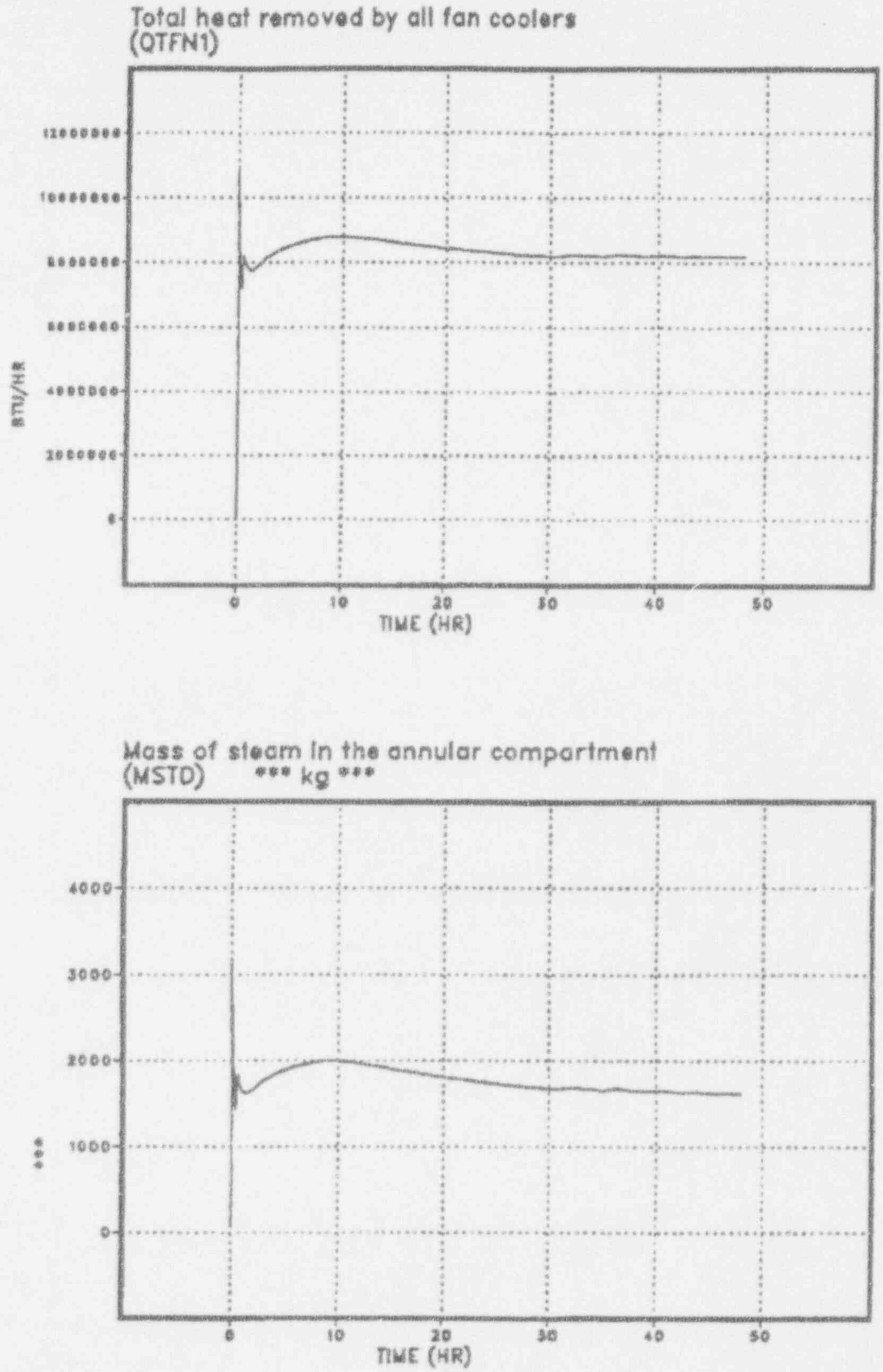
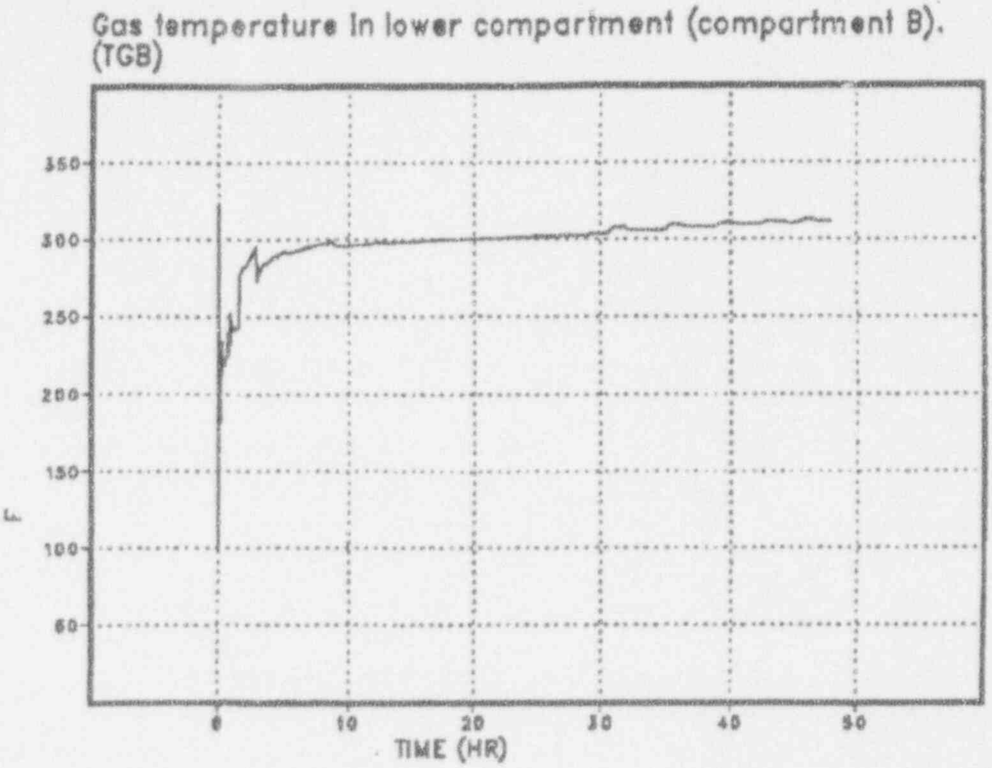


Figure 7.2-19 Large-break LOCA with one FCU & no RWST injection



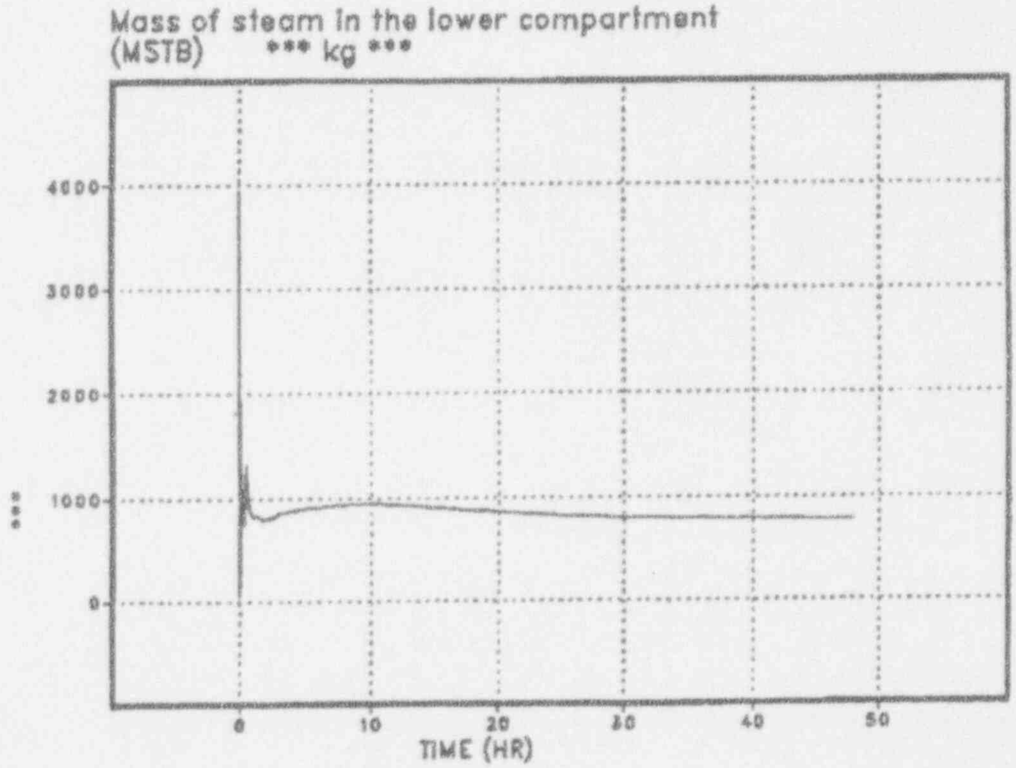
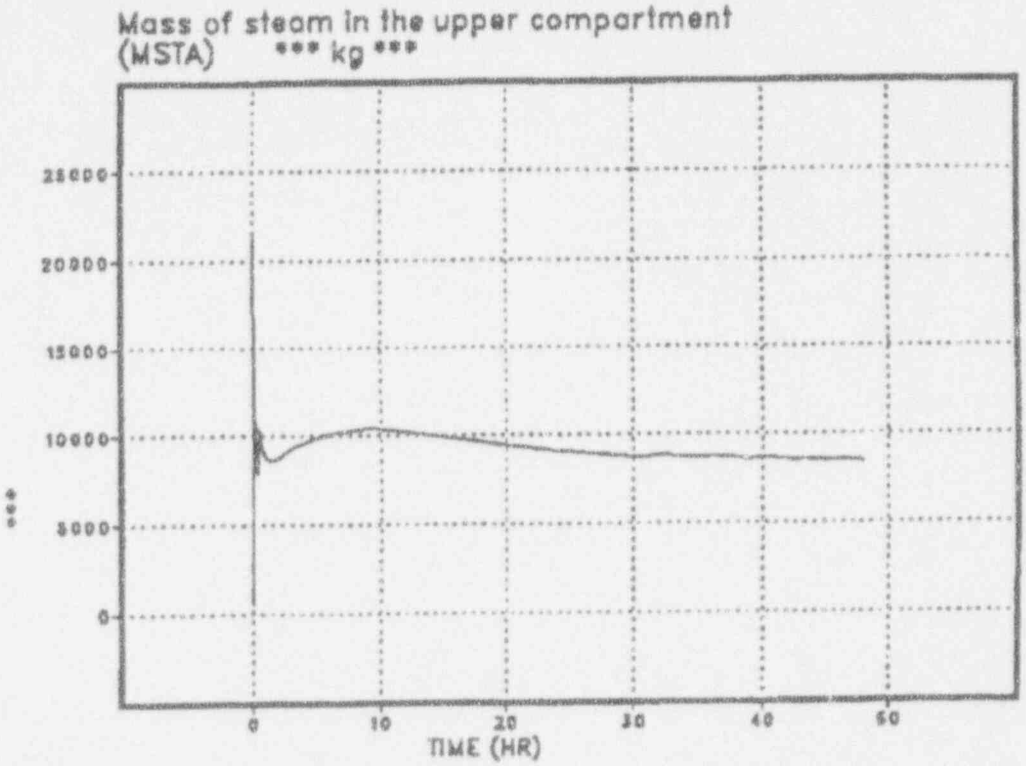


Figure 7.2-20 Large-break LOCA with one FCU & no RWST injection



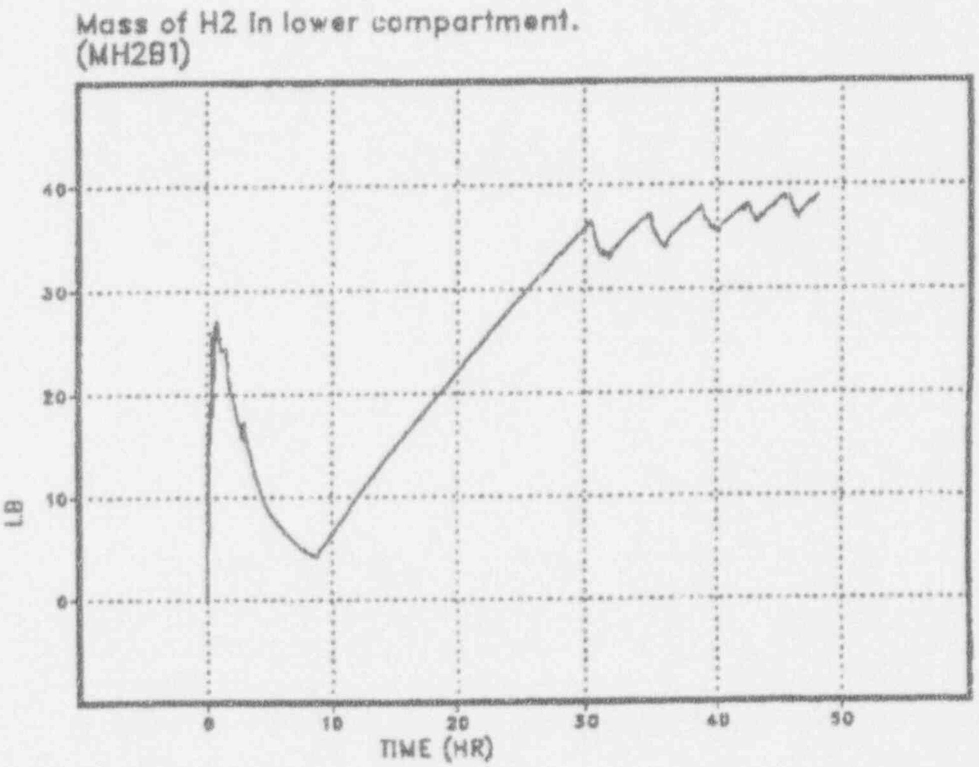


Figure 7.2-21 Large-break LOCA with one FCU & no RWST injection

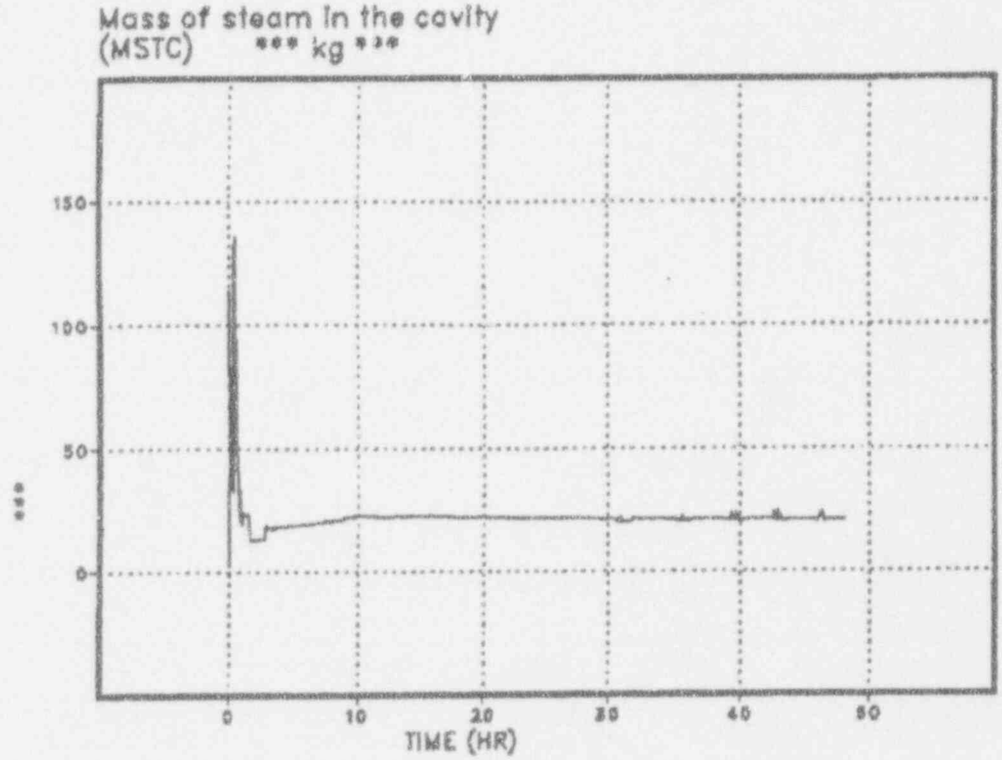


Figure 7.2-22 Large-break LOCA with one FCU & no RWST injection

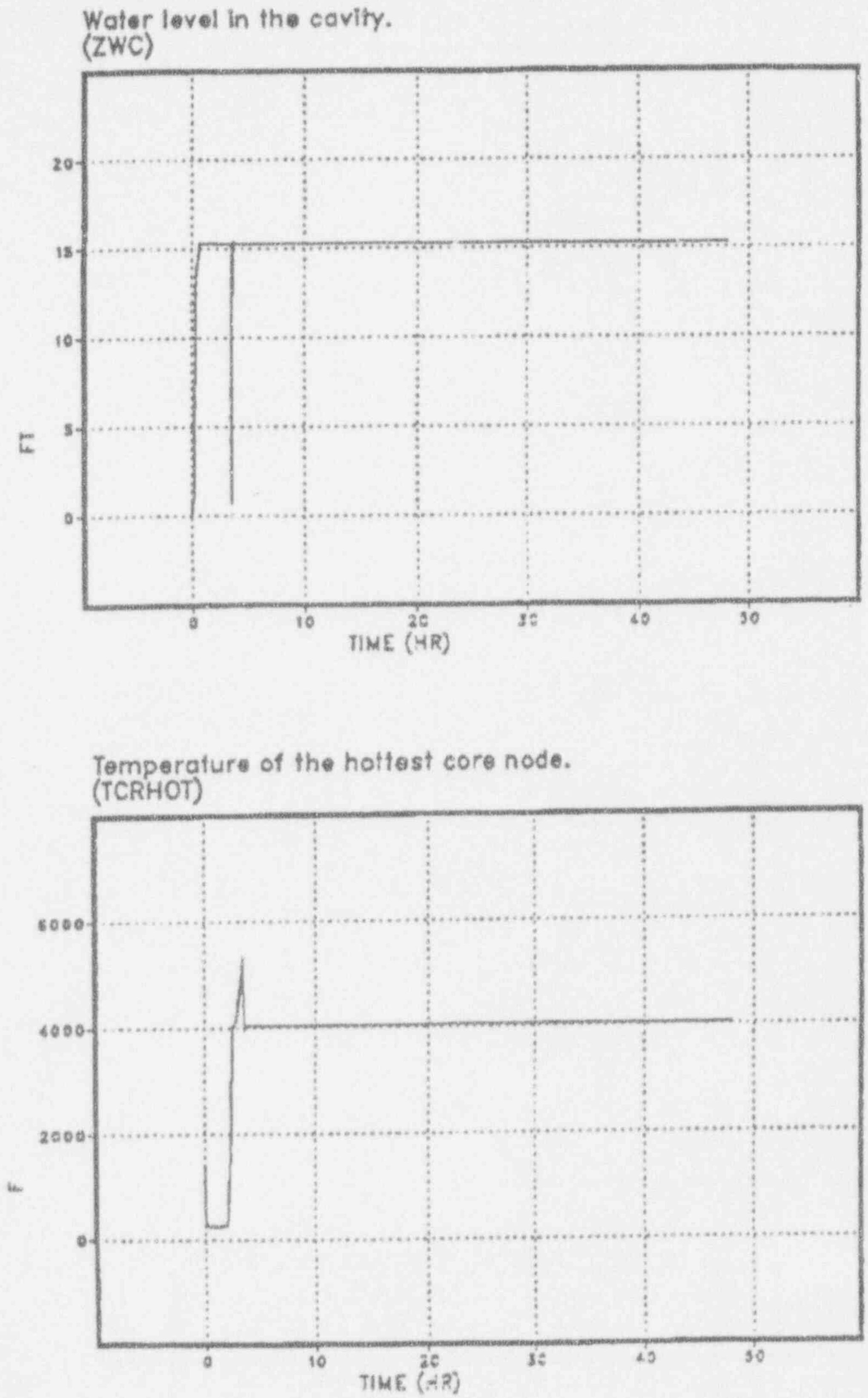
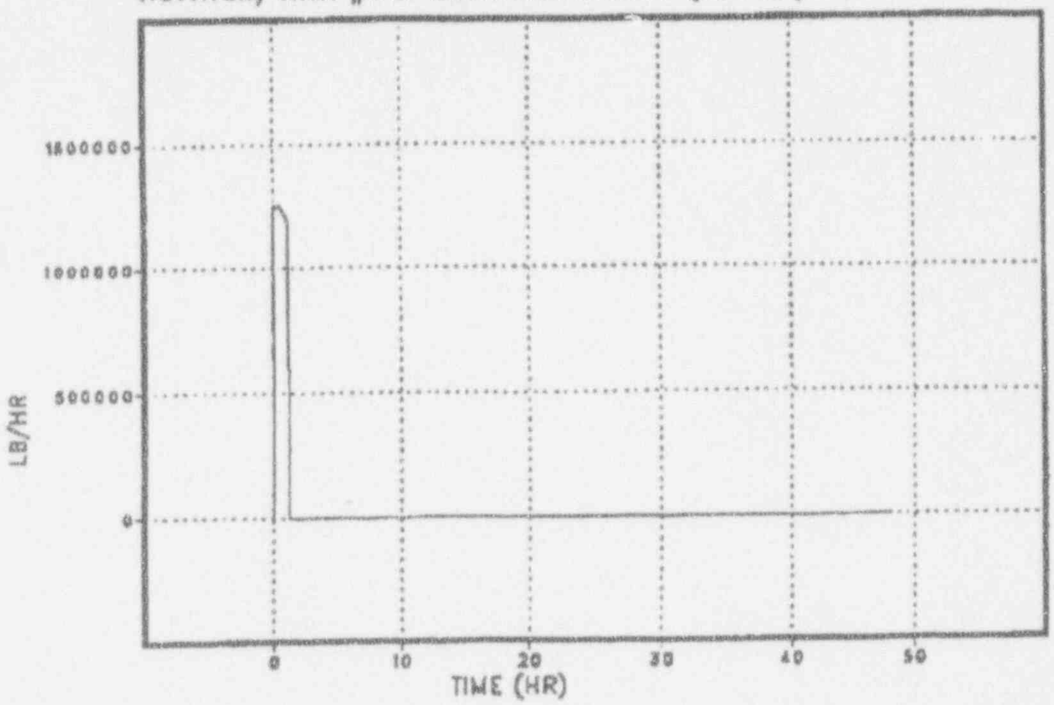


Figure 7.2-23 Large-break LOCA with RWST injection prior to vessel failure

Mass flow rate of LP1 pumps - for Prairie Island, normally RHR #1 or both RHR trains (WLPI1X)



Mass of steam in the upper compartment (MSTA) *** kg ***

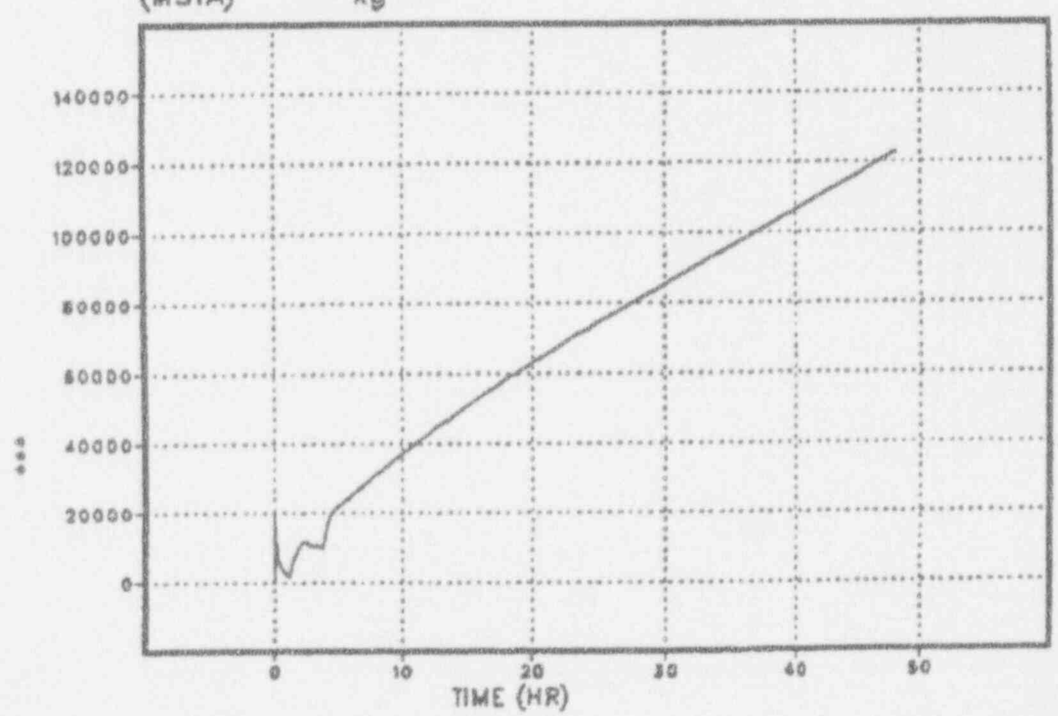
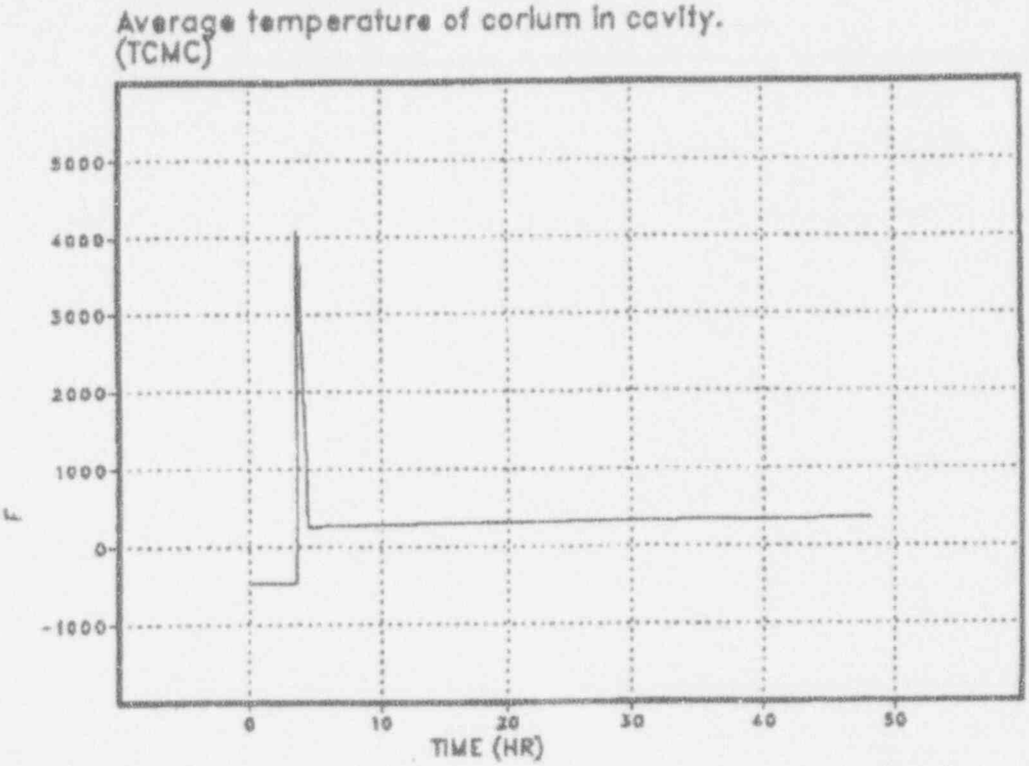


Figure 7.2-24 Large-break LOCA with RWST injection prior to vessel failure



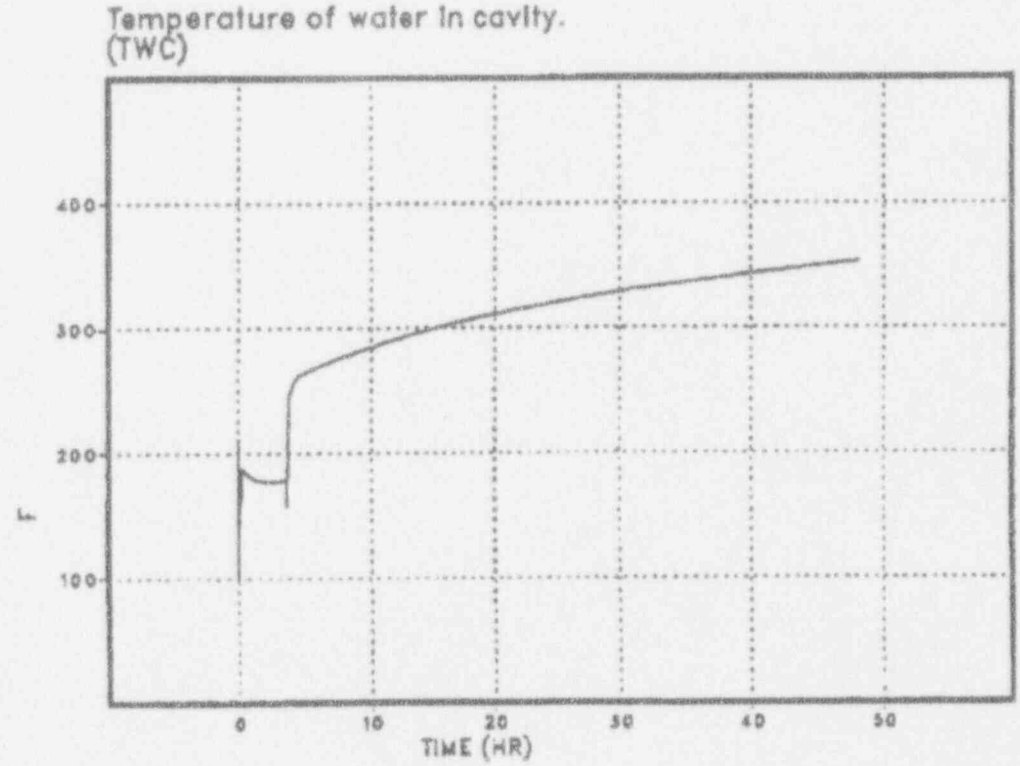


Figure 7.2-25 Large-break LOCA with RWST injection prior to vessel failure

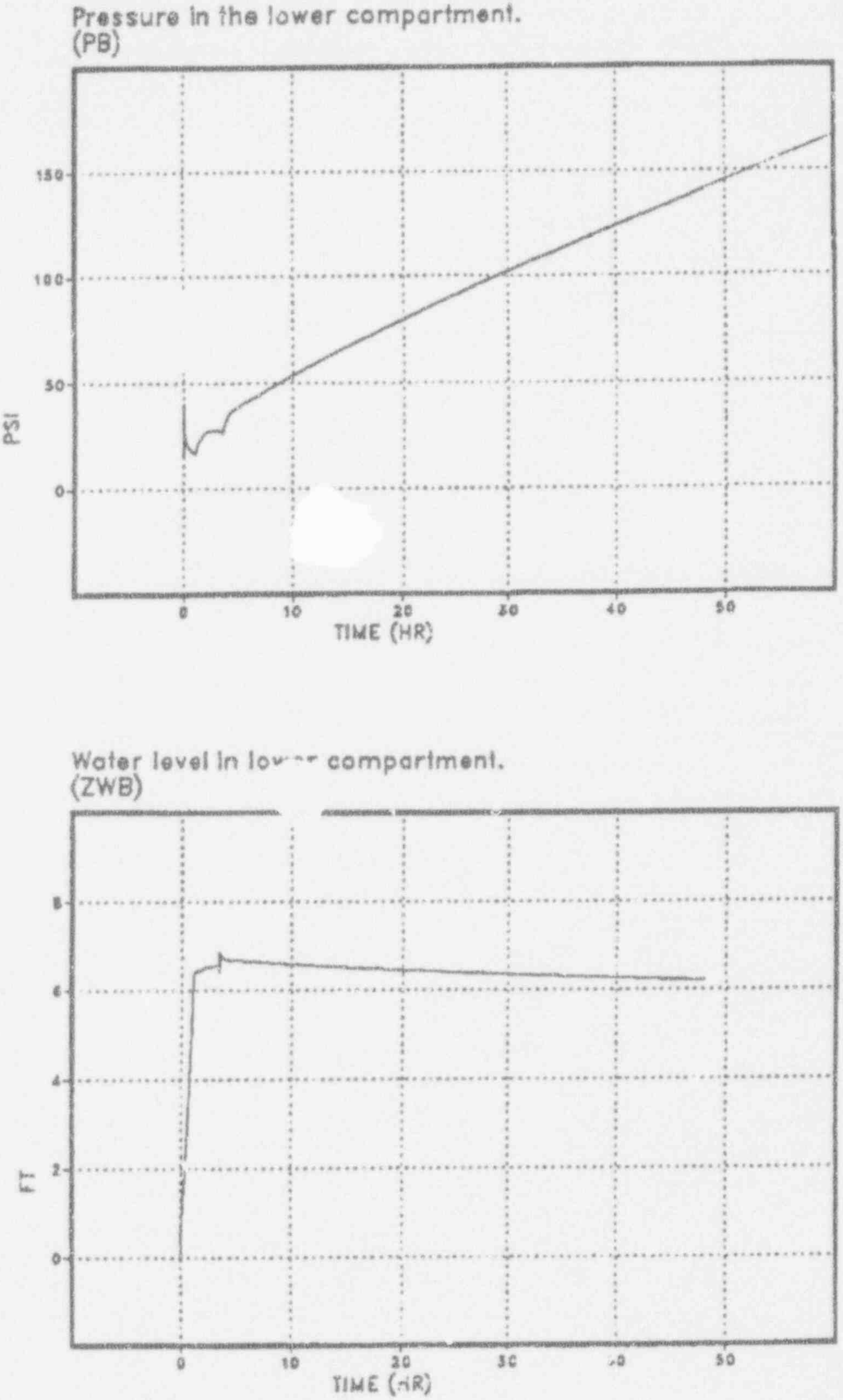
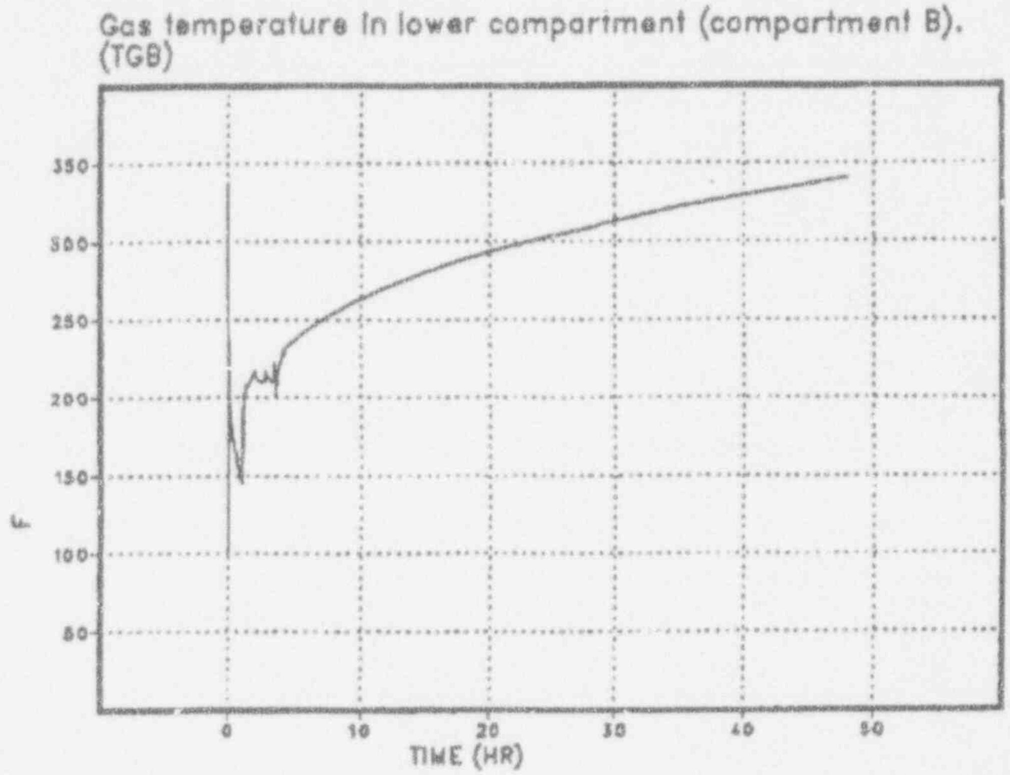


Figure 7.2-26 Large-break LOCA with RWST injection prior to vessel failure



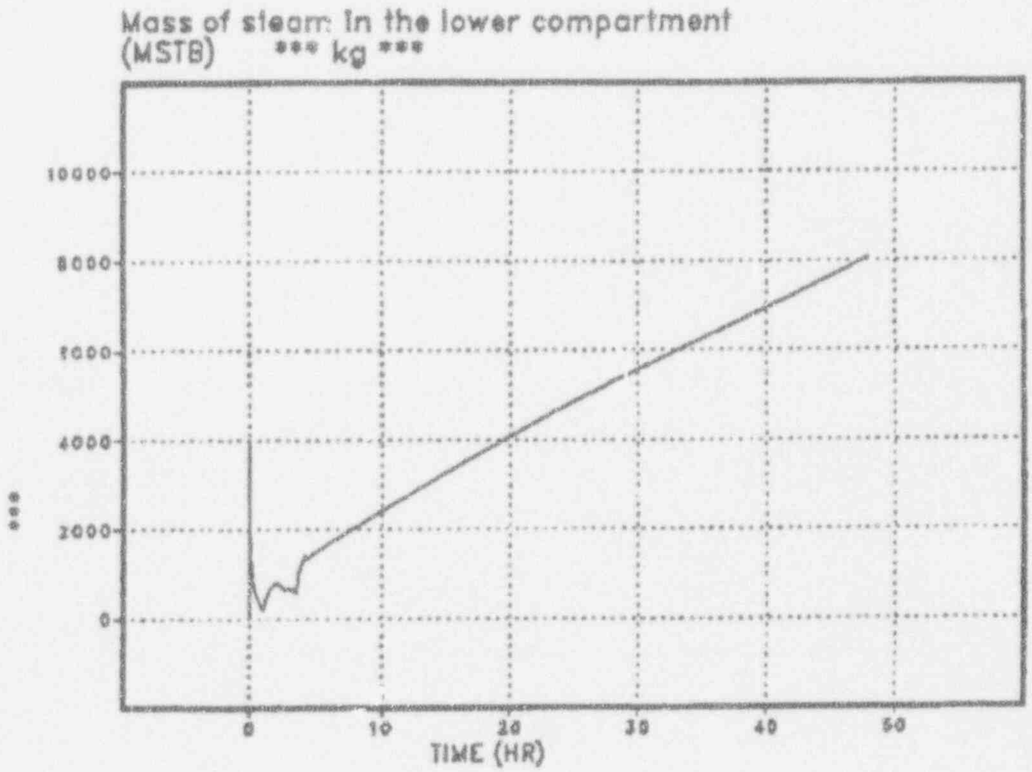


Figure 7.2-27 Large-break I OCA with RWST injection prior to vessel failure

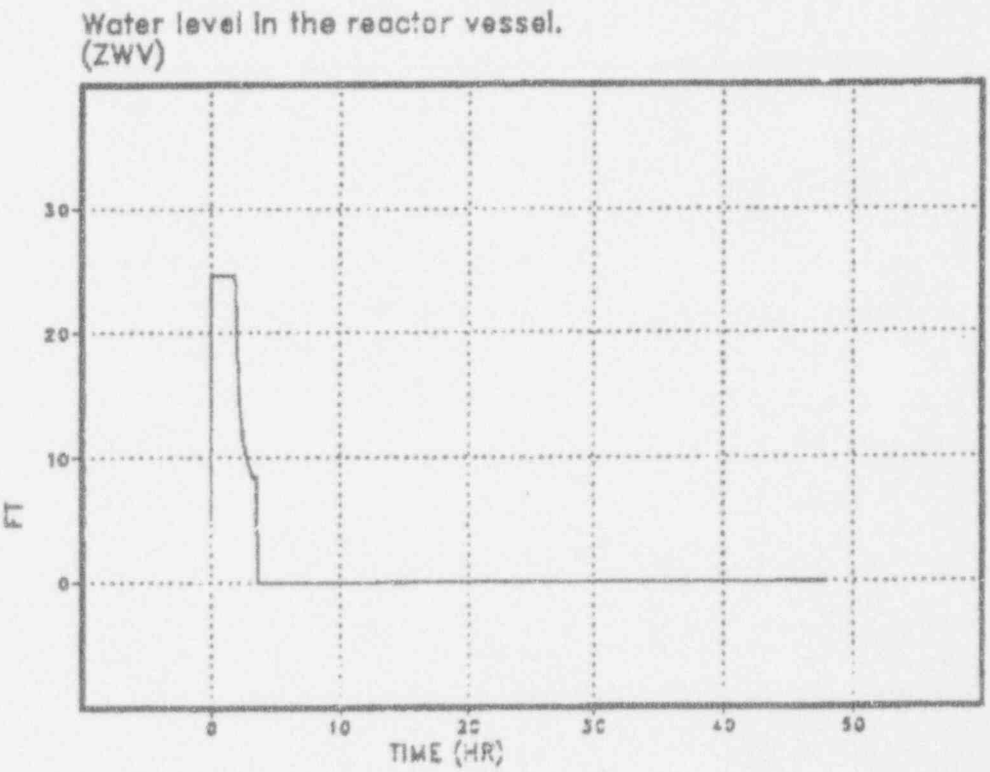


Figure 7.2-28 Large-break LOCA with RWST injection prior to vessel failure